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CALIBRATION OF THE SECOND GENERATION MODEL

Karen Fisher-Vanden
Richard Baron
Jae Edmonds
Hugh Pitcher
Ronald D. Sands
Marshall Wise

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Pacific Northwest National Laboratory

Washington DC

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CALIBRATION OF THE SECOND GENERATION MODEL

Methods and tools used to calibrate specific computable general equilibrium models (CGEMs) have been extensively documented in recent years (e.g. Mansur and Whalley (1984), and Ballard et al. (1985)). Many embodiments of CGEMs have sufficiently similar properties that relatively standard techniques can be employed to implement them. When model design departs substantially from the norm, existing methods must be extended and new methods developed.

The second generation model (SGM) is a CGEM which was designed specifically to address issues associated with global change. As a consequence, the model embodies characters which are novel and interesting. A theoretical description of the model is contained in Edmonds et al (1993). Because the model must be capable of addressing major issues associated with both the emission of radiatively important gases and the potential consequences of atmosphere/-climate change, the model was designed to perform three tasks:

1. Provides estimates of environmentally important emissions associated with human activities,

2. Provides estimates of the consequences of global environmental change, with particular emphasis on human activities, and

3. Provides estimates of the economic consequences of actions to mitigate and adapt to global environmental change.

Further, the nature of the global change problem dictates that the SGM reflect the following characteristics:

1. The issue is **global**, emissions from all sources in all regions of the world determine total atmospheric change,

2. Anticipated changes in the greenhouse effect result from the emission of a **number of gases** including: CO_2, CH_4, CO, N2O, NO_x, SO_2, VOCs, CFCs, and CFC substitutes,

3. **Many human activities** are involved in both emissions and impacts including: Agriculture and Forestry, Energy Production and Consumption, Transportation, Manufacture, Services, Coastal Zone Settlement, Health Care, Water Use, and Land Use,

4. Emissions and impacts depend upon multiple **resources and technologies** including: Managed and Unmanaged Ecosystems, Capital Stocks, and Labor,

5. Emissions and impacts also depend on **international trade patterns**, and possibly, migration patterns,

6. Factors 3, 4, and 5 depend upon **institutional arrangements**,

7. Policy analysis requires both mid-term (5-year) and long-term (100 year) **time horizons**.

As a consequence, the SGM differs from other CGEMs in that it includes:

1. an energy/agriculture focus;
2. a putty-clay vintaged representation of capital;
3. land as a factor of production;
4. depletable natural resources;
5. competition among technologies; and
6. sector- and subsector-level investment decisions.

This paper provides a complete description of how the SGM was calibrated including the methods and tools from existing literature which were applied and the calibration methods which were developed to handle the unique features of the SGM. In addition, the important underlying assumptions and procedures used to produce a data set consistent with the general theoretic principles of the SGM are presented.

I. CALIBRATION VS. MACROECONOMIC PRACTICE

An essential step in applying general equilibrium analysis is the construction of a benchmark data set for the base year of simulation. Contrary to standard macroeconomic models, which are estimated econometrically from time-series data, parameters for most computable general equilibrium models (CGEMs) are not estimated with econometric techniques[1]. From a practical standpoint, this can easily be explained by the number of parameters involved. More importantly, however, is the absence of input-output time series data with satisfactory levels of disaggregation which makes econometric estimations of some model parameters virtually impossible. Although Chipman [1991] demonstrates that the number of observations does not have to be greater than the number of parameters to be estimated in a CGEM, the number of parameters requiring estimation within the SGM is too large for econometric estimation to be a feasible option. This is largely due to the SGM's requirement of 6-digit input-output tables to describe the economy in appropriate detail when, as is the case with the U.S., such data requirements are only published every 5 years[2]. In addition to the problems of data availability, parameters estimated econometrically over 5, 10, or 20 years can be questionable when used for long-term projections[3]. As a result of these data constraints, the method of calibration, described as the process of choosing model parameters to exactly reproduce observations in a given base year, is widely used by developers of CGEMs.

As with econometric estimation, calibration also has its limitations. The method of calibration not only assumes that benchmark year data reflect an economy in equilibrium, it also assumes that the benchmark equilibrium is representative of a "normal" growth path. Input-output tables and national accounts are well suited for use in general equilibrium analysis since they reflect an economy where supply equals demand (including trade). Budget constraints for the government and household sectors, however, are not explicitly reflected in input-output tables, thus requiring some work to reconcile input-output observations with these constraints.

[1] The Jorgenson/Wilcoxen [1990] model is an exception to this rule.
[2] Chipman [1991] shows that to econometrically estimate a linear approximation of a CGEM with 10,000 parameters, a minimum of 8 years of quarterly observations (25 observations) are required.
[3] Reliability, however, can be enhanced with the use of elasticities given by the literature and a comprehensive sensitivity analysis.

II. DATA REQUIREMENTS

The objective of calibration, as previously mentioned, is to choose model parameters so as to exactly reproduce data observations in the chosen base year. Essentially, the calibration process consists of translating available data into a problem-oriented data set which is used not only to reproduce observations in the benchmark years, but also to make long-term projections. A set of appropriate input-output tables (e.g., the 6-digit level 1982 benchmark tables for the US, published by the US Department of Commerce), and the national accounts are the basis for the calibration of the SGM. Other data sources include: 1) time series data on gross capital stocks and discards for each major industry and service, 2) energy data, and 3) input-output tables and national accounts for 1985, the actual benchmark year of the model. Key-parameters, such as elasticities of substitution in production, and income and price elasticities of final demand sectors, were obtained from existing literature.

II.a. Intermediate Production

In order to acquire the model parameters necessary to estimate intermediate production by SGM industry, data are required on the use of factors by industry, and input-output transactions. The "use" and "make" tables of the input-output accounts published by the Bureau of Economic Analysis (Department of Commerce, BEA 1982) provide the necessary data on factor requirements, value-added, and final demand to develop most of these model parameters. The "use" table provides the value of (1) each industry's consumption of commodities as factors of production, (2) each industry's value-added components (i.e., labor expenditures, indirect business taxes, and other value-added components), and (3) final demands for commodities.

Each column in the interindustry portion of the "use" table describes production within a specific industry while the row values pertain to the amount consumed of each commodity as input to the industry's production process. Therefore, the "use" table dimensions of commodity-by-industry. Because of joint production (i.e., multiple commodities produced in a single industry), output by industry is different than output by commodity; hence, row sums do not equal column sums in the "use" table. This presents a problem when using these data to calibrate production functions within a CGE modeling framework where single commodity production is assumed.

In order to produce an "use" table where row sums equal column sums, the construction of a commodity-by-commodity or industry-by-industry "use" table is required. A commodity-by-commodity table was constructed for the SGM since the units of output pertain to actual commodity units and not to a mix of commodities as is the case with an industry-by-industry table. This commodity-by-commodity table was constructed by combining data from the "use" table with data from the "make" table. The "make" table provides a distribution of commodity production across industries. Each row in the "make" table pertains to a single industry and gives the amount produced of each commodity within that industry. Thus, the dimensions of the "make" table are industry-by-commodity. By normalizing this "make" table and post-multiplying it with the "use" table (i.e., "use" table X normalized "make" table), a commodity-by-commodity "use" table is obtained.

Before the "use" and "make" tables can be combined, however, translation of the more disaggregate BEA industry categories to SGM categories is required. The BEA publishes two types of input-output accounts; the "benchmark" I-O accounts and the annual I-O accounts. The benchmark I-O accounts are published for economic census years and therefore include more detailed data than are available on an annual basis. Annual I-O accounts, although published more frequently, include 85 industry categories while the benchmark I-O accounts include 500 industry categories. Although the base year of the SGM is 1985, data from the 1985 annual I-O accounts are not used directly to calibrate the SGM; rather these data are used to project observations of the 1982 benchmark I-O accounts to 1985 levels. This is due to the energy sector detail required in the SGM which is only available in benchmark years.

Table 1 provides a mapping of BEA's 1982 benchmark I-O industry categories to SGM categories. Although most SGM categories are aggregations of BEA categories, a few SGM categories are actually portions of more aggregate BEA categories. In particular, the SGM Crude Oil Extraction and Natural Gas Extraction categories were created by separating the two from the more aggregate BEA category, Crude Oil and Natural Gas Extraction. To separate the two industries, it was assumed that (1) all crude oil and natural gas demand from the Oil Refining industry is actually only crude oil, and (2) all crude oil and natural gas demand from the Gas Transmission and Distribution industry is actually natural gas.

The SGM industry "Uranium Mining and Processing" also required some manipulation of the I-O accounts data. Through discussions with BEA staff, values of uranium mining and uranium processing were determined and extracted from the more aggregate BEA categories of "Nonferrous Metal Ores Mining" and "Industrial Inorganic Chemicals n.e.c".

Table 1

SGM Industry Category	BEA Category	Standard Industrial Classification	BEA Classification
Agriculture	Agriculture, Forestry and Fishing; Food and Kindred Products	01 - 09,20	01 - 04,14
Crude Oil Extraction	Crude Petroleum & Natural Gas*	13	08
Natural Gas Extraction	Crude Petroleum & Natural Gas*	13	08
Coal Mining	Coal Mining	12	07
Uranium Mining and Processing	Nonferrous Metal Ores Mining, except Copper*	1094	0602

	Industrial Inorganic Chemicals n.e.c*	2819	270104
Electricity Generation, Transmission & Distribution	Private Electric Services (Utilities)	4911	6801
	Federal Electric Utilities		7802
	State & Local Electric Utilities		7902
Oil Refining	Petroleum Refining	2911	310101
	Products of Petroleum & Coal n.e.c.	2999	310103
Gas Transmission & Distribution (utilities)	Private Gas Production	492	6802
Other Products	All other industries		

* Part of this industry category.

Upon completion of the commodity-by-commodity (CXC) "use" table, values are adjusted to 1985 levels by using data obtained from the 1985 input-output accounts. Industry output and intermediate consumption totals in 1985 for each of the SGM commodities are estimated using the 1985 I-O data. Using these totals, CXC table values are then adjusted using the RAS (row and column sum) adjustment procedure developed by Michael Bacharach [1971][4]. Other adjustments to the CXC table include industry-specific data reconciliation; for example, splitting crude oil from natural gas and ensuring that uranium is only consumed by the electric generation and defense industries.

II.b. Industry Value Added

Once completed, this CXC table provides the necessary information on the use of produced commodities in the production of other commodities which will be used in the computation of each industry's production function coefficients. Before these coefficients can be estimated, however, information on the use of non-produced factors of production (i.e., land and labor) is required. Each industry's land and labor expenditures are included in the value added portion of the I-O accounts. For benchmark years (e.g., 1982), the value added portion of the I-O accounts included the following components: (1) "compensation of employees" (labor expenditures), (2) "indirect business taxes" (e.g., sales taxes, excise taxes, property taxes, import taxes (duties)), (3)

[4] This procedure adjusts the values within the matrix so that the row and column sums equal the 1985 estimated totals.

"other value added" (e.g., profits, land rents). In order to obtain information on land and labor expenditures in the form required by the SGM, some adjustments to the data provided in the I-O accounts are necessary.

Land

In the I-O accounts, the real estate industry includes rents for buildings but not for land. Land rents paid by each industry is included in the "other value added" component of value added in the I-O accounts. A separate land component is imperative for the SGM to study the effects of greenhouse gas emissions on land use; particularly for the Agriculture sector. The land component for each SGM industry was separated from the "other value added" component by estimating each industry's expenditures on land. Land rents by SGM industry were estimated by applying an average cost of agricultural land (based on data obtained from the U.S. Department of Agriculture) to land use data from the "Statistical Abstract of the U.S." published by the Department of Commerce[5]. These estimates of land rents for each SGM industry are added as a separate component to each industry's value added and accounted for by subtracting an equal value from the "other value added" component of value added.

Labor

Industry labor expenditures are given in the "use" table of the I-O accounts as a component of value added called "compensation of employees". These data are aggregated to SGM industries at the same time as intermediate production. The only adjustment to the industry labor component is the extraction of labor used for government services from the "Other Products" industry sector. Prior to SGM industry aggregation, the industrial production component of the I-O accounts includes a "Government Industry" which contains labor as its only input to production. (This industry was added to the "Other Products" industry during SGM industry aggregation). Since the calibration of the government services' utility function (discussed in Section III.d. below) is conducted separately from industrial production, government labor expenditures need to be included with other government expenditures in the final demand portion of the I-O accounts. Therefore, government services labor expenditures are extracted from the "Other Products" sector and added as another component of the government's final demand.

Corporate Retained Earnings

Included in the total amount of savings available for investment is corporate retained earnings; the amount of corporate profits retained for investment purposes. The SGM estimates the corporate retained earnings rate (the percentage of corporate profits retained) for each sector as follows:

$$RE_i = \alpha_i \left(1 - e^{r \cdot \beta_i}\right) \qquad (1)$$

where

[5] An average agricultural land rental price was used on the assumption that (1) agricultural land makes up the majority of total usable land area and (2) the differential from urban land prices will be reflected in the constant term of the production function.

RE_i = corporate retained earnings rate of sector i;
α_i = the maximum potential retained earnings rate;
r = the real market interest rate; and
β_i = the retained earnings sensitivity to the real interest rate.

Although separate retained earnings rates are defined for each sector, an average retained earnings rate over all sectors was applied to each. To calibrate equation (1) to the 1985 base year it is necessary to first calculate an actual retained earnings rate over all sectors for 1985 by dividing 1985 total corporate retained earnings by 1985 total corporate profits obtained from the "Economic Report of the President, 1992". Next, the maximum potential retained earnings rate was estimated from historical data to be 0.60 (i.e., the percentage of corporate profits retained would never expect to be higher than 60%). Last, assuming a real market interest rate of 3%, the sensitivity parameter (bi) can be directly calculated from equation (1).

II.c. Capital Inputs

In addition to the factor inputs described in the I-O accounts, data on the underlying capital stock used in production are also required to compute each industry's production function coefficients. The SGM requires productive capital stock of each industry to be divided into "vintages" corresponding to the 5-year period in which the capital was initially purchased. "Vintaged" capital stock allows for improvements in production efficiency (e.g., as a result of technological change) within an industry. The SGM also assumes capital to be a fixed factor of production and to be completely productive until its average lifetime is reached[6]. The SGM assumes that at any period of time, an industry produces using capital stock from the number of vintages equal to the average lifetime of capital in that industry divided by 5 (length of a SGM time step (period)). For example, in period 1 (which includes the years 1986 to 1990) an industry with an average capital lifetime of 20 years would have four vintages of capital stock: (1) capital stock purchased during the period 1971-1975, (2) capital stock purchased during the period 1976-1980, (3) capital stock purchased during the period 1981-1985, and (4) capital stock purchased in the current period 1986-1990. Each of these capital stocks would be used to produce output in period 1.

Annual equipment and structures capital stock data were obtained from the "Fixed Reproducible Tangible Wealth in the United States" published by the BEA and are consistent with the national income and product accounts (NIPA). These data include annual values by BEA industry category for gross capital stock, capital inputs, net capital stock, depreciation, and discards. As with the I-O tables, these data require conversion from BEA industries to SGM industries.

To calculate capital stock by vintage for each SGM industry, it is necessary to first calculate annual investment by industry as the difference between the industry's current year's gross capital stock and last year's gross capital stock plus the current year's discards. Capital stock by vintage is calculated by taking the sum of investment over the vintage's corresponding 5-year period and subtracting the "vintage" discards which are calculated on the basis of lifetimes of equipment and structures, and annual investment numbers[7].

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6 This differs from typical accounting methods in which capital is depreciated over time.

7 Note: Since the BEA capital stock data includes actual discards which do not always occur at the exact end of the capital's lifetime (some capital could have been discarded before or after the capital's average

As discussed previously, the production function for each industry is the sum of separate CES production functions for each vintage. For example, an industry with an average capital lifetime of 20 years would have the following production function in Period 0:

$$Q_{0,s} = q_{0,s} + q_{-1,s} + q_{-2,s} + q_{-3,s} \quad (2)$$

where

$Q_{0,s}$ = total production of commodity s in period 0; and
$q_{v,s}$ = output of commodity s produced with vintage v capital stock (based on a CES production function).

This specification allows for improvements in productivity (e.g., technological change) over time. This improvement in productivity is based on the Hicks-neutral technological change rate which consists of a percentage rate of change in production efficiency incorporated into the scale factor (a0) of each vintage's CES production function. Table 2 presents the average capital lifetimes and the historical rate of Hick's-neutral technological change assumption for each SGM sector. These rates were calculated based on historical data on the use of factor inputs in production, and are applied only to historical vintages in the SGM (i.e., vintages prior to period 0). Future productivity growth assumptions were determined separately and are documented in Fisher-Vanden, et. al. [1993].

Table 2

SGM Industry Category	Average Capital Lifetime (in years)	Rate of Hick's-neutral Technological Change (in %)*	Elasticity of Substitution in Production
Agriculture	20	0	0.4
Crude Oil Extraction	15	1.5	0.5
Natural Gas Extraction	15	1.5	0.5
Coal Mining	15	2.5	0.5
Uranium Mining and Processing	15	1.0	0.5

lifetime), adjustments to the capital stock data are needed to reflect the SGM assumption that discards occur at the time the capital's lifetime has been reached. This is done by summing annual investment values (the difference between the current year's gross capital stock and last year's gross capital stock plus the current year's annual discards value given by the BEA) over the 5-year vintage period and adding a "vintage" discards value which is calculated based on the SGM capital retirement assumption. By calculating vintage capital stock this way, the only discards taken into account are those based on the SGM assumption; BEA discards are not included. Since capital stock values include equipment and structures, "vintage" discards in these benchmark data will only exist in cases where either an industry's equipment or structure lifetime is less that the average lifetime for both equipment and structures. This is done only for benchmarking purposes only, and once in the SGM, equipment and structures are combined and retired at the average lifetime of both.

Electricity Generation, Transmission, and Distribution	35**	1.0	0.2
Oil Refining	30	0.5	0.1
Gas Transmission and Distribution	30	0.5	0.15
Everything Else	20	0.5	0.5

* Applied to vintages prior to period 0.
** Except for hydroelectric power plants (65 years).

II.d. Subsectors

In order to fully understand the effects of certain economic activities on potential greenhouse gas emissions and to adequately address the consequences of certain policy actions to reduce greenhouse gas emissions on these activities, some further disaggregation of SGM industries is necessary. In this version of the SGM, the following disaggregation of particular SGM industries was done: (1) the Crude Oil Extraction sector was disaggregated into three subsectors each representing a different "grade" of crude oil; (2) the Natural Gas Extraction sector was also disaggregated into three subsectors each representing a different "grade" of natural gas; and (3) the Electricity Generation sector was disaggregated into six subsectors each representing a different method of electricity generation (e.g., oil-fired electricity generation).

"Grades" of crude oil and natural gas pertain to different levels of extraction costs[8]. For example, grade 1 of crude oil has the lowest cost of extraction which could represent the process of extracting oil close to the earth's surface. Grade 3, on the other hand, would have the highest cost of extraction and could represent extraction which requires much more extensive drilling procedures. Due to the different method of extraction associated with each "grade", a different production function specification is required for each grade. Using assumptions based on the cost of extraction for each grade, the I-O accounts and capital stock data for both the Crude Oil Extraction sector and Natural Gas Extraction sector are partitioned into different grades. It is important to note that although each grade has an associated method of extraction, the output produced is assumed to be homogeneous; thus, unlike sectors within the SGM, each grade faces a common output price of either crude oil or natural gas. Therefore, the likely outcome of the model would be that more of the "cheapest" grade (i.e., the grade with the lowest cost of extraction) would be produced relative to other grades.

The Electricity Generation sector was disaggregated into the following six subsectors based on the method of generation: (1) oil-fired electricity generation; (2) natural gas-fired electricity generation; (3) coal-fired electricity generation; (4) biomass-fired electricity generation; (5) nuclear electricity generation; and (6) hydro or solar electricity generation[9]. Data on annual net electricity generation by energy source and associated costs in addition to assumptions on capital intensity were used to separate the I-O accounts and capital stock data of the Electricity

[8] In the SGM, "grades" do not refer to the quality of crude oil extracted, but rather to the cost of extraction.
[9] Capital purchased in this subsector prior to 1991 is assumed to be used in hydroelectric generation. Subsequent purchases of capital are assumed to be used in solar electricity generation. Different "vintage" production functions are used to reflect this separation.

Generation sector into these six subsectors. As with Crude Oil and Natural Gas Extraction, these data are used to create production functions for each subsector and each subsector faces a common price of output (i.e., the price of electricity).

II.e. Elasticities of Substitution in Production

The final items necessary to estimate production function parameters for each sector (or subsector) are assumptions on the elasticities of substitution among factors of production. Although in most cases elasticities of substitution for each production function were obtained from existing literature (e.g., Ballard et al [1985]), some were estimated based on the underlying assumptions of the SGM. For instance, since activities at a lower level of aggregation are being described within the electricity sector, a lower level of substitutability among factors is implied. Therefore, a quasi-Leontif production function (i.e., a CES production function with an elasticity of substitution value close to 0) was assumed for the electricity subsectors. Table 2 provides the elasticity of substitution values chosen for each sector in the SGM.

III. ESTIMATION OF MODEL PARAMETERS

III.a. Calibration of the CES Production Functions

As previously discussed, each SGM sector and subsector has associated with it a unique production function in order to reflect differences in production processes. As shown in equation (2) above, total production in each sector and subsector is the sum of vintage production (i.e., output associated with each vintage capital stock). Each vintage production is described by the following CES production function:

$$q_{v,s} = \alpha_{0,s,v} \left(\sum_{i=1}^{N-1} \alpha_{i,s} X_{i,s,v}^{\rho} + \alpha_{N,s} X_{N,s,v}^{\rho}\right)^{\frac{1}{\rho}} \qquad (v = -V_s \ldots 0) \tag{3}$$

where

$q_{v,s}$	=	output of commodity s produced with vintage v capital stock;
$\alpha_{0,s,v}$	=	scale coefficient in vintage v's production of commodity s;
$\alpha_{i,s}$	=	factor intensity of the ith input in the production of commodity s;
N-1	=	number of variable inputs (N = total number of inputs; 1 refers to the number of fixed factors (i.e., capital) in Version 0.0);
$X_{i,s,v}$	=	demand for input i in vintage v's production of commodity s;
$\alpha_{N,s}$	=	factor intensity of the capital input (input N) in the production of commodity s;
$X_{N,s,v}$	=	demand for the capital input (input N) in vintage v's production of commodity s;
ρ	=	elasticity of substitution parameter; and
$-V_s$	=	oldest vintage capital stock for industry s (equal to the negative of the average lifetime of capital for industry s divided by the length of a period (i.e., 5 years) plus 1)

As evident from equations (2) and (3), Version 0.0 of the SGM assumes that relative production function factor intensities do not differ between vintages. The difference in production between vintages is due to the overall efficiency of all inputs; not to the efficiencies (or inefficiencies) of individual inputs to production. Therefore, Version 0.0 of the SGM assumes that the factor intensity parameters of each vintage production function (within a sector or subsector) differ only by a scalar (reflected in the scale parameter ($\alpha_{0,s,v}$)). This scalar comprises the Hick's-neutral technological change parameter; a parameter which reflects the overall production efficiency of the vintage. The relative factor intensity parameters, therefore, do not differ between vintages within a sector or subsector and the scale parameters of each vintage production differ only by the rate of Hick's-neutral technological change.

As previously discussed, the following seven data items are required to estimate each sector's production function coefficients: (1) intermediate production data (based on the I-O accounts) by sector and subsector; (2) industry value-added data (also based on the I-O accounts) by sector and subsector; (3) final demand sector and subsector data; (4) capital stock data by sector and subsector and vintage; (5) assumptions on the lifetimes of each sector's capital stock; (6) assumptions on the rate of Hick's-neutral technological change; and (7) assumptions on the elasticities of substitution in production. Once these data are compiled, a method to compute CES production function coefficients is applied. This method was specially developed for the SGM in order to handle vintaged capital stock in production. The steps involved in the computation of these coefficients are as follows:

1. Except for land and labor, set all 1985 input prices[10] equal to 1. Compute the price of land and labor as follows[11]:

$$P_{land} = \frac{TE_{land}}{Total\ Land} \tag{4}$$

$$P_{labor} = \frac{TE_{labor}}{Total\ Labor} \tag{5}$$

where

TE_{land}	=	Total land expenditures in 1985 (discussed in Section 3.2.2).
TE_{labor}	=	Total labor expenditures in 1985 (based on I-O accounts).
Total Land	=	Total U.S. managed land in 1985 (in 1000 km^2).
Total Labor	=	Total U.S. employed population in 1985 (in 1000 persons).

2. Compute the output price of a commodity as,

[10] Setting an input price to 1 is interpreting the unit good as the quantity of the input which can be purchased in 1985 with 1 million 1982 dollars (since the data of the SGM are in millions of 1982 dollars).
[11] Since the price of land is obtained by dividing 1985 total land expenditures (in millions of 1982 dollars) by total managed land (in 1000 km2), the price of land can be interpreted as the millions of 1982 dollars required to purchase 1000 km2 of land in 1985. Similar to the interpretation of the price of land, the price of labor can be interpreted as the millions of 1982 dollars required to hire 1000 workers annually.

$$P_0 = \frac{TO - IBT}{TO} \tag{6}$$

where

P_0	=	Output price of the commodity[12] (in millions of 1982 dollars).
TO	=	Total output of the commodity (in millions of 1982 dollars).
IBT	=	Total indirect business taxes paid in 1985 associated with the production of the commodity (in millions of 1982 dollars).

3. As discussed above, relative factor intensities within a sector or subsector do not differ. Therefore, factor intensity parameters for the variable inputs can be calculated based on the assumption that total output is produced from one vintage (i.e., total production can be described by one CES production function rather than a summation of multiple CES production function (as in equation (2)). The production function factor intensity parameters for the variable inputs are computed using the following equation which is a direct result of the SGM's profit-maximizing assumption:

$$\alpha_{i,j} = \left(\frac{X_{i,j}}{X_{i,other}}\right)^{\frac{\rho}{\mu}} \frac{P_{0,j}}{P_{0,other}} \qquad i = 1 \ldots N-1 \tag{7}$$

where,

$\alpha_{i,j}$	=	factor intensity of the ith input in the production of commodity j,
$X_{i,j}$	=	total demand for the ith input in the production of commodity j,
$X_{i,other}$	=	total demand for the ith input in the production of the "other products" commodity,
$P_{0,j}$	=	output price ("price received") of commodity j,
$P_{0,other}$	=	output price ("price received") of the "other products" commodity,
ρ	=	elasticity of substitution parameter,
μ	=	$\rho / (\rho-1)$,
N-1	=	number of variable inputs.

Derivation of Equation (7)

Hotelling's Lemma states that the partial derivative of the profit function with respect to the price of the ith input results in the negative profit-maximizing total factor demand for that input; i.e.,

$$\frac{\partial \pi_s}{\partial P_{i,s}} = - X_{i,s} \tag{8}$$

where

π_s = total profit in the production of commodity s; i.e.,

[12] This price refers to the price *received* by this sector. The price *paid* is set to 1 (as mentioned in the input price discussion previously) and is the same as the input price for the commodity produced in this sector. As implied, the price received by producers of a commodity is less than the price paid by purchasers of the commodity as long as IBT is positive (i.e., taxes paid in a sector is less than subsidies received).

$$\pi_s = P_{0,s} q_s - \sum_{i=1}^{N-1} P_{i,s} X_{i,s} \tag{9}$$

where

$P_{0,s}$	=	output price (price received) of commodity s,
$P_{i,s}$	=	input price (price paid) of the ith commodity in the production of commodity s,
$X_{i,s}$	=	total demand of the ith input in the production of commodity s,
q_s	=	total output of commodity s,
N	=	number of inputs to production,
N-1	=	number of variable inputs to production (since there is only one fixed factor (capital)).

Evaluating equation (8) using equation (9) and the "single vintage" CES production function defined as,

$$q_s = \alpha_{0,s}\left(\sum_{j=1}^{N-1} \alpha_{i,s} X_{i,s}^{\rho} + \alpha_{N,s} X_{N,s}^{\rho}\right)^{1/\rho} \tag{10}$$

the demand for the ith factor input to the production process can be directly calculated as,

$$X_{i,s} = \left(\alpha_{0,s} P_{0,s} \frac{\alpha_{i,s}}{P_{i,s}}\right)^{\frac{\mu}{\rho}} \left(\frac{Y}{Z}\right)^{\frac{1}{\rho}} \qquad i = 1 \ldots N-1 \tag{11}$$

where, assuming capital is the only fixed factor,

$$Y = \alpha_{N,s} X_{N,s}^{\rho} \tag{12}$$

and

$$Z = 1 - (\alpha_{0,s} P_{0,s})^{\mu} \left(\sum_{i=1}^{N-1} \alpha_{i,s}^{(\mu/\rho)} P_{i,s}^{-\mu}\right) \tag{13}$$

Equation (7) is the result of normalizing Xi,s in equation (11) by dividing by the factor input demand equation for the "Other Products" sector. Note: the aother,s parameter is assumed to be equal to 1 in order to obtain the $\alpha_{i,s}$ parameters in relative terms.

4. As discussed in Step 3, the vintage capital structure of the SGM does not affect the calculation of factor intensity parameters for variable inputs. This vintage capital structure, as designed in Version 0.0 of the SGM, allows for overall efficiency gains in the production process. These overall efficiency gains are incorporated into the scale factor for each vintage, defined as,

$$\alpha_{o,s,v} = \beta_{o,s} * (1+g_s)^{5*v} \tag{14}$$

where

$\alpha_{o,s,v}$ = scale factor in vintage v's production of commodity s;
$\beta_{o,s}$ = overall scale factor in the production of commodity s (constant between vintages);
g_s = Hick's-neutral techological change rate in the production of commodity s;
v = vintage (e.g., v = -3...0 for a sector or subsector whose capital lifetime equals 20 years).

In addition to the calculation of the scale parameter ($\alpha_{o,s,v}$), "vintaging" also affects the calculation of the capital intensity parameter ($\alpha_{N,s}$). As previously discussed, total output in a sector or subsector is described as the summation of vintage production (equations (2) and (3) above). Capital is entered into the production process as separate vintage capital stock; not as a total annualized cost as with the variable inputs to production. Although the capital intensity parameter does not differ between vintages (similar to the variable inputs), due to the vintage capital structure of the SGM, the capital intensity parameter cannot be calculated similar to the variable inputs.

From equation (14), the vintage scale parameter ($\alpha_{0,s,v}$) can be determined given the Hick's-neutral technological change rate and the overall scale factor ($\beta_{o,s}$). Therefore, upon completion of Steps 1 through 3, two parameters still need to be estimated--the overall scale factor ($\beta_{o,s}$) and the capital intensity parameter ($\alpha_{N,s}$). Due to the vintage structure of the production process, these parameters cannot be directly determined; therefore, an iterative process must be applied to solve for $\beta_{0,s}$ and $\alpha_{N,s}$.

The steps involved in this iterative process are as follows:

(1) Choose an initial value for $\beta_{o,s}$.
(2) For each variable factor input, compute $X_{i,s}$ as the total expenditure for the ith input factor in the production of commodity s (value from the IO table) divided by the factor input price ("price paid")[13].
(3) For each variable factor input, calculate $\alpha_{i,s}$ using equation (7).
(4) Solve for $\alpha_{N,s}$ using equation (2) with equation (3); the variables determined in Steps (1) through (3); and assumptions on the elasticity of substitution parameter.
(5) Compute the difference between the actual and estimated input demand for the "other products" commodity in the production of commodity s. The estimated input demand for the "other products" commodity in the production of commodity s is defined as,

$$X_{other,s} = \sum_{v=-V_s}^{0} X_{other,s,v} \tag{15}$$

where

$X_{other,s}$ = estimated input demand for the "other products" commodity in the production of commodity s;

[13] Except for land and labor, input price (price paid) should be equal to 1 in the benchmark year (as previously explained).

$-V_s$ = oldest vintage capital stock for industry s (equal to the negative of the average lifetime of capital for industry s divided by the length of a period (i.e., 5 years) plus 1); and

$X_{other,s,v}$ = estimated input demand for the "other products" commodity in vintage v's production of commodity s defined as,

$$X_{other,s,v} = (\alpha_{0,s,v} P_{0,s} \frac{\alpha_{other,s}}{P_{other,s}})^{\frac{\mu}{\rho}} (\frac{Y}{Z})^{\frac{1}{\rho}} \tag{16}$$

where

$$Y = \alpha_{N,s} X^{\rho}_{N,s,v} \tag{17}$$

and

$$Z = 1 - (\alpha_{0,s} P_{0,s})^{\mu} (\sum_{j=1}^{N-1} \alpha^{\mu/\rho}_{other,s} P^{-\mu}_{other,s}) \tag{18}$$

(6) If the difference computed in Step (5) is sufficiently close to zero (less than a specified convergence criterion), a solution is obtained; otherwise, a search procedure is applied to adjust $\beta_{0,s}$ and Steps (1) through (5) are repeated until a solution is reached.
(7) Once a solution has been found, the factor intensity parameters for each sector are normalized to sum to 100 in order to compare relative intensities between sectors. In addition, estimated production levels and profit rates are verified with actual data from the IO table.
(8) Steps (1) - (7) are repeated for each SGM sector and subsector.

III.b. Computation of Reserves

Upon completion of the CES production function calibration, reserves of depletable resources by vintage for the base year (period 0) are calculated based on estimated levels of production in the depletable resource sectors. Actual total reserves produced in the base year (1985) is available from existing sources, but due to the vintage production structure of the SGM, reserves produced by each vintage need to be estimated. The ratio of actual energy extracted to actual levels of production was used to obtain estimated energy extracted (reserves) from estimated levels of production. The following equation was used to determine vintage reserves of depletable resources produced by each vintage in period 0:

$$Reserves_{j,v} = Q_{j,v}(L_j + 5 * v)\frac{PRDEN_j}{PRD_j} \qquad v = 0...-3 \tag{19}$$

where

$Reserves_{j,v}$[14] = reserves (in exajoules) of depletable resource j produced by vintage v;
$Q_{j,v}$ = output (in $) of depletable resource sector j produced from vintage v;

[14] Vintage 0 reserves pertain to the amount of resources which will be transferred to reserves in period 0.

L_j = lifetime of capital stock in sector j;
$PRDEN_j$ = total depletable resource extracted of commodity j (exajoules) in period 0[15];
PRD_j = actual total production of commodity j (in \$ - from IO tables).

III.c. Calibration of the Investment Function

Annual aggregate investment levels in each sector of the SGM is represented by the following functional relationship which is essentially an accelerator from the previous period's total investment levels:

$$I_{t,s} = \alpha_0 I_{t-1,s}(baserate_t)^{\alpha_1} f(\exp(\pi_{t,s}))^{\alpha_2} \tag{20}$$

where

$I_{t,s}$ = annual level of investment in sector s at time t;
$I_{t+1,s}$ = annual level of investment in sector s at time t+1;
$baserate_t$ = underlying growth in the economy affecting investment;
$f(\exp(\pi_{t,s}))$ = a function of the expected profit rate;
a_0 = scale coefficient; and
a_1, a_2 = sensitivity parameters.

In version 0.0 of the SGM, the baserate variable is represented by the growth in potential employment (labor supply) and growth in lagged productivity; specifically,

$$baserate_t = \left(\frac{PE_t}{PE_{t-1}}\right)\left(\frac{\left(\frac{GNP}{E}\right)_{t-1}}{\left(\frac{GNP}{E}\right)_{t-2}}\right) \tag{21}$$

where

PE = potential employment (population ages 15 to 64);
GNP = gross national product;
E = total employment; and
$(GNP/E)_{t-1}$ = gnp per worker (productivity) at time t-1.

In version 0.0 of the SGM, the function of expected profit is defined as the growth in expected profit ; specifically,

$$f(\exp(\pi_{t,s})) = \frac{\exp(\pi_{t,s})}{\exp(\pi_{t-1,s})} \tag{22a}$$

where

$\exp(\pi_{t,s})$ = the expected profit rate in sector s at time t.

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[15] These data were obtained from the Annual Energy Review 1985.

The expected rate of profit can be interpreted as the present value of an average profit rate occuring at the middle of each year for the lifetime of the capital investment; specifically,

$$f(\exp(\pi_{t,s})) = \frac{1}{(1+r+w_s)^{0.5}} \sum_{i=0}^{lifetime_s-1} \frac{\pi_{t,s}}{(1+r+w_s)^i} \tag{22b}$$

where

r	= the real interest rate (assumed to be 3% in the baseyear);
w_S	= the sector-specific interest rate wedge (representing the additional interest rate risk associated with sector s);
lifetime$_S$	= sector-specific lifetime of capital investment; and
$\pi_{t,s}$	= sector-specific profit rate at time t.

Calibration to the base year

Calibrating sector level investment to the base year involves a two step process. First, in order to obtain the scale and sensitivity parameters (α_0, α_1, α_2) an aggregate investment function (described by equation (20)) was econometrically estimated on the macroeconomy level. Next, these scale and sensitivity parameters were used in each sector-specific investment equation (equation (20) for each sector) to determine sector level investment in the base year. Estimated sector-specific investment levels in period 0 were reconciled with actual investment levels by adjusting the investment wedge parameter for each sector and subsector.

Investment levels at the subsector level are determined separately from sector-level investment. For each sector without subsectors, the investment equation given in equation (20) was calibrated by using the scale and sensitivity parameters which were estimated on an economy-wide scale and adjusting each sector's interest rate wedge until its base year investment level is achieved. Sector-specific variables in the investment equation include lagged investment and the expected profit rate. The base rate variable and the scale and sensitivity parameters are identical across sectors.

In the SGM, investment is determined at the sector level; therefore, investment equations only exist for sectors and not subsectors. Within a sector, investment for each subsector is determined by allocating sector level investment using the following logit share equation:

$$Share_{t,iss} = \frac{(E\,\pi_{t,iss})^{\rho}}{\sum_{iss=1}^{nlss} (E\,\pi_{t,iss})^{\rho}} \tag{23}$$

where

Share$_{t,iss}$	= Share of total sector investment allocated to subsector iss;
$E\pi_{t,iss}$	= expected profit rate for subsector iss at time t; and
ρ	= sensitivity parameter.

In order to calibrate the investment equation for a sector with subsectors, aggregate values for the sector-specific variables (i.e., lagged investment and the expected profit rate) within the investment equation are required. Lagged investment at the sector level is obtained by aggregating subsector lagged investment.

As previously stated, once all other variables and parameters in the sector-level investment equation are determined, the sector-specific interest rate wedge was adjusted to reconcile estimated investment with actual investment. To accomplish this task for a sector with subsectors, calibration of the logit share equation was required. From the investment equation, the sector-level expected profit rate was determined directly since all other variables and parameters are known. This sector-level expected profit rate is essentially the denominator of the logit share equation raised to the sensitivity parameter. Since the share of sector investment for each subsector and the sensitivity parameter were known for the baseyear, subsector-specific investment rate wedges are calculated directly from the logit share equation.

III.d. Calibration of Final Demands

The SGM comprises three final demand sectors - government, households, and trade. These final demand sectors consume commodities produced in the nine producing sectors of the SGM and are not producers of any market commodity[16]. Input-output accounting ensures that the amount of commodities produced by the producing sectors is equal to the amount of commodities consumed by the producing and final demand sectors. Calibration of the final demand sectors is performed to ensure equilibrium by choosing final demand parameters which result in an exact replication of the final demand values provided in the baseyear input-output accounts. Details of each final demand sector's calibration process is provided below.

Government Final Demand

Commodities and primary factors of production (e.g., labor, land) are consumed by the government final demand in order to provide government services. Within the SGM, three government services comprise the government final demand sector - education, national defense, and general government which encompasses all other government services. Government expenditures must satisy the following identity:

$$TXtot \ - \ S_{gov} \ = \ TR_{gov} \ + \ \sum_{i=1}^{N} P_i X_{i,gov} \qquad (24)$$

where

TX_{tot} = total net tax revenues[17];
S_{gov} = net government savings or, for negative values, net government borrowing;
TR_{gov} = transfer payment by the government;

[16] The government final demand sector produces "government services" which are provided "free of charge" to all sectors of the economy. Therefore, although the government final demand sector produces services, it is not a producer of any market commodity as is the case with producing sectors.
[17] Subsidies are measured as negative taxes.

P_i = price paid for input i; and
$X_{i,gov}$ = government demand for input i.

Equation (24) states that government expenditures (right side of the equation) should not exceed the government's budget constraint (left side of the equation).

Net tax revenue

Net tax revenue in the SGM comprises tax revenue from the following four sources: indirect business tax; corporate income tax; social security tax; and personal income tax. The SGM interprets indirect business tax as the difference between price paid (by consumers of a commodity) and price received (by the producer of a commodity)[18]. Indirect business tax expenditures for each producing sector is provided by the input-output accounts in industry value-added. The SGM calculates indirect business tax revenue by applying an indirect business tax rate to the value of production of each commodity. The following equation is used to calculate the indirect business tax rate for each commodity

$$IBTrate_i = \frac{IBTtot_i}{TO_i - IBTtot_i} \qquad (25)$$

where

$IBTrate_i$ = indirect business tax rate for commodity i;
$IBTtot_i$ = total indirect business tax expenditures in the production of commodity i;
TO = total output of commodity i.

Combining Equations (6) and (25),

$$IBTrate_i = \frac{1}{P_0} - 1 \qquad (26)$$

Corporate income tax is a tax on corporate profits. The SGM applies an average corporate income tax rate to all producing sectors. This average corporate income tax rate was determined by solving for CITR in the following equation:

$$Total\ Corporate\ Taxes = \sum_{i=1}^{N} IBT_i + \sum_{i=1}^{N} CITR * Profit_i \qquad (27)$$

where

IBT_i = total indirect business taxes paid by sector i;
CITR = average corporate income tax rate;
$Profit_i$ = total profits of sector i ("other value added" in the I/O accounts); and
N = number of producing sectors.

[18] For all practical purposes, indirect business tax can be interpreted as a sales tax.

Total corporate tax expenditures in 1985 was obtained from the "Economic Report of the President - 1990" and, as previously mentioned, total indirect business tax expenditures and profits for each producing sector was estimated from the 1985 input-output accounts. With knowledge of these data, an average corporate income tax rate can be determined directly from equation (27).

Social security tax is a tax on labor of which half is paid by employers as a tax on labor expenditures while the other half is paid by employees as a tax on earnings. For employers, the social security tax rate was determined using the following equation:

$$SSTR_{employer} = \frac{TLE}{(TLE - TSS / 2)} - 1 \tag{28}$$

where

SSTRemployer = social security tax rate for employers (applied to each employer's labor expenditure);
TLE = total labor expenditures across all sectors; and
TSS = total social security tax expenditures across all sectors.

The social security tax rate for both employers and employees was assumed to be equal; therefore, the social security tax rate computed in equation (28) was assumed to be the social security tax rate charged to employees also.

Lastly, the personal income tax is a tax on income earned by consumers. This income includes: (1) labor income after taxes, (2) income from land rents (all land is assumed to be owned by consumers), and (3) corporate profits net of taxes and retained earnings (corporations are assumed to be owned by consumers (i.e., shareholders)). Both total personal income tax paid by consumers and total personal income for 1985 were obtained from the "Economic Report of the President - 1990" allowing an average personal income tax rate to be determined.

Government transfer payments

It was determined that a significant linear relationship exists between total government transfer payments and population. Therefore, a linear regression was conducted on the following equation using total population and total government transfers time series:

$$Total\ government\ transfers = G0 * Population + G1 \tag{29}$$

where

GO, G1 = appropriate empirically determined coefficients.

Government demand for goods and services

The demand for goods and services by the government sector is modeled in the SGM as a constrained optimization problem. Instead of maximizing profit subject to a budget constraint (as is the case with the producing sectors), the objective of the government is to maximize utility subject to the government's budget constraint defined in equation (24). The following CES utility function defined over the three government services is used:

$$GU = \left(\sum_{ss=1}^{NGS} \delta_{ss} G_{ss}^{\mu}\right)^{(1/\mu)} \tag{30}$$

where

GU	=	government utility, an unobservable variable;
G_{ss}	=	the production of government service ss;
δ_{ss}	=	distribution parameter for service ss;
μ	=	elasticity parameter (equal to -0.5); and
NGS	=	number of government services (equal to 3 in SGM Version 0.0).

As discussed in Edmonds, et. al. [1991], the goal of the government sector is to maximize utility (Equation (30)) subject to its budget constraint (Equation (24)). The utility-maximizing production of government service ss is described as:

$$G_{ss} = (TXtot - S_{gov} - TR_{gov}) \beta_{ss} P_{g,ss}^{(\gamma-1)} \left(\sum_{iss=1}^{NGS} \beta_{iss} P_{g,iss}^{\gamma}\right)^{-1} \tag{31}$$

where

β_{ss}	=	$\delta ss(-1/(m-1))$;
γ	=	$\mu/(\mu-1)$; and

$$P_{g,ss} = \sum_{i=1}^{N} a_{i,g,ss} P_i \tag{32}$$

where

$P_{g,ss}$	=	the cost of the next unit of government service ss;
P_i	=	the price of input i in the production process; and
$a_{i,g,ss}$	=	the amount of input i required to produce government service ss.

The government utility function was calibrated to the base year as follows. First, the $\alpha_{i,g,ss}$ parameters are defined as the ratio of the quantity of input i used in the production of service ss. Therefore, these parameters can be calculated using the input-output account values of each input in the production of government service ss, and the assumed base year prices of these inputs; i.e.,

$$a_{i,g,ss} = \frac{\left(\frac{IO_{i,g,ss}}{P_i}\right)}{\sum_{j=1}^{NIN} IO_{j,g,ss}} \tag{33}$$

where

$IO_{i,g,ss}$	= value of input i used in the production of government service ss (from the input-output accounts);
P_i	= price of input i ("price paid"); and
NIN	= number of inputs.

These $\alpha_{i,g,ss}$ are then used in equation (32) to obtain the value of $P_{g,ss}$ for each government service ss. Once the values of $P_{g,ss}$ are determined, the δ_{ss} parameters in equation (31) can be estimated using an interative process. This process involves minimizing the sum of squared differences between the actual and estimated production of each government service (G_{XX}) by choosing values for the parameters δ_{ss} (substituting $\delta_{ss}^{(-1/(\mu-1))}$ for β_{ss} in equation (31)).

Note: As discussed in Section II.b. above, since the final demand sectors of the I/O table do not include "value added", labor expenditures of the government final demand sectors are found in the row component titled "Government Industry" of the I/O tables. This industry would be included in the SGM "Other Products" sector; therefore, the 1985 "Government Industry" values was separated from government's consumption of the "Other Products" commodity and considered labor expenditures for each of the government final demand sectors.

Similar to the process used to estimate land expenditures for each SGM industry (discussed in Section II.b.), government land expenditures were estimated by applying an average cost of agricultural land to the amount of land used for defense and education obtained from the "Statistical Abstract of the U.S., 1992" published by the Department of Commerce. These land expenditures were then subtracted from government's consumption of the "Other Products" commodity in order to guarantee data consistency.

Net government savings

If positive, net government savings is subtracted from total net tax revenues to obtain the government's budget constraint. In the year 1985, the government (federal, state and local together) ran a budget deficit (implying net government borrowing); therefore, this value would be added to total net tax revenues to obtain the government's budget constraint. Net government savings is calculated for the 1985 base year by subtracting 1985 total government expenditures from total net tax revenue (discussed above). To fund this government deficit, total savings (including personal savings and corporate retained earnings) less total investment was used. Since this amount is not adequate to cover the total government deficit in 1985, the excess was assumed to be funded through a foreign supply of capital. Since this version of the SGM is a closed economy (except for crude oil), the amount of foreign capital supplied was specified exogenously in the SGM's trade component as an import of capital in the base year and is constant through future periods. Since the SGM assumes market equilibrium, no government deficit will exist in future years; but in order to calibrate the SGM to the base year, this exogenous supply of foreign capital is necessary.

Household Final Demand

The SGM assumes that a portion of the households' budget (personal income) is allocated to personal savings while the remainder is used to purchase produced commodities and primary factors of production. Disposable personal income consists of income from wages less taxes on labor; land rents (consumers are assumed to own all usable land) less taxes on land; corporate profits less profits tax and retained earnings; and government transfer payments.

Labor Supply

Household labor supply is estimated in the SGM using the following equation:

$$X_{labor} = WAP * \alpha_{labor} * (1 - e^{\beta_{labor} * P_{labor}}) \tag{34}$$

where

WAP	= total working age population (ages 15 to 64);
α_{labor}	= the maximum potential share of working age population employed in any given year;
β_{labor}	= a labor supply price responsiveness coefficient; and
P_{labor}	= an average annual wage rate ($M per 1000 persons).

The following steps were taken to calibrate equation (34) to the base year: (1) the total working age population in 1985 was obtained from the "Statistical Abstract of the U.S."; (2) an average annual wage rate was calculated by dividing total labor expenditures (less amount paid in social security tax) in 1985 by total employment in 1985 (in thousands of persons); (3) the maximum potential share of working age population employed in any year was estimated to be 0.90 (or 90% of working age population) which assumes that in any given year 10 percent of the working age population cannot be employed; and (4) the labor supply price responsiveness coefficient was directly calculated from equation (34) given the information in (1) through (3).

Land Supply

Land supply is estimated in the SGM using the following equation:

$$X_{land} = TLA * \alpha_{land} * (1 - e^{\beta_{land} * P_{land}}) \tag{35}$$

where

TLA	= total surface area potentially available for allocation;
α_{land}	= the maximum potential share of land supplied to the market;
β_{land}	= a land supply price responsiveness coefficient; and
P_{land}	= an average annual rental rate on a unit of land ($M per 1000 km^2).

The following steps were taken to calibrate equation (35) to the base year: (1) total usable surface area (which excludes unusable land such as deserts, marshes, rock, etc) was obtained from the "Statistical Abstract of the U.S." (equal to 8313 km2); (2) an average annual land rental rate was calculated by dividing total land expenditures in 1985 by total usable land area (in thousands of km2); (3) the maximum potential share of land supplied to the market was estimated to be 1 (or 100% of TLA) since TLA represents total usable land area; and (4) the land supply price responsiveness coefficient was directly calculated from equation (35) given the information in (1) through (3).

Household Savings Supply

The following equation is used in the SGM to estimate the supply of household savings:

$$S_{hh} = Y * \alpha_{hhsave} * (1 - \delta_{hhsave} e^{\beta_{hhsave} * r}) \quad (36)$$

where

Y	= disposable personal income;
α_{hhsave}	= the maximum potential savings rate;
δ_{hhsave}	= a scale parameter;
β_{hhsave}	= the price sensitivity of households to the available interest rate; and
r	= the real market interest rate.

Equation (36) was calibrated by first assuming that the maximum potential savings rate for the U.S. is equal to 0.20 (i.e., 20% of total disposable personal income) and the real market interest rate is equal to 0.03 (i.e., 3%). With these assumptions and knowledge of the 1985 values for disposable personal income and total personal savings, equation (36) can be written in terms of δ_{hhsave} and β_{hhsave}:

$$\delta_{hhsave} = (1 - \frac{S_{hh}}{Y * \alpha_{hhsave}}) e^{-\beta_{hhsave} * r} \quad (37)$$

In addition, the interest elasticity of savings was assumed to be equal to 0.40. The equation for the interest elastiticity of savings is defined as:

$$\frac{\delta S_{hh}}{\delta r} * \frac{r}{S_{hh}} = (\frac{- \delta_{hhsave} \beta_{hhsave} e^{\beta_{hhsave} * r}}{(1 - \delta_{hhsave} e^{\beta_{hhsave} * r})}) * r = 0.40 \quad (38)$$

Combining equations (37) and (38), values for dhhsave and bhhsave can be determined.

Household Demand for Final Products

Household demand for the primary factors land and labor are computed separately from demands for other goods and services. Household demand for land is defined as:

$$X_{land,hh} = NHH \; \alpha_{land,hh} \; P_{land} \quad (39)$$

where

$\alpha_{land,hh}$ = the household land intensity factor;

P_{land} = the price of land; and
NHH = the number of households (in 1000s) which is defined as,

$$NHH = \frac{TOTPOP}{\beta_{hh}} \tag{40}$$

where

TOTPOP = total population (in 1000s); and
β_{hh} = the average number of people per household.

Equation (40) was calibrated to the base year (1985) by solving for β_{hh} using 1985 actual values for NHH and TOTPOP. Similarly, equation (39) was calibrated to the base year by solving for $\alpha_{land,hh}$ using estimated 1985 household demand for land (discussed in Section II.b.); 1985 price of land (discussed in Section III.a.); and the estimated 1985 value for NHH from equation (40).

Similar to the process used to estimate land expenditures for each SGM industry (discussed in Section II.b.), household land expenditures were estimated by applying an average cost of agricultural land to a portion (assumed to be 75%) of urban and transportation land obtained from the "Statistical Abstract of the U.S., 1992" published by the Department of Commerce. These land expenditures were then subtracted from household's consumption of the "Other Products" commodity in order to guarantee data consistency.

Household demand for labor is defined as:

$$X_{labor,hh} = X_{labor} \; \alpha_{labor,hh} \; P_{labor} \tag{41}$$

where

$\alpha_{labor,hh}$ = the household labor intensity factor;
P_{labor} = the price of labor; and
X_{labor} = total labor supply (in 1000s).

Equation (41) was calibrated to the base year by solving for $\alpha_{labor,hh}$ using estimated 1985 household demand for labor; 1985 price of labor (discussed in Section III.a.); and the estimated 1985 total labor supply from equation (34).

Since the final demand sectors of the I/O table do not include "value added", labor expenditures of the household final demand sector is found in the row component titled "Household Industry" of the I/O tables. This industry would be included in the SGM Everything Else sector; therefore, the 1985 "Household Industry" value was separated from household's consumption of the Everything Else commodity and considered labor expenditures for the household final demand sector.

Household demand for other goods and services are estimated as follows:

$$Xd_{i,hh} = \alpha_{i,hh} \; P_i^{\beta_{i,hh}} \; Y_c^{\gamma_{i,hh}} \left(\frac{1}{\lambda}\right) \qquad (42)$$

$$Y_c = Y - S_{hh} - X_{land,hh} \; P_{land} - X_{labor,hh} \; P_{labor} \qquad (43)$$

where

$Xd_{i,hh}$	= household demand for good i;
$\alpha_{i,hh}$	= the household demand intensity factor for good i;
$\beta_{i,hh}$	= the household price elasticity of demand for good i;
Y_c	= total value of consumption which is defined as,
$\gamma_{i,hh}$	= the household income elasticity of demand for good i; and

$$\lambda = \sum_{i=1}^{NS} \alpha_{i,hh} \; P_i^{\beta_{i,hh}+1} \, Y_c^{\gamma_{i,hh}-1} \qquad (44)$$

Table 3 contains the household price and income elasticities used in the SGM which were obtained from existing literature.

Table 3

	Price Elasticity	Income Elasticity
Agriculture	-0.28	0.30
Everything Else	-1.00	1.10
Crude Oil	N/A	N/A
Natural Gas	N/A	N/A
Coal	-0.82	0.89
Biomass	N/A	N/A
Uranium	N/A	N/A
Electricity	-0.82	0.89
Refined Oil	-0.82	0.89
Gas T&D	-0.82	0.89

N/A: commodity not consumed by the household sector.

Except for values of $\alpha_{i,hh}$, 1985 values of all the variables in equation (41) were determined as follows: (1) 1985 household demand for each good was obtained from the input-output accounts; (2) as previously discussed, all prices (except land and labor) were assumed to be 1 in the base year; (3) Since the 1985 values all of the components of equation (43) are either known or have been previously calculated, the total value of consumption (Y_c) can be determined. With these values determined, the values of $\alpha_{i,hh}$ can be calculated from equation (42).

Trade

As previously discussed, Version 0.0 of the SGM assumes a closed economy (i.e. zero trade) for all goods except crude oil. For calibration purposes, it is necessary to exogenously add 1985 net exports to demand and supply in order to replicate the 1985 base year values. Net exports for all tradeable commodities[19] (except Crude Oil and Other Products) are held constant at 1985 values for each period in the model. Net exports in the Crude Oil sector are set at 1985 values from the I/O tables for the base year, but are allowed to change in future periods; making up for the difference in domestic excess demand for crude oil. The SGM assumes balanced trade and implements this constraint by making up for any trade imbalances in the Other Products sector; therefore, a trade deficit would be set to zero by an equal amount in export demand for the Other Products commodity.

[19] In the SGM, "tradeable" commodities refer to those commodities which could be traded and in Version 0.0 include all commodities except electricity, land, and labor.

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Return to 1990: The Cost of Mitigating United States Carbon Emissions in the Post-2000 Period

JA Edmonds
SH Kim
CN MacCracken
RD Sands
MA Wise

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ABSTRACT

The Second Generation Model (SGM) is employed to examine four hypothetical agreements to reduce emissions in Annex I nations (OECD nations plus most of the nations of Eastern Europe and the former Soviet Union) to levels in the neighborhood of those which existed in 1990, with obligations taking effect in the year 2010. We estimate the cost to the United States of complying with such agreements under three distinct conditions: no trading of emissions rights, trading of emissions rights only among Annex I nations, and a fully global trading regime.

We find that the cost of returning to 1990 emissions levels in the United States in the absence of trading opportunities is approximately $108 per metric ton carbon in 2010. The total cost in that year is approximately 0.2 percent of GDP. Emissions reductions are accomplished via energy conservation across a broad range of residential, commercial, industrial and transportation activities and by replacing coal fired power stations with natural gas facilities.

International trade in emissions permits lowers the cost of achieving any mitigation objective by equalizing the marginal cost of carbon mitigation among countries. This is sometimes referred to as "where" flexibility. "Where" flexibility allows least expensive emissions reductions to be undertaken first, regardless of where they occur among trade participants.

For the four mitigation scenarios in this study, economic costs to the United States remain below 1% of GDP through at least the year 2020. This was the case even in the scenarios where the United States met its mitigation targets without international trading of carbon permits.

Return to 1990
The Cost of Mitigating United States Carbon Emissions in the Post-2000 Period

James A. Edmonds
Son H. Kim
Christopher N. MacCracken
Ronald D. Sands
Marshall A. Wise

Pacific Northwest National Laboratory

More than 160 nations have signed the Framework Convention on Climate Change (FCCC). That agreement required Annex I nations,[1] the developed nations of the world plus economies of the Former Soviet Union and Eastern Europe, to undertake measures to return emissions to 1990 levels or below in the year 2000. The parties to the FCCC met in Berlin in the Spring of 1995 and determined that additional measures were required to implement the ultimate objective of the FCCC, "*to stabilize the concentration of greenhouse gases in the atmosphere at a level which would prevent dangerous anthropogenic interference with the climate system.*"

Subsequent to the Berlin discussions, nations of the world have begun to consider measures that would set quantifiable emissions limitation requirements in the post-2000 period for Annex I nations. Various measures have been considered. The purpose of this paper is to explore the economic consequences of efficient policy instruments—carbon taxes or tradable emissions permits—which might be employed to achieve a variety of targets in the post-2000 time frame.[2] Using the Second Generation Model (SGM), we estimate the costs to the United States of complying with of four Annex I mitigation scenarios under three permit trading regimes. Specifically, we examine the carbon taxes required for emissions mitigation and provide measures of the costs of mitigation.

We begin by describing the variety of policy options to be considered and our general approach to modeling those policies. We then review some of the necessary assumptions for this exercise, as well as the structure and calibration of the SGM. Finally, we discuss the results of our analysis, including time paths of emissions and measures of cost.

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[1] Australia, Austria, Belarus, Belgium, Bulgaria, Canada, Czechoslovakia, Denmark, European Economic Community, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, Latvia, Lithuania, Luxembourg, Netherlands, New Zealand, Norway, Poland, Portugal, Romania, Russian Federation, Spain, Sweden, Switzerland, Turkey, Ukraine, United Kingdom of Great Britain and Northern Ireland, and the United States.

[2] In the United States, efforts were undertaken by the Interagency Analytical Team (IAT), and results were summarized in United States Government (1997). The Second Generation Modeling team was one of three modeling teams that participated in the evaluation of potential emission mitigation measures under discussion. Note that the results presented in this paper differ from SGM results presented under the auspices of the IAT. The IAT effort assumed higher rates of technical change induced by a response to policy implementation. This study does not make the same assumptions.

APPROACH

The SGM was used to simulate the impact of mitigation policies on the United States economy. The SGM is a computable general equilibrium economic model that projects economic activity, energy consumption, and carbon emissions for the United States and 11 other world regions. A more complete description of the SGM follows in the next section.

Four scenarios were constructed that reduce carbon dioxide emissions in Annex I countries by 2010. The four policies, designated 'M_', are listed below. Figure 1 shows United States emissions paths for the four scenarios and the reference case in million metric tons of carbon (MMTC). The reference case is a business-as-usual scenario, or what we project will happen in the absence of a mitigation policy. In each mitigation scenario, allowable emissions are reduced linearly from the reference level in 2000 to the emissions target in 2010.

M1990 — Emissions from Annex I regions must be no greater than 1990 emissions levels beginning in the year 2010.

M1990+10% — Emissions from Annex I regions must be no greater than 10% above 1990 emissions levels, beginning in the year 2010.

M1990-10% — Emissions from Annex I regions must be no greater than 10% below 1990 emissions levels, beginning in the year 2010.

M1995 — Emissions from Annex I regions must be no greater than 1995 emissions levels beginning in the year 2010.

[Figure 1. Carbon Dioxide Emissions Scenarios for the United States]

The four emissions mitigation scenarios each define a set of emissions rights for the Annex I regions. In a mitigation scenario, regions must possess permits, or rights to emit, for every million metric ton of domestic carbon dioxide emissions. Three emissions permit trading regimes were modeled under each mitigation policy: independent emissions mitigation, Annex I joint mitigation, and Annex I mitigation with global permit trading. The 12 SGM regions listed in Table 1 provide the necessary global coverage to simulate these trading systems. Carbon taxes were used to constrain emissions for each of the policy-trade combinations.

Table 1. Regions in the SGM

Annex I	Non-Annex I
United States	China
Canada	India
Western Europe	Mexico
Japan	South Korea
Australia	Rest of World[3]

[3] The Rest of World includes Latin America, Africa, and other Asian countries.

Former Soviet Union	
Eastern Europe	

In the independent mitigation case, each Annex I region must individually meet its required emissions targets without any trading of permits across regions. A time series of carbon taxes is determined for each region to reduce emissions to be equal to its allocated emissions rights.

With Annex I joint mitigation, a common carbon tax is applied to all Annex I regions to meet the overall Annex I emissions target. However, regions are allowed to trade permits amongst themselves so long as the total constraint is met in each time period. Regions may only emit more carbon than their allocated emissions rights allow if another Annex I region is willing to sell a corresponding number of its permits, thereby forcing the seller region to reduce its domestic emissions beyond the required target.

In the global trading case, emissions rights are allocated to Annex I regions at the same levels as in the Annex I trading case. Under global trading, however, the Annex I regions are allowed to purchase permits from each other and from non-Annex I regions so long as the global emissions constraint is met. The global constraint in each period is composed of the Annex I constraint and the sum of the non-Annex I regions' reference level emissions in that period. The SGM is used to determine a global carbon tax just large enough to meet the global emissions target.

In none of the above scenarios and trading combinations are non-Annex I regions forced to constrain their emissions below reference levels. No mitigation targets or emissions trajectories are imposed on those regions. Under the global permit trading regime, non-Annex I regions participate in the market for carbon permits only when it is to their economic benefit to do so. These regions are allocated permits equal to their projected reference emissions, so they are only required to reduce their emissions by an amount equal to the number of permits they wish to sell.

Eastern Europe and Former Soviet Union Permit Allocations

While carbon dioxide emissions in most regions are anticipated to continually increase over time beyond 1990 levels, this is not true for the Eastern Europe and Former Soviet Union regions. Emissions in these regions have declined since 1990. Their reference case emissions trajectories reflect this decline from 1990 to 1995 and then increase slowly from 1995 onward. The downturn in emissions poses a special problem when allocating emissions rights. Two approaches to permit allocations for the regions have been discussed in recent months. The first allocates permits based on the stated policy scenario (e.g., M1990 allocates permits based on 1990 emissions level) so that permits are allocated to them in the same way as they are to other Annex I regions. Because of the decline in emissions in those regions from 1990 to 1995, however, this approach results in emissions permits being granted to Eastern Europe and the Former Soviet Union in the policy years that are greater than their reference level emissions. These 'paper credits' are equal to the difference between the lower post-1990 emissions and the policy-level (i.e., 1990) emissions. For example, the Former Soviet Union's reference emissions level in 2010 is 836 TgC, significantly lower than its 1990 emissions of 1050 TgC. If granted permits equal to its 1990 emissions, it would receive 214 TgC worth of permits more in 2010 than its projected emissions, giving it 214 TgC worth of permits to sell without incurring any emissions reductions of its own.

The second approach to allocating permits to Eastern Europe and the Former Soviet Union is to grant permits equal to reference level emissions in each period until the projected path is constrained by the policy. For example, in the M1990 case, the Former Soviet Union would be granted permits equal to its projected reference emissions through 2020 because emissions in the policy years never recover to 1990 levels.

For the purpose of this exercise, we chose to emphasize the latter approach in allocating emissions to Eastern Europe and the Former Soviet Union. This reference allocation scheme ensures that the stated Annex I emissions targets are achieved in both the independent mitigation and permit trading scenarios. Because a final decision on the permit allocation method has yet to be made, however, we have also included a discussion of the impacts of the mitigation policies utilizing the first approach.

MODEL OVERVIEW

The SGM is designed specifically to address issues associated with global change. The model is designed to perform the following types of analysis:

1. Provide estimates of future time paths of environmentally important emissions associated with economic activity.

2. Provide estimates of the economic cost of actions to reduce greenhouse gas emissions.

Sectors

The SGM has nine producing sectors and twelve inputs to production. The inputs are land, labor, capital, and the nine produced goods. Economic detail is maintained in the energy supply and transformation sectors that are important for greenhouse gas emissions projections, but aggregated elsewhere into one large "everything else" sector.

Five different fuels are used for producing electricity, resulting in five subsectors for the electric generating sector. A separate economic production function, of the constant elasticity of substitution (CES) functional form, is used for each sector or subsector. Capital investment decisions depend on an assumed lifetime of capital for each sector or subsector. Capital lifetimes range from 15 years in the oil, gas, and coal production sectors to 70 years for hydroelectric power. The relative size of each production sector and subsector is shown in Table 2.

Table 2. Producing Sectors in the SGM

	Producing Sector	Gross Output in 1985 (millions of 1985 $)	
1	Agriculture	468,618	
2	Everything Else	5,086,486	
3	Oil Production	64,171	
4	Gas Production	45,804	
5	Coal Production	20,006	
6	Uranium Processing	2,195	
7	Electricity Generation	165,800	
	a. oil		10,959
	b. gas		34,152
	c. coal		85,930
	d. nuclear		21,370
	e. hydro		13,389
8	Petroleum Refining	145,015	
9	Gas Transmission and Distribution	105,330	

Market Clearing

In the SGM, markets are said to *clear*. In other words, the SGM solves for the set of prices for all markets (or sectors) in the modeled economy so that demands and supplies of each market are in equilibrium. The set of prices in which the equilibrium holds is called the *market-clearing* price set. In an equilibrium model like the SGM, markets are linked to other markets through the market-clearing process. For example, a change in the demand for coal will have an effect on not just the price of coal, but also the prices of oil, gas, and, at least indirectly, the prices of all markets in the economy.

Carbon permit prices and taxes are also solved by the SGM as part of the market equilibrium. Specifically, the SGM finds the carbon price such that the amount of carbon emitted is just equal to the carbon constraint of the region or group of regions under a carbon emissions limitation constraint.

Carbon Taxes and Revenue Recycling

The SGM uses a carbon tax within each region to provide an economic incentive for the economy to substitute away from carbon. Revenues obtained from the carbon tax can be very large, and how the revenues are recycled, or redistributed to the economy, makes a difference in the final economic cost. For this exercise, we assume that all carbon tax revenues are recycled back to consumers through a lump-sum government transfer.

For the cases where emissions rights are traded between countries, each SGM region is allocated an initial number of carbon emissions permits based on the stated mitigation policy (e.g., 1990 emissions levels for the M1990 scenario). Carbon permits can then be traded between countries at a price that clears the global market in these permits.

Modes of Operation

All of the SGM regions were initially developed as single-region models with a base year of 1985. Each regional model operates in five-year time steps generally through 2030, 2050, or 2100. Most of the single-region models were developed in collaboration with experts from that country. It is possible to run all of the regions individually or simultaneously in a global model with international trade. The three modes of operation for the SGM are:

1. Single Region
2. Global with Partial Market Clearing
3. Global with Full Market Clearing

Single-region operation. For each SGM region, all produced goods are classified as being tradable, nontradable, or traded at a fixed quantity. When SGM regions are operated independently, a fixed world price is assumed for certain tradable goods; regions may import or export as much of that good as desired at that fixed world price, subject to an overall balance of payments constraint. For all nontradable goods, the quantity of trade is fixed in advance. The following assignments are used when the United States model is operated independently:

Numeraire Sector:	everything else (price always equals 1)
Fixed World Price:	crude oil
Fixed Trade Quantities:	agriculture, coal, nuclear fuel, refined petroleum, electricity
Nontradables:	distributed gas, land, labor

For each region, the large 'everything else' sector is the numeraire, with its price fixed at 1 for all time periods. The prices of the other sectors in the economy are reported relative to this fixed value. The 'everything else' good is a tradable good for all regions. An exogenous balance-of-payments constraint is specified in advance for each region. Most regions are assumed to move linearly from a historical trade balance in 1985 to balanced trade by 2005.

Given a trial set of prices, the SGM computes supply and demand for all producing sectors and primary factors of production. Markets for the nontradables and goods traded at fixed quantities are brought into equilibrium by searching for a set of prices that equate supply and demand. Prices are adjusted until supply and demand are within 0.01% of each other.

Global model with partial market clearing. The global version of the SGM is used when there is at least one market that must clear globally. For the scenarios described in this paper, that market is tradable carbon emission permits. The model searches for a global carbon tax, which can be interpreted as a world carbon permit price, that clears the market for permits.

Each region is initially allocated a number of carbon permits and may trade those permits at the world permit price. Some regions will be sellers of permits and some will be buyers. After trading permits, all regions must hold permits equal to the domestic level of carbon emissions.

All regions are still subject to a period-by-period balance of payments constraint. The model does not allow borrowing to pay for carbon emissions permits. Imports of permits must be paid for with exports of some other good.

Global model with full market clearing. There are no longer any markets with a fixed world price. A set of world prices is found that clears all world markets. Also, world markets can be created for goods that were traded in fixed quantities in the single-region model.

All of the scenarios described in this paper were run in the second mode, global with partial market clearing. This mode was chosen for two reasons. The first is that we chose to adopt a fixed time path of world oil prices for SGM model runs that were completed for the United States Government during the spring of 1997. This meant that the world oil market would not be allowed to clear in the model. The second reason is that model results are often easier to interpret when some variables in the model remain predetermined over time.

Data Requirements

Three types of data are used to construct and calibrate each region of the SGM:

1. Economic and Demographic Data
2. Energy Balances
3. Technology Descriptions

Economic data include input-output tables and supplemental information from the national income accounts. Population projections were obtained from the World Bank. Energy balance tables were obtained either from the International Energy Agency or from government agencies within a region.

Input-output tables describe, in value terms, the flow of goods between industries and consumers in an economy. However, a model concerned with quantities of carbon emissions must also be concerned with quantities of energy. An input-output table alone is not sufficient to determine the quantities of oil, gas, coal, electricity, and refined petroleum that are produced and consumed. Supplemental information on energy quantities is required to map currency units from an input-output table to energy units needed to calculate levels of carbon emissions. We combine economic input-output tables with energy balance tables to create a hybrid input-output table with units of joules for energy products and real dollars for all other products. Miller and Blair (1985) provide a general description of, and the motivation for using, hybrid input-output tables.

Individual energy technologies are characterized by the annualized cost of providing an energy service. Data needed to determine the annualized cost include capital cost, equipment lifetime, annual fuel requirements, the interest rate, and other annual maintenance and operating costs.

REFERENCE CASE AND CALIBRATION

The cost of reducing greenhouse gas emissions is dependent on the reference case. The higher the growth rate of emissions in the reference case, the greater the cost of returning to 1990 emissions. Therefore, much effort is expended to create an acceptable reference case before running any of the mitigation scenarios.

Results for this study are reported for the years 1990 through 2020. The United States reference case was closely calibrated to the Annual Energy Outlook 1997 (AEO97). Since AEO97 projects only up to the year 2015, projections beyond 2015 are SGM model results and are not calibrated to any other established projections. Projections of carbon emissions, population, gross domestic product (GDP), energy consumption, and electricity generation for the United States are described below.

For the other global regions, economic and energy consumption growth rates were roughly calibrated to regional projections from the World Energy Outlook 1996 (WEO96). For the Eastern Europe and Former Soviet Union regions, projected energy consumption levels were adjusted downward from the WEO96 projection to reflect recent events. Population projections for all regions with the exception of the United States were set exogenously based on the World Population Projections 1994-1995, published by the World Bank. The United States population projection was set according to AEO97 projections. As mentioned earlier, the international crude oil price trajectory was also taken from the AEO97. Prices for all other fuels and goods in the model were determined endogenously.

The general calibration procedure was to first match GDP growth by adjusting parameters that control total factor productivity in the 'everything else' sector. Then energy consumption by fuel was calibrated by adjusting input-specific technical change parameters. Carbon emissions are an output of the model derived directly from primary energy consumption by applying fuel-specific emission factors.

Carbon Emissions

In 1990, total carbon dioxide emissions from the combustion of fossil fuels in the United States were 1,350 million metric tons of carbon. Model results show that total carbon dioxide emissions continue to rise as fossil fuel consumption increases and emissions reach 1,871 million metric tons by 2020. This amounts to a 39 percent increase in total emissions and an emissions growth rate of 1.1 percent per year. Reference case carbon emissions were shown earlier in Figure 1.

Gross Domestic Product

The two most important determinants of GDP are population growth and rates of change in productivity. Total population levels for the United States were taken directly from AEO97. United States population grows from 250 million in 1990 to 323 million in 2020. This represents an annual population growth rate of 0.85 percent per year.

GDP for the United States was matched to AEO97 projections by changing the total factor productivity parameter for the 'everything else' sector. Beginning with the 1990 GDP of 6.1 trillion dollars, the economy grows at nearly 2 percent annually to reach 10.6 trillion dollars by 2020.

Energy Consumption

Total energy consumption from 1990 to 2015 was calibrated to within 2 percent of projections from AEO97. Energy consumption by fuel is shown for the United States in Figure 2. Total consumption increases from 86 EJ in 1990 to 118 EJ in 2020. This increase represents an average annual growth rate of 1.1 percent over that period. The annual growth rate in energy consumption declines over time and by 2020 decreases to 0.5 percent per year.

Petroleum remains the major source of energy through 2020, but its share of total consumption declines over time, giving way to natural gas and, to a lesser extent, renewable energy sources. Coal is the third largest source of energy and its consumption grows steadily at slightly less than 1 percent per year. Nuclear energy's contribution to energy consumption declines over time.

[Figure 2. Energy Consumption – United States Reference Case]

Energy consumption does not grow as fast as GDP, which results in the energy-GDP ratio falling over time at an average annual rate of 1.0 percent per year. Figure 3 shows the energy-GDP ratio generated by the SGM for the United States reference case.

[Figure 3. Energy-GDP Ratio – United States Reference Case]

Electricity Generation

Projections of electricity generation are similar to those of the AEO97. SGM total electricity generation results are higher than the AEO97 projections by approximately 10 percent. Electricity generation from natural gas is the reason for the higher result. Total electricity generated in 1990 is nearly 11 EJ, which grows at 1.5 percent per year and expands to 17 EJ by 2020. The major source of electricity is the combustion of coal; however, electricity generation from natural gas plays a significantly larger role with time. In 1990, electricity generation from coal contributed 53 percent of the total generation, while that from natural gas combustion contributed 17 percent of the total. By 2020, the shares of electricity generation from coal and natural gas are closer. Electricity generation from coal and natural gas comprise 44 and 34 percent shares of the total, respectively. Highly efficient and low-cost natural gas combined cycle power plants incorporated into the SGM contribute to the growth of natural gas as the choice fuel for electricity generation. Nuclear power's contribution to the overall demand for electricity declines with time as existing power plants are retired and no new additional plants are constructed.[4] Renewable energy sources for electricity generation include hydroelectricity, solar photovoltaics and others. Generation of electricity from renewable sources increases slightly from 1990 to 2020; however, renewable energy's share of total electricity remains below 10 percent of the total.

COST OF EMISSIONS MITIGATION

[4] The assumption of no new starts reflects a de facto nuclear moratorium. Were nuclear power to be allowed to compete against other energy forms on the basis of price alone, the model would continue to build new facilities.

Although this exercise employed the 12-region version of the SGM, discussion of results in this paper will focus on the United States. The SGM provides output on regional GDP and its components and a detailed description of the composition of energy supply. In this analysis, we focus on the broad economic impacts to the economy. Specifically, we discuss the permit prices required to meet the various mitigation requirements and the costs to the United States economy of undertaking such policies. We also discuss the impacts of the domestic carbon taxes on energy consumption.

Permit Prices

Table 3 shows the permit prices by trading regime required for the United States to meet its emissions targets under the four mitigation scenarios. Permit prices in the United States must reach $108 per metric ton of carbon to reduce United States emissions to 1990 levels in 2010 in the independent mitigation case. This price increases significantly with the tighter constraint imposed under the M1990-10% case. Permit prices in the M1995 and M1990+10% scenarios are very similar as only 5 TgC separate the constraints in the two cases in 2010.

Table 3. United States Carbon Taxes Required to Meet Policy Goal
Eastern Europe & FSU Allocated Reference Case Permits
(1992 US$ per Metric Ton of Carbon)

– EE+FSU have higher permits in Kyoto
– Also umbrella & 6 gases lower.

	Independent Mitigation		Annex I Joint Mitigation		Annex I Mitigation with Global Trade	
	2010	2020	2010	2020	2010	2020
M1990	108	170	72	87	26	27
M1990+10%	60	110	42	58	16	18
M1990–10%	173	260	109	122	38	36
M1995	61	112	70	106	26	32

Permit prices fall as more regions are included in the market for carbon permits. In the independent emissions mitigation case, carbon emitters in the United States may undertake emissions mitigation options available only within the United States. In the Annex I joint and global permit cases, however, regions are included that have mitigation options with significantly lower costs, thereby lowering the marginal cost to the carbon permit market of meeting the desired emissions targets. As we will discuss, this 'where' flexibility in meeting emissions targets has a significant impact on costs as well as permit prices.

A fixed emissions level and an increasing reference case emissions level imply both a rising percentage emissions reduction and a rising price of meeting the fixed emissions target. Increasing population in the United States, and the economic growth that accompanies it, put upward pressure on emissions that, in turn, forces larger shifts away from coal toward natural gas and renewable energy sources. The availability of relatively inexpensive abatement options in the developing world allows the permit price to remain relatively constant over time in those cases.

As the permit prices decrease across trading regimes, the United States purchases increasing quantities of permits from abroad, thereby enabling it to emit more than its allocated permits alone would allow. Figure 4 shows United States emissions for the M1990 case across the three trading regimes. Under the independent emissions mitigation regime, the United States is limited to emitting only what it is allocated under the scenario, its 1990 emissions level. With Annex I trading, however, the United States purchases 209 TgC worth of permits in 2010 and 244 TgC in 2020 from the Former Soviet Union and Eastern Europe. The purchases increase to 316 TgC and 436 TgC in 2010 and 2020, respectively, under the global trading regime. Again, 'where' flexibility reduces the amount by which a permit-buying region must reduce its emissions and, therefore, reduces the cost to the region.

[Figure 4. United States Carbon Emissions – M1990 Cases]

The M1995 Annex I trading case is the only case in which the United States sells permits to other regions. The permit price under independent mitigation in 2010, as shown in Table 3, is less than that shown under Annex I trading. Because the United States can mitigate emissions less expensively in 2010 than other Annex I regions, it reduces its emissions beyond the required 1995 target and sells permits to other Annex I regions. By 2020, however, the United States begins to purchase permits from Eastern Europe and the Former Soviet Union.

Energy Consumption

Emissions mitigation is achieved primarily through two mechanisms: energy conservation - reduction in total energy consumption - and replacement of coal-fired capacity with less carbon-intensive fuels such as natural gas and renewables in the electricity sector. In the no-trading cases, fuel switching from coal to natural gas and renewable fuels in the electricity generation sector accounts for roughly 60 percent of the reduction in total emissions. Energy conservation makes up the remaining 40 percent of the reduction. The domestic carbon tax of $108 in 2010 in the M1990 case results in a reduction of total energy consumption by 14 percent relative to the reference case. Consumption of coal drops by 57 percent while consumption of petroleum drops by 7 percent. Consumption of natural gas, however, increases by 4 percent due to fuel switching. Figure 5 shows energy consumption by fuel in the year 2010 for the four mitigation scenarios. Note that even when emissions are returned to 1990 levels, the scale of the total energy system is not. The fuel switching mentioned above allows the emissions targets to be met without reducing total consumption by the same percentage as the required reduction in emissions.

[Figure 5. United States Energy Consumption in 2010]

Fuel substitution in the electricity sector results in the share of electricity generated from coal dropping from 45 percent in the reference case to 20 percent in the M1990 case. The reduction in electricity generation from coal is compensated for by increased generation from natural gas. The share of electricity generation from natural gas increases from 29 percent in the reference case to 51 percent M1990 case.

As discussed above, the domestic cost of stabilizing emissions at 1990 levels in 2010 without trade is $108 per metric ton carbon. This cost roughly reflects the cost of abandoning existing coal-fired power generation capacity and replacing it with a new combined-cycle natural gas-fired unit. A $108 per metric ton tax adds approximately $0.02 per kilowatt-hour to the operations and maintenance (O&M) cost of power generation in a coal-fired plant. This additional cost makes the O&M cost of the coal plant higher than the levelized cost of installing a new gas-fired combined-cycle unit, roughly $0.05 per kilowatt-hour. The $108 tax, therefore, provides an emissions mitigation plateau for permit prices that is not exceeded until most of the existing coal capacity is replaced.

Certain caveats apply to the discussion above concerning the marginal cost of substituting natural gas-fired electricity generation capacity for existing coal-fired capacity. The cost analysis requires that the tax be levied indefinitely. If the tax policy is believed to be only temporary, the amount of substitution is likely to be much less substantial and the tax level required for stabilizing emissions could be higher. The tax level required for mitigation also depends on the cost of developing the infrastructure necessary to supply natural gas to potential new users. Extending pipelines to particular areas, for example, might increase the cost of gas enough so as to discourage switching from coal-fired plants in those areas.

Cost Calculations

A very convenient way to characterize the response of any SGM region to a carbon tax is by constructing a marginal cost of carbon curve. Figure 6 is a scatter plot of various carbon taxes applied to the United States economy and the corresponding reduction in carbon emissions. Data points plotted in Figure 6 are from the four independent mitigation scenarios for the United States. Note that a positive tax is required to achieve any reductions in carbon emissions.

[Figure 6. Marginal Cost of Carbon]

The marginal cost curve is used to calculate one measure of cost that we will call the *direct cost*. For any level of carbon emissions mitigation, the direct cost is defined as the area under the marginal cost curve up to that amount of mitigation.[5] While the first units of emissions reductions are very inexpensive; successive units become more and more expensive. So, as the constraints on emissions become tighter across cases and over time, the cost of mitigation increases. Figure 7 shows the direct costs for the United States for the four independent mitigation scenarios. Direct costs are shown at 5-year intervals through 2020 as a percentage of GDP. These costs are plotted as negative numbers.

[Figure 7. Cost of Emissions Mitigation – No Trading]

[5] Note that these costs do not include the costs of establishing a domestic or international permit trading system nor do they include the transaction costs associated with permit trading among firms and/or regions.

Figure 8 focuses on the M1990 case and shows how costs to the United Sates are reduced with trade in emissions permits between countries. The 'independent' cost line shown in Figure 8 is the same as the M1990 cost line in Figure 7. In 2010, costs are reduced somewhat with Annex I trading and reduced by about one-half with global trading. In later years, the flexibility in where emissions reductions are undertaken impacts mitigation costs even more significantly.

[Figure 8. Illustration of 'Where' Flexibility – Costs for M1990 Cases]

Cost calculations for the emissions trading cases are different than in the independent case. Costs for the trading case take into account the value of permits traded. For a buyer of permits, such as the United States, net cost includes the direct cost plus expenditures on carbon permits. A breakdown of these two cost components is shown for the M1990 Annex I trading case in Figure 9. Direct cost is roughly half of the net cost. The remaining cost, the difference between the 'direct cost' and 'net cost' lines in Figure 9, is the value of emissions permits that would be purchased from other Annex I countries.

[Figure 9. Cost Breakdown – M1990 Annex I Trading Case]

Impact of Alternative Permit Allocation Approach

The results discussed thus far have been based on the assumption that Eastern Europe and the Former Soviet Union are allocated permits equal to the minimum of their reference-level emissions and the policy-level emissions. This section will discuss the impacts of an alternative permit allocation method in which Eastern Europe and the Former Soviet Union are granted permits equal to their policy-level emissions in every period. Recall that 'policy-level' refers to the emissions target set by the chosen mitigation policy. For example, the policy-level emissions in the M1990 case would be 1990 level emissions starting in 2010, and for the M1995 case they would be 1995 level emissions beginning in 2010. This assumption results in the 'paper credits' discussed earlier that significantly impact the permit prices required to meet Annex I emissions targets in the Annex I and global trading cases.

Table 4 shows the permit prices required to meet the policy goal under the policy-level permit allocation approach. The prices required for independent mitigation in the United States do not change from Table 3 above because the paper credits in those cases are not available for purchase outside Eastern Europe and the Former Soviet Union. Permit prices also remain unchanged under the M1995 case because by that time the two regions have already suffered the worst of their economic downturns so that emissions levels are at their lowest point in the 1990 to 2020 time frame. The permit prices under the other trading scenarios are significantly less under this allocation approach, however, because the regions are able to sell the paper credits without incurring any cost domestically. In the M1990 case in 2010, the paper credits allocated to Eastern Europe and the Former Soviet Union account for 37 percent of the emissions reductions necessary for the remaining Annex I regions to meet their target emissions. This addition of permits available for purchase reduces the permit price by $33, or by 46 percent, relative to the permit price under the reference-level allocation approach. Figure 10 shows the difference in permit prices for the M1990 case with Annex I trading between the two permit allocation approaches in 2010 and 2020.

Note that the difference decreases over time as emissions in Eastern Europe and the Former Soviet Union approach the policy goal.

Table 4. United States Carbon Taxes Required to Meet Policy Goal Eastern Europe & FSU Allocated Policy-level Permits (1992 US$ per Metric Ton of Carbon)

	Independent Mitigation		Annex I Joint Mitigation		Annex I Mitigation with Global Trade	
	2010	2020	2010	2020	2010	2020
M1990	108	170	39	73	15	22
M1990+10%	60	110	6	35	2	11
M1990–10%	173	260	88	124	31	36
M1995	61	112	70	106	26	32

[Figure 10. Permit Prices under Alternative Permit Allocation Methods for EE & FSU – M1990 Annex I Trading Case]

The lower permit prices under the policy-level approach result in lower total costs of emissions mitigation to the United States. In the M1990 Annex I trading case, costs as a percentage of GDP are reduced from 0.18 percent under the reference-level allocation approach to 0.12 percent under the policy-level approach in 2010. Figure 11 shows costs as a percentage of GDP for the M1990 Annex I trading case for both allocation methods.

[Figure 11. Cost of Emissions Mitigation under Alternative Permit Allocation Methods for EE & FSU – M1990 Annex I Trading Case]

DISCUSSION

In this section, we summarize some of the insights gained from our modeling activities using the SGM. First, economic costs depend a great deal on our assumptions about future carbon emissions. Second, several measures of cost are available from the SGM. Third, the distribution of costs among countries in a system of global permit trading is sensitive to assumptions on exchange rates as well as the initial allocation of permits. Fourth, any system of global trade in carbon permits implies potentially large transfers of wealth from one region to another. Finally, we discuss how some of our assumptions affect the results on costs.

Role of Reference Emissions in Shaping Marginal Mitigation Costs

All of the results in this study depend on assumptions used to create a reference emissions scenario from the present to 2020. The amount of mitigation required to return to 1990 levels depends directly on reference case emissions for each region. In the Annex I trading cases, carbon permit prices are particularly sensitive to reference scenarios for potential sellers of permits, especially Eastern Europe and the Former Soviet Union.

Among the Annex I countries, projecting future carbon emissions is especially uncertain for Eastern Europe and the Former Soviet Union. Of particular importance is when emissions in these regions will once again reach 1990 levels. If this point is reached before 2010, then we model EE and FSU just as any other Annex I country. If this point is reached after 2010, then emissions restrictions are not binding in EE and FSU until that point in time.

Measuring and Reporting Costs

At least two measures of cost are available from the SGM and from other models as well. The first measure, which we call the *direct cost*, can be thought of as either a deadweight loss or the integral under the marginal cost curve for carbon. Using either approach, direct cost is approximately equal to one-half of the carbon tax (or permit price) times the reduction in carbon emissions. For the permit trading cases, direct costs are then adjusted by the value of transfer payments required to purchase or sell permits. This measure of net cost is simple to construct and is comparable across models.

Of ultimate interest, however, is the net impact on some broader measure of economic activity (such as GDP) or on economic welfare (such as real consumption). There are many reasons why the change in GDP (or real consumption) is different than direct cost net of transfer payments. These other components of cost include the effects of pre-existing distortionary taxes, changes in terms of trade, and how tax revenues are recycled. In addition, measurement of GDP (or real consumption) depends on the choice of index and base year used to construct that index. This reflects real-world problems in constructing a quantity index for GDP when relative prices are changing.

Foreign Exchange Rates

Permit prices for the global permit trading cases are very sensitive to assumptions about exchange rates. And while the United States follows a largely free market approach to exchange rates, most developing nations do not. Therefore it may be perfectly reasonable to assume that over the long-term the United States exchange rate with other free market trading partners would tend toward the purchasing power parity rate, this assumption is questionable with other partners. This is particularly true for developing countries where market exchange rates, in local currency per U.S. dollar, can be three to five times the corresponding exchange rate based on purchasing power parity. A global permit price of $100 per metric ton translates, at market exchange rates, into a much higher relative price in the developing countries than in the United States.

Exchange rates based on purchasing power parity are usually used to compare income levels between countries, but market exchange rates must be used for goods actually traded between countries. This creates a potential problem for developing countries considering participation in a global permit trading program; carbon permits would be traded at market exchange rates, while GDP losses are better measured using purchasing power parity. For developing countries, losses in GDP could be greater than the value of carbon permits sold.

International Transfer Payments

We have modeled an international system of carbon permit trading that implies potentially large wealth transfers from buyers to sellers of permits. These transfers also change the pattern of other goods traded internationally. For a buyer of permits, this annual transfer of wealth is equal to the annual quantity of permits purchased times the world market price of the permits. The size of these transfers depends directly on the initial allocation of permits between countries. The initial allocation determines not only the amount of permits traded by each country, but also whether a country is a buyer or seller of permits.

For this study, the initial allocation of permits among Annex I countries is simply the emissions targets defined by the four mitigation scenarios. Non-Annex I regions were allocated permits equal to reference case emissions. These four mitigation scenarios represent only a few of the many possible ways of setting global emissions limits and allocating emissions rights among countries to meet those limits. Each allocation implies a different pattern of wealth transfers among countries.

Each region in the SGM is assigned a period-by-period balance of payments constraint. Buyers of carbon permits must, therefore, export more of other traded goods than otherwise to pay for the purchased permits. Conversely, sellers of permits use the permit revenues to increase imports of other goods.

Sensitivity of Costs to Model Assumptions

Economic costs reported by the SGM for the United States are sensitive to many of the model inputs. These include the choice of exchange rate, the inclusion of paper permits, and the method of revenue recycling.

If purchasing power parity exchange rates were used instead of market exchange rates for the developing countries, then any given world permit price would translate into a lower carbon tax in that country's local currency. For global trading cases, this would increase the global permit price needed to meet a global emissions limit, and the SGM would report higher costs for the United States.

For Eastern Europe and the Former Soviet Union, carbon permits were allocated based on their reference case, and not on 1990 emissions. If we had allocated permits based on 1990 levels, these extra 'paper credits' would create a less-stringent Annex I target. The model would then report a lower permit price for the trading cases, and a lower cost to the United States.

In this study, we assumed that all revenues from a carbon tax would be recycled as a lump sum to consumers. Another option is to use the carbon tax revenues to offset other taxes. This has the potential to reduce overall costs, since carbon tax revenues would displace other distortionary taxes.

KEY OBSERVATIONS

Economic costs are reduced with a permit-trading program that equalizes the marginal cost of carbon between countries. The least expensive emissions reductions are taken first, regardless of where they occur. Costs shown in Figure 8 provide a good example of the importance of this 'where' flexibility.

For the four mitigation scenarios in this study, economic costs to the United States remain below 1% of GDP through at least the year 2020. This was the case even in the scenarios where the United States met its mitigation targets without international trading of carbon permits.

Each region in the SGM can be characterized by a marginal cost of carbon curve, as was shown in Figure 6. This shows the approximate carbon tax required for any given level of carbon emissions reduction. For the amount of emissions reductions needed in 2010 to return to 1990 levels, a carbon tax of $108 per metric ton of carbon is required.

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Figure 1. Carbon Dioxide Emissions Scenarios for the United States

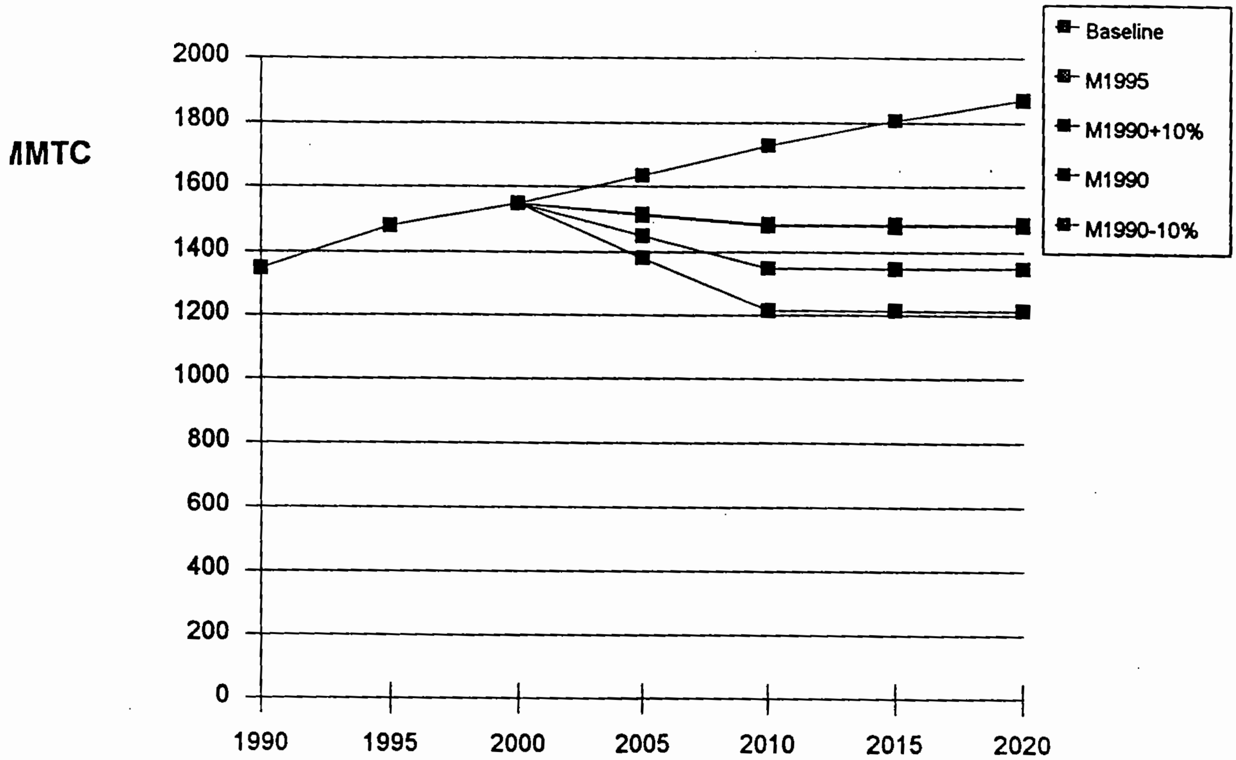
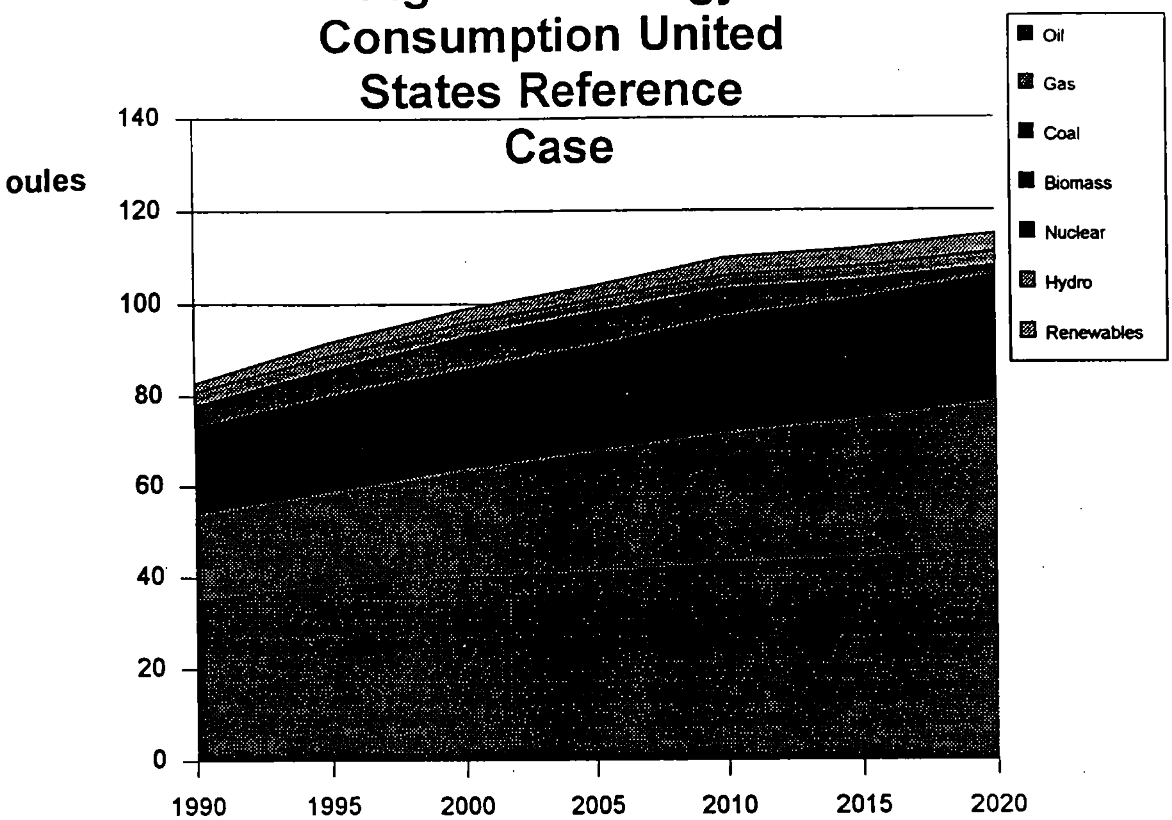


Figure 2. Energy Consumption United States Reference Case



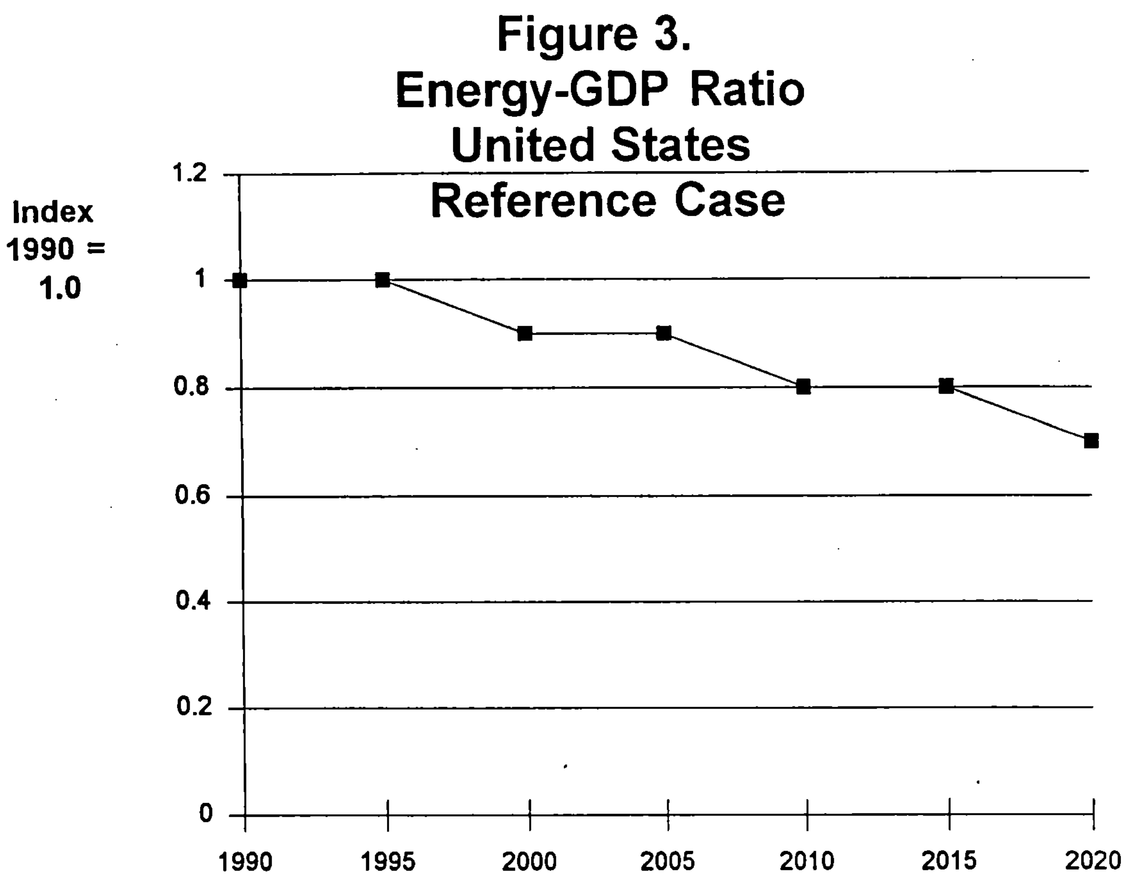
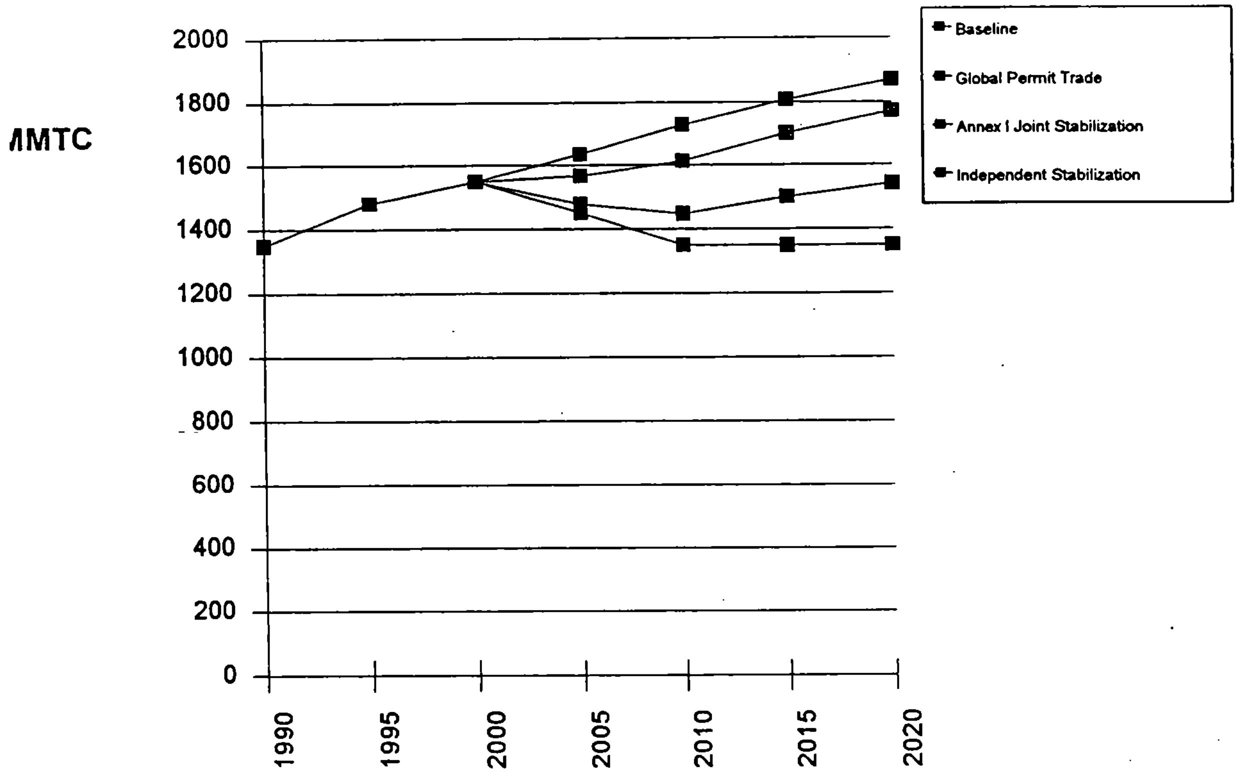


Figure 3.
Energy-GDP Ratio
United States
Reference Case
Index
1990 =
1.0
1.2
1
0.8
0.6
0.4
0.2
0
1990
1995
2000
2005
2010
2015
2020

Figure 4. United States Carbon Dioxide Emissions M1990 Cases



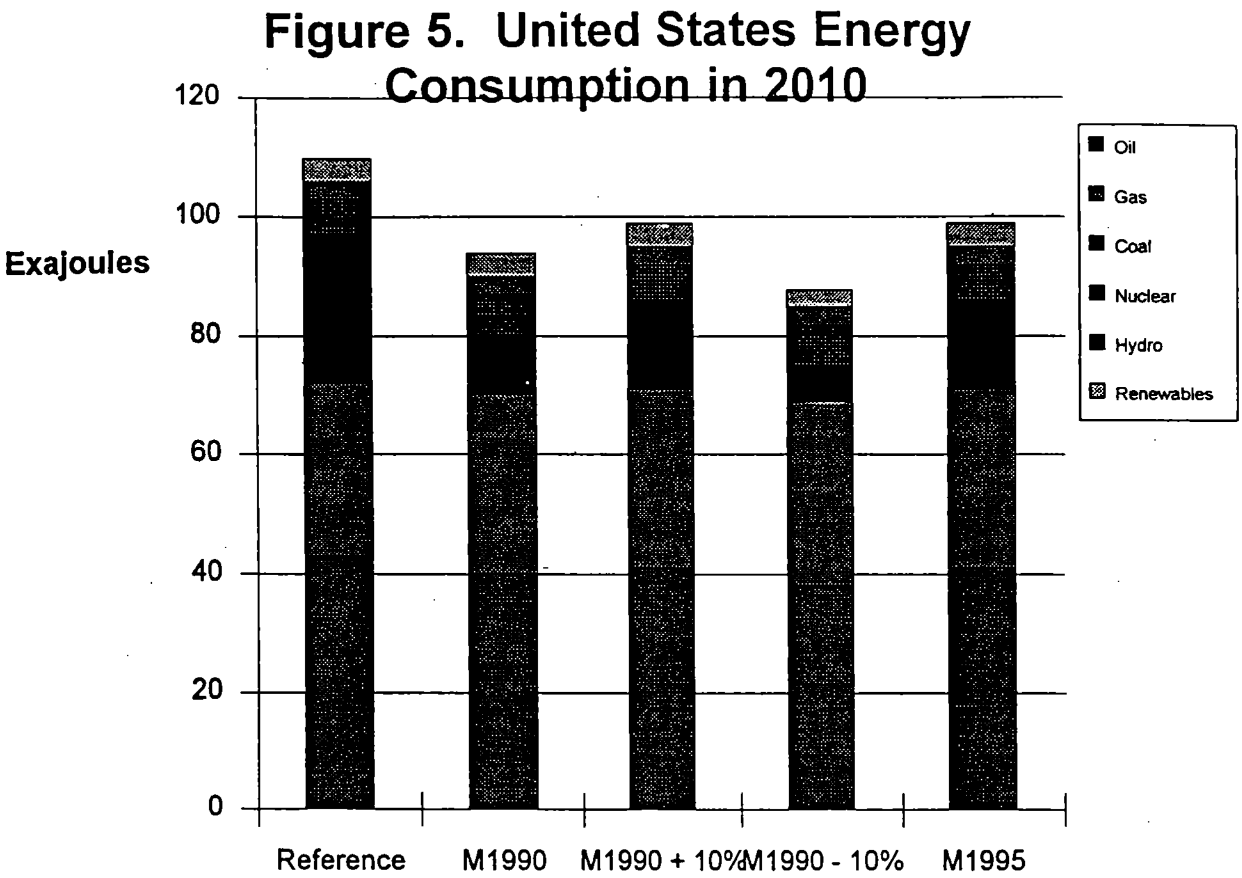


Figure 5. United States Energy Consumption in 2010
Exajoules
120
100
80
60
40
20
0
Reference
M1990
M1990 + 10%
M1990 - 10%
M1995
Oil
Gas
Coal
Nuclear
Hydro
Renewables

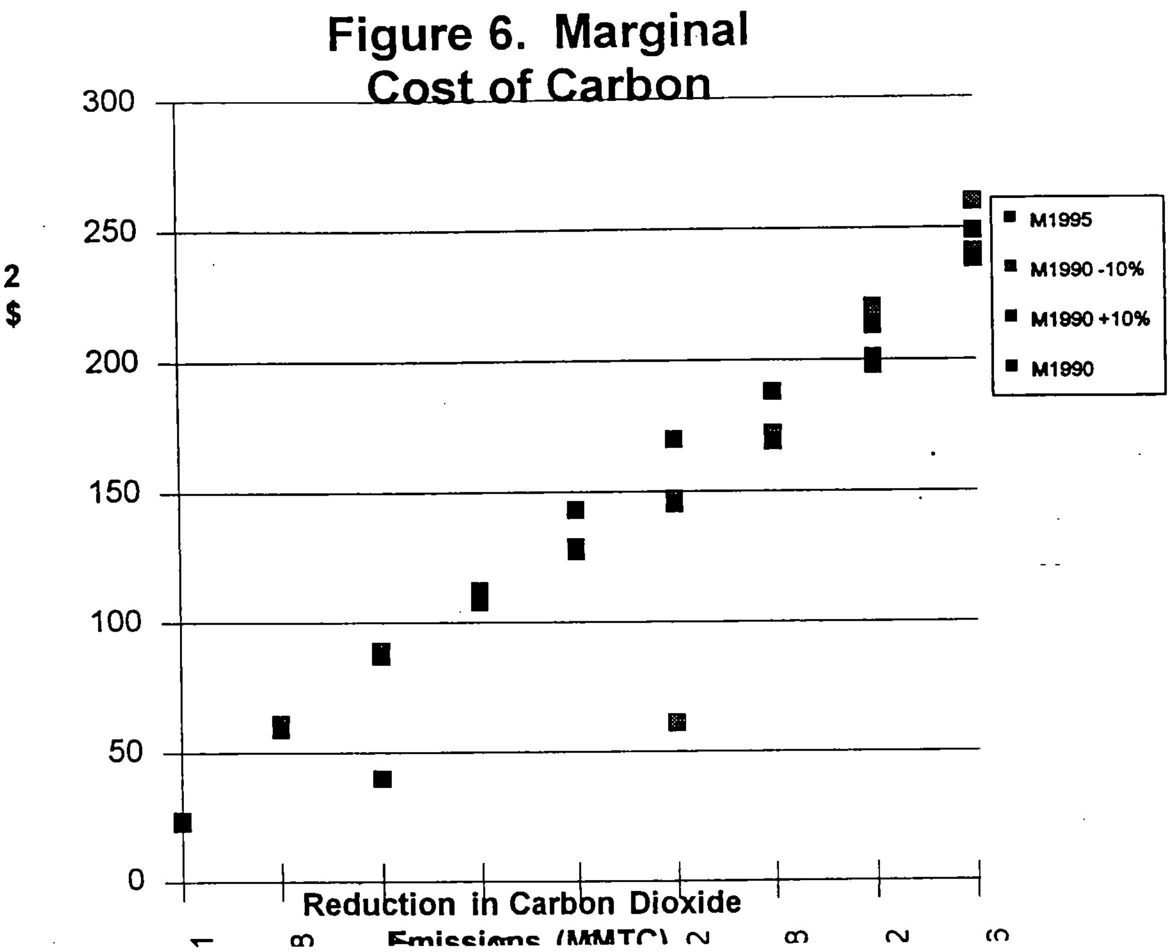


Figure 6. Marginal
Cost of Carbon
300
250
200
150
100
50
0
2
$
M1995
M1990 -10%
M1990 +10%
M1990
Reduction in Carbon Dioxide

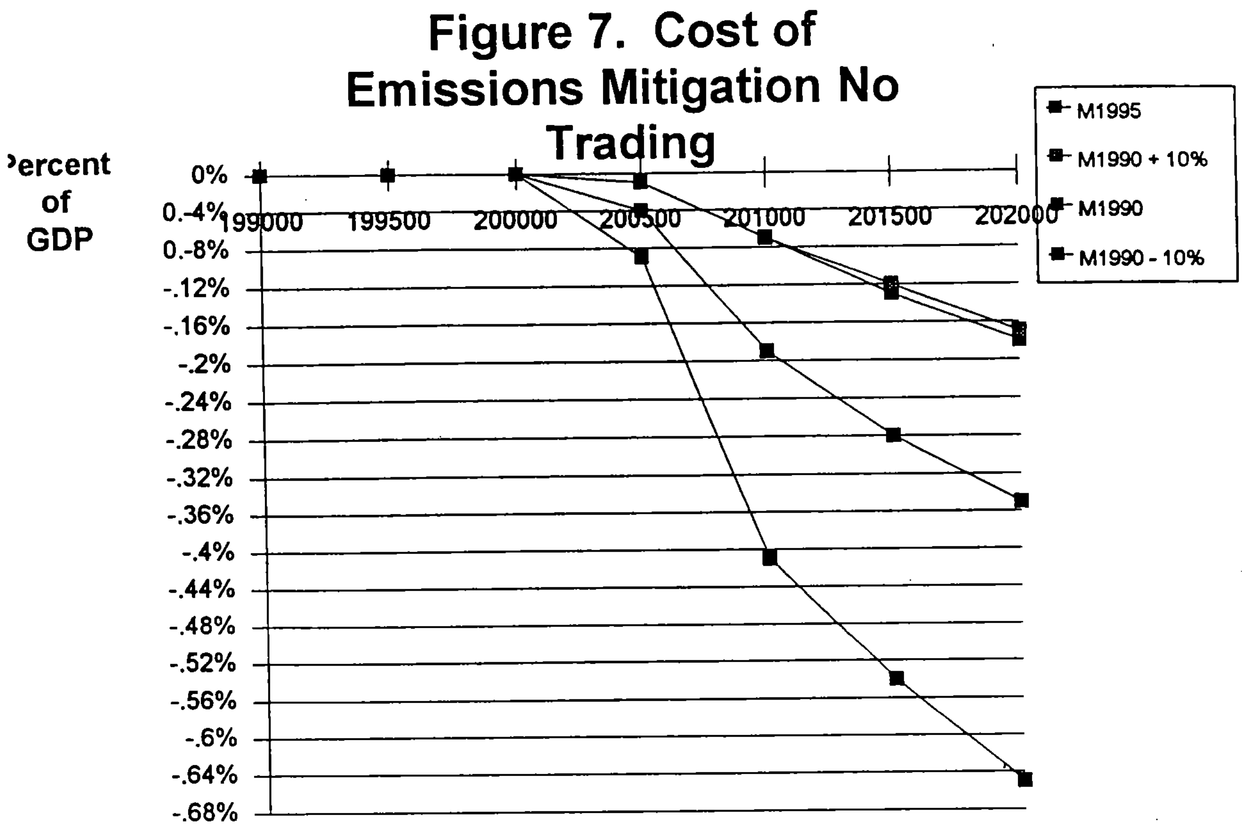
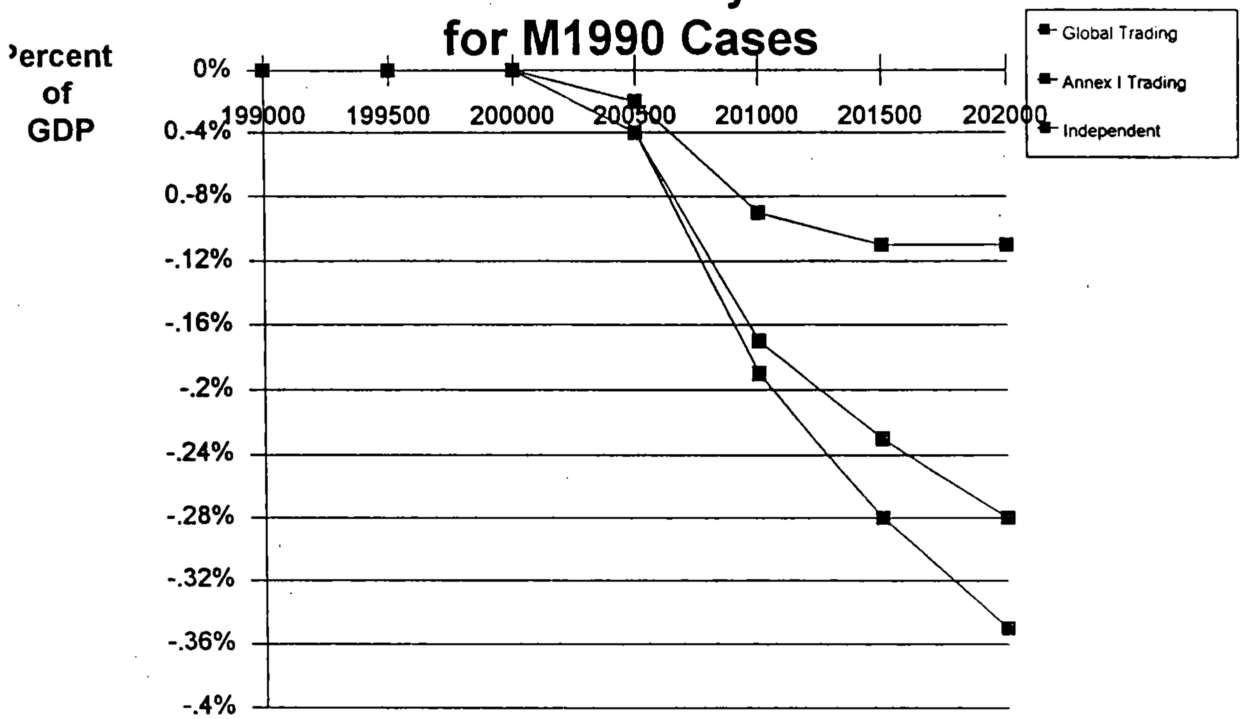


Figure 7. Cost of Emissions Mitigation No Trading
Percent of GDP
0%
0.-4%
0.-8%
-.12%
-.16%
-.2%
-.24%
-.28%
-.32%
-.36%
-.4%
-.44%
-.48%
-.52%
-.56%
-.6%
-.64%
-.68%
199000
199500
200000
200500
201000
201500
202000
M1995
M1990 + 10%
M1990
M1990 - 10%

Figure 8. Illustration of 'Where' Flexibility Costs for M1990 Cases



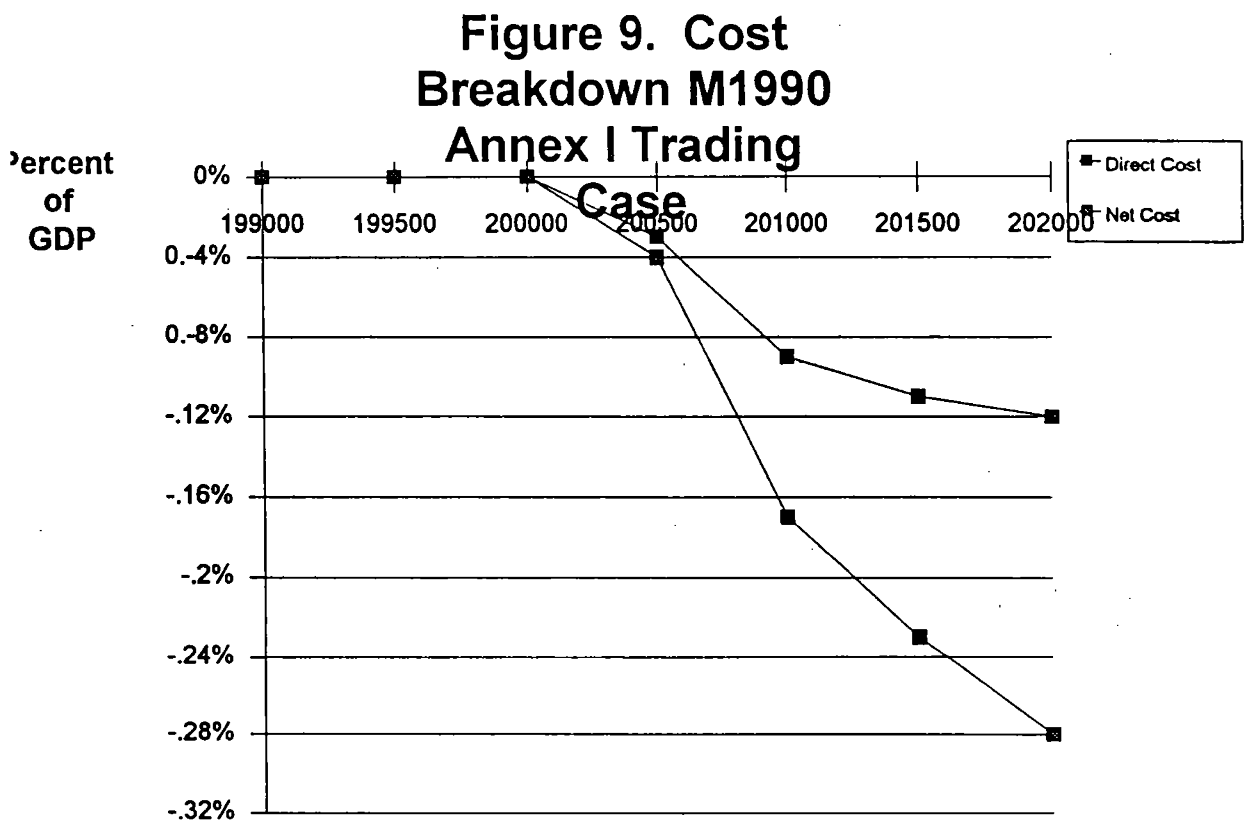


Figure 9. Cost Breakdown M1990 Annex I Trading Case
Percent of GDP
0%
0.-4%
0.-8%
-.12%
-.16%
-.2%
-.24%
-.28%
-.32%
199000
199500
200000
200500
201000
201500
202000
Direct Cost
Net Cost

Figure 10. Permit Prices under Alternative Permit Allocation Methods for EE & FSU: M1990 Annex I Trading Case

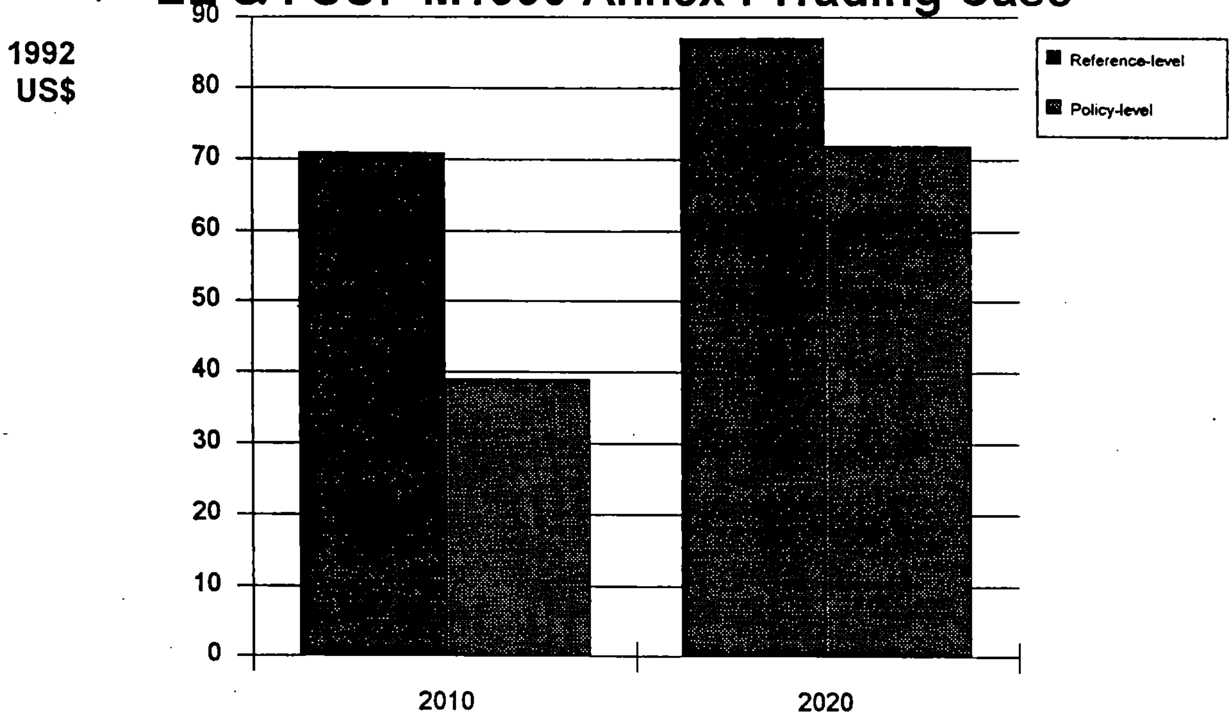
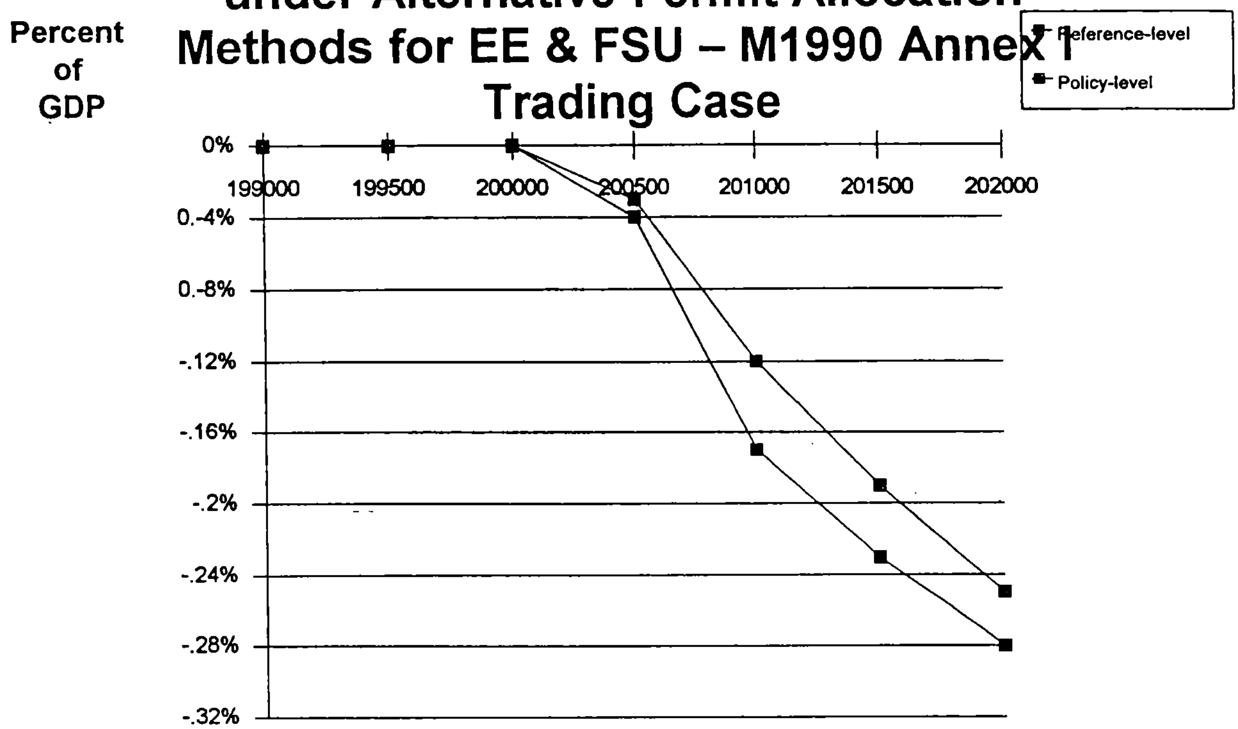


Figure 11. Cost of Emissions Mitigation under Alternative Permit Allocation Methods for EE & FSU – M1990 Annex 1 Trading Case



EMF-14 MODEL COMPARISONS

Model	WGI-450	WGI-550	WGI-650
SGM (Battelle)	$80	$48	$24
Minicam (Battelle)	$160	$115	$77
CETA (Peck & Teisberg)	$145	$88	$37
CPBRIVM (Dutch Team)	$30	$19	$12
CRTM (Montgomery & Rutherford)	$242	$127	$92

Full Global Trading: 2010 Permit Prices

KYOTO PROTOCOL ANALYSIS

Model	No Trading	Annex 1	Umbrella - EU	Annex 1 + Ideal JI
SGM (Battelle)	$171	$48	$26	$19
G^3 (Shackleton)	$55	$32	$16	$11
MRT (Montgomery & Rutherford)	$279	$97	NA	$34

G[3] 1/98 results

Kyoto, U.S. Only, Lump-Sum	2010	2015	2020
U.S.			
Gross National Product ($90, % Change f/ Base)	-0.6%	-0.5%	-0.4%
Gross Domestic Product ($90, % Change f/ Base)	-0.6%	-0.5%	-0.5%
Permit Price ($90)	49	52	56
Emission Reductions (MMTC)	-514	-652	-811
Real Effective Exchange Rate (% Change from Base)	2%	3%	4%
Exports ($90, % Change From Base)	-2%	-3%	-4%
Net Int'l Invest. Pos. (Change from Base, $90 Billion)	-60	2	62
Japan			
Gross National Product ($90, % Change f/ Base)	0.0%	0.0%	0.1%
Gross Domestic Product ($90, % Change f/ Base)	-0.1%	-0.1%	-0.1%
Permit Price ($90)	0	0	0
Emission Reductions (MMTC)	-1	-1	-2
Real Effective Exchange Rate (% Change from Base)	-4%	-5%	-5%
Exports ($90, % Change From Base)	2%	2%	2%
Net Int'l Invest. Pos. (Change from Base, $90 Billion)	13	10	1
Australia			
Gross National Product ($90, % Change f/ Base)	0.0%	0.0%	0.1%
Gross Domestic Product ($90, % Change f/ Base)	0.3%	0.3%	0.2%
Permit Price ($90)	0	0	0
Emission Reductions (MMTC)	2	2	2
Real Effective Exchange Rate (% Change from Base)	2%	2%	2%
Exports ($90, % Change From Base)	0%	0%	0%
Net Int'l Invest. Pos. (Change from Base, $90 Billion)	-9	-12	-14
Other OECD			
Gross National Product ($90, % Change f/ Base)	-0.1%	-0.1%	-0.1%
Gross Domestic Product ($90, % Change f/ Base)	-0.1%	-0.1%	-0.1%
Permit Price ($90)	0	0	0
Emission Reductions (MMTC)	0	-1	-1
Real Effective Exchange Rate (% Change from Base)	-4%	-5%	-5%
Exports ($90, % Change From Base)	2%	2%	2%
Net Int'l Invest. Pos. (Change from Base, $90 Billion)	68	56	35
China			
Gross National Product ($90, % Change f/ Base)	0.0%	0.0%	0.0%
Gross Domestic Product ($90, % Change f/ Base)	0.0%	0.0%	0.0%
Permit Price ($90)	0	0	0
Emission Reductions (MMTC)	0	2	2
Real Effective Exchange Rate (% Change from Base)	0%	0%	0%
Exports ($90, % Change From Base)	0%	0%	0%
Net Int'l Invest. Pos. (Change from Base, $90 Billion)	8	10	12
LDC's			
Gross National Product ($90, % Change f/ Base)	0.4%	0.4%	0.4%
Gross Domestic Product ($90, % Change f/ Base)	0.3%	0.3%	0.2%
Permit Price ($90)	0	0	0
Emission Reductions (MMTC)	22	23	25
Real Effective Exchange Rate (% Change from Base)	7%	6%	6%
Exports ($90, % Change From Base)	-7%	-6%	-5%
Net Int'l Invest. Pos. (Change from Base, $90 Billion)	6	-9	-22
OPEC Oil Exports ($90, % Change from Base)	-2%	-2%	-2%
OPEC Oil Price (% Change from Base)	-4%	-5%	-5%

Kyoto, No Trading, Lump-Sum, OOECD Target = 300 MMTC	2010	2015	2020
U.S.			
Gross National Product ($90, % Change f/ Base)	-0.3%	-0.3%	-0.2%
Gross Domestic Product ($90, % Change f/ Base)	0.0%	0.0%	0.1%
Permit Price ($90)	54	57	60
Emission Reductions (MMTC)	-516	-662	-804
Real Effective Exchange Rate (% Change from Base)	12%	13%	14%
Exports ($90, % Change From Base)	-14%	-16%	-18%
Net Int'l Invest. Pos. (Change from Base, $90 Billion)	-528	-578	-572
Japan			
Gross National Product ($90, % Change f/ Base)	-0.9%	-0.7%	-0.4%
Gross Domestic Product ($90, % Change f/ Base)	-1.5%	-1.5%	-1.5%
Permit Price ($90)	222	230	237
Emission Reductions (MMTC)	-96	-122	-146
Real Effective Exchange Rate (% Change from Base)	-23%	-22%	-22%
Exports ($90, % Change From Base)	13%	12%	12%
Net Int'l Invest. Pos. (Change from Base, $90 Billion)	28	44	30
Australia			
Gross National Product ($90, % Change f/ Base)	-2.4%	-3.6%	-4.5%
Gross Domestic Product ($90, % Change f/ Base)	-0.1%	-0.7%	-1.2%
Permit Price ($90)	49	66	84
Emission Reductions (MMTC)	-27	-44	-65
Real Effective Exchange Rate (% Change from Base)	16%	13%	10%
Exports ($90, % Change From Base)	-10%	-8%	-7%
Net Int'l Invest. Pos. (Change from Base, $90 Billion)	-68	-116	-165
Other OECD			
Gross National Product ($90, % Change f/ Base)	-1.1%	-1.4%	-1.6%
Gross Domestic Product ($90, % Change f/ Base)	-1.2%	-1.4%	-1.5%
Permit Price ($90)	111	148	184
Emission Reductions (MMTC)	-301	-473	-673
Real Effective Exchange Rate (% Change from Base)	-23%	-23%	-23%
Exports ($90, % Change From Base)	15%	14%	14%
Net Int'l Invest. Pos. (Change from Base, $90 Billion)	460	604	688
China			
Gross National Product ($90, % Change f/ Base)	0.0%	0.1%	0.1%
Gross Domestic Product ($90, % Change f/ Base)	-0.1%	-0.1%	-0.1%
Permit Price ($90)	0	0	0
Emission Reductions (MMTC)	1	4	4
Real Effective Exchange Rate (% Change from Base)	-1%	-1%	-1%
Exports ($90, % Change From Base)	1%	0%	0%
Net Int'l Invest. Pos. (Change from Base, $90 Billion)	34	46	57
LDC's			
Gross National Product ($90, % Change f/ Base)	2.4%	2.4%	2.2%
Gross Domestic Product ($90, % Change f/ Base)	1.4%	1.4%	1.2%
Permit Price ($90)	0	0	0
Emission Reductions (MMTC)	83	88	95
Real Effective Exchange Rate (% Change from Base)	47%	45%	44%
Exports ($90, % Change From Base)	-34%	-30%	-25%
Net Int'l Invest. Pos. (Change from Base, $90 Billion)	124	117	115
OPEC Oil Exports ($90, % Change from Base)	-9%	-9%	-9%
OPEC Oil Price (% Change from Base)	-14%	-15%	-17%

Kyoto, No Trading, Lump-Sum, OOECD Target = 400 MMTC	2010	2015	2020
U.S.			
Gross National Product ($90, % Change f/ Base)	-0.3%	-0.2%	-0.2%
Gross Domestic Product ($90, % Change f/ Base)	0.1%	0.1%	0.2%
Permit Price ($90)	55	58	62
Emission Reductions (MMTC)	-520	-673	-824
Real Effective Exchange Rate (% Change from Base)	13%	14%	15%
Exports ($90, % Change From Base)	-16%	-18%	-20%
Net Int'l Invest. Pos. (Change from Base, $90 Billion)	-581	-628	-626
Japan			
Gross National Product ($90, % Change f/ Base)	-0.8%	-0.6%	-0.3%
Gross Domestic Product ($90, % Change f/ Base)	-1.6%	-1.6%	-1.5%
Permit Price ($90)	219	226	233
Emission Reductions (MMTC)	-96	-121	-144
Real Effective Exchange Rate (% Change from Base)	-24%	-24%	-24%
Exports ($90, % Change From Base)	14%	13%	13%
Net Int'l Invest. Pos. (Change from Base, $90 Billion)	22	35	22
Australia			
Gross National Product ($90, % Change f/ Base)	-2.5%	-3.7%	-4.6%
Gross Domestic Product ($90, % Change f/ Base)	-0.1%	-0.7%	-1.2%
Permit Price ($90)	49	67	84
Emission Reductions (MMTC)	-27	-44	-65
Real Effective Exchange Rate (% Change from Base)	17%	13%	10%
Exports ($90, % Change From Base)	-10%	-8%	-7%
Net Int'l Invest. Pos. (Change from Base, $90 Billion)	-68	-117	-166
Other OECD			
Gross National Product ($90, % Change f/ Base)	-1.4%	-1.6%	-1.8%
Gross Domestic Product ($90, % Change f/ Base)	-1.5%	-1.6%	-1.7%
Permit Price ($90)	146	179	212
Emission Reductions (MMTC)	-391	-574	-780
Real Effective Exchange Rate (% Change from Base)	-26%	-25%	-25%
Exports ($90, % Change From Base)	17%	15%	16%
Net Int'l Invest. Pos. (Change from Base, $90 Billion)	508	654	739
China			
Gross National Product ($90, % Change f/ Base)	0.0%	0.1%	0.1%
Gross Domestic Product ($90, % Change f/ Base)	-0.1%	-0.1%	-0.1%
Permit Price ($90)	0	0	0
Emission Reductions (MMTC)	1	4	5
Real Effective Exchange Rate (% Change from Base)	-1%	-1%	-1%
Exports ($90, % Change From Base)	1%	0%	0%
Net Int'l Invest. Pos. (Change from Base, $90 Billion)	37	49	61
LDC's			
Gross National Product ($90, % Change f/ Base)	2.7%	2.6%	2.5%
Gross Domestic Product ($90, % Change f/ Base)	1.6%	1.5%	1.3%
Permit Price ($90)	0	0	0
Emission Reductions (MMTC)	91	96	103
Real Effective Exchange Rate (% Change from Base)	53%	51%	49%
Exports ($90, % Change From Base)	-38%	-33%	-28%
Net Int'l Invest. Pos. (Change from Base, $90 Billion)	141	137	133
OPEC Oil Exports ($90, % Change from Base)	-10%	-10%	-10%
OPEC Oil Price (% Change from Base)	-16%	-17%	-19%

Kyoto, Annex I Trading, Lump-Sum, OOECD Target = 400 MMTC	2010	2015	2020
U.S.			
Gross National Product ($90, % Change f/ Base)	-0.2%	-0.5%	-0.7%
Gross Domestic Product ($90, % Change f/ Base)	-0.1%	-0.3%	-0.4%
Permit Price ($90)	32	52	67
Emission Reductions (MMTC)	-321	-625	-935
Real Effective Exchange Rate (% Change from Base)	5%	6%	7%
Exports ($90, % Change From Base)	-6%	-8%	-9%
Net Int'l Invest. Pos. (Change from Base, $90 Billion)	-238	-302	-265
Japan			
Gross National Product ($90, % Change f/ Base)	-0.2%	-0.2%	-0.1%
Gross Domestic Product ($90, % Change f/ Base)	-0.5%	-0.6%	-0.6%
Permit Price ($90)	32	52	67
Emission Reductions (MMTC)	-19	-31	-43
Real Effective Exchange Rate (% Change from Base)	-14%	-14%	-14%
Exports ($90, % Change From Base)	8%	7%	7%
Net Int'l Invest. Pos. (Change from Base, $90 Billion)	50	88	95
Australia			
Gross National Product ($90, % Change f/ Base)	-2.0%	-3.3%	-4.1%
Gross Domestic Product ($90, % Change f/ Base)	0.1%	-0.5%	-0.9%
Permit Price ($90)	32	52	67
Emission Reductions (MMTC)	-17	-34	-51
Real Effective Exchange Rate (% Change from Base)	13%	11%	9%
Exports ($90, % Change From Base)	-7%	-6%	-4%
Net Int'l Invest. Pos. (Change from Base, $90 Billion)	-61	-104	-147
Other OECD			
Gross National Product ($90, % Change f/ Base)	-0.5%	-0.7%	-0.9%
Gross Domestic Product ($90, % Change f/ Base)	-0.5%	-0.7%	-0.7%
Permit Price ($90)	32	52	67
Emission Reductions (MMTC)	-98	-173	-250
Real Effective Exchange Rate (% Change from Base)	-16%	-16%	-16%
Exports ($90, % Change From Base)	11%	10%	10%
Net Int'l Invest. Pos. (Change from Base, $90 Billion)	402	550	603
China			
Gross National Product ($90, % Change f/ Base)	0.0%	0.1%	0.1%
Gross Domestic Product ($90, % Change f/ Base)	-0.1%	0.0%	0.0%
Permit Price ($90)	0	0	0
Emission Reductions (MMTC)	-1	1	3
Real Effective Exchange Rate (% Change from Base)	0%	0%	0%
Exports ($90, % Change From Base)	0%	0%	0%
Net Int'l Invest. Pos. (Change from Base, $90 Billion)	21	30	38
LDC's			
Gross National Product ($90, % Change f/ Base)	1.4%	1.4%	1.3%
Gross Domestic Product ($90, % Change f/ Base)	0.9%	0.8%	0.7%
Permit Price ($90)	0	0	0
Emission Reductions (MMTC)	44	53	62
Real Effective Exchange Rate (% Change from Base)	26%	26%	25%
Exports ($90, % Change From Base)	-20%	-18%	-15%
Net Int'l Invest. Pos. (Change from Base, $90 Billion)	63	53	38
OPEC Oil Exports ($90, % Change from Base)	-4%	-5%	-5%
OPEC Oil Price (% Change from Base)	-3%	-6%	-9%

Kyoto, "Umbrella", Lump-Sum, OOECD Target = 400 MMTC	2010	2015	2020
U.S.			
Gross National Product ($90, % Change f/ Base)	0.1%	0.0%	-0.1%
Gross Domestic Product ($90, % Change f/ Base)	0.3%	0.1%	0.0%
Permit Price ($90)	16	30	40
Emission Reductions (MMTC)	-127	-325	-519
Real Effective Exchange Rate (% Change from Base)	8%	8%	8%
Exports ($90, % Change From Base)	-10%	-11%	-12%
Net Int'l Invest. Pos. (Change from Base, $90 Billion)	-344	-396	-362
Japan			
Gross National Product ($90, % Change f/ Base)	-0.1%	0.0%	0.1%
Gross Domestic Product ($90, % Change f/ Base)	-0.5%	-0.5%	-0.6%
Permit Price ($90)	16	30	40
Emission Reductions (MMTC)	-13	-21	-29
Real Effective Exchange Rate (% Change from Base)	-16%	-15%	-15%
Exports ($90, % Change From Base)	8%	8%	8%
Net Int'l Invest. Pos. (Change from Base, $90 Billion)	29	73	97
Australia			
Gross National Product ($90, % Change f/ Base)	-1.3%	-2.1%	-2.6%
Gross Domestic Product ($90, % Change f/ Base)	0.1%	-0.3%	-0.6%
Permit Price ($90)	16	30	40
Emission Reductions (MMTC)	-8	-19	-30
Real Effective Exchange Rate (% Change from Base)	7%	6%	4%
Exports ($90, % Change From Base)	-4%	-4%	-3%
Net Int'l Invest. Pos. (Change from Base, $90 Billion)	-21	-41	-62
Other OECD			
Gross National Product ($90, % Change f/ Base)	-1.2%	-1.4%	-1.5%
Gross Domestic Product ($90, % Change f/ Base)	-1.3%	-1.5%	-1.6%
Permit Price ($90)	146	179	212
Emission Reductions (MMTC)	-388	-568	-772
Real Effective Exchange Rate (% Change from Base)	-19%	-18%	-17%
Exports ($90, % Change From Base)	13%	11%	11%
Net Int'l Invest. Pos. (Change from Base, $90 Billion)	426	576	653
China			
Gross National Product ($90, % Change f/ Base)	0.0%	0.1%	0.1%
Gross Domestic Product ($90, % Change f/ Base)	-0.1%	0.0%	0.0%
Permit Price ($90)	0	0	0
Emission Reductions (MMTC)	0	2	4
Real Effective Exchange Rate (% Change from Base)	0%	0%	0%
Exports ($90, % Change From Base)	0%	0%	0%
Net Int'l Invest. Pos. (Change from Base, $90 Billion)	23	32	40
LDC's			
Gross National Product ($90, % Change f/ Base)	1.8%	1.8%	1.7%
Gross Domestic Product ($90, % Change f/ Base)	1.0%	1.0%	0.8%
Permit Price ($90)	0	0	0
Emission Reductions (MMTC)	53	61	69
Real Effective Exchange Rate (% Change from Base)	32%	31%	30%
Exports ($90, % Change From Base)	-24%	-21%	-18%
Net Int'l Invest. Pos. (Change from Base, $90 Billion)	102	106	104
OPEC Oil Exports ($90, % Change from Base)	-6%	-6%	-7%
OPEC Oil Price (% Change from Base)	-8%	-10%	-12%

Kyoto, Full "JI", Lump-Sum, OOECD Target = 400 MMTC	2010	2015	2020
U.S.			
Gross National Product ($90, % Change f/ Base)	0.0%	0.0%	0.0%
Gross Domestic Product ($90, % Change f/ Base)	0.0%	0.0%	-0.1%
Permit Price ($90)	11	16	20
Emission Reductions (MMTC)	-102	-177	-267
Real Effective Exchange Rate (% Change from Base)	3%	3%	3%
Exports ($90, % Change From Base)	-3%	-3%	-4%
Net Int'l Invest. Pos. (Change from Base, $90 Billion)	-78	-86	-47
Japan			
Gross National Product ($90, % Change f/ Base)	0.0%	0.0%	0.0%
Gross Domestic Product ($90, % Change f/ Base)	-0.2%	-0.2%	-0.2%
Permit Price ($90)	11	16	20
Emission Reductions (MMTC)	-6	-9	-12
Real Effective Exchange Rate (% Change from Base)	-5%	-6%	-6%
Exports ($90, % Change From Base)	3%	3%	3%
Net Int'l Invest. Pos. (Change from Base, $90 Billion)	25	44	38
Australia			
Gross National Product ($90, % Change f/ Base)	-0.7%	-1.1%	-1.3%
Gross Domestic Product ($90, % Change f/ Base)	-0.1%	-0.2%	-0.3%
Permit Price ($90)	11	16	20
Emission Reductions (MMTC)	-6	-10	-15
Real Effective Exchange Rate (% Change from Base)	3%	2%	2%
Exports ($90, % Change From Base)	-2%	-1%	-1%
Net Int'l Invest. Pos. (Change from Base, $90 Billion)	-9	-17	-27
Other OECD			
Gross National Product ($90, % Change f/ Base)	-0.2%	-0.2%	-0.3%
Gross Domestic Product ($90, % Change f/ Base)	-0.2%	-0.2%	-0.2%
Permit Price ($90)	11	16	20
Emission Reductions (MMTC)	-33	-52	-74
Real Effective Exchange Rate (% Change from Base)	-6%	-6%	-6%
Exports ($90, % Change From Base)	4%	4%	4%
Net Int'l Invest. Pos. (Change from Base, $90 Billion)	183	259	311
China			
Gross National Product ($90, % Change f/ Base)	-0.5%	-0.1%	0.3%
Gross Domestic Product ($90, % Change f/ Base)	-0.6%	-0.5%	-0.7%
Permit Price ($90)	11	16	20
Emission Reductions (MMTC)	-278	-471	-697
Real Effective Exchange Rate (% Change from Base)	7%	11%	14%
Exports ($90, % Change From Base)	-5%	-7%	-8%
Net Int'l Invest. Pos. (Change from Base, $90 Billion)	-41	-46	-36
LDC's			
Gross National Product ($90, % Change f/ Base)	0.2%	0.1%	0.1%
Gross Domestic Product ($90, % Change f/ Base)	-0.1%	-0.2%	-0.3%
Permit Price ($90)	11	16	20
Emission Reductions (MMTC)	-118	-205	-308
Real Effective Exchange Rate (% Change from Base)	7%	6%	6%
Exports ($90, % Change From Base)	-5%	-5%	-4%
Net Int'l Invest. Pos. (Change from Base, $90 Billion)	51	50	40
OPEC Oil Exports ($90, % Change from Base)	-1%	-1%	-1%
OPEC Oil Price (% Change from Base)	-4%	-5%	-6%

G-Cubed Analysis of the Impact of Carbon Emissions Reductions From the Kyoto Agreement

A simulation of the Kyoto agreement was carried out using version V31L2 of the G-Cubed model, an 8-region, 14-sector general equilibrium model of the global economy developed by McKibbin and Wilcoxen. (A brief description of the model is attached.) The simulation required two simplifying assumptions:

- Since the model covers only energy-related carbon emissions, the analysis assumed that 88% of required reductions are undertaken from carbon in the energy sector.
- The analysis has a significantly different emissions baseline than the CEA baseline, mainly because it does not capture the effects of reduced coal use in the UK and Germany, or the merger of East and West Germany. To accommodate this limitation, the required reductions were assumed to be proportional to those required in the CEA baseline.

For instance, since the "Other OECD" region reduces carbon emissions 26% below baseline in 2010, the region reduces emissions 26% below baseline in the G-Cubed analysis. This increases the reductions required of the Other OECD region; however, requiring higher reductions is likely to yield a more realistic characterization of the costs of meeting the commitment than requiring emissions of only 298 MMTC, since the model's reductions are taken from a higher stock of emissions than is likely to be the case.

	(1) CEA 2010 Carbon Emissions	(2) CEA 2010 Total GHG Commitment	(3) CEA Commitment * 0.88	(4) (3) / (1)	(5) GCubed 2010 Carbon Emissions	(6) GCubed 2010 Commitment (5)*(4)
U.S.	1838	600	528	-29%	1822	-523
Japan	368	113	99	-27%	358	-97
Australia	88	21	18	-21%	133	-28
Other OECD	1158	339	298	-26%	1560	-401

G-Cubed is a general equilibrium model, and thus represents each region as a competitive market economy in dynamic equilibrium with other regions. As a consequence, the representation of the former Soviet Bloc does not capture the shock associated with the institutional collapse of the formerly planned economy, the consequent dramatic decrease in emissions, or the consequent stock of "paper tons" that is likely to be available in the region in 2010. However, since the region has relatively little interaction with the rest of the world in the model (as a consequence of the calibration that renders it in equilibrium in the base year), the analysis treats the former Soviet Bloc exogenously, and assumes both the "paper tons" and the "supply curve" of additional reductions available from the SGM analysis. Thus the analysis assumes 426 MMTC of paper tons available in 2010, declining to about 350 MMTC in 2015 and 290 MMTC in 2020, and roughly an additional 140 MMTC available at a cost of $25/MTC ($92).[1]

[1] The SGM numbers, in turn, are based on the results of a joint project between the OECD, the World Bank and the Office of Policy Development at US EPA (see OECD document OECD/GD(97)154 "Environmental Implications of Energy and Transport Subsidies" or Chapter 6 of OECD publication "Reforming.Energy and Transport Subsidies."

The analysis included the following scenarios:

1. **U.S. Only.** U.S. meets its commitment alone (this scenario illustrates the importance of trade and capital flows in the absence of any action by other countries).
2. **Annex I No Trading, OOECD = 300 MMTC.** The Annex I countries meet their commitments with no international permit trading (by implication, however, the countries of the "Other OECD," which includes the EU, Canada and New Zealand, are assumed to be trading amongst themselves). The "Other OECD" target is assumed to be 300 MMTC.
3. **Annex I No Trading, OOECD = 400 MMTC.** The Annex I countries meet their commitments with no international permit trading, and the "Other OECD" target is assumed to be 400 MMTC.
4. **Annex I Trading.** The Annex I countries meet their commitments with full international permit trading amongst the Annex I countries. In this and all of the following scenarios, the "Other OECD" target is assumed to be 400 MMTC.
5. **"Umbrella."** The Annex I countries meet their commitments with international permit trading amongst all Annex I countries except those in the "Other OECD" region. This is the model's nearest approximation of an "Umbrella, no EU" scenario.
6. **Full "JI".** The Annex I countries meet their commitments with full international permit trading and full "joint implementation," where it is assumed that developing countries have agreed to emissions rights equivalent to their modeled baseline, and have agreed to make those permits available on international markets.
7. **"JI" 20% of Reductions.** The Annex I countries meet their commitments with full international permit trading and "joint implementation," where "JI" tons are constrained to be only 20% of total emission reductions.
8. **20% of "JI."** The Annex I countries meet their commitments with full international permit trading and "joint implementation," where "JI" tons are constrained to be only 20% of the total "JI" tons in the Full "JI" scenario (6).

The analysis includes two versions of each of the above scenarios. The first simulates a system of freely distributed permits as a carbon tax with the revenues recycled through lump-sum reductions in personal income taxes (there are no distributional implications because there is only one representative agent per region). The second simulates a system of auctioned permits through a carbon tax with revenues used to reduce budget deficits in each region. The two versions of each scenario provide a reasonable bound of the impacts of different fiscal approaches to carbon controls.

Appendix: G-Cubed Model Description

This analysis was carried out using the G-Cubed model, a general equilibrium model of the global economy with 8 regions (the United States, Japan, Australia, Other OECD, China, non-oil exporting developing countries, former Soviet Bloc, and OPEC) and 13 sectors, including 5 energy sectors (electric and gas utilities, petroleum refining, coal mining, and crude oil and gas extraction) and 8 non-energy sectors (other mining, agriculture, forestry and wood products, durable manufacturing, non-durable manufacturing, transportation, services, and a sector producing investment goods). This model combines the international detail of the McKibbin-Sachs Global (MSG) global dynamic macroeconomic framework with the detailed, econometrically-based framework of the Jorgenson-Wilcoxen general equilibrium model of the U.S. economy. In this framework, carbon emissions are related to a variety of economic activities, while intertemporal behavior such as saving, investment and exchange rate arbitrage is modeled as forward-looking optimization by infinitely-lived "representative agents" (with 30% forward-looking, 70% adaptive expectations) and forward-looking firms "firms" all subject to appropriate intertemporal budget constraints. The model treats international trade and capital flows in a consistent general equilibrium framework, so that international trade and payments balances and exchange rates are simultaneously determined in the context of long-run growth and gradual convergence of developing economies' production possibilities to those of the developed countries. Using such a framework, we can show that consideration of all of these effects in a consistent manner greatly clarifies the likely effects of emission controls, particularly of differential commitments in different regions. We can also show that capital flows are likely to play a significant role in determining overall effects of differential commitments.

Consumer demand. Consumer behavior is represented by a two-tier system of nested constant elasticity of substitution (CES) utility functions. At the top tier, the household allocates spending between household capital services, labor services, energy and materials. In the current version of the model, the elasticity of substitution between these inputs is set to unity, rendering this tier Cobb-Douglas and probably overstating the ability of households to substitute away from energy toward other inputs. At the second tier, spending on energy and spending on materials are allocated among individual goods. The elasticity of substitution between energy goods is 0.8 and the elasticity of substitution among materials is 1.0. Both of these values were determined by econometric estimation.

Producer behavior. Similarly, production possibilities are represented by sector-specific nested factor demand equations. A top tier of equations specifies demand for capital, labor, energy and materials aggregates; while equations in lower tiers specify demand for specific energy inputs and materials inputs. The top tier substitution elasticities used in this analysis – most of them estimated from historical data for the U.S., but a few imposed exogenously to limit the limit the degree of fuel input substitution in the energy conversion sectors – range from 0.2 for most of the energy sectors to nearly 1.3 in Agriculture; while the substitution elasticities among energy inputs range from less than 0.2 in Coal Mining to over 1.1 in Other Mining; and those among materials inputs range from 0.2 for most energy sectors to 3.0 for Services.

Saving and investment. As noted above, 70% of households are assumed to be liquidity constrained and consume all of their income in each period. The remaining 30% are assumed to be full intertemporal optimizers who choose current consumption to maximize an intertemporal utility function. (The key parameters of the utility function are the intertemporal elasticity of substitution, imposed to be unity, and the rate of time preference, imposed to be 2.5%) The difference between the consumption of the intertemporal optimizers and their income determines total private domestic saving. Private domestic saving is augmented by public saving (or dissaving, as the case may be) and capital inflows from abroad (discussed below). This total is then allocated to investment in sector-specific capital goods according to a set of q-theoretic investment models. There is one capital good for each industry, plus one for capital used in producing capital goods themselves, plus one more for household capital, for a total of 14. Once installed in a particular sector, physical capital is completely immobile – it cannot move between sectors or from one country to another. Capital is not vintaged and depreciates geometrically.

G-Cubed Model V.31 CES Substitution Elasticities

Sector	Top Tier		Energy Tier	Materials Tier
	(Estimated)	(Imposed in this analysis)	(Estimated)	(Estimated)
Electricity	0.763	0.200	0.200	1.000
Natural Gas	0.810	0.200	0.932	0.200
Petroleum Refining	0.543	0.200	0.200	0.200
Coal Mining	1.703	0.493	0.159	0.529
Crude Oil & Gas	0.493	0.493	0.137	0.200
Other Mining	1.001	1.001	1.147	2.765
Agriculture	1.283	1.283	0.628	1.732
Forestry/Wood Products	0.935	0.935	0.939	0.176
Durables	0.410	0.410	0.804	0.200
Non-Durables	1.004	1.004	1.000	0.057
Transportation	0.537	0.537	0.200	0.200
Services	0.256	0.256	0.321	3.006
Investment Goods		1.000	1.000	1.000

Technological change. Technological change is represented primarily as exogenous labor-augmenting productivity growth, but the model also provides for total factor productivity (TFP) growth and energy-saving technological change (sometimes referred to as autonomous energy efficiency improvement, or AEEI). In the current version of the model, there is no endogenous technology response to changes in relative prices (apart from substitution).

Taxes. The model includes taxes on household income, corporate income, sales of goods and services and tariffs. It also includes a number of potential taxes that are zero in the base case but can be made nonzero for policy analysis: carbon and BTU taxes on primary fossil fuels, an investment tax credit, and a second lump-sum tax. It does not include a value added tax. Tax rates are generally set exogenously.

Fiscal policy. Government spending is set exogenously. Because spending and taxes are both exogenous, the government fiscal surplus or deficit will be endogenous. Government deficits accumulate into a stock of debt on which interest payments must be made in each period. The government's long term budget constraint is imposed by requiring that in each period the government levy a lump sum tax large enough to pay for that year's interest obligation. (That is, the government is not allowed to borrow to finance interest payments.) In essence this means that all government borrowing takes the form of consols backed by the revenue from an earmarked tax. Because some of the agents are not full intertemporal optimizers, the model does not yield Ricardian equivalence: government budget deficits do not lead to equivalent increases in savings, and so can influence real output.

Money, nominal wages and monetary policy. Money is supplied exogenously by each country's central bank and is demanded for transactions. The demand for real money balances depends positively on the volume of transactions (measured by total value of industry output) and negatively on the interest rate. The interest elasticity of money demand is -0.6. In the long run the model reaches full employment and the size of the labor force is determined by the exogenous rate of population growth. In the short run, however, wages are set in nominal terms and adjust slowly to changes in employment and to changes in current and expected inflation rates. As a result, monetary shocks have real short term effects because they change the real wage.

Trade. International trade is modeled as a set of bilateral flows of all twelve commodities between all eight regions. Within each country the demand for imports of each commodity is determined by imperfect substitution between the domestic good and imports from each of the other countries (the Armington approach). In the current version of the model, the elasticity of substitution between each domestic good and competing imports from all other countries is set to unity. For most of the goods in the model, this is likely to overstate the substitutability of foreign and domestic products. The model's sectors are highly aggregated and each includes a large variety of products that are at best, only very poor substitutes for each other. (That is, the product mix in imported durable goods does not look very much like the domestic product mix.) As a consequence, unitary Armington elasticities probably yields rather elastic responses to changes in exchange rates and relative prices, relative to empirical estimates. For petroleum products, on the other hand, the model may understate the substitutability of foreign and domestic varieties. (Empirical evidence on this point is mixed, however, in part because the history of regulation and institutions in the world oil market makes it difficult to estimate substitutability.)

The model also includes full integration of international capital flows. All trade imbalances must be financed by offsetting flows of financial capital. Capital inflows accumulate into stocks of debt that must be serviced by future trade surpluses. At the same time, financial capital is fully mobile and flows to regions offering the highest rates of return after adjusting for expected changes in exchange rates. Together, these two mechanisms (trade imbalances and forward-looking interest rate arbitrage) determine exchange rates.

Model solution. The model has a large number of forward-looking variables: within each country there are 14 *q* variables corresponding to the 14 capital stocks, wealth, and the exchange rate. Adding up across countries brings the total to over 100. In addition, there are about 6,000 equations that must hold within each period. At the moment, the only feasible methods for solving a model of this size are based on linearization. G-Cubed uses a hybrid form of linearization in which price equations are linearized in logs and other equations are linearized in differences. All linearization is done about the model's benchmark year data set, which at the moment is for 1987. Once the linearization is complete, the resulting model is algebraically compressed into its minimal dynamic representation and solved numerically to obtain an expression relating the model's dynamic variables to current and future values of the exogenous variables (the model's "stable manifold"). Finally, this expression is then used to compute solutions to the model. Linearization has both benefits and costs. The principal cost is that the solutions will involve truncation error (and hence will be somewhat inaccurate) when simulating large shocks. The benefit, however, is that a large model with considerable detail in agents' expectations and intertemporal optimization decisions can be solved, and generally solved very quickly.

Baseline Projections. In order to solve the model, projections must be provided on the future course of key exogenous variables. These include: population growth by region, productivity growth by sector and region, energy efficiency improvements by sector and region, and tax rates, fiscal spending patterns and monetary policy by region. Unfortunately, few of these can be projected with any precision. The most important for climate policy are population and productivity growth. The base population assumption in G-Cubed is that regional population growth rates follow the paths projected by the United Nations. It is straightforward, however, to impose other population projections. For productivity, the base assumption in G-Cubed is that the pattern of technical change at the sector level is similar to the historical record for the United States (where data is available). In regions other than the United States, however, the sector-level rates of technical change are scaled up or down in order to match the region's observed rate of aggregate productivity growth. This approach attempts to capture the fact that the rate of technical change varies considerably across industries while reconciling it with regional differences in overall growth. It is, at best, a rough approximation: it would be better to estimate productivity growth for each sector in each region but the necessary data is largely unavailable. As with population projections, it is straightforward to impose other assumptions about future productivity growth. The default specification is that productivity is labor-augmenting but it can also be given as total factor productivity growth, or as a combination of the two. Energy-augmenting technical change can also be imposed.

The Effects of Full Worldwide Permit Trading on Consumption Losses by OECD Countries

Model	Pathway	Trading	No Trading	Trading/No Trading
CETA	WRE	1.86	1.83	1.02
CPBRIVM	WRE	0.17	0.64	0.27
FUND	WRE	1.47	9.82	0.15
MERGE	WRE	0.60	0.85	0.71
MiniCAM	WRE	0.54	1.58	0.34
SGM	WRE	0.13	1.84	0.07
CETA	WG-1	4.03	5.94	0.68
CPBRIVM	WG-1	0.99	3.25	0.30
FUND	WG-1	4.97	11.71	0.42
MERGE	WG-1	3.24	6.12	0.53
MiniCAM	WG-1	3.44	6.51	0.53
SGM	WG-1	1.48	6.17	0.24
			Average:	0.44

Trading and No Trading Values are in trillions of 1990 US$

MEMORANDUM **DRAFT**

TO: Distribution

SUBJECT: Nordhaus's arguments against strict action.

Executive Summary and Key Findings

- Nordhaus finds that the optimal policy, given the current state of knowledge and ignoring uncertainty, is to do very little in the short term (a $6/ton tax in 2005) and only marginally more in the long term. While his mild long-term policy suggestion helps to inform the basis of his short term recommendations, Nordhaus only intends to propose a short-term strategy and emphasizes that policies should change as we learn more.

- Recognizing wide-ranging uncertainties and the possibility of calamity, Nordhaus investigates optimal policy choices over a reasonable distribution of possible states of the world. He shows that while the median optimal carbon tax is on the order of $6/ton in 2005, the mean optimal carbon tax is somewhat larger, at $18/ton in 2005.

- His conclusions are viewed with skepticism by some critics, who believe some or all of the following: he overstates control costs, he understates control benefits, and his choice of a positive pure rate of time preference is indefensible. Others find his results and methodology more robust.

Introduction

In a 1994 book[1], Nordhaus calculates an optimal policy response to the problem of climate change. A distinguishing feature of this work is that it aims to uncover a truly optimal policy — that is, one that maximizes *net* benefit as opposed to one that merely minimizes the cost of achieving an *ad hoc* CO2 concentration target.

Basic Results

Ignoring uncertainty and with a best guess of costs and benefits (based on a wide purview of existing studies) Nordhaus finds that the optimal policy is to do close to nothing. With the optimal policy, carbon taxes rise from $6 per ton in 2005 to $20 per ton (1989 dollars) in 2100. Global average temperature under this policy increases 3.2°C — only 0.2°C less than in the baseline case. On net, the world economy under this scenario enjoys a small net benefit relative to the baseline case. See Table 1.

Restricting emissions of greenhouse gases to 1990 levels, on the other hand, inflicts relatively large net costs. Carbon taxes rise to $400/ton in 2100, and the increase in global average

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[1]"Managing the Global Commons," which presents analysis based on Nordhaus's DICE model. It is the culmination of arguments made in earlier papers.

temperature is limited to only 2.4°C — a full degree less than in the baseline.

Given that the optimal policy is much closer to doing nothing than to restricting to 1990 levels, it appears that literally doing nothing in the short term is superior to current proposals oriented on 1990 emissions levels.

Table 1[2]

	Global Net Benefit[3]			Carbon Tax ($/ton)		
	NPV ($billions)	Annualized ($billions)	NPV as % of PV of baseline output	2005	2055	2105
Optimal Policy (no uncertainty)	271	11	0.04	6	15	21
Restrict to 1990 levels	- 7,069	- 283	- 0.98	50	230	400
Stabilize at 1.5°C increase	- 40,980	- 1,639	- 5.94	200	700	800

It is worth emphasizing that Nordhaus's result is not simply a matter of delaying controls. While the typical *cost-minimization* exercise also shows that carbon emissions should be allowed to follow a near-baseline path at first, Nordhaus's result goes further: he finds that relatively little should be done even over the long term. In his optimal scenario, carbon concentrations are allowed to grow without apparent bound.

Incorporating uncertainty, Nordhaus's results change though the basic message of modest short-term measures does not.

- Nordhaus examines how the optimal policy changes when key parameter values vary from his best guess and finds that the mean optimal policy calls for higher carbon taxes than he finds for the best-guess case. The mean optimal policy calls for a carbon tax of $18/ton in 2005 and $53/ton in 2045.

- The "mean" result differs from the "best guess" result because the distribution of outcomes is skewed so that favorable climate change scenarios are similar to the best-guess case and occur with high probability while extremely unfavorable scenarios occur with low probability.

- Nordhaus finds that only 2% of possible scenarios -- the least favorable -- would call for a carbon tax in 1995 of over $100/ton.

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[2]Source for Tables 1 and 2: Nordhaus, "Managing the Global Commons", 1994. These data come from the DICE model.

[3]Net benefits are measured relative to the base case of taking no action.

Basis for Results

Nordhaus's results derive from three key assumptions:

- that the *costs* of reducing carbon emissions are relatively high;
- that the *benefits* of carbon control (in the form of averted damages) are relatively low; and
- that the social rate of discount is greater than zero.

Critics have attacked Nordhaus on all three points, and it is worth examining each point in greater detail.

1. Costs

The cost of reducing carbon emissions is determined by the responsiveness of the economy to a given level of carbon-control effort. For example, if a $10 carbon fee elicits a large response in terms of lower carbon emissions, the cost of carbon control will be low. Conversely, if a $10 carbon fee elicits a small response, program cost will be high.

The impact on the economy of a carbon-control program in Nordhaus's model is determined by two key assumptions — one concerning the "static" response, given current technologies and carbon use, the other concerning the "dynamic" response, reflecting induced changes in carbon use and advances in technology.

- Nordhaus bases his assumption about static responses on existing empirical studies. His assumptions here are not particularly contentious.
- Nordhaus attempts to capture dynamic responses by assuming that technology will improve at about the same rate in the future as it has done in the past. Importantly, the trend rate of improvement is not allowed to vary depending on the price of carbon permits or the level of a carbon tax. Critics find fault with this approach, since his model thus assumes that carbon taxes will in no way accelerate the development of non-carbon technologies — in stark contrast to the "technologist" view.

Nordhaus notes that his results are sensitive to assumptions about technology, but he does not document the extent of that sensitivity in isolation from other uncertainties.

2. Benefits

The benefits of carbon control are determined by the magnitude of damages averted -- that is, damages that would have occurred in the absence of a control program. Nordhaus calculates that these damages would be relatively modest. For example, he estimates that a 3 °C temperature increase results in only a 1.3 percent loss of output per year.

Some critics feel that damages averted will be greater than Nordhaus assumes. They note that SO2 and particulate emissions will be reduced, biodiversity will be better maintained, and negative health effects will be avoided.

In a survey of experts, Nordhaus finds that the median cost prediction for a 3 °C rise in temperature is 1.9 percent of output annually -- 40% higher than his own. The mean prediction is much higher, at 3.6 percent.

3. The social rate of discount

Given that costs are borne up front and benefits accrue mainly in the distant future, assumptions about the social rate of discount are crucial. Nordhaus assumes that the social rate of discount is 3 percent per year; this rate is sufficiently large as to significantly reduce the present value of the distant and already modest benefits.

Many critics (mainly non-economists) feel that a social rate of discount greater than zero is indefensible on ethical grounds. However, mainstream economists strongly endorse the approach to discounting which Nordhaus uses and find it difficult to understand very low rates of time preference in the context of observed behavior.

Nordhaus re-evaluates the optimal policy when the pure rate of time preference is only 1 percent and finds that the optimal carbon tax in this case is considerably greater (see Table 2).

Table 2

	Optimal Carbon Tax ($/ton)		
Rate of Time Preference	1995	2045	2095
3%	5.3	13.7	21.0
1%	23.6	52.6	77.5

Conclusion

Nordhaus's analysis implies that little should be done either in the short term or in the long term. His results hinge on assumptions about technology improvements, appropriate discount rates, and the size of potential damages. Critics feel that Nordhaus may be:

- overestimating mitigation costs because he ignores the possible influence of higher energy prices in spurring the development of new technology; and

- underestimating damages from climate change.

While both would tend to cause Nordhaus to be too lax in his policy recommendations, it is not clear that such criticisms can be sustained far enough to overturn Nordhaus's basic point that strict action is inappropriate in the short term. The discount rate issue, while crucial, is difficult to settle.

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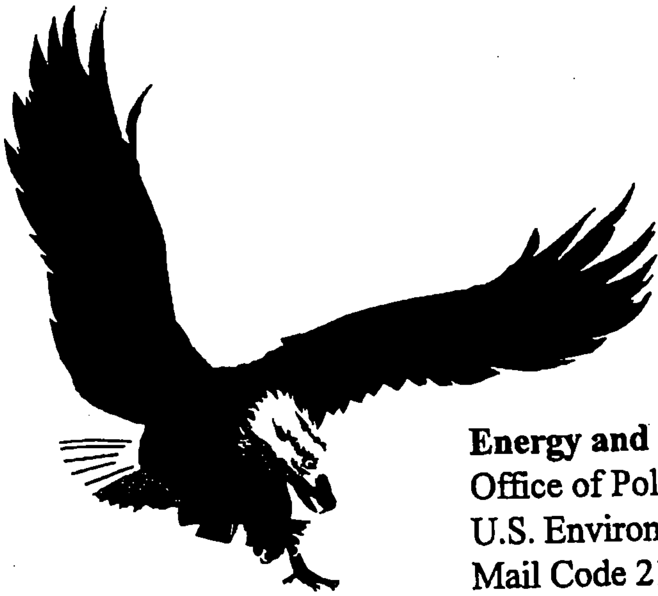

Energy and Transportation Sectors Division
Office of Policy, Planning and Evaluation
U.S. Environmental Protection Agency
Mail Code 2126
401 M Street, SW
Washington, DC 20460

2

Telephone (202) 260-5490
Fax (202) 260-0512

TO: Randy Cutler

Voice:

Fax 395-6870

FROM: Bob Noland

Voice: (202) 260- 2418

Number of pages to follow: 5

Comments:

Bob / FYI Ken

Standard & Poor's
A Division of The McGraw-Hill Companies

Memorandum

Date: January 21, 1998

To: Heidi Nelson, ICF

CC: Tracy Terry, EPA

From: James Lin, DRI James Lin

Subject: TD #18, WA #1-07, Contract # 68-W6-0029
The Carbon Emissions Impacts of a Federal Gasoline Tax Reduction

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This memorandum summarizes the results from our simulation analysis of the carbon emissions impacts of eliminating the 4.3 cent federal gasoline tax enacted in 1993. The first section describes the basic structure of the Transportation Submodel of DRI's U.S. Energy Model which was used to forecast vehicle demand for oil. The second section reports the estimated impacts of the proposed gasoline tax reduction on transportation fuel demand and carbon emissions.

DRI's Transportation Fuel Demand Model

DRI's Transportation Fuel Demand Model is a vintage capital model. It is premised on the notion that the demand for motor fuels is derived from the demand for travel and consumer's preferences toward particular vehicles. Consumers determine the level of travel as well as the vehicle stock composition through their purchase decisions. The stock composition, associated efficiency characteristics, and vehicle vintage patterns determine the level of fuel consumption. Both vehicle purchase patterns and travel decisions are derived within the model as functions of economic activity and fuel prices. The model is capable of examining dynamic adjustments to fiscal policies such as road pricing and fuel taxes, as well as policies directly affecting technological characteristics of the vehicle stock.

The process of determining fuel consumption begins with consumers' vehicle purchase decisions, particularly the timing of the purchase and the type of vehicle bought. Total sales of imported cars, domestic cars, light trucks, medium trucks, and heavy trucks are obtained from DRI's Automotive Service. The next step is to determine the vehicle stock in any given year, which is a function of past sales patterns and the technological characteristics of those sales, as embodied in the survival probabilities associated with specific vehicle age groups. The vehicle stock in a particular class in any given year depends upon the number of vehicles sold in each of the previous "N" years and the probabilities that these vehicles will still be on the road in that year.

The total number of miles traveled by the stock of vehicles of a particular class and fuel-using type is the product of the number of vehicles in that class' stock and the number of miles traveled per vehicle in that stock. The vehicle miles traveled is estimated econometrically. It varies across the class of vehicle and the age of the vehicles within that class (Generally, the older the vehicle, the fewer miles it is driven each year). It also changes with changes in the real cost per mile and real disposable income. The real cost per mile is defined by dividing fuel prices by the vehicle fuel efficiency.

Fuel consumption for a particular class and model year of vehicle is derived by multiplying each segment's vehicle stock by the miles traveled per vehicle and then dividing by the average fuel efficiency of the vehicle stock. The average fuel efficiency of the vehicle stock is calculated as a stock-weighted average of the vehicle fuel efficiencies by vintage. Overtime, new vehicles are purchased and old vehicles are retired. Since new fuel vehicle efficiencies are affected by fuel costs, real fuel prices increasingly influence the stock efficiency and hence gasoline consumption over time. Total fuel consumption is the sum of fuel consumption for each of the vehicle classes and model years.

The Impacts of the Gasoline Tax Reduction

In this study, we applied the Transportation Model to simulation the carbon emissions impacts of eliminating the 4.3 cent federal gasoline tax enacted in 1993. The DRI's Fall 1997 Energy Forecast was used as the baseline. As shown in the attached Excel workbook, the 4.3 cent reduction in federal gasoline tax reduces real gasoline prices by 3.40% in 1998, 2.31% in 2010, and 1.37% in 2020. Consequently, the total number of vehicle miles traveled (VMT) rises and new vehicle fuel efficiency falls. The VMT of passenger cars in 2020 increases by 0.68% from 1627 billion vehicle-miles in the baseline to 1638 billion vehicle-miles while that of light trucks increases by 0.67% from 1947 to 1955 billion vehicle-miles. The new vehicle fuel efficiency declines by about 0.1-0.2 miles per gallon (MPG) from the baseline, which in turn causes a reduction in vehicle stock fuel efficiency.

The higher VMT and lower MPG result in an increase in transportation oil demand and carbon emissions. Compared with the baseline, the annual highway gasoline consumption increases by 0.6%-1.7% and total transportation oil demand increases by no more than 1% for most years during the forecast period. The projected increase in total carbon emissions from the transportation sector is about 1.8 million tonnes (0.37% of the baseline) in 1998, 4.6 million tonnes (0.85% of the baseline) in 2010, and 3.5 million tonnes (0.60% of the baseline) in 2020.

Maryann -
For comparison purposes, we estimated that CMAQ would reduce carbon emissions by 3.5 to 5.3 mil. metric tons. Ken Adler

%CH

1/21/98

Transportation Sector Outlook
(Percent Change from the Baseline to GasTaxCH Case)

	1996	1997	1998	1999	2000	2005	2010	2015	2020
CARBON EMISSIONS									
Total Emissions (Million Tonnes)	0.00	0.00	0.37	0.50	0.68	1.03	0.85	0.66	0.60
FUEL CONSUMPTION									
Total Oil Demand (Trillion BTU)	0.00	0.00	0.37	0.51	0.65	1.01	0.82	0.64	0.58
Highway Gasoline (Billion Gallons)	0.00	0.00	0.58	0.86	0.99	1.57	1.30	1.08	0.93
GASOLINE RETAIL PRICES ~~(Cents/Gallon)~~ %									
1996 Dollars	0.00	0.00	-3.40	-3.36	-3.21	-2.72	-2.31	-1.82	-1.37
Nominal Dollars	0.00	0.00	-3.34	-3.30	-3.23	-2.75	-2.28	-1.82	-1.42
Federal Tax	0.00	0.00	-23.50	-23.50	-23.50	-23.50	-23.50	-19.28	-14.19
PASSENGER CARS									
VMT (Billion)	0.00	0.00	0.58	0.72	0.93	1.34	1.09	0.91	0.68
Miles/Car	0.00	0.00	0.57	0.77	0.95	1.35	1.09	0.88	0.67
Miles/Gallon (On-Road)									
New Car Avg	0.00	0.00	0.00	0.00	-0.45	-0.43	-0.40	-0.38	-0.74
Stock Avg	0.00	0.00	0.00	0.00	0.00	0.00	-0.43	0.00	-0.39
LIGHT TRUCKS									
VMT (Billion)	0.00	0.00	0.54	0.81	0.96	1.38	1.09	0.85	0.67
Miles/Truck	0.00	0.00	0.57	0.77	0.95	1.36	1.09	0.89	0.66
Miles/Gallon (On-Road)									
New Truck Avg	0.00	0.00	0.00	0.00	-0.60	0.00	0.00	-0.48	-0.45
Stock Avg	0.00	0.00	0.00	0.00	0.00	-0.60	0.00	-0.53	-0.50

2000 = 7 years out

price decline 3.21¢ ≈ 3.2%

.9 % VMT

given [illegible] ≈ 3.

⇒ .9/3.2 = e [illegible] .28

BASE

1/21/98

Transportation Sector Outlook
(DRI Fall 1997 Baseline Forecast)

	1996	1997	1998	1999	2000	2005	2010	2015	2020
CARBON EMISSIONS									
Total Emissions (Million Tonnes)	445.3	453.4	464.8	476.8	487.4	523.6	553.1	573.2	587.3
FUEL CONSUMPTION									
Total Oil Demand (Trillion BTU)	23496.2	23895.2	24488.8	25119.1	25675	27606.6	29208.2	30296.4	31059.9
Highway Gasoline (Billion Gallons)	119.5	121.7	124.8	128.1	131	140.3	146.2	148.8	150.2
GASOLINE RETAIL PRICES (Cents/Gallon)									
1996 Dollars	128.8	125.6	123.4	121.9	121.5	125	129.8	137.2	146
Nominal Dollars	128.8	128.2	128.8	130.2	133.1	156.4	189	236.7	301.9
Federal Tax	18.3	18.3	18.3	18.3	18.3	18.3	18.3	22.3	30.3
PASSENGER CARS									
VMT (Billion)	1375	1375	1386	1398	1405	1423	1470	1541	1627
Miles/Car	11049	11090	11214	11353	11463	11921	12378	12772	13151
Miles/Gallon (On-Road)									
New Car Avg	21.3	21.5	21.7	21.8	22	23.2	25	26.2	27.1
Stock Avg	20.8	20.8	20.9	21	21.1	21.8	23.2	24.6	25.8
LIGHT TRUCKS									
VMT (Billion)	813	861	921	983	1044	1307	1558	1771	1942
Miles/Truck	11473	11525	11664	11819	11945	12472	12993	13434	13847
Miles/Gallon (On-Road)									
New Truck Avg	16	16.1	16.3	16.4	16.6	17.8	19.5	20.9	22
Stock Avg	15.5	15.6	15.7	15.8	15.9	16.7	17.7	19	20.2

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1/21/98

Transportation Sector Outlook
(Gasoline Tax Reduction Scenario)

	1996	1997	1998	1999	2000	2005	2010	2015	2020
CARBON EMISSIONS									
Total Emissions (Million Tonnes)	445.3	453.4	468.5	479.2	490.7	529	557.8	577	590.8
FUEL CONSUMPTION									
Total Oil Demand (Trillion BTU)	23498.2	23895.2	24578.2	25248.8	25843	27888.8	29448.3	30491.4	31240.4
Highway Gasoline (Billion Gallons)	119.5	121.7	125.5	129.2	132.3	142.5	148.1	150.4	151.6
GASOLINE RETAIL PRICES (Cents/Gallon)									
1996 Dollars	128.8	125.6	119.2	117.8	117.6	121.6	126.8	134.7	144
Nominal Dollars	128.8	128.2	124.5	125.9	128.8	152.1	184.7	232.4	297.6
Federal Tax	18.3	18.3	14	14	14	14	14	18	26
PASSENGER CARS									
VMT (Billion)	1375	1375	1394	1408	1418	1442	1486	1555	1638
Miles/Car	11049	11090	11278	11440	11572	12082	12513	12885	13239
Miles/Gallon (On-Road)									
New Car Avg	21.3	21.5	21.7	21.8	21.9	23.1	24.9	26.1	26.9
Stock Avg	20.8	20.8	20.9	21	21.1	21.8	23.1	24.6	25.7
LIGHT TRUCKS									
VMT (Billion)	813	861	926	991	1054	1325	1575	1786	1955
Miles/Truck	11473	11525	11730	11910	12059	12641	13135	13553	13939
Miles/Gallon (On-Road)									
New Truck Avg	16	16.1	16.3	16.4	16.5	17.8	19.5	20.8	21.9
Stock Avg	15.5	15.6	15.7	15.8	15.9	16.8	17.7	18.9	20.1

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Table 62. Nitrogen Oxide Emissions from Electricity Generators by Region (million tons)

ricity Supply and Demand	2000	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
. States	5.54	5.50	5.55	5.57	5.56	5.60	5.63	5.62	5.65	5.67	5.69	5.69	5.68	5.70	5.77	5.82	5.85	5.88
entral Area Reliability Coordination Agreement	1.35	1.37	1.37	1.37	1.38	1.39	1.39	1.38	1.38	1.37	1.38	1.37	1.36	1.36	1.41	1.44	1.44	1.46
ic Reliability Council of Texas	.42	.38	.38	.37	.34	.33	.33	.32	.33	.33	.33	.33	.33	.33	.33	.34	.35	.35
lantic Area Council	.26	.24	.24	.24	.25	.25	.26	.25	.26	.26	.26	.26	.26	.26	.27	.27	.27	.28
erica Interconnected Network	.47	.45	.45	.46	.46	.47	.47	.47	.47	.48	.48	.48	.48	.48	.48	.49	.49	.50
ntinent Area Power Pool	.36	.38	.38	.38	.38	.39	.39	.39	.39	.39	.39	.39	.39	.39	.40	.40	.40	.40
east Power Coordinating Council/New York	.10	.07	.07	.07	.07	.07	.07	.08	.08	.08	.08	.08	.08	.08	.08	.08	.08	.09
east Power Coordinating Council/New England	.09	.10	.10	.10	.10	.10	.10	.10	.10	.10	.10	.10	.10	.10	.10	.08	.09	.09
eastern Electric Reliability Council/Florida	.26	.27	.28	.28	.27	.27	.27	.28	.28	.28	.28	.29	29	.30	.31	.31	.31	.31
eastern Electric Reliability Council/Excl. Florida	.95	.97	.98	.99	.99	1.00	1.01	1.02	1.02	1.03	1.02	1.03	1.03	1.03	1.01	1.02	1.02	1.02
west Power Pool	.62	.63	.63	.63	.63	.63	.63	.64	.63	.63	.62	.62	.61	.61	.61	.61	.61	.61
rn Systems Coordinating Council/NWP	.21	.22	.22	.22	.22	.23	.22	.23	.23	.23	.23	.23	.23	.23	.23	23	.23	.23
rn Systems Coordinating Council/RA	.27	.28	.29	.28	.28	.28	.28	.28	.28	.28	.28	.28	.28	.28	.28	.29	.29	.29
rn Systems Coordinating Council/CNV	.17	.15	.16	.17	.17	.18	.18	.19	.19	.20	.20	.24	.24	.24	.25	.25	.26	.26

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Table 62. Nitrogen Oxide Emissions from Electricity Generators by Region (Million tons)

tricity Supply and Demand	2000	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
d States	5.54	5.39	5.43	5.45	5.45	5.09	4.76	4.48	4.38	4.41	4.33	4.43	4.42	4.35	4.43	4.48	4.52	4.49
Central Area Reliability Coordination Agreement	1.33	1.33	1.33	1.34	1.36	1.24	1.13	1.05	.97	.93	.84	.85	.88	.87	.91	.94	.95	.95
ric Reliability Council of Texas	.42	.38	.39	.37	.34	.32	.27	.22	.20	.20	.20	.23	.22	.22	.23	.23	.24	.24
tlantic Area Council	.27	.25	.25	.25	.25	.24	.24	.24	.24	.24	.23	.24	.24	.22	.24	.24	.24	.24
merica Interconnected Network	.48	.41	.41	.42	.42	.39	.35	.33	.33	.35	.33	.35	.35	.34	.34	34	.34	.35
ontinent Area Power Pool	.35	.37	.37	.38	.39	.35	.34	.31	.32	.33	.32	.33	.34	.33	.33	.33	.33	.33
east Power Coordinating Council/New York	.10	.07	.07	.07	.07	.05	.05	.06	.06	.06	.07	.06	.07	.06	.06	.06	.06	.06
east Power Coordinating Council/New England	.09	.10	.10	.10	.09	.08	.07	.06	.06	.07	.06	.05	.06	.07	.07	07	.07	.07
eastern Electric Reliability Council/Florida	.26	.25	.26	.26	.25	.23	.22	.22	.21	.22	.23	.24	.22	.22	.24	.24	.24	.24
eastern Electric Reliability Council/Excl. Florida	.97	.99	1.01	1.02	1.02	.98	.96	.93	.93	.93	.94	.96	.95	.94	.95	.95	.96	.95
west Power Pool	.61	.60	.60	.59	.59	.56	.51	.48	.47	.49	.50	.51	.50	.47	.47	.47	.49	.48
rn Systems Coordinating Council/NWP	.17	.15	.15	.16	.17	.17	.17	.17	.17	.17	.17	19	.19	.19	.19	.20	.20	.20
rn Systems Coordinating Council/RA	.21	.22	.22	.22	.22	.22	.20	.20	.19	.19	.19	.20	.19	.19	.19	.19	.19	.19
rn Systems Coordinating Council/CNV	.27	26	.27	.27	.27	.26	.24	.22	.21	.23	.24	.23	.22	.22	.22	.21	.21	.21

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Post-it® Fax Note 7671	Date 1/8/98	# of pages ▶ 2
To Randy Lutter	From Ray Squitieri	
Co./Dept. CEA	Co.	
Phone #	Phone #	
Fax # 395-6870	Fax #	

5:00 pm 1/7/98

From The Desk Of

ANDY S. KYDES

To: Ray Squitieri Date: January 8, 1998

Re: Outputs requested for the $ 100/ton case

Attached is a summary table relating the NO_x emissions for the AEO98 reference case versus a case that represents what might occur with a $ 100/ton carbon permit fee (fee100). You should be aware of certain caveats and assumptions that go with these runs when you consider the analysis.

- The reference case in AEO98 does not incorporate the new NO_x standards and consequently the path of NO_x emissions in the reference case, if they were incorporated, would probably be a little but not substantially lower than indicated.

- The sensitivity case that we ran with the $100/ton carbon fee makes the following assumptions: (a) the $100/ton fee is ramped up over three years reaching and retaining a plateau of $100/ton in 2010, (b) that a carbon fee of $100/ton will trigger the development and availability of advanced menu of end-use technologies as defined in the AEO98 advanced cost reduction technology cases, (c) supply side technologies remain defined as in the AEO98 reference case, (d) an advanced ethanol technology as an oxygenate and for gasohol is made available by 2010, (e) economic overbuilding in excess of required reserve margins on a year-to-year basis *is allowed* to reach 7 percent of the existing generation base in the utility sector.

A cursory observation of the runs reveals the following:

- The availability and penetration of advanced end-use technologies is projected to reduce primary energy consumption by about 4 Quads (3.7%) in 2010.
- Natural gas use for generation increases substantially at the expense of coal generation. In 2010, steam coal generation is about 5.5 Quads lower and natural gas generation is over 3 Quads higher, resulting in a NO_x reduction of about 1.1 million tons from generation.
- Non-hydropower renewable generation is projected to be over 25% higher in the $100/ton fee case than in the reference case in 2010.
- The $ 100/ton carbon fee increases electricity prices by about 33 percent in 2010 relative to the reference case in 2010. Relative to the 1996 price of electricity, the $100/ton fee case raises electricity prices in 2010 by about 14 percent.
- Primary energy intensity in the reference case declines by 0.9 percent annually between 1996-2020. Energy intensity in the $100/ton case declines by 1.2 percent annually.

I hopes this helps.

Andy

Post-it® Fax Note 7671	Date 1-15-98	# of pages ▶ 14
To Randy Lutter	From Ray Squitieri	
Co./Dept.	Co. US Treasury	
Phone # 395-6870	Phone # 622-2340	
Fax # 260-6870	Fax # 622-1294	

U. S. Department of Energy

TELEFAX TRANSMISSION

FROM

ENERGY INFORMATION ADMINISTRATION
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1000 Independence Avenue, S.W.
Washington, D.C. 20585

DATE: 1/14/98

TO: Ray Squitieri

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FROM: Andy Kydes
1000 INDEPENDENCE AVE FAX NUMBER: (202) 586-3045

MESSAGE:

From The Desk Of

ANDY S. KYDES

To: Ray Squitieri, Treasury Date: January 14, 1998

Re: Summary Tables of Carbon Permit Impacts

Attached please find a copy of NEMS summary tables in response to your request for information on the impact of alternative carbon fees on NOx and SOx emissions. A complete set of printouts are available as in the AEO98 reference case in the event you want them. In these tables, the results are derived as follows:

Column 1: AEO98 results

Column 2: New base: Advanced AEO98 demand technologies case with some further adjustments. The sensitivity cases that we ran with the various carbon fees make the following assumptions: (a) the fees are ramped up over three years reach and retain a plateau in 2010, (b) that a carbon fee greater than or equal to $100/ton will trigger the development and availability of an advanced menu of end-use technologies as defined in the AEO98 advanced cost reduction technology cases, (c) supply side technologies remain defined as in the AEO98 reference case, (d) an advanced ethanol technology as an oxygenate and for gasohol is made available by 2010, (e) economic overbuilding in excess of required reserve margins on a year-to-year basis *is allowed* to reach 7 percent of the existing generation base in the utility sector.

Column 3: New Base with a $100/ton carbon fee

Column 4: New Base with a $200/ton carbon fee

Column 5: New Base with a $300/ton carbon fee

-potentially mislabeled.
7/28/97

Table 62 is the table with the national and regional level Sox, Nox, and Carbon emissions.

Please let me know if you need anything else or want any explanation or further analysis.

Andy

cc Mary J. Hutzler
Scott Sitzer
Art Andersen

NATIONAL ENERGY MODELING SYSTEM

Table 1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2000 (1)	2000 (2)	2000 (3)	2000 (4)	2000 (5)	2010 (1)	2010 (2)	2010 (3)	2010 (4)	2010 (5)	2015 (1)	2015 (2)	2015 (3)	2015 (4)	2015 (5)
Production															
Crude Oil & Lease Condensate	13.06	13.06	13.06	13.06	13.06	11.79	11.62	11.56	11.51	11.50	11.09	10.85	10.44	10.35	10.29
Natural Gas Plant Liquids	2.39	2.36	2.35	2.37	2.36	2.95	2.78	3.22	3.34	3.39	3.12	2.98	3.45	3.24	3.22
Dry Natural Gas	20.84	20.66	20.58	20.69	20.64	25.39	24.03	27.65	28.55	28.97	26.05	25.75	28.14	27.67	27.50
Coal	24.34	24.20	24.06	23.98	24.02	26.62	25.35	13.32	11.60	9.70	27.73	25.60	9.58	8.47	7.40
Nuclear Power	7.36	7.36	7.36	7.36	7.36	6.36	6.36	6.36	6.36	6.36	5.12	5.12	5.12	5.12	5.13
Renewable Energy	6.82	6.80	6.92	6.96	7.82	7.41	7.31	10.16	10.74	11.27	7.59	7.61	15.35	14.17	14.57
Other	.56	.55	.56	.56	.56	.48	.48	.46	.60	.60	.47	.63	1.16	1.15	1.11
Total	75.37	74.99	74.89	74.97	75.01	81.08	77.92	72.69	72.70	71.80	81.97	78.45	71.24	70.13	69.30
Imports															
Crude Oil	19.18	19.10	19.08	19.07	19.07	23.17	23.37	22.12	21.20	20.57	24.36	24.49	22.99	22.59	21.98
Petroleum Products	4.25	4.39	4.27	4.25	4.27	7.61	6.89	5.02	4.89	5.07	9.01	7.53	5.07	5.03	5.12
Natural Gas	4.20	4.21	4.23	4.22	4.22	4.66	4.53	4.69	4.60	4.60	5.04	4.81	5.71	5.82	5.88
Other Imports	.62	.63	.63	.63	.63	.57	.59	1.08	1.20	1.41	.54	.58	1.06	1.26	1.39
Total	28.26	28.33	28.21	28.17	28.19	36.02	35.38	32.91	32.05	31.74	38.96	37.41	34.82	34.70	34.37
Exports															
Petroleum	1.71	1.72	1.71	1.71	1.71	1.80	1.76	1.40	1.44	1.32	1.89	1.83	1.59	1.55	1.63
Natural Gas	.28	.28	.28	.28	.28	.29	.29	.29	.29	.29	.30	.30	.30	.30	.30
Coal	2.41	2.41	2.41	2.41	2.41	2.84	2.84	2.84	2.84	2.84	3.03	3.03	3.03	3.03	3.03
Total	4.39	4.40	4.40	4.40	4.40	4.93	4.90	4.61	4.58	4.45	5.21	5.15	4.91	4.87	4.96
Discrepancy	.58	.40	.62	.60	.63	.08	-.39	.02	-.39	-.37	.00	-.24	-.15	-.21	-.17
Consumption															
Petroleum Products	38.35	38.26	38.26	38.25	38.26	44.33	43.05	40.68	39.95	39.60	46.20	44.45	41.46	40.66	40.03
Natural Gas	24.74	24.57	24.51	24.61	24.55	29.63	28.13	31.78	32.69	33.23	31.44	30.12	33.35	32.99	32.89
Coal	22.14	21.99	21.87	21.76	21.82	24.03	22.75	11.15	8.94	7.01	24.95	22.74	6.82	5.71	4.70
Nuclear Power	7.36	7.36	7.36	7.36	7.36	6.36	6.36	6.36	6.36	6.36	5.12	5.12	5.12	5.12	5.13
Renewable Energy	6.82	6.81	6.92	6.96	7.82	7.42	7.33	10.17	10.75	11.20	7.62	7.64	15.37	14.19	14.59
Other	.41	.41	.41	.41	.41	.40	.39	.88	1.08	1.22	.40	.41	.87	1.07	1.20
Total	99.8	99.4	99.3	99.3	99.4	112.2	108.0	101.0	99.0	98.71	115.7	110.5	101.0	99.7	98.54
Net Imports - Petroleum	21.72	21.70	21.64	21.62	21.63	28.99	28.50	25.66	24.64	24.32	31.40	30.19	26.47	26.08	25.46
Prices (1996 dollars per unit)															
World Oil Price ($ per bbl)	19.11	19.07	19.07	19.07	19.06	20.81	20.21	18.85	18.42	18.26	21.48	20.48	17.88	17.61	17.36
Gas Wellhead Price($ / Mcf)	2.11	2.12	2.11	2.13	2.11	2.31	1.92	2.44	2.59	2.61	2.30	1.92	2.94	2.89	2.91
Coal Minemouth Price ($ / ton)	17.45	17.30	17.37	17.35	17.35	15.05	14.99	17.93	18.24	18.95	13.99	14.05	17.95	18.48	18.74
Aver. Electricity (cents / Kwh)	6.5	6.5	6.5	6.5	6.5	5.9	5.9	9.4	10.1	10.6	5.6	5.6	9.1	9.6	10.2

neo98b.d100197a - AEO98 Reference Case, nodbase.d011398a - Carbon Reference (1), fem100.d011398a (2), fem200.d011498a (3), fem300.d011398b (4)

ENERGY INFORMATION ADMINISTRATION

NATIONAL ENERGY MODELING SYSTEM

Table 17. Carbon Emissions by Sector and Source

(Million Metric Tons per Year, Unless Otherwise Noted)

ector and Source	2000 (1)	2000 (2)	2000 (3)	2000 (4)	2000 (5)	2010 (1)	2010 (2)	2010 (3)	2010 (4)	2010 (5)	2015 (1)	2015 (2)	2015 (3)	2015 (4)	2015 (5)
esidential															
Petroleum	25.8	25.7	25.7	25.7	25.7	24.8	24.3	21.8	21.2	20.6	24.5	23.9	21.5	20.9	20.4
Natural Gas	77.0	76.8	76.8	76.8	76.8	81.1	81.1	70.5	68.4	66.8	83.0	83.2	70.8	68.9	67.2
Coal	1.4	1.4	1.4	1.4	1.4	1.3	1.4	1.3	1.3	1.2	1.3	1.3	1.2	1.2	1.2
Electricity	281.5	199.6	198.2	197.6	198.0	230.9	214.0	134.7	121.6	109.8	248.8	225.5	108.1	98.7	91.4
Total	305.6	303.5	302.1	301.5	301.9	338.1	320.8	228.2	212.5	198.5	358.5	334.0	201.6	189.7	180.2
ommercial															
Petroleum	12.8	12.8	12.8	12.8	12.8	12.8	12.7	12.3	12.1	12.0	12.7	12.6	12.2	12.0	11.9
Natural Gas	49.9	49.7	49.7	49.7	49.7	54.0	52.7	49.4	48.6	47.9	55.4	53.4	49.3	48.6	47.9
Coal	2.2	2.2	2.2	2.2	2.2	2.4	2.4	2.4	2.4	2.4	2.5	2.5	2.5	2.5	2.5
Electricity	182.2	181.3	180.1	179.5	179.9	205.1	196.3	122.3	109.8	99.0	217.8	203.6	95.7	87.1	80.4
Total	247.1	246.0	244.8	244.2	244.6	274.4	264.2	186.4	173.0	161.4	288.4	272.1	159.7	150.2	142.8
ndustrial ..															
Petroleum	103.3	102.7	102.6	102.6	102.7	115.6	112.4	104.5	98.4	98.1	119.3	114.5	107.5	105.2	103.3
Natural Gas	155.5	154.4	154.4	154.4	154.3	165.8	158.6	158.5	161.0	158.4	167.1	158.9	146.7	145.2	141.2
Coal	60.7	59.4	59.4	59.4	59.4	62.8	55.9	47.7	47.0	46.5	61.7	53.3	45.7	45.1	44.7
Electricity	187.3	185.9	184.4	183.9	184.3	219.1	205.3	141.3	126.2	115.6	230.6	210.4	112.8	102.3	94.4
Total	506.7	502.3	500.7	500.3	500.7	563.3	532.1	444.0	423.5	408.6	578.7	537.1	412.8	396.7	385.5
ransportation															
Petroleum	502.4	502.4	502.2	502.2	502.2	601.0	591.1	557.1	545.7	538.6	632.3	613.0	552.3	542.2	533.2
Natural Gas	12.2	12.1	12.0	12.1	12.0	17.2	16.4	17.4	17.9	17.9	18.6	17.9	10.4	10.1	10.1
Other	.1	.1	.1	.1	.1	1.5	1.5	1.3	1.3	1.2	2.2	2.3	1.9	1.9	1.8
Electricity	3.2	3.3	3.2	3.2	3.2	7.3	8.7	5.5	5.0	4.5	9.5	10.6	5.1	4.7	4.3
Total	517.9	517.7	517.5	517.6	517.5	627.5	617.7	581.4	569.9	562.3	662.7	644.6	577.0	566.9	557.4
otal Carbon Emissions ..															
Petroleum	644.4	643.6	643.3	643.4	643.3	754.2	740.5	695.6	677.5	669.4	788.9	764.9	693.5	680.4	668.0
Natural Gas	294.6	292.9	292.8	293.0	292.8	318.1	308.8	287.8	284.7	282.9	324.9	313.4	285.3	278.9	274.5
Coal	64.3	63.0	63.0	63.0	63.1	66.6	59.7	51.4	50.7	50.2	65.6	57.1	49.5	48.8	48.4
Other	.1	.1	.1	.1	.1	1.5	1.5	1.3	1.3	1.2	2.2	2.3	1.9	1.9	1.8
Electricity	574.0	570.1	565.9	564.2	565.4	662.9	624.4	403.8	362.6	327.0	706.8	650.1	320.9	292.6	270.5
Total	1577	1570	1565	1564	1565	1803	1735	1440	1379	1331	1888	1788	1351	1303	1264
ectric Generators ..															
Petroleum	11.4	10.6	10.8	10.5	10.7	7.4	7.2	4.6	5.3	6.8	6.8	6.2	6.3	4.5	4.6
Natural Gas	59.6	58.0	57.9	59.3	58.6	106.3	94.5	167.9	162.1	193.8	125.4	118.5	193.1	194.3	197.4
Coal	503.0	500.6	497.2	494.5	496.1	549.3	522.8	231.3	175.2	126.4	574.5	525.4	121.5	93.9	68.6
Total	574.0	570.1	565.9	564.2	565.4	662.9	624.4	403.8	362.6	327.0	706.8	650.1	320.9	292.6	270.5
otal Carbon Emissions ..															
Petroleum	655.8	654.2	654.0	653.8	654.1	761.5	747.7	700.2	682.8	676.3	795.7	771.1	699.7	684.9	673.4
Natural Gas	354.2	351.7	350.8	352.2	351.4	424.4	403.2	455.7	446.8	476.7	450.3	431.9	478.4	473.1	471.8
Coal	567.3	563.7	560.2	557.5	559.1	615.9	582.4	282.7	225.9	176.6	640.1	582.5	171.0	142.7	116.9
Other	.1	.1	.1	.1	.1	1.5	1.5	1.3	1.3	1.2	2.2	2.3	1.9	1.9	1.8
Total	1577	1570	1565	1564	1565	1803	1735	1440	1379	1331	1888	1788	1351	1303	1264
arbon Emissions (tons per person)	5.7	5.7	5.7	5.7	5.7	6.0	5.6	4.8	4.6	4.5	6.1	5.7	4.3	4.2	4.1

ec98b.d100197a - AEO98 Reference Case, nembase.d011398a - Carbon Reference (1), fee100.d011398a (2), fee200.d011698a (3), fee300.d011398b (4)

1

N A T I O N A L   E N E R G Y   M O D E L I N G   S Y S T E M

Table 62. Emissions by NERC Region (million short tons)
except Carbon and Carbon Dioxide (million metric tons)

	2000 (1)	2000 (2)	2000 (3)	2000 (4)	2000 (5)	2010 (1)	2010 (2)	2010 (3)	2010 (4)	2010 (5)	2015 (1)	2015 (2)	2015 (3)	2015 (4)	2015 (5)
Emissions..............................															
United States															
Total Carbon....................	574.8	570.1	565.9	564.2	565.4	662.9	624.4	483.8	342.6	327.0	786.8	658.1	320.9	292.6	278.5
Carbon Dioxide..................	2104	2090	2075	2069	2073	2431	2289	1401	1330	1199	2591	2384	1177	1075	991.9
Sulfur Dioxide..................	10.19	10.19	10.42	10.44	10.43	9.22	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00
Nitrogen Oxide..................	6.14	6.11	6.06	6.03	6.05	6.51	6.19	3.52	2.97	2.45	6.75	6.29	2.13	1.84	1.56
						6.51		3.52	2.17	2.45					
East Central Area Reliability															
Total Carbon....................	128.0	128.1	125.6	125.7	126.0	144.3	136.8	100.0	90.46	80.31	148.5	137.6	76.82	69.74	64.18
Carbon Dioxide..................	472.4	469.6	461.3	461.0	462.0	529.1	498.6	366.7	331.7	294.5	544.5	504.4	281.7	255.7	235.3
Sulfur Dioxide..................	3.45	3.38	3.54	3.61	3.58	3.07	2.93	4.16	3.94	4.04	2.06	2.70	5.06	5.45	5.81
Nitrogen Oxide..................	1.50	1.49	1.47	1.46	1.47	1.62	1.53	1.01	.80	.65	1.64	1.51	.69	.63	.53
Electric Reliability Council Tx															
Total Carbon....................	45.89	45.75	45.73	45.73	45.75	51.05	47.25	27.01	25.81	24.69	52.53	48.62	21.91	21.43	19.66
Carbon Dioxide..................	168.3	167.7	167.7	167.7	167.7	187.2	173.3	99.0	94.61	90.53	192.6	178.3	80.35	78.59	72.08
Sulfur Dioxide..................	.35	.35	.35	.35	.35	.34	.32	.06	.07	.09	.33	.30	.12	.14	.19
Nitrogen Oxide..................	.47	.47	.47	.47	.47	.40	.36	.23	.21	.20	.38	.36	.11	.10	.16
Mid-Atlantic Area Council															
Total Carbon....................	34.52	34.10	33.33	33.75	33.76	40.01	37.60	29.90	25.50	24.34	42.05	38.99	21.99	20.32	19.57
Carbon Dioxide..................	126.6	125.0	122.2	123.8	123.8	146.7	137.9	109.6	93.50	89.23	154.2	143.0	80.64	74.51	71.74
Sulfur Dioxide..................	.56	.54	1.09	1.09	1.10	.53	.40	1.04	.90	1.10	.51	.46	.62	.40	.43
Nitrogen Oxide..................	.29	.29	.28	.29	.29	.31	.28	.21	.15	.15	.31	.29	.11	.09	.08
Mid-America Interconnected Netw															
Total Carbon....................	40.82	40.56	40.26	40.37	40.61	47.77	45.08	25.64	23.07	21.14	50.52	46.37	25.05	22.67	21.09
Carbon Dioxide..................	149.7	148.7	147.6	148.0	148.9	175.2	165.3	94.01	84.57	77.52	185.2	170.0	91.86	83.12	77.33
Sulfur Dioxide..................	.93	.87	.96	.99	.99	.65	.63	.48	.39	.33	.61	.58	.46	.33	.32
Nitrogen Oxide..................	.52	.52	.52	.52	.52	.54	.52	.19	.16	.12	.56	.52	.13	.13	.09
Mid-Continent Area Power Pool															
Total Carbon....................	32.66	32.45	31.88	31.71	31.92	38.87	36.67	20.54	17.37	13.92	41.28	38.41	10.43	8.98	8.63
Carbon Dioxide..................	119.7	119.0	116.6	116.3	117.0	142.5	134.5	75.31	63.70	51.03	151.3	140.8	38.23	32.62	31.63
Sulfur Dioxide..................	.42	.41	.39	.40	.39	.43	.41	.27	.29	.25	.42	.39	.08	.06	.13
Nitrogen Oxide..................	.39	.39	.38	.38	.38	.45	.43	.20	.16	.13	.46	.43	.05	.05	.05
Northeast Power Council/New York															
Total Carbon....................	13.50	13.53	13.39	13.32	13.32	14.13	13.01	10.31	9.96	9.97	15.31	14.22	10.03	9.93	8.89
Carbon Dioxide..................	49.50	49.60	49.11	48.83	48.83	51.82	47.71	37.81	36.51	36.57	56.15	52.12	36.78	36.41	32.58
Sulfur Dioxide..................	.24	.24	.26	.26	.26	.19	.18	.13	.10	.07	.17	.16	.15	.17	.18
Nitrogen Oxide..................	.11	.11	.11	.11	.11	.09	.08	.05	.04	.04	.09	.09	.04	.04	.03
Northeast Power Council/New Engl															
Total Carbon....................	11.59	11.45	11.59	11.57	11.62	14.09	14.47	8.92	8.74	7.90	14.32	13.98	8.01	7.97	7.65
Carbon Dioxide..................	42.48	41.97	42.51	42.43	42.60	51.67	53.04	32.72	32.05	28.95	52.49	51.27	29.38	29.22	28.05
Sulfur Dioxide..................	.18	.18	.16	.16	.17	.14	.17	.04	.06	.06	.13	.14	.06	.07	.09

aeo98b.d100197a - AEO98 Reference Case, nmdbase.d011398a - Carbon Reference (1), fee100.d011398a (2), fee200.d011498a (3), foe

NATIONAL ENERGY MODELING SYSTEM

Table 62. Emissions by NERC Region (million short tons) (Continued)
except Carbon and Carbon Dioxide (million metric tons)

	2000 (1)	2000 (2)	2000 (3)	2000 (4)	2000 (5)	2010 (1)	2010 (2)	2010 (3)	2010 (4)	2010 (5)	2015 (1)	2015 (2)	2015 (3)	2015 (4)	2015 (5)
Southeastern Electric/Florida															
Total Carbon	26.44	26.18	25.82	25.82	25.74	32.84	30.37	20.58	19.43	18.36	38.16	33.84	19.23	18.69	17.46
Carbon Dioxide	96.93	96.01	94.64	94.65	94.37	120.4	111.4	74.45	71.26	67.33	139.9	121.1	70.50	68.51	64.02
Sulfur Dioxide	.39	.40	.32	.32	.32	.37	.34	.16	.17	.16	.37	.37	.19	.21	.18
Nitrogen Oxide	.29	.29	.28	.28	.28	.35	.30	.16	.18	.13	.38	.32	.12	.12	.10
Southeastern Electric/Excl Fla															
Total Carbon	104.2	103.1	104.1	101.9	102.5	122.0	113.8	80.90	74.09	65.59	131.5	121.1	63.22	57.66	51.04
Carbon Dioxide	382.1	378.1	381.8	373.7	375.6	447.3	417.2	296.6	271.3	240.5	482.0	444.1	231.8	211.4	187.1
Sulfur Dioxide	2.56	2.70	2.21	2.12	2.14	2.48	2.82	2.38	2.74	2.65	2.63	2.95	1.83	1.75	1.39
Nitrogen Oxide	1.06	1.05	1.06	1.03	1.04	1.18	1.12	.77	.70	.57	1.23	1.13	.44	.37	.28
Southwest Power Pool															
Total Carbon	59.86	59.67	59.02	59.33	59.26	68.26	65.90	35.12	32.20	29.35	70.37	66.71	26.57	24.39	23.59
Carbon Dioxide	219.5	218.8	216.4	217.6	217.3	250.3	241.6	128.8	118.1	107.6	258.0	244.6	97.41	89.41	86.50
Sulfur Dioxide	.68	.67	.68	.68	.68	.62	.62	.21	.20	.18	.59	.59	.23	.19	.17
Nitrogen Oxide	.69	.68	.67	.68	.68	.71	.70	.33	.32	.26	.69	.67	.16	.14	.12
Western Systems Council/NWP															
Total Carbon	24.83	24.76	24.70	24.72	24.66	29.61	28.71	15.01	10.85	10.23	30.44	29.53	12.09	10.09	9.14
Carbon Dioxide	91.05	90.78	90.56	90.64	90.41	108.6	105.3	55.03	39.78	37.50	111.6	108.3	44.32	37.00	33.50
Sulfur Dioxide	.16	.16	.16	.16	.16	.14	.14	.03	.02	.01	.13	.13	.02	.01	.01
Nitrogen Oxide	.24	.24	.23	.24	.23	.25	.25	.09	.05	.04	.25	.25	.05	.04	.03
Western Systems Council/RA															
Total Carbon	27.94	27.99	27.94	28.04	28.04	31.83	30.92	17.13	15.52	13.47	33.15	31.91	15.72	13.36	12.10
Carbon Dioxide	102.5	102.6	102.4	102.8	102.8	116.7	113.4	62.79	56.91	49.39	121.6	117.0	57.64	48.97	44.37
Sulfur Dioxide	.21	.21	.21	.21	.21	.18	.18	.13	.12	.12	.16	.16	.16	.15	.17
Nitrogen Oxide	.30	.30	.30	.29	.29	.31	.31	.14	.12	.09	.32	.31	.11	.08	.08
Western Systems Council/CNV															
Total Carbon	22.87	22.43	22.39	22.27	22.32	28.16	24.67	13.03	9.73	7.69	38.66	29.63	9.87	7.50	7.35
Carbon Dioxide	83.84	82.25	82.10	81.66	81.85	103.5	90.46	47.79	35.67	28.21	141.7	108.6	36.18	27.48	26.96
Sulfur Dioxide	.08	.08	.08	.08	.08	.08	.08	.01	.01	.01	.08	.08	.02	.01	.01
Nitrogen Oxide	.18	.19	.19	.19	.19	.22	.21	.10	.06	.05	.33	.26	.06	.03	.03

aeo98b.d100197a - AEO98 Reference Case, nembase.d011398a - Carbon Reference (1), fea100.d011398a (2), fea201.d011498a (3), fea300.d011

ENERGY INFORMATION ADMINISTRATION

NATIONAL ENERGY MODELING SYSTEM

Table 117. National Impacts of the Clean Air Act Amendments of 1990 (CAAA90)

	2000 (1)	2000 (2)	2000 (3)	2000 (4)	2000 (5)	2010 (1)	2010 (2)	2010 (3)	2010 (4)	2010 (5)	2015 (1)	2015 (2)	2015 (3)	2015 (4)	2015 (5)
Scrubber Retrofits (gigawatts)	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Interregional SO2 Allowances Traded (thousand tons)	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
SO2 Allowance Price	120.9	137.3	76.25	75.11	73.70	189.4	186.5	.00	.00	.00	181.0	177.7	.00	.00	.00
SO2 Emissions (million tons)	10.19	10.19	10.42	10.44	10.43	9.22	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00
Coal Production by Sulfur Categ. (million tons)															
Low Sulfur (< .61 lbs s/mmBtu)	468.1	473.0	453.9	450.9	451.3	594.1	569.1	167.7	137.9	97.83	680.9	595.0	101.0	80.70	69.53
Med.Sulfur(.61-1.67 lbs.S/mmBtu)	490.7	492.9	484.5	482.0	484.6	470.1	454.3	294.5	266.3	234.9	464.9	440.9	225.7	209.5	193.0
High Sulfur (> 1.67 lbs.S/mmBtu)	177.9	173.9	194.7	195.9	195.4	192.9	181.3	121.3	100.5	84.10	200.3	179.1	87.30	72.51	55.65
Gasoline Prices															
Traditional Gasoline	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Oxygenated Gasoline	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Reformulated Gasoline	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
High-Oxygen Reformulated Gas	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Average	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Gasoline Quantities															
Traditional Gasoline	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Oxygenated Gasoline	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Reformulated Gasoline	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
High-Oxygen Reformulated Gas	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Total	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Distillate Prices															
Distillate <= 0.05% Sulfur	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Distillate > 0.05% Sulfur	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Average	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Distillate Quantities															
Distillate <= 0.05% Sulfur	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Distillate > 0.05% Sulfur	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Total	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00

aeo98b.d101197a - AEO98 Reference Case, nexbase.d011398a - Carbon Reference (1), fem180.d011398a (2), fem200.d011498a (3), fem300.d011398b

ENERGY INFORMATION ADMINISTRATION

U. S. Department of Energy

TELEFAX TRANSMISSION

FROM

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FROM: Andy Kydes

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MESSAGE:

From The Desk Of

ANDY S. KYDES

To: Ray Squitieri, Treasury Date: January 14, 1998

Re: Summary Tables of Carbon Permit Impacts

Attached please find a copy of NEMS summary tables in response to your request for information on the impact of alternative carbon fees on NOx and SOx emissions. A complete set of printouts are available as in the AEO98 reference case in the event you want them. In these tables, the results are derived as follows:

Column 1: AEO98 results

Column 2: New base: Advanced AEO98 demand technologies case with some further adjustments. The sensitivity cases that we ran with the various carbon fees make the following assumptions: (a) the fees are ramped up over three years reach and retain a plateau in 2010, (b) that a carbon fee greater than or equal to $100/ton will trigger the development and availability of an advanced menu of end-use technologies as defined in the AEO98 advanced cost reduction technology cases, (c) supply side technologies remain defined as in the AEO98 reference case, (d) an advanced ethanol technology as an oxygenate and for gasohol is made available by 2010, (e) economic overbuilding in excess of required reserve margins on a year-to-year basis *is allowed* to reach 7 percent of the existing generation base in the utility sector.

Column 3: New Base with a $100/ton carbon fee
Column 4: New Base with a $200/ton carbon fee
Column 5: New Base with a $300/ton carbon fee

Table 62 is the table with the national and regional level Sox, Nox, and Carbon emissions.

Please let me know if you need anything else or want any explanation or further analysis.

Andy

cc Mary J. Hutzler
Scott Sitzer
Art Andersen

N A T I O N A L   E N E R G Y   M O D E L I N G   S Y S T E M

Table 1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2000 (1)	2000 (2)	2000 (3)	2000 (4)	2000 (5)	2010 (1)	2010 (2)	2010 (3)	2010 (4)	2010 (5)	2015 (1)	2015 (2)	2015 (3)	2015 (4)	2015 (5)
Production															
Crude Oil & Lease Condensate	13.06	13.06	13.04	13.06	13.06	11.79	11.62	11.56	11.51	11.50	11.09	10.85	10.44	10.33	10.29
Natural Gas Plant Liquids	2.39	2.36	2.35	2.37	2.36	2.95	2.78	3.22	3.34	3.39	3.12	2.98	3.45	3.24	3.22
Dry Natural Gas	20.84	20.66	20.58	20.69	20.64	25.39	24.03	27.63	28.55	28.97	26.85	25.75	28.14	27.67	27.50
Coal	24.34	24.20	24.05	23.98	24.02	26.62	25.35	13.32	11.10	9.70	27.73	23.80	9.50	8.47	7.40
Nuclear Power	7.36	7.36	7.36	7.36	7.36	6.36	6.36	6.36	6.36	6.36	5.12	5.12	5.12	5.12	5.13
Renewable Energy	6.82	6.88	6.92	6.96	7.02	7.41	7.31	10.15	10.74	11.27	7.59	7.61	13.35	14.17	14.87
Other	.56	.55	.56	.56	.56	.48	.48	.46	.68	.69	.47	.63	1.16	1.15	1.11
Total	75.37	74.99	74.89	74.97	75.01	81.00	77.92	72.69	72.70	71.88	81.97	78.45	71.24	70.13	69.50
Imports															
Crude Oil	19.18	19.10	19.08	19.07	19.07	23.17	23.37	22.12	21.20	20.57	24.36	24.49	22.99	22.59	21.90
Petroleum Products	4.25	4.39	4.27	4.25	4.27	7.61	6.09	5.02	4.89	5.07	9.01	7.53	5.07	5.03	5.12
Natural Gas	4.20	4.21	4.23	4.22	4.22	4.66	4.53	4.69	4.68	4.68	5.04	4.81	5.71	5.82	5.88
Other Imports	.62	.63	.63	.63	.63	.57	.59	1.08	1.28	1.41	.84	.88	1.06	1.24	1.39
Total	28.26	28.33	28.21	28.17	28.19	36.02	35.38	32.91	32.05	31.74	38.96	37.41	34.82	34.70	34.37
Exports															
Petroleum	1.71	1.72	1.71	1.71	1.71	1.80	1.76	1.48	1.44	1.32	1.89	1.83	1.59	1.55	1.63
Natural Gas	.28	.28	.28	.28	.28	.29	.29	.29	.29	.29	.30	.30	.30	.30	.30
Coal	2.41	2.41	2.41	2.41	2.41	2.84	2.84	2.84	2.84	2.84	3.03	3.03	3.03	3.03	3.03
Total	4.39	4.40	4.40	4.40	4.40	4.93	4.90	4.61	4.58	4.45	5.21	5.15	4.91	4.87	4.96
Discrepancy	.58	.48	.62	.60	.63	.08	-.39	.02	-.39	-.37	.00	-.24	-.15	-.21	-.17
Consumption															
Petroleum Products	38.35	38.26	38.26	38.25	38.26	44.33	43.05	40.68	39.95	39.40	46.20	44.49	41.46	40.66	40.03
Natural Gas	24.74	24.57	24.51	24.61	24.55	29.63	28.13	31.78	32.69	33.23	31.44	30.12	33.35	32.99	32.89
Coal	22.14	21.99	21.87	21.76	21.82	24.03	22.75	11.15	8.94	7.01	24.95	22.74	6.82	5.71	4.70
Nuclear Power	7.36	7.36	7.36	7.36	7.36	6.36	6.36	6.36	6.36	6.36	5.12	5.12	5.12	5.12	5.15
Renewable Energy	6.82	6.81	6.92	6.94	7.02	7.42	7.33	10.17	10.75	11.28	7.62	7.64	13.57	14.19	14.59
Other	.41	.41	.41	.41	.41	.40	.39	.80	1.08	1.22	.40	.41	.87	1.07	1.20
Total	99.8	99.4	99.3	99.3	99.4	112.2	108.0	101.0	99.8	98.71	115.7	110.5	101.0	99.7	98.54
Net Imports - Petroleum	21.72	21.78	21.64	21.62	21.63	28.99	28.68	25.64	24.64	24.32	31.48	30.19	26.47	26.08	25.46
Prices (1996 dollars per unit)															
World Oil Price ($ per bbl)	19.11	19.07	19.07	19.07	19.06	20.01	20.21	18.85	18.42	18.26	21.48	20.40	17.88	17.61	17.36
Gas Wellhead Price($ / Mcf)	2.11	2.12	2.11	2.11	2.11	2.31	1.92	2.44	2.59	2.61	2.38	1.92	2.94	2.89	2.91
Coal Minemouth Price ($ / ton)	17.45	17.38	17.37	17.33	17.35	15.05	14.99	17.93	18.24	18.95	13.99	14.43	17.95	18.48	18.74
Aver. Electricity (cents / Kwh)	6.5	6.5	6.5	6.5	6.5	5.9	5.9	9.4	10.1	10.6	5.6	5.6	9.1	9.6	10.2

[illegible] - AEO98 Reference Case, [illegible] - Carbon Reference (1), fem160.d011398a (2), fem230.d011498a (3), fem300.d011398b (4)

E N E R G Y   I N F O R M A T I O N   A D M I N I S T R A T I O N

	(1)	(2)	(3)	(4)	(5)	(1)	(2)	(3)	(4)	(5)	(1)	(2)	(3)	(4)	(5)
Residential															
Petroleum	25.8	25.7	25.7	25.7	25.7	24.8	24.3	21.8	21.2	20.6	24.5	23.9	21.5	20.9	20.4
Natural Gas	77.0	76.8	76.8	76.8	76.8	81.1	81.1	70.5	68.4	66.8	83.8	83.2	70.8	68.9	67.2
Coal	1.4	1.4	1.4	1.4	1.4	1.3	1.4	1.3	1.3	1.2	1.3	1.3	1.2	1.2	1.2
Electricity	201.5	199.6	198.2	197.6	198.0	230.9	214.0	134.7	121.6	109.0	248.8	225.5	108.1	98.7	91.4
Total	305.6	303.5	302.1	301.5	301.9	338.1	320.8	228.2	212.6	198.6	358.5	334.0	201.6	189.7	180.2
Commercial															
Petroleum	12.8	12.8	12.8	12.8	12.8	12.8	12.7	12.3	12.1	12.0	12.7	12.6	12.2	12.0	11.9
Natural Gas	49.9	49.7	49.7	49.7	49.7	54.0	52.7	49.4	48.6	47.9	55.4	53.4	49.3	48.6	47.9
Coal	2.2	2.2	2.2	2.2	2.2	2.4	2.4	2.4	2.4	2.4	2.5	2.5	2.5	2.5	2.5
Electricity	182.2	181.3	180.1	179.3	179.9	205.1	196.3	122.3	109.8	99.0	217.8	205.6	95.7	87.1	80.4
Total	247.1	246.0	244.8	244.2	244.6	274.4	264.2	186.4	173.0	161.4	288.4	278.1	159.7	150.2	142.8
Industrial															
Petroleum	103.3	102.7	102.6	102.6	102.7	115.6	112.4	104.5	98.4	98.1	119.3	114.5	107.6	105.2	103.3
Natural Gas	155.5	154.4	154.4	154.4	154.3	163.8	158.6	158.5	151.8	150.4	167.1	158.9	144.7	143.2	141.2
Coal	60.7	59.4	59.4	59.4	59.4	62.0	55.9	47.7	47.0	46.6	61.7	53.3	45.7	45.1	44.7
Electricity	187.3	185.9	184.4	183.9	184.3	219.1	205.3	141.3	126.2	113.6	230.6	210.4	112.0	102.3	94.4
Total	506.7	502.3	500.7	500.3	500.7	563.3	532.1	444.0	423.5	408.6	578.7	537.1	412.0	395.7	385.5
Transportation															
Petroleum	502.4	502.4	502.2	502.2	502.2	601.0	591.1	557.1	545.7	538.6	632.3	615.0	552.3	542.2	533.2
Natural Gas	12.2	12.1	12.0	12.1	12.0	17.2	16.4	17.4	17.9	17.9	18.6	17.9	18.4	18.1	18.1
Other	.1	.1	.1	.1	.1	1.5	1.5	1.8	1.3	1.2	2.2	2.3	1.9	1.9	1.8
Electricity	3.2	3.3	3.2	3.2	3.2	7.3	8.7	5.5	5.0	4.5	9.5	10.6	5.1	4.7	4.3
Total	517.9	517.7	517.5	517.6	517.5	627.3	617.7	581.4	569.9	562.3	662.7	644.6	577.8	566.9	557.4
Total Carbon Emissions															
Petroleum	644.4	643.6	643.3	643.4	643.3	754.2	740.5	695.6	677.5	669.4	788.9	764.9	693.5	680.4	668.8
Natural Gas	294.6	292.9	292.8	293.0	292.8	318.1	308.8	287.8	286.7	282.9	324.9	313.4	283.3	278.9	274.3
Coal	64.3	63.0	63.0	63.0	63.1	66.6	59.7	51.4	50.7	50.2	65.6	57.1	49.5	48.8	48.4
Other	.1	.1	.1	.1	.1	1.5	1.5	1.3	1.3	1.2	2.2	2.3	1.9	1.9	1.8
Electricity	574.0	570.1	565.9	564.2	565.4	662.9	624.4	403.8	362.6	327.0	706.8	650.1	320.9	292.6	270.5
Total	1577	1570	1565	1564	1565	1803	1735	1440	1379	1331	1888	1788	1351	1303	1264
Electric Generators															
Petroleum	11.4	10.6	10.8	10.5	10.7	7.4	7.2	4.6	5.3	6.8	6.8	6.2	6.3	4.5	4.6
Natural Gas	59.6	58.8	57.9	59.3	58.6	106.3	94.5	167.9	182.1	193.8	125.4	110.5	193.1	194.3	197.4
Coal	503.0	500.6	497.2	494.5	496.1	549.3	522.8	231.3	175.2	126.4	574.5	525.4	121.5	93.9	68.6
Total	574.0	570.1	565.9	564.2	565.4	662.9	624.4	403.8	362.6	327.0	706.8	650.1	320.9	292.6	270.5
Total Carbon Emissions															
Petroleum	655.8	654.2	654.0	653.8	654.1	761.5	747.7	700.2	682.8	676.3	795.7	771.1	699.7	684.9	673.4
Natural Gas	354.2	351.7	350.8	352.2	351.4	424.4	403.2	455.7	468.8	476.7	450.3	431.9	470.4	473.1	471.8
Coal	547.3	563.7	560.2	557.5	559.1	615.9	582.4	282.7	225.9	176.6	640.1	582.5	171.0	142.7	116.9
Other	.1	.1	.1	.1	.1	1.5	1.5	1.3	1.3	1.2	2.2	2.3	1.9	1.9	1.8
Total	1577	1570	1565	1564	1565	1803	1735	1440	1379	1331	1888	1788	1351	1303	1264
Carbon Emissions															
(tons per person)	5.7	5.7	5.7	5.7	5.7	6.0	5.8	4.8	4.6	4.5	6.1	5.7	4.3	4.2	4.1

mo98b.d100197a - AEO98 Reference Case, nonbase.d011398a - Carbon Reference (1), fea100.d011398a (2), fea200.d011498a (3), fea300.d011398b (4)

NATIONAL ENERGY MODELING SYSTEM

Table 62. Emissions by NERC Region (million short tons) except Carbon and Carbon Dioxide (million metric tons)

	2000 (1)	2000 (2)	2000 (3)	2000 (4)	2000 (5)	2010 (1)	2010 (2)	2010 (3)	2010 (4)	2010 (5)	2015 (1)	2015 (2)	2015 (3)	2015 (4)	2015 (5)
Emissions															
United States															
Total Carbon	574.0	570.1	565.9	564.2	565.4	662.9	624.4	403.8	362.6	327.0	706.8	658.1	320.9	292.6	270.5
Carbon Dioxide	2104	2090	2075	2069	2073	2431	2289	1481	1330	1199	2591	2504	1177	1073	991.9
Sulfur Dioxide	10.19	10.19	10.42	10.44	10.43	9.22	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00
Nitrogen Oxide	6.14	6.11	6.06	6.01	6.05	6.51	6.19	3.52	2.97	2.45	6.75	6.29	2.33	1.84	1.56
East Central Area Reliability															
Total Carbon	128.8	128.1	125.8	125.7	126.0	144.3	136.0	108.8	90.46	80.31	148.5	137.6	76.82	69.74	64.18
Carbon Dioxide	472.4	469.6	461.3	461.0	462.0	529.1	490.6	364.7	331.7	294.5	544.5	514.4	281.7	255.7	235.3
Sulfur Dioxide	3.43	3.34	3.54	3.61	3.58	3.07	2.93	4.16	3.94	4.04	2.06	2.70	5.06	5.45	5.81
Nitrogen Oxide	1.50	1.49	1.47	1.46	1.47	1.62	1.53	1.01	.80	.65	1.64	1.51	.69	.63	.53
Electric Reliability Council Tx															
Total Carbon	45.89	45.75	45.75	45.73	45.75	51.05	47.25	27.01	25.61	24.69	52.53	48.62	21.91	21.43	19.64
Carbon Dioxide	168.3	167.7	167.7	167.7	167.7	187.2	173.3	99.0	94.61	90.55	192.6	178.3	80.35	78.59	72.01
Sulfur Dioxide	.35	.35	.35	.35	.35	.34	.32	.06	.07	.09	.33	.30	.12	.14	.19
Nitrogen Oxide	.47	.47	.47	.47	.47	.40	.36	.23	.21	.28	.38	.36	.11	.10	.10
Mid-Atlantic Area Council															
Total Carbon	34.52	34.10	33.33	33.75	33.76	40.01	37.60	29.90	23.50	24.34	42.05	38.99	21.99	20.52	19.57
Carbon Dioxide	126.6	125.0	122.2	123.8	123.8	146.7	137.9	109.6	93.50	89.23	154.2	143.0	80.64	74.51	71.74
Sulfur Dioxide	.54	.54	1.09	1.09	1.10	.53	.40	1.04	.90	1.10	.51	.44	.62	.40	.43
Nitrogen Oxide	.29	.29	.28	.29	.29	.31	.20	.21	.15	.15	.31	.29	.11	.09	.08
Mid-America Interconnected Netw															
Total Carbon	40.82	40.56	40.26	40.37	40.61	47.77	45.08	25.64	23.07	21.14	50.52	46.37	25.05	22.67	21.09
Carbon Dioxide	149.7	148.7	147.6	148.0	148.9	175.2	165.3	94.01	84.57	77.52	185.2	170.0	91.86	83.12	77.35
Sulfur Dioxide	.93	.87	.96	.99	.99	.65	.63	.40	.30	.33	.61	.58	.46	.33	.32
Nitrogen Oxide	.52	.52	.52	.52	.52	.54	.52	.19	.16	.12	.56	.52	.13	.11	.09
Mid-Continent Area Power Pool															
Total Carbon	32.64	32.45	31.80	31.71	31.92	38.87	36.67	20.54	17.37	13.92	41.28	38.41	10.43	8.90	8.63
Carbon Dioxide	119.7	119.0	116.6	116.3	117.0	142.5	134.5	75.31	63.70	51.03	151.3	140.8	38.23	32.62	31.63
Sulfur Dioxide	.42	.41	.39	.40	.39	.43	.41	.27	.29	.25	.42	.39	.08	.06	.13
Nitrogen Oxide	.39	.39	.38	.38	.38	.45	.43	.20	.16	.13	.46	.43	.05	.05	.05
Northeast Power Council/New York															
Total Carbon	13.50	13.53	13.39	13.32	13.32	14.23	13.01	10.31	9.96	9.97	15.31	14.22	10.05	9.93	8.89
Carbon Dioxide	49.50	49.60	49.13	48.83	48.83	51.82	47.71	37.81	36.51	36.57	56.15	52.12	36.78	36.41	32.58
Sulfur Dioxide	.24	.24	.26	.24	.26	.19	.18	.13	.18	.07	.17	.16	.15	.17	.18
Nitrogen Oxide	.11	.11	.11	.11	.11	.09	.08	.05	.04	.04	.09	.09	.04	.04	.03
Northeast Power Council/New Engl															
Total Carbon	11.59	11.45	11.59	11.57	11.62	14.09	14.47	8.92	8.74	7.98	14.32	13.98	8.01	7.97	7.65
Carbon Dioxide	42.40	41.97	42.51	42.43	42.60	51.67	53.04	32.72	32.05	28.95	52.49	51.27	29.36	29.22	28.05
Sulfur Dioxide	.18	.18	.16	.16	.37	.14	.17	.04	.06	.06	.13	.14	.06	.07	.09

aeo98b.d100197a - AEO98 Reference Case, ovgbase.d011398a - Carbon Reference (1), fee108.d011398a (2), fee200.d011498a (3), fee

ENERGY INFORMATION ADMINISTRATION

NATIONAL ENERGY MODELING SYSTEM

Table 62. Emissions by NERC Region (million short tons) (Continued)
except Carbon and Carbon Dioxide (million metric tons)

	2000 (1)	2000 (2)	2000 (3)	2000 (4)	2000 (5)	2010 (1)	2010 (2)	2010 (3)	2010 (4)	2010 (5)	2015 (1)	2015 (2)	2015 (3)	2015 (4)	2015 (5)
Southeastern Electric/Florida															
Total Carbon	26.44	26.28	25.82	25.82	25.74	32.84	30.37	20.30	19.43	18.86	38.16	33.04	19.23	18.69	17.46
Carbon Dioxide	96.93	96.01	94.66	94.65	94.37	120.4	111.4	74.45	71.26	67.33	139.9	121.1	70.50	68.51	64.02
Sulfur Dioxide	.39	.40	.32	.32	.32	.37	.34	.16	.17	.16	.37	.37	.19	.21	.18
Nitrogen Oxide	.29	.29	.28	.28	.28	.33	.30	.16	.18	.13	.30	.22	.12	.12	.10
Southeastern Electric/Excl Fla															
Total Carbon	104.2	103.1	104.1	101.9	102.5	122.0	113.8	80.98	74.08	65.59	131.5	121.1	63.22	57.66	51.04
Carbon Dioxide	382.1	378.1	381.8	373.7	375.6	447.3	417.2	296.4	271.3	240.5	482.0	444.1	231.8	211.4	187.1
Sulfur Dioxide	2.56	2.70	2.21	2.12	2.14	2.48	2.52	2.38	2.74	2.65	2.63	2.95	1.83	1.75	1.59
Nitrogen Oxide	1.06	1.05	1.06	1.03	1.04	1.18	1.12	.77	.78	.57	1.23	1.13	.44	.57	.28
Southwest Power Pool															
Total Carbon	59.86	59.67	59.02	59.35	59.26	68.26	65.98	35.12	32.20	29.35	70.37	66.71	26.87	24.39	23.59
Carbon Dioxide	219.5	218.8	216.4	217.6	217.3	250.3	241.6	128.8	118.1	107.6	258.0	244.6	97.41	89.41	86.58
Sulfur Dioxide	.68	.67	.68	.68	.68	.62	.62	.21	.20	.10	.59	.59	.23	.19	.17
Nitrogen Oxide	.69	.68	.67	.68	.68	.71	.70	.38	.52	.26	.69	.67	.16	.14	.12
Western Systems Council/NWP															
Total Carbon	24.83	24.76	24.70	24.72	24.66	29.61	28.71	15.01	10.85	10.23	31.44	29.53	12.09	10.09	9.14
Carbon Dioxide	91.05	90.78	91.56	90.64	90.41	108.6	105.3	55.03	39.78	37.50	111.6	108.3	44.32	37.00	33.51
Sulfur Dioxide	.16	.16	.16	.16	.16	.14	.14	.03	.02	.01	.15	.15	.02	.01	.01
Nitrogen Oxide	.24	.24	.23	.24	.23	.25	.25	.09	.05	.04	.25	.25	.05	.04	.03
Western Systems Council/RA															
Total Carbon	27.94	27.99	27.94	28.04	28.04	31.83	30.92	17.13	15.52	13.47	33.15	31.91	15.72	13.36	12.10
Carbon Dioxide	102.5	102.6	102.4	102.8	102.8	116.7	113.4	62.79	56.91	49.39	121.6	117.0	57.64	48.97	44.37
Sulfur Dioxide	.21	.21	.21	.21	.21	.18	.18	.15	.12	.12	.16	.16	.16	.13	.17
Nitrogen Oxide	.30	.30	.30	.29	.29	.31	.31	.14	.12	.09	.32	.31	.11	.08	.06
Western Systems Council/CNV															
Total Carbon	22.87	22.45	22.39	22.27	22.32	28.16	24.67	13.03	9.73	7.69	38.66	29.65	9.87	7.48	7.35
Carbon Dioxide	83.84	82.25	82.10	81.66	81.85	103.3	90.46	47.79	35.67	28.21	141.7	108.6	36.18	27.48	26.96
Sulfur Dioxide	.05	.05	.08	.08	.08	.08	.08	.02	.01	.01	.08	.06	.02	.01	.01
Nitrogen Oxide	.18	.19	.19	.19	.19	.22	.21	.10	.04	.03	.33	.26	.06	.05	.03

aeo98b.d100197a - AEO98 Reference Case, [illegible]base.d011398a - Carbon Reference (1), fee181.d011398a (2), fee291.d011498a (3), fee300.d011[illegible]

ENERGY INFORMATION ADMINISTRATION

NATIONAL ENERGY MODELING SYSTEM

Table 117. National Impacts of the Clean Air Act Amendments of 1990 (CAAA90)

	2000 (1)	2000 (2)	2000 (3)	2000 (4)	2000 (5)	2010 (1)	2010 (2)	2010 (3)	2010 (4)	2010 (5)	2015 (1)	2015 (2)	2015 (3)	2015 (4)	2015 (5)
Scrubber Retrofits (gigawatts)..	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Interregional SO2 Allowances Traded (thousand tons).........	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
SO2 Allowance Price	120.9	137.3	76.25	75.11	73.70	189.4	186.5	.00	.00	.00	181.0	177.7	.00	.00	.00
SO2 Emissions (million tons)....	10.19	10.19	10.42	10.44	10.43	9.22	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00
Coal Production by Sulfur Categ. (million tons)															
Low Sulfur (< .61 lbs S/mmBtu)..	468.1	473.8	453.9	456.9	451.3	594.1	569.1	167.7	137.9	97.63	646.9	593.8	101.8	66.70	69.53
Med.Sulfur(.61-1.67 lbs.S/mmBtu)	498.7	492.9	484.3	482.8	484.6	478.1	454.3	294.5	266.3	234.9	464.9	440.9	225.7	209.5	195.8
High Sulfur (> 1.67 lbs.S/mmBtu)	177.9	173.9	194.7	196.9	195.4	192.9	181.3	121.3	100.5	84.10	200.3	179.1	87.30	72.82	55.63
Gasoline Prices															
Traditional Gasoline............	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Oxygenated Gasoline.............	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Reformulated Gasoline...........	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
High-Oxygen Reformulated Gas....	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Average.........................	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Gasoline Quantities															
Traditional Gasoline............	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Oxygenated Gasoline.............	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Reformulated Gasoline...........	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
High-Oxygen Reformulated Gas....	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Total...........................	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Distillate Prices															
Distillate <= 0.05% Sulfur......	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Distillate > 0.05% Sulfur.......	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Average.........................	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Distillate Quantities															
Distillate <= 0.05% Sulfur......	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Distillate > 0.05% Sulfur.......	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Total...........................	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00

aeo98b.d101197a - AEO98 Reference Case, newbase.d011598a - Carbon Reference (1), fee100.d011598a (2), fee200.d012498a (3), fee300.d011598b

ENERGY INFORMATION ADMINISTRATION

January 15, 1998

NOTE

TO: Randy Lutter, President's Council of Economic Advisors

FROM: John Berg, FHWA

SUBJECT: Potential Impacts of hypothetical fuel price increases

Randy,Since we haven't been able to connect by phone, I thought I'd send you over a few thoughts via fax. Since the effects you are interested in (investment req'ts. and traffic congestion) stem from the effect on overall travel, I'll start by speculating on possible effects of tax-induced price increases on fuel consumption. Most models relating fuel consumption to price use short-run elasticities in the range of -0.1 to -0.15 or -0.2. I've seen longer-run elasticities of -0.4, and sometimes higher. However, even with these higher long-run fuel price elasticities, the effect on travel has been much reduced because, once consumers perceive that the fuel price increase is long lasting, they tend to upgrade the fuel efficiency of their vehicles, so travel elasticities are much lower.

I don't have recent DOE estimates of these relationships, but a 1991 report, "Studies of Energy Taxes," provides some relevant information. The estimates DOE calculated for a 50-cent tax increase in 1991 indicate a 2.5 percent reduction (from the no-tax baseline) in fuel consumption in 1991, and a 7.5 percent reduction in 2000. Although I can't tell from the report, I would assume that they kept the price of fuel 50 cents higher than the baseline in real terms over the 1991 to 2000 period (that is, with further increases in fuel price in nominal terms over the intervening years).

The estimates of the effects of this tax increase on travel are quite revealing. Here, you see a 2.8 percent reduction in vehicle miles traveled in 1991, but by 2000, travel is only 1.1 percent below the baseline. From these figures I calculate a compound rate of growth of vmt of .008 percent per year in the base case (very low estimate compared to historical trends), and .007 percent per year in the case of the 50 cent tax. A 50 cent tax in 2010 would of course have a much reduced real effect than the tax examined in the 1991 study. While I'm sure DOE has updated these estimates, I think they make the point that, for your purposes, a 50-cent tax would not be likely to have a perceptible affect on overall travel, much less urban travel or congestion, and would not be likely to have a noticeable effect on investment requirements.

I guess we could speculate further on how these travel reductions would be reflected in urban travel and congestion. My guess is that urban congestion would be less effected by the fuel price increase than would longer non-urban trips, but that is only speculation. I personally think that the only way a price increase is going to significantly effect congestion, is if the price increase is in the form of a congestion fee (place and time specific), unless you're talking about a very substantial price increase (one that would substantially shut down economic activity). In a paper included in the National Academy of Sciences study of urban transportation pricing (Curbing Gridlock, 1994), the late Greig Harvey shows estimates of the effects of a gasoline tax increase of $2.00 per gallon resulting in reductions in vmt of 8.1 percent, and 7.6 percent in trips (the years aren't clear here).

In sum, I guess my advice is that a gas tax in the range of 50 cents per gallon would not be expected to have much effect on either congestion or investment requirements. Another thing to keep in mind is that a major part of the Administration's current Global Climate Change initiative is on improvements to the energy efficiency of vehicles and fuels. This would imply even a lesser affect of a fuel tax increase on travel.

I suggest you touch base with the Department of Energy, Energy Information Administration for their latest estimates of fuel tax policies on consumption and travel. The name and number included in the 1991 report is Gerald Peabody, Distributional and Energy Demand Analysis, 202-586-6160. Another excellent contact is Dave Greene, with the Oak Ridge National Labs. David has been doing a considerable amount of work in the area of energy and transportation demand in the context of the current global climate change discussions. The number I have for him is 615-574-5963. I hope this information is helpful to you and I would be glad to discuss this with you further.

U. S. Department of Energy

TELEFAX TRANSMISSION

FROM

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Carbon fee tables requested from Andy Kydes

(640 of 710
instead

NATIONAL ENERGY MODELING SYSTEM

Table 1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2000 (1)	2000 (2)	2000 (3)	2000 (4)	2005 (1)	2005 (2)	2005 (3)	2005 (4)	2010 (1)	2010 (2)	2010 (3)	2010 (4)	2015 (1)	2015 (2)	2015 (3)	2015 (4)	2020 (1)	2020 (2)	2020 (3)	2020 (4)
Production																				
Crude Oil & Lease Condensate.	13.06	13.06	13.07	13.07	12.33	12.33	12.33	12.26	11.80	11.80	11.77	11.56	11.07	11.05	10.97	10.61	10.33	10.31	10.15	9.76
Natural Gas Plant Liquids....	2.39	2.38	2.37	2.36	2.63	2.64	2.66	2.56	2.93	2.94	3.02	3.04	3.28	3.13	3.24	3.17	3.30	3.29	3.40	3.25
Dry Natural Gas.............	20.85	20.76	20.75	20.60	22.83	22.90	23.10	22.25	25.30	25.35	26.09	26.19	26.72	26.88	27.86	27.16	28.12	28.09	28.92	27.72
Coal.......................	24.33	24.42	24.42	24.21	25.52	25.52	24.99	24.22	26.50	26.33	23.52	19.25	27.64	27.18	23.54	18.96	28.37	28.06	24.25	19.42
Nuclear Power..............	7.36	7.36	7.36	7.36	6.87	6.87	6.87	6.87	6.36	6.36	6.36	6.36	5.12	5.12	5.12	5.12	4.09	4.09	4.09	4.09
Renewable Energy	6.82	6.82	6.84	6.83	7.11	7.11	7.17	7.34	7.41	7.42	7.97	8.05	7.86	8.00	8.89	9.06	8.19	8.48	9.32	9.83
Other	.56	.56	.56	.56	.55	.54	.54	.54	.49	.48	.55	.60	.64	.83	1.01	.92	.89	.98	1.25	1.37
Total......................	75.36	75.35	75.37	74.98	77.84	77.90	77.65	76.04	80.79	80.67	79.28	75.04	82.32	82.19	80.63	74.98	83.29	83.29	81.37	75.44
Imports																				
Crude Oil	19.18	19.19	19.15	19.11	21.98	22.09	22.10	21.91	23.18	23.31	23.16	22.96	24.35	24.65	24.34	24.09	25.40	25.71	25.34	24.97
Petroleum Products	4.39	4.26	4.27	4.40	5.55	5.51	5.52	5.19	7.56	7.30	7.10	5.62	8.81	8.21	7.60	5.89	9.50	9.02	8.24	6.19
Natural Gas	4.21	4.23	4.22	4.21	4.44	4.43	4.52	4.42	4.70	4.72	4.87	4.85	5.06	5.10	5.38	5.28	5.36	5.35	5.74	5.53
Other Imports	.62	.62	.62	.63	.58	.58	.58	.60	.57	.57	.59	.66	.54	.54	.57	.64	.56	.56	.58	.66
Total......................	28.40	28.31	28.27	28.35	32.55	32.61	32.73	32.12	36.01	35.90	35.72	34.08	38.77	38.51	37.89	35.91	40.82	40.67	39.90	37.35
Exports																				
Petroleum	1.73	1.73	1.74	1.73	1.73	1.73	1.73	1.72	1.78	1.70	1.70	1.70	1.86	1.82	1.82	1.80	1.64	1.53	1.59	1.66
Natural Gas................	.26	.28	.28	.28	.28	.28	.26	.28	.29	.29	.29	.29	.30	.30	.30	.30	.32	.32	.32	.32
Coal.......................	2.41	2.41	2.41	2.41	2.64	2.64	2.64	2.64	2.84	2.84	2.84	2.84	3.03	3.03	3.03	3.03	3.23	3.23	3.23	3.23
Total......................	4.41	4.41	4.42	4.41	4.65	4.65	4.66	4.65	4.91	4.84	4.83	4.83	5.19	5.14	5.15	5.13	5.20	5.09	5.15	5.21
Discrepancy	.49	.63	.63	.46	.05	.01	.03	-.07	.14	.19	-.27	-.31	-.09	.13	.05	.00	-.07	-.08	.00	-.05
Consumption																				
Petroleum Products	38.37	38.38	38.35	38.26	41.38	41.41	41.43	40.69	44.37	44.37	43.72	41.82	46.21	46.20	45.42	42.87	47.69	47.70	46.82	43.85
Natural Gas................	24.76	24.69	24.68	24.51	26.93	27.00	27.28	26.34	29.57	29.63	30.51	30.56	31.32	31.53	32.76	31.97	33.00	32.99	34.16	32.75
Coal.......................	22.13	22.22	22.21	22.01	23.11	23.10	22.63	21.83	23.91	23.73	20.91	16.71	24.87	24.41	20.78	16.28	25.40	25.09	21.26	16.49
Nuclear Power..............	7.36	7.36	7.36	7.36	6.87	6.87	6.87	6.87	6.36	6.36	6.36	6.36	5.12	5.12	5.12	5.12	4.09	4.09	4.09	4.09
Renewable Energy	6.82	6.82	6.84	6.84	7.12	7.12	7.17	7.35	7.43	7.43	7.99	8.07	7.88	8.02	8.92	9.06	8.22	8.51	9.35	9.86
Other	.41	.41	.41	.41	.37	.37	.37	.37	.40	.39	.42	.46	.41	.41	.43	.46	.43	.43	.45	.49
Total......................	99.8	99.9	99.9	99.4	105.8	105.9	105.8	103.4	112.0	111.9	109.9	104.0	115.8	115.7	113.4	105.8	118.8	118.8	116.1	107.5
Net Imports - Petroleum.........	21.84	21.73	21.69	21.79	25.80	25.87	25.89	25.37	28.97	28.91	28.56	26.88	31.30	31.04	30.12	28.18	33.26	33.20	31.99	29.50
Prices (1996 dollars per unit)																				
World Oil Price ($ per bbl) ...	19.12	19.11	19.11	19.06	20.25	20.27	20.25	19.76	20.60	20.77	20.36	19.17	21.17	21.08	20.35	19.12	21.82	21.81	21.06	19.95
Gas Wellhead Price($ / Mcf)...	2.13	2.12	2.13	2.13	2.15	2.15	2.19	2.08	2.26	2.29	2.49	2.36	2.32	2.37	2.67	2.58	2.49	2.56	2.85	2.64
Coal Minemouth Price ($ / ton).	17.36	17.44	17.46	17.40	16.00	16.26	16.26	16.17	14.87	15.15	15.50	15.82	13.88	14.24	14.61	14.58	13.26	13.50	13.74	14.26
Aver. Electricity (cents / Kwh)	6.5	6.5	6.5	6.5	6.2	6.2	6.3	6.2	6.0	6.2	7.1	7.9	5.6	5.8	6.8	7.6	5.5	5.6	5.7	7.6

newbase.d012198a - 0 Tax, Reference Demand Technology (1), fee005.d012298a (2), fee050.d012298a (3), fee100.d012298a (4)

NATIONAL ENERGY MODELING SYSTEM

Table 17. Carbon Emissions by Sector and Source
(Million Metric Tons per Year, Unless Otherwise Noted)

Sector and Source	2000 (1)	2000 (2)	2000 (3)	2000 (4)	2005 (1)	2005 (2)	2005 (3)	2005 (4)	2010 (1)	2010 (2)	2010 (3)	2010 (4)	2015 (1)	2015 (2)	2015 (3)	2015 (4)	2020 (1)	2020 (2)	2020 (3)	2020 (4)
Residential																				
Petroleum	25.8	25.8	25.8	25.7	25.0	25.0	25.0	24.8	24.8	24.7	24.1	23.1	24.6	24.5	24.0	22.7	24.3	24.2	23.8	22.2
Natural Gas	77.0	76.9	76.9	76.8	78.7	78.7	78.5	78.2	81.3	80.8	77.8	74.7	84.0	83.3	79.8	75.7	86.1	85.4	82.1	77.4
Coal	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Electricity	201.3	201.8	201.6	199.4	215.6	215.6	212.7	202.4	229.8	228.5	209.1	174.0	247.9	244.5	219.4	179.9	265.8	262.9	235.5	190.4
Total	305.5	306.0	305.8	303.3	320.7	320.7	317.6	306.8	337.3	335.4	312.3	273.1	357.9	353.6	324.5	279.6	377.5	373.8	342.6	291.3
Commercial																				
Petroleum	12.9	12.9	12.9	12.8	12.9	12.9	12.9	12.6	12.8	12.8	12.7	12.5	12.7	12.7	12.6	12.4	12.5	12.4	12.3	12.1
Natural Gas	49.9	49.9	49.9	49.7	52.1	52.0	52.0	51.2	54.1	53.9	53.0	50.8	55.5	55.3	54.2	51.1	55.6	55.3	54.3	50.7
Coal	2.2	2.2	2.2	2.2	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.4	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Electricity	182.1	182.6	182.4	181.1	192.8	192.8	190.3	184.9	204.1	202.9	185.1	158.6	216.9	213.8	190.7	160.5	223.9	221.3	196.5	162.9
Total	247.1	247.5	247.4	245.8	260.1	260.1	257.5	251.3	273.5	272.1	253.2	224.3	287.7	284.3	260.0	226.5	294.4	291.6	265.7	228.3
Industrial																				
Petroleum	103.3	103.2	103.1	102.6	109.6	109.9	109.9	107.9	115.4	116.0	113.4	109.7	118.6	119.5	117.1	110.4	119.3	120.0	117.4	110.6
Natural Gas	155.5	155.5	155.5	154.4	158.6	158.6	158.7	153.4	166.0	165.3	163.1	153.9	167.2	166.6	164.4	152.3	167.9	166.8	164.4	151.4
Coal	60.6	60.6	60.6	59.4	62.3	62.3	62.4	57.9	62.7	62.2	57.3	49.3	61.6	61.1	56.5	47.0	60.5	60.1	55.3	44.6
Electricity	187.5	188.0	187.6	185.6	203.0	203.5	201.3	193.2	217.0	217.5	207.2	182.5	228.5	227.8	213.8	184.7	237.4	237.3	221.4	187.8
Total	506.8	507.2	506.8	502.0	533.5	534.3	532.2	512.5	561.2	561.0	541.2	495.4	575.9	575.0	551.7	494.5	585.3	584.3	558.5	494.4
Transportation																				
Petroleum	502.7	502.8	502.8	502.3	552.7	553.1	553.2	549.6	600.6	599.8	589.3	569.5	628.1	622.6	607.4	580.8	649.0	646.1	627.0	591.3
Natural Gas	12.1	12.1	12.1	12.0	14.5	14.4	14.6	14.3	17.2	17.2	17.1	17.0	18.3	18.3	18.6	18.3	19.7	19.7	19.9	19.1
Other	.1	.1	.1	.1	.5	.5	.5	.5	1.4	1.4	1.4	1.4	2.2	2.2	2.2	2.1	2.7	2.7	2.6	2.5
Electricity	3.3	3.3	3.3	3.3	5.9	5.9	5.8	5.8	8.7	8.7	8.0	7.2	10.7	10.6	9.5	8.5	12.2	12.1	10.9	9.7
Total	518.2	518.2	518.2	517.7	573.6	574.0	574.1	570.2	627.9	627.1	615.8	595.0	659.4	653.7	637.7	609.7	683.6	680.6	660.3	622.6
Total Carbon Emissions ..																				
Petroleum	644.7	644.6	644.6	643.4	700.1	700.9	701.0	695.1	753.6	753.4	739.6	714.8	784.0	779.3	761.1	726.3	805.1	802.9	780.5	736.2
Natural Gas	294.5	294.3	294.5	292.8	303.9	303.7	303.7	297.1	318.6	317.2	311.0	296.4	325.0	323.5	316.9	297.4	329.3	327.2	320.6	298.6
Coal	64.2	64.2	64.2	63.0	66.0	66.1	66.2	61.6	66.5	65.9	61.1	53.0	65.5	65.0	60.3	50.8	64.5	63.9	59.1	48.4
Other	.1	.1	.1	.1	.5	.5	.5	.5	1.4	1.4	1.4	1.4	2.2	2.2	2.2	2.1	2.7	2.7	2.6	2.5
Electricity	574.1	575.7	574.9	569.4	617.3	617.9	610.1	586.4	659.7	657.7	609.4	522.3	704.0	696.7	633.4	533.6	739.2	733.5	664.3	550.8
Total	1578	1579	1578	1569	1688	1689	1681	1641	1800	1796	1722	1588	1881	1867	1774	1610	1941	1930	1827	1637
Electric Generators ..																				
Petroleum	11.2	11.6	11.1	10.6	9.2	9.3	9.5	9.1	8.2	8.2	9.1	6.5	7.6	7.7	9.1	7.8	7.8	8.3	9.3	7.3
Natural Gas	60.0	59.1	58.7	57.9	81.8	82.9	87.1	80.4	104.9	107.3	126.1	141.9	123.7	128.2	152.5	161.1	143.6	145.4	168.7	171.1
Coal	502.9	505.1	505.0	500.8	526.3	525.7	513.5	497.0	546.7	542.2	474.3	373.4	572.7	560.8	471.8	364.7	587.9	579.8	486.4	372.4
Total	574.1	575.7	574.9	569.4	617.3	617.9	610.1	586.4	659.7	657.7	609.4	522.3	704.0	696.7	633.4	533.6	739.2	733.5	664.3	550.8
Total Carbon Emissions ..																				
Petroleum	655.9	656.2	655.7	654.1	709.3	710.2	710.5	704.2	761.8	761.6	748.6	721.7	791.7	787.0	770.2	734.2	812.9	811.2	789.7	743.5
Natural Gas	354.5	353.4	353.2	350.8	385.7	386.6	390.8	377.5	423.5	424.4	437.1	438.3	448.7	451.7	469.4	458.5	472.8	472.6	489.3	469.7
Coal	567.1	569.3	569.2	563.9	592.3	591.8	579.7	558.6	613.2	608.1	535.4	426.4	638.2	625.7	532.1	415.5	652.4	643.8	545.5	420.9
Other	.1	.1	.1	.1	.5	.5	.5	.5	1.4	1.4	1.4	1.4	2.2	2.2	2.2	2.1	2.7	2.7	2.6	2.5
Total	1578	1579	1578	1569	1688	1689	1681	1641	1800	1796	1722	1588	1881	1867	1774	1610	1941	1930	1827	1637
Carbon Emissions (tons per person)	5.7	5.7	5.7	5.7	5.9	5.9	5.9	5.7	6.0	6.0	5.8	5.3	6.0	6.0	5.7	5.2	6.6	6.0	5.6	5.1

newbase.d012198a - 0 Tax, Reference Demand Technology (1), fee005.d012298a (2), fee050.d012298a (3), fee100.d012298a (4)

Table 62. Emissions by NERC Region (million short tons)
except Carbon and Carbon Dioxide (million metric tons)

	2000 (1)	2000 (2)	2000 (3)	2000 (4)	2005 (1)	2005 (2)	2005 (3)	2005 (4)	2010 (1)	2010 (2)	2010 (3)	2010 (4)	2015 (1)	2015 (2)	2015 (3)	2015 (4)	2020 (1)	2020 (2)	2020 (3)	2020 (4)
Emissions																				
United States																				
Total Carbon	574.1	575.7	574.9	569.4	617.3	617.9	610.1	586.4	659.7	657.7	609.4	522.3	704.0	696.7	633.4	533.6	739.2	733.5	664.3	550.8
Carbon Dioxide	2105	2111	2108	2088	2263	2265	2237	2150	2419	2411	2234	1915	2581	2555	2322	1957	2711	2690	2436	2020
Sulfur Dioxide	10.19	10.19	10.19	10.19	9.69	9.69	9.69	9.69	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00
Nitrogen Oxide	6.15	6.17	6.16	6.10	6.29	6.28	6.18	5.96	6.48	6.44	5.81	4.86	6.75	6.64	5.81	4.74	6.94	6.86	5.99	4.83
East Central Area Reliability																				
Total Carbon	129.0	129.1	129.1	127.0	135.7	136.8	134.4	129.4	143.8	143.7	130.1	106.5	149.2	148.6	134.4	99.0	155.3	155.5	139.6	105.9
Carbon Dioxide	472.9	473.5	473.4	465.7	497.6	501.6	492.9	474.5	527.3	527.0	476.9	390.6	547.0	544.9	492.8	363.1	569.6	570.0	511.9	388.3
Sulfur Dioxide	3.39	3.61	3.61	3.60	3.33	3.53	3.48	3.41	2.98	3.10	3.11	3.28	2.84	3.10	3.22	3.01	2.80	3.10	3.02	3.11
Nitrogen Oxide	1.50	1.50	1.50	1.48	1.55	1.57	1.52	1.47	1.61	1.61	1.41	1.04	1.64	1.63	1.42	.88	1.68	1.68	1.45	.95
Electric Reliability Council Tx																				
Total Carbon	45.92	45.91	45.89	45.74	47.40	47.40	47.28	46.27	50.00	49.80	45.62	33.86	52.61	51.91	47.59	36.42	54.64	54.40	50.01	38.41
Carbon Dioxide	168.4	168.3	168.3	167.7	173.8	173.8	173.4	169.7	183.3	182.6	167.3	124.2	192.9	190.3	174.5	133.5	200.3	199.5	183.3	140.8
Sulfur Dioxide	.35	.35	.35	.35	.34	.34	.35	.35	.34	.34	.31	.15	.33	.33	.30	.19	.32	.32	.29	.22
Nitrogen Oxide	.47	.47	.47	.47	.43	.43	.43	.42	.38	.37	.33	.25	.38	.38	.33	.26	.39	.39	.35	.27
Mid-Atlantic Area Council																				
Total Carbon	34.48	34.36	34.37	34.04	35.70	35.62	35.24	34.30	39.69	39.72	38.37	35.19	41.62	41.76	39.66	35.46	45.23	44.36	42.49	37.84
Carbon Dioxide	126.4	126.0	126.0	124.8	130.9	130.6	129.2	125.8	145.5	145.6	140.7	129.0	152.6	153.1	145.4	130.0	165.8	162.7	155.8	138.7
Sulfur Dioxide	.55	.63	.63	.72	.54	.63	.63	.71	.50	.60	.57	.64	.50	.56	.49	.57	.52	.56	.49	.57
Nitrogen Oxide	.29	.29	.29	.29	.28	.28	.28	.27	.30	.30	.28	.26	.31	.31	.28	.25	.33	.33	.30	.27
Mid-America Interconnected Netw																				
Total Carbon	40.87	41.08	40.99	40.77	44.56	42.61	41.35	38.37	47.70	45.45	41.88	35.31	50.20	48.18	42.72	36.21	52.30	50.53	44.22	37.36
Carbon Dioxide	149.8	150.6	150.3	149.5	163.4	156.2	151.6	140.7	174.9	166.6	153.6	129.5	184.1	176.7	156.6	132.8	191.8	185.3	162.1	137.0
Sulfur Dioxide	.88	1.00	1.01	.98	.70	.72	.74	.75	.65	.65	.64	.71	.61	.52	.78	.82	.57	.58	.86	.99
Nitrogen Oxide	.52	.53	.53	.52	.52	.50	.48	.45	.54	.52	.45	.36	.56	.54	.46	.36	.59	.57	.48	.37
Mid-Continent Area Power Pool																				
Total Carbon	32.68	32.65	32.63	32.19	37.10	37.19	37.45	35.14	38.85	38.54	36.79	32.04	41.10	40.98	38.39	34.25	42.13	42.06	39.06	34.28
Carbon Dioxide	119.8	119.8	119.6	118.0	136.0	136.4	137.3	128.8	142.5	141.3	134.9	117.5	150.7	150.2	140.8	125.6	154.5	154.2	143.2	125.7
Sulfur Dioxide	.42	.42	.43	.41	.44	.45	.46	.41	.43	.43	.41	.37	.42	.42	.39	.37	.40	.40	.38	.35
Nitrogen Oxide	.39	.39	.39	.39	.43	.44	.44	.41	.45	.44	.41	.34	.45	.45	.41	.36	.46	.46	.41	.35
Northeast Power Council/New York																				
Total Carbon	13.60	13.56	13.54	13.46	13.11	13.09	13.19	12.55	14.04	13.97	13.07	11.86	15.26	15.33	14.18	12.84	16.16	16.33	15.94	11.99
Carbon Dioxide	49.51	49.73	49.64	49.36	48.06	48.00	48.36	46.01	51.48	51.21	47.91	43.48	55.97	56.22	51.98	47.09	59.26	59.87	58.44	43.95
Sulfur Dioxide	.24	.24	.24	.24	.20	.20	.21	.20	.19	.19	.14	.14	.17	.16	.13	.14	.16	.16	.15	.12
Nitrogen Oxide	.11	.11	.11	.11	.09	.09	.09	.08	.09	.09	.07	.06	.09	.09	.07	.07	.09	.10	.09	.06
Northeast Power Council/New Engl																				
Total Carbon	11.59	11.59	11.59	11.50	14.59	14.58	14.58	14.19	14.97	15.00	14.61	11.76	14.95	14.95	13.88	11.53	15.50	15.45	14.25	12.34
Carbon Dioxide	42.50	42.51	42.49	42.16	53.48	53.47	53.46	52.03	54.90	54.99	53.57	43.12	54.82	54.81	50.91	42.28	56.85	56.64	52.25	45.26
Sulfur Dioxide	.18	.18	.19	.18	.20	.20	.20	.19	.17	.18	.17	.10	.16	.16	.15	.09	.14	.19	.15	.10
Nitrogen Oxide	.10	.10	.10	.10	.11	.11	.11	.11	.11	.11	.11	.07	.11	.11	.10	.07	.11	.11	.09	.08

newbase.d012198a - 0 Tax, Reference Demand Technology (1), fee005.d012298a (2), fee050.d012298a (3), fee100.d012298a (4)

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NATIONAL ENERGY MODELING SYSTEM

Table 62. Emissions by NERC Region (million short tons) (Continued)
except Carbon and Carbon Dioxide (million metric tons)

	2000 (1)	2000 (2)	2000 (3)	2000 (4)	2005 (1)	2005 (2)	2005 (3)	2005 (4)	2010 (1)	2010 (2)	2010 (3)	2010 (4)	2015 (1)	2015 (2)	2015 (3)	2015 (4)	2020 (1)	2020 (2)	2020 (3)	2020 (4)
Southeastern Electric/Florida																				
Total Carbon	26.48	26.33	26.25	26.12	30.55	29.97	28.09	27.22	32.60	32.13	29.05	25.19	37.72	36.06	31.43	27.04	43.57	41.44	33.27	28.85
Carbon Dioxide	97.09	96.55	96.24	95.76	112.0	109.9	103.0	99.8	120.2	117.8	106.5	92.37	138.3	132.2	115.2	99.1	159.7	251.9	122.0	105.8
Sulfur Dioxide	.40	.39	.36	.35	.35	.37	.34	.34	.33	.37	.31	.27	.36	.38	.32	.26	.43	.42	.34	.27
Nitrogen Oxide	.29	.29	.29	.28	.32	.31	.29	.28	.33	.32	.28	.24	.37	.35	.29	.25	.43	.40	.30	.26
Southeastern Electric/Excl Fla																				
Total Carbon	104.0	105.6	105.1	104.1	112.5	114.8	115.9	111.3	120.6	122.1	114.4	103.5	130.9	130.6	120.4	108.1	135.8	138.0	126.0	112.2
Carbon Dioxide	381.3	387.0	385.3	381.8	412.4	421.0	425.0	408.1	442.3	447.8	419.6	379.3	480.0	478.7	441.4	396.3	497.8	506.0	461.9	411.2
Sulfur Dioxide	2.64	2.24	2.24	2.21	2.51	2.19	2.21	2.25	2.39	2.12	2.38	2.52	2.66	2.30	2.34	2.74	2.74	2.36	2.45	2.47
Nitrogen Oxide	1.06	1.07	1.07	1.07	1.12	1.13	1.14	1.11	1.17	1.17	1.11	1.04	1.24	1.21	1.10	1.04	1.22	1.24	1.11	1.05
Southwest Power Pool																				
Total Carbon	59.92	59.75	59.73	59.35	65.03	64.95	62.68	61.37	68.41	67.94	62.74	54.31	70.22	69.59	62.25	56.89	72.96	71.73	66.18	56.29
Carbon Dioxide	219.7	219.1	219.0	217.6	238.4	238.1	229.8	225.0	250.8	249.1	230.0	199.2	257.5	255.2	228.2	208.6	267.5	263.0	242.6	206.4
Sulfur Dioxide	.68	.68	.68	.68	.64	.64	.65	.65	.62	.61	.58	.46	.59	.59	.51	.50	.56	.56	.54	.48
Nitrogen Oxide	.69	.69	.68	.68	.70	.70	.67	.66	.71	.70	.62	.54	.69	.68	.57	.54	.70	.68	.61	.52
Western Systems Council/NWP																				
Total Carbon	24.84	24.73	24.76	24.71	28.20	28.10	27.87	28.92	29.74	29.85	28.91	25.77	31.31	31.11	30.42	26.77	32.57	32.40	31.05	26.23
Carbon Dioxide	91.07	90.69	90.79	90.61	103.4	103.0	102.2	106.0	109.1	109.5	106.0	94.50	114.8	114.1	111.5	98.17	119.4	118.8	113.8	96.18
Sulfur Dioxide	.16	.16	.16	.16	.15	.16	.15	.15	.14	.14	.14	.11	.13	.13	.12	.10	.12	.12	.12	.09
Nitrogen Oxide	.24	.24	.24	.24	.24	.24	.24	.25	.25	.25	.24	.21	.26	.26	.25	.22	.26	.26	.25	.21
Western Systems Council/RA																				
Total Carbon	27.99	28.16	27.98	27.91	30.32	30.22	29.45	28.60	31.98	31.81	30.00	25.89	33.10	32.57	30.42	26.08	34.21	33.77	30.35	24.95
Carbon Dioxide	102.6	103.2	102.6	102.3	111.2	110.8	108.0	104.9	117.3	116.6	110.0	94.91	121.4	119.4	111.5	95.63	125.4	123.8	111.3	91.49
Sulfur Dioxide	.21	.21	.21	.21	.20	.20	.20	.20	.18	.18	.18	.17	.16	.16	.16	.15	.16	.16	.15	.14
Nitrogen Oxide	.30	.30	.30	.30	.31	.31	.30	.29	.31	.31	.29	.25	.32	.31	.29	.24	.32	.32	.28	.22
Western Systems Council/CNV																				
Total Carbon	22.87	22.90	22.97	22.47	22.53	22.52	22.59	18.72	27.12	27.63	23.88	21.07	35.82	35.09	27.65	23.03	38.87	37.58	31.95	24.23
Carbon Dioxide	83.85	83.97	84.24	82.40	82.52	82.56	82.82	68.64	99.4	101.3	87.54	77.24	131.4	128.7	101.4	84.44	142.5	137.8	117.1	88.82
Sulfur Dioxide	.08	.08	.08	.08	.08	.08	.08	.08	.08	.08	.08	.07	.08	.08	.08	.07	.08	.08	.08	.07
Nitrogen Oxide	.19	.19	.19	.19	.18	.18	.18	.15	.23	.24	.20	.18	.32	.31	.23	.20	.35	.34	.28	.21

newbase.d012198a - 0 Tax, Reference Demand Technology (1), fee005.d012298a (2), fee050.d012298a (3), fee100.d012298a (4)

Table 117. National Impacts of the Clean Air Act Amendments of 1990 (CAAA90)

	2000 (1)	2000 (2)	2000 (3)	2000 (4)	2005 (1)	2005 (2)	2005 (3)	2005 (4)	2010 (1)	2010 (2)	2010 (3)	2010 (4)	2015 (1)	2015 (2)	2015 (3)	2015 (4)	2020 (1)	2020 (2)	2020 (3)	2020 (4)
Scrubber Retrofits (gigawatts)..	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Interregional SO2 Allowances Traded (thousand tons).........	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
SO2 Allowance Price	133.7	82.24	79.59	79.91	181.4	163.7	139.0	129.5	224.4	184.3	114.5	31.53	181.9	149.2	106.5	18.52	166.9	113.4	101.4	35.86
SO2 Emissions (million tons)....	10.19	10.19	10.19	10.19	9.69	9.69	9.69	9.69	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00
Coal Production by Sulfur Categ. (million tons)																				
Low Sulfur (< .61 lbs s/mmBtu)..	474.6	459.1	458.3	455.8	538.1	512.5	501.1	482.8	608.4	572.3	476.8	352.2	667.5	625.4	500.0	374.9	697.6	668.9	552.7	385.5
Med.Sulfur(.61-1.67 lbs.S/mmBtu)	493.2	494.5	494.4	490.0	482.7	489.2	486.0	471.3	467.1	472.1	450.5	375.5	459.8	456.4	422.4	331.2	454.4	451.2	411.9	336.0
High Sulfur (> 1.67 lbs.S/mmBtu)	178.4	194.0	194.2	192.8	185.9	197.1	185.1	184.7	188.1	201.3	174.3	163.2	196.6	207.8	183.6	180.6	214.6	222.7	186.5	184.2
Gasoline Prices																				
Traditional Gasoline...........	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Oxygenated Gasoline............	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Reformulated Gasoline..........	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
High-Oxygen Reformulated Gas...	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Average........................	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Gasoline Quantities																				
Traditional Gasoline...........	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Oxygenated Gasoline............	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Reformulated Gasoline..........	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
High-Oxygen Reformulated Gas...	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Total..........................	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Distillate Prices																				
Distillate <= 0.05% Sulfur.....	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Distillate > 0.05% Sulfur......	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Average........................	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Distillate Quantities																				
Distillate <= 0.05% Sulfur.....	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Distillate > 0.05% Sulfur......	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Total..........................	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00

newbase.d012198a - 0 Tax, Reference Demand Technology (1), fee005.d012298a (2), fee050.d012298a (3), fee100.d012298a (4)

N A T I O N A L   E N E R G Y   M O D E L I N G   S Y S T E M

Table 1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2000 (1)	2000 (2)	2000 (3)	2000 (4)	2005 (1)	2005 (2)	2005 (3)	2005 (4)	2010 (1)	2010 (2)	2010 (3)	2010 (4)	2015 (1)	2015 (2)	2015 (3)	2015 (4)	2020 (1)	2020 (2)	2020 (3)	2020 (4)
Production																				
Crude Oil & Lease Condensate	13.06	13.07	13.07	13.06	12.33	12.26	12.26	12.26	11.80	11.51	11.47	11.42	11.07	10.49	10.37	10.29	10.33	9.60	9.45	9.39
Natural Gas Plant Liquids	2.39	2.35	2.36	2.36	2.63	2.55	2.55	2.52	2.93	3.16	3.13	3.13	3.28	3.25	3.30	3.35	3.30	3.37	3.47	3.46
Dry Natural Gas	20.85	20.57	20.65	20.64	22.83	22.21	22.15	21.95	25.30	27.18	26.94	26.80	26.72	27.75	28.15	28.53	28.12	28.73	29.62	29.44
Coal	24.33	24.11	23.98	24.02	25.52	24.15	24.00	23.93	26.50	15.13	12.83	11.11	27.64	13.78	9.30	7.62	28.37	13.26	8.64	6.36
Nuclear Power	7.36	7.36	7.36	7.36	6.87	6.87	6.87	6.87	6.36	6.36	6.36	6.36	5.12	5.12	5.12	5.12	4.09	4.09	4.09	4.09
Renewable Energy	6.82	6.86	6.94	6.97	7.11	7.56	7.60	8.29	7.41	9.38	10.40	11.27	7.86	11.17	13.50	14.47	8.19	12.79	14.76	16.46
Other	.56	.56	.56	.56	.55	.54	.54	.54	.46	.54	.43	.60	.64	1.20	1.15	1.13	.89	1.32	1.22	1.14
Total	75.36	74.89	74.92	74.98	77.84	76.14	76.16	76.35	80.79	73.25	71.56	70.69	82.32	72.77	70.88	70.50	83.29	73.1s	71.24	70.33
Imports																				
Crude Oil	19.18	19.10	19.08	19.08	21.98	21.94	21.76	21.60	23.18	22.38	21.84	21.20	24.35	23.68	22.80	21.95	25.40	24.79	24.07	22.90
Petroleum Products	4.39	4.40	4.40	4.41	5.55	5.16	5.27	5.43	7.56	5.37	5.33	5.15	8.81	5.10	5.15	5.24	9.50	5.41	5.26	5.73
Natural Gas	4.21	4.22	4.23	4.24	4.44	4.41	4.42	4.42	4.70	5.10	5.18	5.27	5.06	5.61	5.72	5.64	5.36	5.85	5.98	6.11
Other Imports	.62	.63	.63	.63	.58	.60	.60	.60	.57	.85	1.08	1.28	.54	.87	1.06	1.26	.56	.88	1.07	1.27
Total	28.40	28.35	28.33	28.35	32.55	32.12	32.05	32.06	36.01	33.70	33.43	32.90	38.77	35.25	34.72	34.09	40.82	36.93	36.39	36.01
Exports																				
Petroleum	1.73	1.73	1.72	1.71	1.73	1.72	1.72	1.72	1.78	1.68	1.46	1.37	1.86	1.68	1.55	1.49	1.64	1.54	1.42	1.31
Natural Gas	.28	.28	.28	.28	.28	.28	.28	.28	.29	.29	.29	.29	.30	.30	.30	.30	.32	.32	.32	.32
Coal	2.41	2.41	2.41	2.41	2.64	2.64	2.64	2.64	2.84	2.84	2.84	2.84	3.03	3.03	3.03	3.03	3.23	3.23	3.23	3.23
Total	4.41	4.41	4.40	4.40	4.65	4.64	4.64	4.64	4.91	4.81	4.59	4.50	5.19	5.00	4.87	4.82	5.20	5.09	4.97	4.86
Discrepancy	.49	.48	.46	.46	.05	-.11	-.03	-.04	.14	-.27	-.36	-.28	-.09	-.04	.01	.05	-.07	-.15	-.13	-.12
Consumption																				
Petroleum Products	38.37	38.25	38.25	38.26	41.38	40.67	40.62	40.61	44.37	41.10	40.48	40.05	46.21	42.07	41.34	40.72	47.69	42.87	41.99	41.37
Natural Gas	24.76	24.49	24.58	24.58	26.93	26.29	26.24	26.04	29.57	31.83	31.65	31.55	31.32	32.88	33.38	33.66	33.00	34.06	35.08	35.01
Coal	22.13	21.93	21.78	21.80	23.11	21.75	21.63	21.55	23.91	12.54	10.26	8.49	24.87	11.03	6.51	4.76	25.40	10.30	5.70	3.32
Nuclear Power	7.36	7.36	7.36	7.36	6.87	6.87	6.87	6.87	6.36	6.36	6.35	6.36	5.12	5.12	5.12	5.12	4.09	4.09	4.09	4.09
Renewable Energy	6.82	6.86	6.94	6.97	7.12	7.56	7.81	8.29	7.43	9.40	10.42	11.28	7.88	11.20	13.52	14.49	8.22	12.82	14.79	16.49
Other	.41	.41	.41	.41	.37	.37	.37	.37	.40	.65	.88	1.08	.41	.69	.87	1.07	.43	.71	.89	1.09
Total	99.8	99.3	99.3	99.4	105.8	103.5	103.5	103.7	112.0	101.9	100.0	98.81	115.8	103.0	100.7	99.8	118.8	104.9	102.5	101.4
Net Imports - Petroleum	21.84	21.78	21.76	21.77	25.80	25.38	25.31	25.31	28,97	26.07	25.71	24.98	31.30	27.10	26.40	25.70	33.26	28.66	27.92	27.32
Prices (1996 dollars per unit)																				
World Oil Price ($ per bbl)	19.12	19.08	19.08	19.06	20.25	19.75	19.75	19.76	20.80	18.73	18.49	18.18	21.17	18.30	17.95	17.81	21.82	19.56	19.24	19.17
Gas Wellhead Price ($ / Mcf)	2.13	2.11	2.12	2.12	2.15	2.05	2.05	2.03	2.26	2.59	2.65	2.68	2.32	2.91	2.98	2.94	2.49	2.84	2.96	3.00
Coal Minemouth Price ($ / ton)	17.36	17.39	17.34	17.38	16.00	16.18	16.14	16.17	14.87	16.79	17.86	18.41	13.88	15.65	17.75	18.54	13.26	15.52	17.03	18.33
Aver. Electricity (cents / Kwh)	6.5	6.5	6.5	6.5	6.2	6.2	6.2	6.2	6.0	8.7	9.4	10.1	5.6	8.5	9.1	9.5	5.5	8.3	9.0	9.4

newbase.d012198a - 0 Tax, Reference Demand Technology (1), fee150.d012298a (2), fee200.d012298a (3), fee250.d012298a (4)

E N E R G Y   I N F O R M A T I O N   A D M I N I S T R A T I O N

NATIONAL ENERGY MODELING SYSTEM

Table 17. Carbon Emissions by Sector and Source

(Million Metric Tons per Year, Unless Otherwise Noted)

Sector and Source	2000 (1)	2000 (2)	2000 (3)	2000 (4)	2005 (1)	2005 (2)	2005 (3)	2005 (4)	2010 (1)	2010 (2)	2010 (3)	2010 (4)	2015 (1)	2015 (2)	2015 (3)	2015 (4)	2020 (1)	2020 (2)	2020 (3)	2020 (4)
Residential																				
Petroleum	25.8	25.7	25.7	25.7	25.0	24.8	24.8	24.8	24.8	22.4	21.8	21.2	24.6	22.2	21.5	20.9	24.3	21.7	21.1	20.4
Natural Gas	77.0	76.8	76.8	76.8	78.7	78.4	78.2	78.5	81.3	71.9	69.8	67.9	84.0	72.6	70.5	68.7	86.1	74.5	72.0	69.9
Coal	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.3	1.3	1.3	1.3	1.3	1.2	1.2	1.3	1.2	1.2	1.2
Electricity	201.3	198.7	197.8	197.9	215.6	201.4	200.1	198.5	229.8	145.1	127.3	114.5	247.9	140.8	105.9	93.6	265.8	142.9	108.1	90.1
Total	305.5	302.6	301.7	301.8	320.7	305.9	304.5	303.2	337.3	240.7	220.2	204.9	357.9	236.9	199.1	184.4	377.5	240.3	202.4	181.7
Commercial																				
Petroleum	12.9	12.8	12.8	12.8	12.9	12.8	12.8	12.8	12.8	12.4	12.3	12.1	12.7	12.3	12.2	12.0	12.5	12.0	11.9	11.8
Natural Gas	49.9	49.7	49.7	49.6	52.1	51.2	51.2	51.3	54.1	49.8	49.1	48.3	55.5	50.1	49.3	48.6	55.6	49.8	48.9	48.1
Coal	2.2	2.2	2.2	2.2	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.4	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Electricity	182.1	180.5	179.6	179.8	192.8	184.0	182.8	181.3	204.1	131.8	115.3	103.3	216.9	125.2	93.8	82.6	223.9	121.7	91.8	76.3
Total	247.1	245.1	244.3	244.4	260.1	250.3	249.1	247.7	273.5	196.4	179.1	166.2	287.7	190.1	157.7	145.7	294.4	186.0	155.1	138.7
Industrial ..																				
Petroleum	103.3	102.6	102.6	102.6	109.6	107.7	107.3	107.2	115.4	107.3	104.6	104.4	118.6	108.1	107.2	108.4	119.3	108.1	106.2	107.5
Natural Gas	155.5	154.3	154.4	154.4	158.6	153.4	153.7	153.7	166.0	151.4	148.3	145.4	167.2	148.0	146.0	142.5	167.9	148.8	148.0	141.1
Coal	60.6	59.4	59.4	59.4	62.3	57.9	57.9	57.8	62.7	48.5	47.5	46.8	61.6	45.3	45.5	44.8	60.6	43.9	43.2	42.6
Electricity	187.5	184.9	183.9	184.3	203.0	192.0	190.6	188.6	217.0	154.4	134.7	120.3	228.5	146.2	109.8	97.2	237.4	142.3	108.0	39.9
Total	506.8	501.2	500.3	500.7	533.5	511.0	509.4	507.3	561.2	461.5	435.1	417.0	573.9	448.7	408.5	392.9	585.3	443.1	405.4	381.1
Transportation																				
Petroleum	502.7	502.2	502.2	502.2	552.7	549.6	549.3	549.2	600.6	561.1	552.9	541.0	628.1	562.3	550.6	540.9	649.0	577.9	565.6	554.8
Natural Gas	12.1	12.0	12.0	12.0	14.5	14.4	14.4	14.2	17.2	17.4	17.2	17.0	18.3	18.6	18.5	18.6	19.7	19.7	20.2	20.2
Other	.1	.1	.1	.1	.5	.5	.5	.5	1.4	1.3	1.3	1.2	2.2	2.0	1.9	1.8	2.7	2.5	2.4	2.3
Electricity	3.3	3.2	3.2	3.2	5.9	5.8	5.7	5.7	8.7	6.0	5.2	4.7	10.7	6.7	5.0	4.4	12.2	7.2	5.4	4.5
Total	518.2	517.5	517.5	517.6	573.6	570.3	570.0	569.6	627.9	585.8	576.7	563.9	659.4	589.7	576.1	565.8	683.6	507.3	593.6	581.8
Total Carbon Emissions ..																				
Petroleum	644.7	643.2	643.2	643.3	700.1	694.9	694.1	694.0	753.6	703.1	691.6	678.7	784.0	704.9	691.5	682.3	805.1	719.7	704.7	694.5
Natural Gas	294.5	292.8	292.9	292.8	303.9	297.4	297.6	297.6	318.6	290.5	284.4	278.6	325.0	289.3	284.3	278.4	329.3	292.8	289.1	279.4
Coal	64.2	63.0	63.0	63.0	66.0	61.6	61.6	61.5	66.5	52.2	51.3	50.5	65.5	50.1	49.2	48.5	64.5	47.7	46.9	46.4
Other	.1	.1	.1	.1	.5	.5	.5	.5	1.4	1.3	1.3	1.2	2.2	2.0	1.9	1.8	2.7	2.5	2.4	2.3
Electricity	574.1	567.3	564.5	565.2	617.3	583.1	579.3	574.2	659.7	437.3	382.5	342.8	704.0	419.0	314.5	277.7	739.2	414.1	313.3	260.9
Total	1578	1566	1564	1564	1688	1638	1633	1628	1800	1484	1411	1352	1881	1465	1341	1289	1941	1477	1356	1283
Electric Generators ..																				
Petroleum	11.2	10.7	10.6	10.7	9.2	8.8	8.9	8.7	8.2	4.8	4.7	5.4	7.6	6.7	6.0	3.4	7.8	4.9	3.6	3.0
Natural Gas	60.0	57.8	59.0	58.9	81.8	79.3	78.4	75.5	104.9	165.9	169.5	173.9	123.7	182.3	194.4	204.5	143.6	195.9	214.1	222.8
Coal	502.9	498.8	495.0	495.5	526.3	494.9	492.0	490.0	546.7	266.5	208.3	163.5	572.7	230.0	114.1	69.8	587.9	213.4	95.6	35.1
Total	574.1	567.3	564.5	565.2	617.3	583.1	579.3	574.2	659.7	437.3	382.5	342.8	704.0	419.0	314.5	277.7	739.2	414.1	313.3	260.9
Total Carbon Emissions ..																				
Petroleum	655.9	653.9	653.8	654.0	709.3	703.7	702.9	702.7	761.8	707.9	696.3	684.1	791.7	711.6	697.4	685.7	612.9	724.6	708.4	697.5
Natural Gas	354.5	350.5	351.8	351.8	385.7	376.8	376.0	373.1	423.5	456.4	454.0	452.5	448.7	471.6	478.7	482.9	472.8	488.6	503.3	502.2
Coal	567.1	561.8	558.0	558.6	592.3	556.5	553.6	551.5	613.2	318.7	259.5	214.1	638.2	280.1	163.4	118.3	652.4	261.1	142.5	81.4
Other	.1	.1	.1	.1	.5	.5	.5	.5	1.4	1.3	1.3	1.2	2.2	2.0	1.9	1.8	2.7	2.5	2.4	2.3
Total	1578	1566	1564	1564	1688	1638	1633	1628	1800	1484	1411	1352	1881	1465	1341	1289	1941	1477	1355	1283
Carbon Emissions (tons per person)	5.7	5.7	5.7	5.7	5.9	5.7	5.7	5.7	6.0	5.0	4.7	4.5	6.0	4.7	4.3	4.1	6.0	4.6	4.2	4.0

newbase.d012198a - 0 Tax, Reference Demand Technology (1), fee150.d012298a (2), fee200.d012298a (3), fee250.d012298a (4)

NATIONAL ENERGY MODELING SYSTEM

Table 62. Emissions by NERC Region (million short tons) except Carbon and Carbon Dioxide (million metric tons)

	2000 (1)	2000 (2)	2000 (3)	2000 (4)	2005 (1)	2005 (2)	2005 (3)	2005 (4)	2010 (1)	2010 (2)	2010 (3)	2010 (4)	2015 (1)	2015 (2)	2015 (3)	2015 (4)	2020 (1)	2020 (2)	2020 (3)	2020 (4)
missions																				
nited States																				
Total Carbon	574.1	567.3	564.5	565.2	617.3	583.1	579.3	574.2	659.7	437.3	382.5	342.8	704.0	419.0	314.5	277.7	739.2	414.1	313.3	260.9
Carbon Dioxide	2105	2080	2070	2072	2263	2138	2124	2105	2419	1603	1402	1257	2581	1536	1153	1018	2711	1518	1149	956.4
Sulfur Dioxide	10.19	10.19	10.42	10.33	9.69	9.69	9.69	9.69	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00
Nitrogen Oxide	6.15	6.08	6.04	6.04	6.29	5.94	5.90	5.85	6.48	3.84	3.25	2.78	6.75	3.29	2.04	1.57	6.94	3.15	1.86	1.16
ast Central Area Reliability																				
Total Carbon	129.0	126.2	125.7	126.1	135.7	128.8	128.4	128.1	143.8	99.5	93.60	86.31	149.2	80.15	71.04	64.17	155.3	74.49	58.55	52.28
Carbon Dioxide	472.9	462.7	461.0	462.4	497.6	472.4	470.9	469.7	527.3	364.7	343.2	316.4	547.0	293.9	260.5	235.3	569.6	273.1	214.7	191.7
Sulfur Dioxide	3.39	3.68	3.57	3.51	3.33	3.43	3.33	3.33	2.98	4.07	4.43	4.76	2.84	3.10	4.73	5.89	2.80	2.31	1.99	3.18
Nitrogen Oxide	1.50	1.47	1.46	1.47	1.55	1.46	1.46	1.46	1.61	1.00	.96	.89	1.64	.63	.59	.53	1.68	.48	.29	.23
lectric Reliability Council Tx																				
Total Carbon	45.92	45.73	45.72	45.74	47.40	46.25	46.17	46.07	50.00	29.33	26.67	25.58	52.61	27.66	22.18	20.70	54.64	27.34	21.85	19.40
Carbon Dioxide	168.4	167.7	167.6	167.7	173.8	169.6	169.3	168.9	183.3	107.6	97.80	93.77	192.9	101.4	81.32	75.89	200.3	100.2	80.11	71.14
Sulfur Dioxide	.35	.35	.35	.35	.34	.35	.34	.35	.34	.09	.06	.08	.33	.14	.13	.19	.32	.14	.19	.53
Nitrogen Oxide	.47	.47	.47	.47	.43	.43	.43	.42	.38	.23	.22	.21	.38	.15	.10	.10	.39	.15	.10	.07
id-Atlantic Area Council																				
Total Carbon	34.48	33.80	33.62	33.84	35.70	34.34	33.58	33.47	39.69	30.39	27.04	24.06	41.62	28.36	21.40	19.70	45.23	27.06	21.07	18.24
Carbon Dioxide	126.4	123.9	123.3	124.1	130.9	125.9	123.1	122.7	145.5	111.4	99.2	88.20	152.6	104.0	78.48	72.23	165.8	99.2	77.24	66.86
Sulfur Dioxide	.55	.61	1.10	1.11	.54	.63	1.04	1.05	.50	.51	.84	.77	.50	.39	.53	.41	.52	.35	.64	.63
Nitrogen Oxide	.29	.29	.29	.29	.28	.27	.26	.26	.30	.19	.16	.13	.31	.16	.10	.08	.33	.15	.09	.07
id-America Interconnected Netw																				
Total Carbon	40.87	40.78	40.53	40.27	44.56	37.66	37.83	37.94	47.70	30.30	24.88	22.86	50.20	32.12	24.39	22.00	52.30	31.30	24.46	20.00
Carbon Dioxide	149.8	149.5	148.5	147.7	163.4	138.1	138.7	139.1	174.9	111.1	91.20	83.83	184.1	117.8	89.41	80.65	191.8	114.8	89.67	73.34
Sulfur Dioxide	.88	.99	.99	.97	.70	.75	.73	.73	.55	.68	.37	.31	.61	.90	.50	.38	.57	1.14	1.00	.67
Nitrogen Oxide	.52	.52	.52	.52	.52	.45	.44	.44	.54	.25	.17	.14	.56	.29	.13	.10	.59	.29	.15	.09
id-Continent Area Power Pool																				
Total Carbon	32.68	31.54	31.76	31.78	37.10	34.89	34.04	33.53	38.85	24.95	17.58	15.30	41.10	21.08	10.00	9.41	42.13	14.62	9.21	8.18
Carbon Dioxide	119.8	115.6	116.4	116.5	136.0	127.9	124.8	122.9	142.5	91.47	64.47	56.09	150.7	77.28	36.67	34.52	154.5	53.62	33.78	29.98
Sulfur Dioxide	.42	.40	.40	.40	.44	.41	.38	.38	.43	.32	.23	.23	.42	.28	.02	.03	.40	.17	.01	.02
Nitrogen Oxide	.39	.38	.38	.38	.43	.41	.40	.39	.45	.24	.16	.13	.45	.18	.04	.04	.46	.11	.04	.03
ortheast Power Council/New York																				
Total Carbon	13.50	13.50	13.41	13.45	13.11	12.56	12.32	12.27	14.04	10.85	10.13	10.57	15.26	10.60	9.65	9.72	16.16	10.70	9.58	9.15
Carbon Dioxide	49.51	49.50	49.17	49.32	48.06	46.06	45.19	45.00	51.48	39.79	37.13	38.75	55.97	38.88	35.40	35.64	59.26	39.23	35.13	33.55
Sulfur Dioxide	.24	.24	.26	.26	.20	.20	.20	.20	.19	.15	.14	.12	.17	.14	.15	.20	.16	.16	.21	.36
Nitrogen Oxide	.11	.11	.11	.11	.09	.08	.08	.08	.09	.05	.04	.04	.09	.05	.04	.04	.09	.05	.04	.03
ortheast Power Council/New Engl																				
Total Carbon	11.59	11.52	11.58	11.60	14.59	14.15	14.26	14.24	14.97	10.46	9.30	8.94	14.95	10.00	8.52	8.25	15.50	9.59	8.58	8.42
Carbon Dioxide	42.50	42.25	42.44	42.53	53.48	51.90	52.28	52.23	54.90	38.34	34.10	32.77	54.82	36.68	31.23	30.24	56.85	35.15	31.47	30.86
Sulfur Dioxide	.18	.18	.16	.16	.20	.19	.17	.17	.17	.08	.05	.05	.16	.09	.07	.11	.14	.07	.08	.23
Nitrogen Oxide	.10	.10	.10	.10	.11	.11	.11	.11	.11	.05	.04	.04	.11	.05	.04	.04	.11	.05	.04	.04

newbase.d012198a - 0 Tax, Reference Demand Technology (1), fee150.d012298a (2), fee200.d012298a (3), fee250.d012298a (4)

ENERGY INFORMATION ADMINISTRATION

Table 62. Emissions by NERC Region (million short tons) (Continued)
except Carbon and Carbon Dioxide (million metric tons)

	2000 (1)	2000 (2)	2000 (3)	2000 (4)	2005 (1)	2005 (2)	2005 (3)	2005 (4)	2010 (1)	2010 (2)	2010 (3)	2010 (4)	2015 (1)	2015 (2)	2015 (3)	2015 (4)	2020 (1)	2020 (2)	2020 (3)	2020 (4)
outheastern Electric/Florida																				
Total Carbon	26.48	25.97	25.66	25.75	30.55	26.56	26.65	26.52	32.80	21.34	20.35	19.53	37.72	22.49	19.55	18.03	43.57	26.13	22.37	18.36
Carbon Dioxide	97.09	95.23	94.10	94.41	112.0	97.38	97.73	97.23	120.2	78.25	74.63	71.59	138.3	82.45	71.67	66.11	159.7	95.80	82.01	67.32
Sulfur Dioxide	.40	.35	.32	.32	.35	.34	.31	.31	.33	.21	.19	.21	.36	.22	.24	.24	.43	.32	.35	.38
Nitrogen Oxide	.29	.28	.28	.28	.32	.28	.28	.28	.33	.18	.17	.16	.37	.17	.13	.11	.43	.22	.16	.10
outheastern Electric/Excl Fla																				
Total Carbon	104.0	104.1	102.3	102.3	112.5	111.1	110.1	109.2	120.6	84.25	75.37	67.52	130.9	86.54	61.76	50.96	135.8	98.78	68.50	52.89
Carbon Dioxide	381.3	381.9	375.2	375.2	412.4	407.2	403.7	400.5	442.3	308.9	276.3	247.6	480.0	324.6	226.4	186.8	497.8	362.2	251.2	193.9
Sulfur Dioxide	2.64	2.26	2.12	2.09	2.51	2.31	2.11	2.11	2.39	2.29	2.27	2.17	2.66	3.01	2.10	1.10	2.74	3.68	3.86	1.94
Nitrogen Oxide	1.06	1.07	1.04	1.04	1.12	1.11	1.10	1.09	1.17	.79	.70	.59	1.24	.82	.44	.26	1.22	.91	.51	.24
outhwest Power Pool																				
Total Carbon	59.92	59.07	59.21	59.38	65.03	61.01	60.41	59.81	68.41	41.89	33.36	29.69	70.22	40.53	26.10	24.40	72.96	38.25	27.77	22.65
Carbon Dioxide	219.7	216.6	217.1	217.7	238.4	223.7	221.5	219.3	250.8	153.6	122.3	108.9	257.5	148.6	95.68	89.44	267.5	140.3	101.8	83.03
Sulfur Dioxide	.68	.68	.68	.68	.64	.65	.65	.65	.62	.35	.23	.17	.59	.43	.25	.23	.56	.38	.36	.53
Nitrogen Oxide	.69	.67	.67	.68	.70	.65	.65	.64	.71	.39	.29	.26	.69	.34	.15	.13	.70	.32	.17	.11
estern Systems Council/NWP																				
Total Carbon	24.84	24.74	24.72	24.82	28.20	27.92	27.67	28.65	29.74	18.00	15.47	10.95	31.31	20.72	12.23	9.97	32.57	20.00	13.84	9.13
Carbon Dioxide	91.07	90.70	90.64	91.01	103.4	102.4	101.4	105.0	109.1	66.00	56.73	40.16	114.8	75.99	44.83	36.56	119.4	73.32	50.73	33.47
Sulfur Dioxide	.16	.16	.16	.16	.15	.16	.15	.15	.14	.04	.04	.01	.13	.08	.03	.02	.12	.07	.05	.01
Nitrogen Oxide	.24	.24	.23	.24	.24	.24	.24	.24	.25	.12	.10	.04	.26	.15	.06	.04	.26	.14	.08	.03
estern Systems Council/RA																				
Total Carbon	27.99	27.90	27.92	28.09	30.32	28.58	28.23	27.35	31.98	21.09	16.59	14.59	33.10	21.89	16.89	12.91	34.21	21.98	16.86	14.81
Carbon Dioxide	102.6	102.3	102.4	103.0	111.2	104.8	103.5	100.3	117.3	77.32	60.85	53.49	121.4	80.25	61.93	47.34	125.4	80.60	61.83	54.30
Sulfur Dioxide	.21	.21	.21	.22	.20	.20	.20	.19	.18	.18	.13	.11	.16	.19	.22	.18	.16	.19	.24	.49
Nitrogen Oxide	.30	.30	.30	.29	.31	.29	.29	.28	.31	.19	.13	.11	.32	.20	.13	.08	.32	.20	.13	.10
Western Systems Council/CNV																				
Total Carbon	22.87	22.37	22.37	21.98	22.53	19.29	19.58	16.98	27.12	14.96	12.16	6.93	35.82	14.81	10.81	7.50	38.87	13.89	10.67	7.35
Carbon Dioxide	83.85	82.03	82.04	80.58	82.62	70.72	71.79	62.25	99.4	54.84	44.59	25.42	131.4	54.32	39.64	27.51	142.5	50.93	39.14	26.95
Sulfur Dioxide	.08	.08	.08	.08	.08	.08	.08	.08	.08	.04	.01	.01	.08	.05	.02	.01	.08	.04	.02	.03
Nitrogen Oxide	.19	.19	.19	.18	.18	.16	.16	.14	.23	.12	.09	.04	.32	.11	.07	.03	.35	.09	.06	.02

newbase.d012198a - 0 Tax, Reference Demand Technology (1), fee150.d012298a (2), fee200.d012298a (3), fee250.d012298a (4)

Table 117. National Impacts of the Clean Air Act Amendments of 1990 (CAAA90)

	2000 (1)	2000 (2)	2000 (3)	2000 (4)	2005 (1)	2005 (2)	2005 (3)	2005 (4)	2010 (1)	2010 (2)	2010 (3)	2010 (4)	2015 (1)	2015 (2)	2015 (3)	2015 (4)	2020 (1)	2020 (2)	2020 (3)	2020 (4)
Scrubber Retrofits (gigawatts)..	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Interregional SO2 Allowances Traded (thousand tons).........	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
SO2 Allowance Price	133.7	62.63	77.26	88.93	181.4	119.0	145.1	134.7	224.4	.00	.00	.00	181.9	.00	.00	.00	166.9	.00	.00	.00
SO2 Emissions (million tons)....	10.19	10.19	10.42	10.33	9.69	9.69	9.69	9.69	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00
Coal Production by Sulfur Categ. (million tons)																				
Low Sulfur (< .61 lbs s/mmBtu)..	474.6	454.0	451.1	453.6	535.1	478.8	481.4	477.8	608.4	229.2	163.2	125.0	667.5	217.9	105.7	74.31	697.6	198.4	103.9	64.44
Med.Sulfur(.61-1.67 lbs.S/mmBtu)	493.2	484.2	482.1	486.3	482.7	471.3	465.6	465.6	467.1	317.1	285.0	258.7	459.6	279.6	219.8	197.0	454.4	270.8	208.7	176.8
High Sulfur (> 1.67 lbs.S/mmBtu)	178.4	197.1	195.6	190.4	185.9	185.5	181.2	180.9	188.1	138.0	114.8	98.04	196.6	134.5	78.84	54.92	214.5	131.5	66.62	30.54
Gasoline Prices																				
Traditional Gasoline...........	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Oxygenated Gasoline............	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Reformulated Gasoline..........	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
High-Oxygen Reformulated Gas...	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Average........................	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Gasoline Quantities																				
Traditional Gasoline...........	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Oxygenated Gasoline............	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Reformulated Gasoline..........	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
High-Oxygen Reformulated Gas...	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Total..........................	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Distillate Prices																				
Distillate <= 0.05% Sulfur.....	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Distillate > 0.05% Sulfur......	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Average........................	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Distillate Quantities																				
Distillate <= 0.05% Sulfur.....	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Distillate > 0.05% Sulfur......	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Total..........................	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00

newbase.d012198a - 0 Tax, Reference Demand Technology (1), fee150.d012298a (2), fee200.d012298a (3), fee250.d012298a (4)

Table 1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2000 (1)	2000 (2)	2005 (1)	2005 (2)	2010 (1)	2010 (2)	2015 (1)	2015 (2)	2020 (1)	2020 (2)
Production										
Crude Oil & Lease Condensate.	13.06	13.06	12.33	12.25	11.60	11.37	11.07	10.21	10.33	9.29
Natural Gas Plant Liquids....	2.39	2.36	2.63	2.52	2.93	3.19	3.28	3.27	3.30	3.34
Dry Natural Gas............	20.85	20.66	22.83	21.94	25.30	27.25	26.72	27.94	28.12	28.54
Coal......................	24.33	23.98	25.52	23.88	26.50	9.35	27.64	6.98	28.37	5.81
Nuclear Power..............	7.36	7.36	6.87	6.87	6.36	6.36	5.12	5.12	4.09	4.20
Renewable Energy	6.82	7.02	7.11	8.41	7.41	11.84	7.86	14.88	8.19	17.02
Other	.56	.55	.55	.54	.48	.60	.64	1.10	.89	1.12
Total..................	75.36	74.99	77.84	76.40	80.79	69.95	82.32	69.49	83.29	69.33
Imports										
Crude Oil	19.18	19.06	21.98	21.58	23.18	20.53	24.35	21.86	25.40	22.78
Petroleum Products	4.39	4.41	5.55	5.43	7.56	5.51	8.81	5.17	9.50	5.42
Natural Gas	4.21	4.22	4.44	4.41	4.70	5.34	5.06	5.68	5.36	6.08
Other Imports	.62	.63	.58	.60	.57	1.40	.54	1.39	.56	1.41
Total..................	28.40	28.32	32.55	32.02	36.01	32.77	38.77	34.09	40.82	35.69
Exports										
Petroleum	1.73	1.70	1.73	1.71	1.78	1.31	2.86	1.55	1.64	1.32
Natural Gas................	.28	.28	.28	.28	.29	.29	.30	.30	.32	.32
Coal......................	2.41	2.41	2.64	2.64	2.84	2.84	3.03	3.03	3.23	3.23
Total..................	4.41	4.39	4.65	4.64	4.91	4.44	5.19	4.88	5.20	4.87
Discrepancy	.49	.47	.05	-.14	.14	-.43	-.09	-.22	-.07	-.36
Consumption										
Petroleum Products	38.37	38.24	41.38	40.58	44.37	39.56	46.21	39.94	47.69	40.41
Natural Gas................	24.76	24.57	26.93	26.00	29.57	32.13	31.32	33.12	33.00	34.10
Coal......................	22.13	21.79	23.11	21.40	23.91	6.77	24.87	4.20	25.40	2.82
Nuclear Power..............	7.36	7.36	6.87	6.87	6.36	6.36	5.12	5.12	4.09	4.20
Renewable Energy	6.82	7.02	7.12	8.42	7.43	11.85	7.88	14.90	8.22	17.05
Other	.41	.41	.37	.37	.40	1.19	.41	1.20	.43	1.22
Total..................	99.8	99.4	105.8	103.6	112.0	97.85	115.8	98.48	118.8	99.8
Net Imports - Petroleum........	21.84	21.77	25.80	25.29	28.97	24.73	31.30	25.47	33.26	26.89
Prices (1996 dollars per unit)										
World Oil Price ($ per bbl) ...	19.12	19.04	20.25	19.76	20.80	17.82	21.17	17.51	21.82	18.92
Gas Wellhead Price($ / Mcf)...	2.13	2.13	2.15	2.02	2.26	2.84	2.32	2.97	2.49	2.78
Coal Minemouth Price ($ / ton).	17.36	17.33	16.00	16.14	14.87	19.08	13.88	18.77	13.26	18.68
Aver. Electricity (cents / Kwh)	6.5	6.5	6.2	6.2	6.0	10.6	5.6	10.2	5.5	10.1

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NATIONAL ENERGY MODELING SYSTEM

Table 17. Carbon Emissions by Sector and Source
(Million Metric Tons per Year, Unless Otherwise Noted)

Sector and Source	2000 (1)	2000 (2)	2005 (1)	2005 (2)	2010 (1)	2010 (2)	2015 (1)	2015 (2)	2020 (1)	2020 (2)
Residential										
Petroleum	25.8	25.7	25.0	24.8	24.8	20.6	24.6	20.3	24.3	19.9
Natural Gas	77.0	76.8	78.7	78.4	81.3	65.8	84.0	66.8	86.1	68.6
Coal	1.4	1.4	1.4	1.4	1.4	1.2	1.3	1.2	1.3	1.2
Electricity	201.3	197.5	215.6	196.9	229.8	104.9	247.9	88.7	265.8	82.5
Total	305.5	301.4	320.7	301.5	337.3	192.6	357.9	177.0	377.5	172.2
Commercial										
Petroleum	12.9	12.8	12.9	12.8	12.8	12.0	12.7	11.9	12.5	11.7
Natural Gas	49.9	49.6	52.1	51.2	54.1	47.4	55.5	47.8	55.6	47.6
Coal	2.2	2.2	2.3	2.3	2.4	2.4	2.5	2.5	2.5	2.5
Electricity	182.1	179.4	192.8	179.8	204.1	94.3	216.9	78.0	223.9	69.6
Total	247.1	244.1	260.1	246.2	273.5	156.2	287.7	140.3	294.4	131.4
Industrial ..										
Petroleum	103.3	102.7	109.6	107.2	115.4	102.0	118.6	103.7	119.3	101.4
Natural Gas	155.5	154.3	158.6	153.5	166.0	144.0	167.2	139.8	167.9	141.2
Coal	60.6	59.4	62.3	57.8	62.7	46.3	61.6	44.3	60.6	42.1
Electricity	187.5	184.1	203.0	187.1	217.0	110.0	228.5	91.9	237.4	81.7
Total	506.8	500.5	533.5	505.5	561.2	402.4	575.9	379.7	585.3	366.4
Transportation										
Petroleum	502.7	502.3	552.7	549.2	600.6	533.1	628.1	531.6	649.0	544.2
Natural Gas	12.1	12.0	14.5	14.3	17.2	17.2	18.3	18.1	19.7	19.5
Other	.3	.1	.5	.5	1.4	1.2	2.2	1.8	2.7	2.2
Electricity	3.3	3.2	5.9	5.6	8.7	4.3	10.7	4.1	12.2	4.1
Total	518.2	517.7	573.6	569.6	627.9	555.7	659.4	555.7	683.6	569.9
Total Carbon Emissions ..										
Petroleum	644.7	643.5	700.1	693.9	753.6	667.8	784.0	667.6	805.1	677.1
Natural Gas	294.5	292.7	303.9	297.4	318.6	274.4	325.0	272.5	329.3	276.9
Coal	64.2	63.1	66.0	61.5	66.5	50.0	65.5	48.0	64.5	45.9
Other	.1	.1	.5	.5	1.4	1.2	2.2	1.8	2.7	2.2
Electricity	574.1	564.2	617.3	569.4	659.7	313.5	704.0	262.8	739.2	238.0
Total	1578	1564	1688	1623	1800	1307	1881	1253	1941	1240
Electric Generators ..										
Petroleum	11.2	10.1	9.2	8.2	8.2	7.1	7.6	4.0	7.8	2.8
Natural Gas	60.0	59.0	81.8	75.2	104.9	186.3	123.7	202.6	143.6	212.2
Coal	502.9	495.1	526.3	486.1	546.7	120.1	572.7	56.2	587.9	22.9
Total	574.1	564.2	617.3	569.4	659.7	313.5	704.0	262.8	739.2	238.0
Total Carbon Emissions ..										
Petroleum	655.9	653.7	709.3	702.0	761.8	674.9	791.7	671.6	812.9	679.9
Natural Gas	354.5	351.7	385.7	372.6	423.5	460.8	448.7	475.1	472.8	489.1
Coal	567.1	558.2	592.3	547.6	613.2	170.1	638.2	104.2	652.4	68.7
Other	.1	.1	.5	.5	1.4	1.2	2.2	1.8	2.7	2.2
Total	1578	1564	1688	1623	1800	1307	1881	1253	1941	1240
Carbon Emissions (tons per person)	5.7	5.7	5.9	5.7	6.0	4.4	6.0	4.0	6.0	3.8

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N A T I O N A L   E N E R G Y   M O D E L I N G   S Y S T E M

Table 52. Emissions by NERC Region (million short tons) except Carbon and Carbon Dioxide (million metric tons)

	2000 (1)	2000 (2)	2005 (1)	2005 (2)	2010 (1)	2010 (2)	2015 (1)	2015 (2)	2020 (1)	2020 (2)
Emissions										
United States										
Total Carbon	574.1	564.2	617.3	569.4	659.7	313.5	704.0	262.8	739.2	238.0
Carbon Dioxide	2105	2069	2263	2088	2419	1149	2581	963.5	2711	872.5
Sulfur Dioxide	10.19	10.45	9.69	9.69	9.00	9.00	9.00	9.00	9.00	9.00
Nitrogen Oxide	6.15	6.03	6.29	5.78	6.48	2.30	6.75	1.41	6.94	.98
East Central Area Reliability										
Total Carbon	129.0	125.5	135.7	127.0	143.8	76.76	149.2	59.23	155.3	49.44
Carbon Dioxide	472.9	460.0	497.6	465.8	527.3	281.4	547.0	217.2	569.6	181.3
Sulfur Dioxide	3.39	3.58	3.33	3.28	2.98	4.57	2.84	5.95	2.80	3.50
Nitrogen Oxide	1.50	1.46	1.55	1.44	1.61	.67	1.64	.46	1.68	.20
Electric Reliability Council Tx										
Total Carbon	45.92	45.76	47.40	45.52	50.00	24.48	52.61	20.01	54.64	17.05
Carbon Dioxide	168.4	167.8	173.8	166.9	183.3	89.74	192.9	73.35	200.3	62.50
Sulfur Dioxide	.35	.35	.34	.35	.34	.10	.33	.24	.32	.75
Nitrogen Oxide	.47	.47	.43	.41	.38	.20	.38	.10	.39	.06
Mid-Atlantic Area Council										
Total Carbon	34.48	33.40	35.70	33.18	39.69	23.12	41.62	19.32	45.23	16.89
Carbon Dioxide	126.4	122.5	130.9	121.6	145.5	84.75	152.6	70.82	165.8	61.91
Sulfur Dioxide	.55	1.09	.54	1.05	.50	.85	.50	.41	.52	.65
Nitrogen Oxide	.29	.29	.28	.26	.30	.12	.31	.08	.33	.06
Mid-America Interconnected Netw										
Total Carbon	40.87	40.78	44.56	37.75	47.70	21.65	50.20	21.04	52.30	18.61
Carbon Dioxide	149.8	149.5	163.4	138.4	174.9	79.39	184.1	77.15	191.8	68.23
Sulfur Dioxide	.68	.96	.70	.73	.65	.32	.61	.37	.57	.69
Nitrogen Oxide	.52	.53	.52	.44	.54	.12	.56	.09	.59	.07
Mid-Continent Area Power Pool										
Total Carbon	32.68	31.80	37.10	32.95	38.85	11.85	41.10	8.78	42.13	6.73
Carbon Dioxide	119.8	116.6	136.0	120.8	142.5	43.47	150.7	32.21	154.5	24.66
Sulfur Dioxide	.42	.39	.44	.36	.43	.19	.42	.12	.40	.02
Nitrogen Oxide	.39	.38	.43	.39	.45	.10	.45	.04	.46	.03
Northeast Power Council/New York										
Total Carbon	13.50	13.43	13.11	12.32	14.04	9.25	15.26	8.98	16.16	8.24
Carbon Dioxide	49.51	49.25	48.06	45.17	51.48	33.93	55.97	32.93	59.26	30.20
Sulfur Dioxide	.24	.26	.20	.19	.19	.09	.17	.19	.16	.28
Nitrogen Oxide	.11	.11	.09	.08	.09	.03	.09	.03	.09	.03
Northeast Power Council/New Engl										
Total Carbon	11.59	11.54	14.59	14.11	14.97	8.59	14.95	7.56	15.50	6.74
Carbon Dioxide	42.50	42.31	53.48	51.73	54.90	31.49	54.82	27.73	56.85	24.73
Sulfur Dioxide	.18	.19	.20	.19	.17	.06	.16	.09	.14	.33
Nitrogen Oxide	.10	.10	.11	.11	.11	.04	.11	.04	.11	.03

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E N E R G Y   I N F O R M A T I O N   A D M I N I S T R A T I O N

Table 62. Emissions by NERC Region (million short tons) (Continued)
except Carbon and Carbon Dioxide (million metric tons)

	2000 (1)	2000 (2)	2005 (1)	2005 (2)	2010 (1)	2010 (2)	2015 (1)	2015 (2)	2020 (1)	2020 (2)
Southeastern Electric/Florida										
Total Carbon	26.48	25.19	30.55	26.33	32.80	18.52	37.72	16.57	43.57	16.60
Carbon Dioxide	97.09	92.36	112.0	96.54	120.2	67.91	138.3	60.74	159.7	60.86
Sulfur Dioxide	.40	.34	.35	.33	.33	.23	.36	.20	.43	.22
Nitrogen Oxide	.29	.27	.32	.27	.33	.14	.37	.09	.43	.07
Southeastern Electric/Excl Fla										
Total Carbon	104.0	102.9	112.5	108.5	120.6	62.65	130.9	49.71	135.8	49.44
Carbon Dioxide	381.3	377.1	412.4	397.8	442.3	229.7	480.0	182.2	497.8	181.3
Sulfur Dioxide	2.64	2.14	2.51	2.11	2.39	2.31	2.66	1.00	2.74	1.44
Nitrogen Oxide	1.06	1.04	1.12	1.08	1.17	.52	1.24	.24	1.22	.19
Southwest Power Pool										
Total Carbon	59.92	59.11	65.03	59.89	68.41	28.08	70.22	22.71	72.96	18.20
Carbon Dioxide	219.7	216.7	238.4	219.6	250.8	102.9	257.5	83.27	267.5	66.73
Sulfur Dioxide	.68	.68	.64	.65	.62	.16	.59	.21	.56	.43
Nitrogen Oxide	.69	.67	.70	.64	.71	.23	.69	.11	.70	.07
Western Systems Council/NWP										
Total Carbon	24.84	24.65	28.20	29.60	29.74	9.73	31.31	9.04	32.57	8.84
Carbon Dioxide	91.07	90.39	103.4	108.5	109.1	35.66	114.8	33.16	119.4	32.42
Sulfur Dioxide	.16	.16	.15	.15	.14	.00	.13	.01	.12	.02
Nitrogen Oxide	.24	.23	.24	.25	.25	.03	.26	.03	.26	.03
Western Systems Council/RA										
Total Carbon	27.99	28.01	30.32	26.88	31.98	12.17	33.10	12.50	34.21	14.67
Carbon Dioxide	102.6	102.7	111.2	98.55	117.3	44.63	121.4	45.82	125.4	53.78
Sulfur Dioxide	.21	.21	.20	.20	.18	.10	.16	.22	.16	.61
Nitrogen Oxide	.30	.29	.31	.28	.31	.07	.32	.08	.32	.10
Western Systems Council/CNV										
Total Carbon	22.87	22.23	22.53	15.39	27.12	6.65	35.82	7.33	38.87	6.52
Carbon Dioxide	83.85	81.52	82.62	56.42	99.4	24.39	131.4	26.87	142.5	23.92
Sulfur Dioxide	.08	.08	.05	.08	.08	.01	.08	.02	.08	.04
Nitrogen Oxide	.19	.19	.18	.12	.23	.03	.32	.02	.35	.02

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NATIONAL ENERGY MODELING SYSTEM

Table 117. National Impacts of the Clean Air Act Amendments of 1990 (CAAA90)

	2000 (1)	2000 (2)	2005 (1)	2005 (2)	2010 (1)	2010 (2)	2015 (1)	2015 (2)	2020 (1)	2020 (2)
Scrubber Retrofits (gigawatts)..	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Interregional SO2 Allowances Traded (thousand tons).........	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
SO2 Allowance Price	133.7	71.72	181.4	155.1	224.4	.00	181.9	.00	166.9	.00
SO2 Emissions (million tons)....	10.19	10.45	9.69	9.69	9.00	9.00	9.00	9.00	9.00	9.00
Coal Production by Sulfur Categ. (million tons)										
Low Sulfur (< .61 lbs s/mmBtu)..	474.6	452.9	538.1	478.2	608.4	93.18	667.5	63.87	697.6	55.20
Med.Sulfur(.61-1.67 lbs.S/mmBtu)	493.2	482.3	482.7	464.7	467.1	228.2	459.8	188.4	454.4	169.0
High Sulfur (> 1.67 lbs.S/mmBtu)	178.4	194.6	185.9	178.6	188.1	78.95	196.6	45.39	214.5	22.34
Gasoline Prices										
Traditional Gasoline...........	.00	.00	.00	.00	-.00	.00	.00	.00	.00	.00
Oxygenated Gasoline............	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Reformulated Gasoline..........	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
High-Oxygen Reformulated Gas...	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Average........................	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Gasoline Quantities										
Traditional Gasoline...........	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Oxygenated Gasoline............	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Reformulated Gasoline..........	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
High-Oxygen Reformulated Gas...	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Total..........................	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Distillate Prices										
Distillate <= 0.05% Sulfur.....	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Distillate > 0.05% Sulfur......	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Average........................	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Distillate Quantities										
Distillate <= 0.05% Sulfur.....	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Distillate > 0.05% Sulfur......	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Total..........................	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00

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