Economic Analysis for the OCS 5-Year Program 1997-2002:

Theory and Methodology

A Working Paper

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U.S. Department of the Interior
Minerals Management Service

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I Introduction

The purpose of this paper is to document the theoretical background and methodology of the economic analysis performed for the *Proposed Outer Continental Shelf Oil and Gas Leasing Program 1997 to 2002* (5-Year Program). The economic analysis, which the Minerals Management Service (MMS) prepares, provides the Secretary of the Interior (the Secretary) with a logically consistent analytical basis for deciding among an array of leasing alternatives. It is important at the outset to make clear that the results of the economic analysis are simply one criterion among many for choosing among the alternatives. Other valid criteria could lead the Secretary to choose an alternative other than the one that would be chosen solely on the basis of the economic analysis.

The U.S. and many other modern societies traditionally use cost-benefit analysis (CBA) as the technical basis for public decisionmaking. The courts have approved CBA as an appropriate basis for the Secretary's decision about Outer Continental Shelf (OCS) leasing. Thus, the development of estimates using this approach and the Secretary's consideration of those results is consistent with a legally sanctioned basis for decisionmaking.

The theory and practice of CBA has sanctioned a specific measure for determining the desirability of a public action. This measure is the present value of the future stream of net social benefits (gross benefits minus gross costs) from the investment or policy. In this case, the net benefits under consideration are those that would accrue to society from the OCS natural gas and oil leasing included in the 5-Year Program.

The MMS divides the U.S. OCS into 26 "planning areas." An initial review of planning areas and leasing considerations narrows the locations for leasing within planning areas into "program areas." Program areas are portions of one or more planning areas being considered for leasing in a 5-Year Program. MMS ranks the program areas using the methodology described in this paper. However, the ranking is based on estimates of the total resources available in the program area. The results of the ranking are used as the rationale for developing a discreet number of specific lease sale alternatives called "program alternatives."

MMS then calculates and compares the net benefits attributable to each program area for each program alternative, including "no action." Because society receives benefits from past leasing and the resultant production of OCS oil and gas, only the net benefits from further leasing (or none at all) are considered. This process is called "valuation of program alternatives." Although the ranking process and valuation of program alternatives both use the same methodology, this paper will describe the methodology in terms of valuation of program alternatives only. Appendix 2 and the body of the Program Decision Document discuss the inputs and results of the ranking process.

The methodology developed in this paper builds on the work of Boskin et al (1985), Boskin and Robinson (1987), and Rosenthal et al (1988), all of whom estimated the value of total OCS oil and gas resources. King (1996) uses methodology identical to that used in this paper to estimate the total value of OCS oil and gas. This paper also builds on previous "5-Year Programs" especially *Outer Continental Shelf Natural Gas and Oil Resource Management Comprehensive Program 1992-1997*.

II Theoretical Development

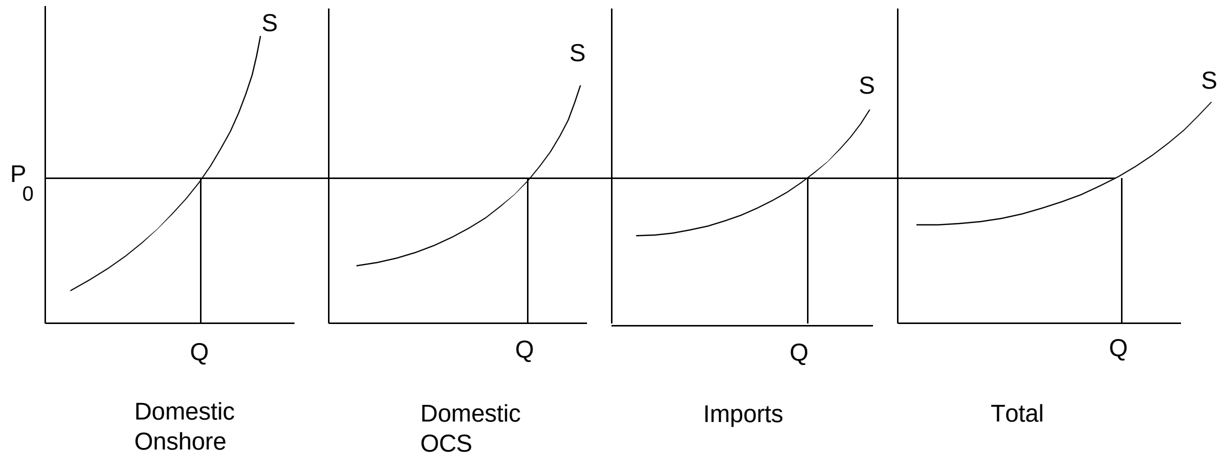
In general, CBA focuses on the microeconomic (market specific) benefits and costs associated with investments or policies. Complete consideration of microeconomic measures must encompass both supply and demand sides. Sometimes net macroeconomic benefits are considered along with the microeconomic measures. For ease of exposition the following discussion of these components only refers to oil; however, development of a model to estimate benefits from natural gas production would be virtually indistinguishable from that for oil.

II.A Microeconomics

Three sources supply the U.S. oil market: (1) domestic onshore production, (2) domestic OCS production, and (3) imports. Figure I shows these components summed horizontally to form the total U.S. market supply of oil. Figure I and all other figures and analysis in this paper assume that the international oil market acts like a locally competitive system in dealing with the relatively small shifts in international demand being analyzed here. More specifically, the paper assumes that supply curves for oil are locally continuous and upward sloping.

Figure II provides a more detailed view of the three combined components forming a stepped envelope of supply. With U.S. demand intersecting the total U.S. supply curve at E_0, domestic onshore provides *0* to Q_0^D of production, domestic OCS provides Q_0^D to Q_0^O of production, and imports provide Q_0^O to Q_0^T; however, these quantities are not drawn to an empirical scale.

The initial total benefits consist of the economic rent (producer surplus) plus the consumer surplus. Economic rent is the difference between the total revenue collected by producers and their total costs of production including normal returns to labor, money, capital, management expertise, and other factors of production. This surplus revenue adds to the income of producers and their investors. Consumer surplus is the



P_0 = the price of crude oil in the initial period
S = the sectoral supply curve for oil
Q = the market clearing quantity of oil at P_0

Figure I. Components of the U.S. Oil Supply.

difference between the maximum that consumers would be willing to pay for all units up to the market clearing quantity of the good and what they actually had to pay at the market clearing price. Thus, consumers benefit by this amount compared to what they might be forced to pay in a noncompetitive economy. In Figure II, the horizontally shaded area above the initial price line (P_0) represents consumer surplus. The three shaded areas below P_0 represent economic rent.

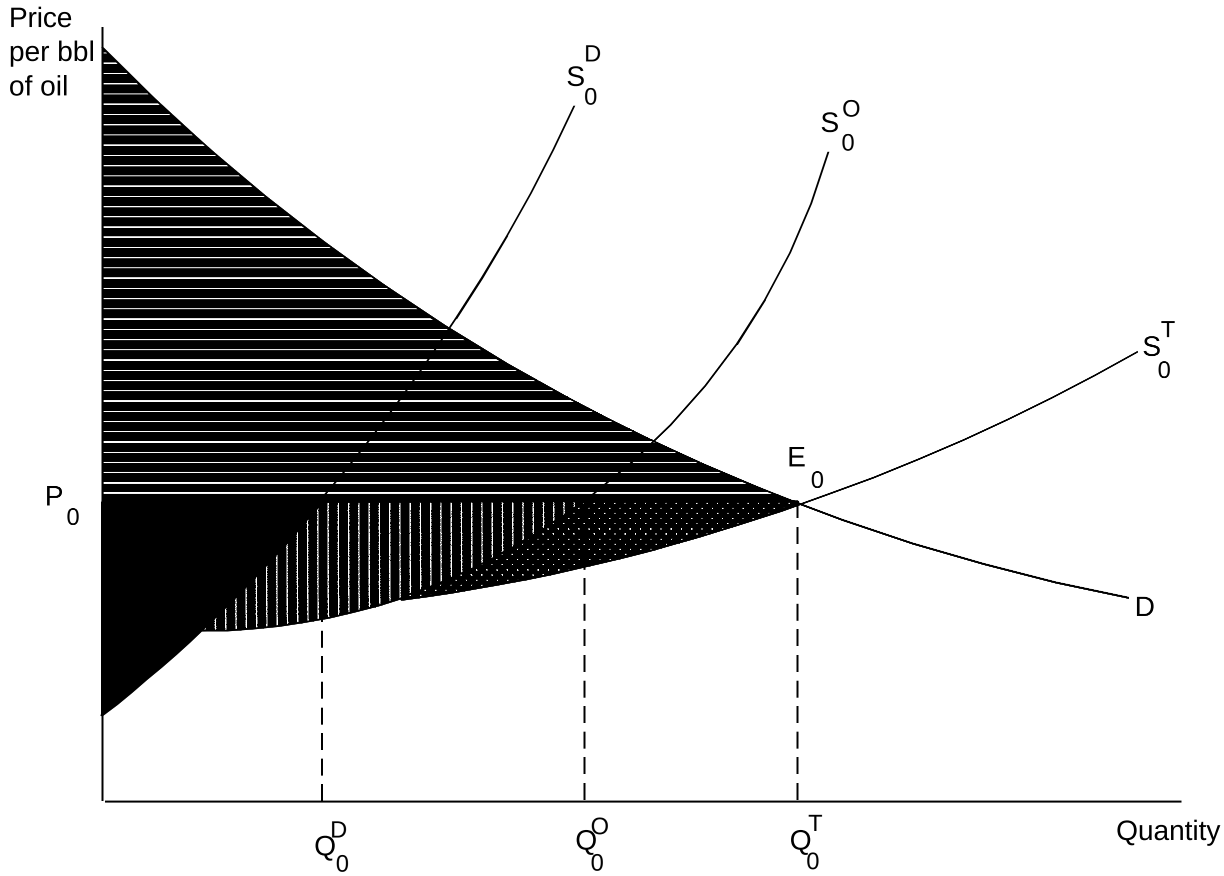
Comparing the market without the OCS to the market with the OCS can help identify the microeconomic benefits from domestic OCS oil production. Figure III illustrates the case where there is no oil production from the OCS. Compared to Figure II, the total supply curve shifts leftward by the amount of the lost OCS production and the new equilibrium occurs at E_1. Without OCS production, domestic society experiences a reduction in economic rent represented by the shaded area. This reduction is, of course, part of the benefit of continued OCS production.

MMS calculates a gross economic rent estimate for both oil and gas equivalent to the shaded area in figure III
using:

$$NEV_i = \sum_{t=1}^{n} \left[\frac{(AG_{it} \cdot PG_t) + (AO_{it} \cdot PO_t) - C_{it}}{(1+r)^t} \right] \qquad \textbf{\textit{(1)}}$$

where:

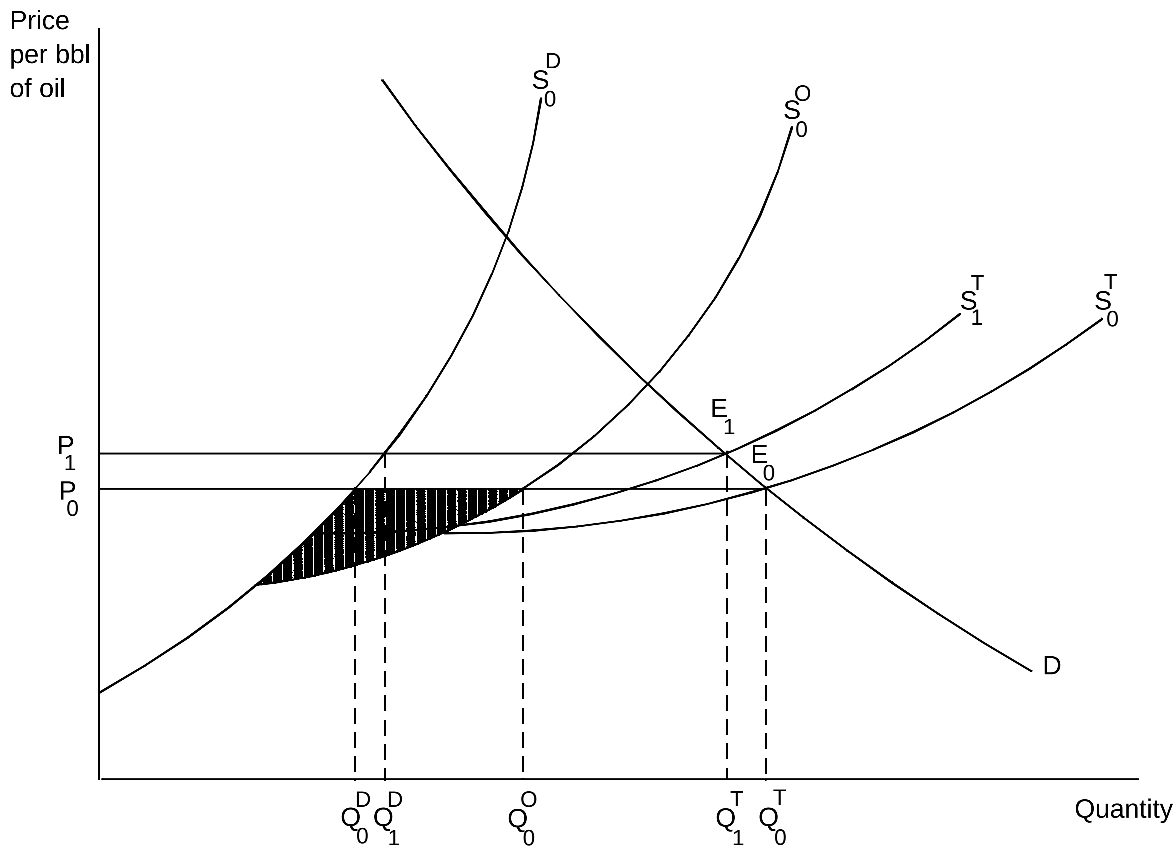
NEV_i = the estimated net present value of gross economic rent in the ith program area. MMS calls this "net economic value," thus NEV.



E_0 = the equilibrium in the initial period
S_0^D = the supply curve for domestic onshore crude oil
S_0^O = the supply curve for domestic OCS crude oil
S_0^T = the supply curve for imported crude oil
Q_0^D = the market clearing quantity of domestic onshore crude oil
Q_0^O = the total market clearing quantity of domestic onshore and OCS crude oil
Q_0^T = the total market clearing quantity of crude oil
the horizontally shaded area = the consumer surplus
the black area = the economic rent from domestic onshore oil production
the vertically shaded area = the economic rent from OCS production
the stippled area = the economic rent from imports

Figure II. The Combined Supply Curve for U.S. Oil.

Ag_{it} = the anticipated production of natural gas from program area i in year t
PG_t = the natural gas price expected in year t
AO_{it} = the anticipated production of oil from program area i in year t
Po_t = the oil price expected in year t
C_{it} = a vector of exploration, development, and operating costs, except transfers to the government.

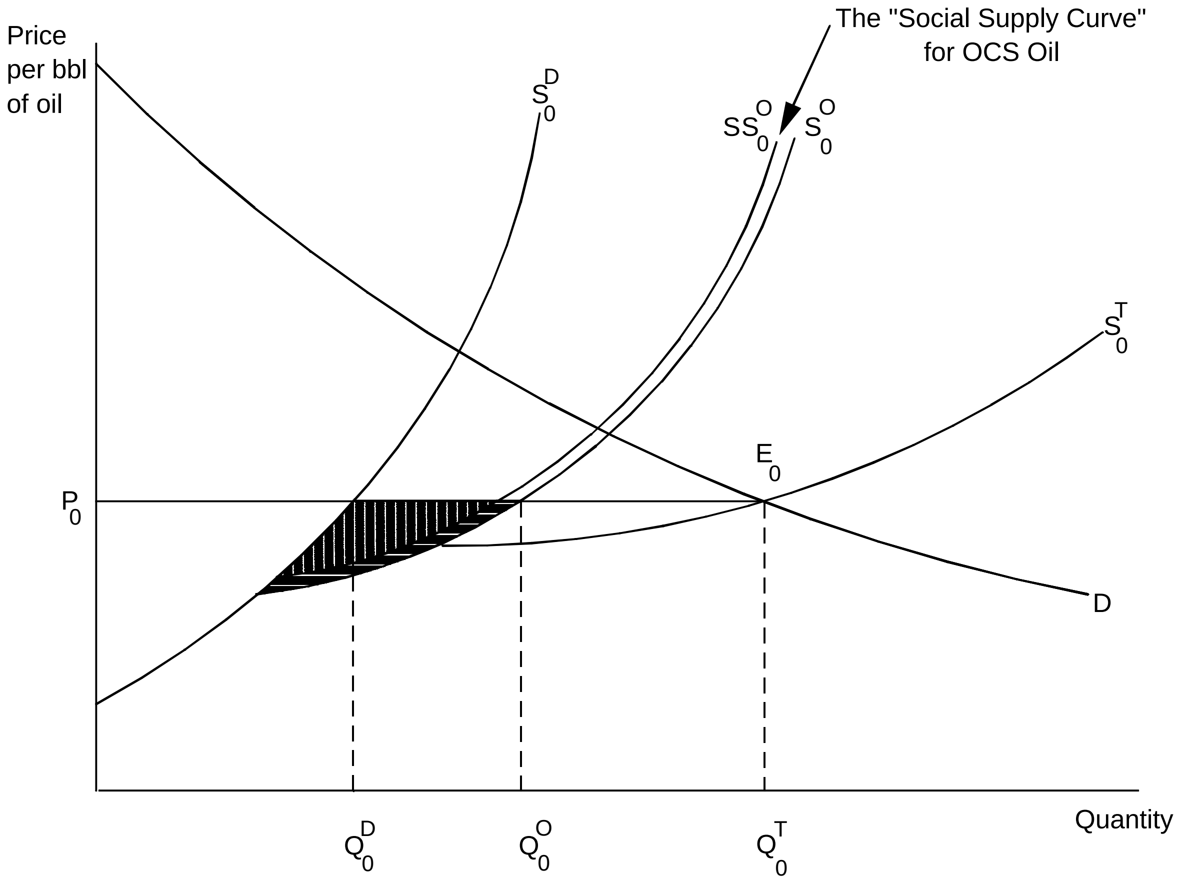


S_1^T = the total supply curve for crude oil without OCS production
E_0 = the new equilibrium without OCS production
P_1 = the new price without OCS production
Q_1^D = the market clearing quantity of domestic onshore crude oil without OCS production
Q_1^T = the total market clearing quantity of crude oil without OCS production
the vertically shaded area = the reduction in economic rent without OCS production = the economic rent benefit from OCS production

Figure III. Without OCS Oil Production: The Effect on Economic Rent.

r = a social discount rate
n = years of production associated with the leasing schedule.

Production of OCS oil imposes external environmental and social costs on society. These costs take the form of air and water pollution, increased risk of oil spills, pressure on overtaxed local services during development, and a range of similar impacts. Regulations have internalized many of these costs; however, some persist. In figure IV, the externalities that have not been internalized are represented by an upward shift (not to scale) in the "social supply curve" of OCS oil which includes the full cost to society of producing OCS oil.



the horizontally shaded area = the environmental and social costs of OCS production
the vertically shaded area = the net OCS economic rent

Figure IV. Environmental and Social Costs from OCS Production.

The perceived risk from environmental and social costs influences the political process to limit the availability of some offshore lands for oil and gas production. Nevertheless, the OCS production process is so structured that the external environmental and social costs associated with this process that actually occur have no measurable influence on production. Given this relationship, environmental and social costs reduce society's rent from OCS production as shown by the horizontally shaded area in figure IV. This leaves the net OCS economic rent represented by the vertically shaded area.

Of course, domestic onshore and imported oil also impose external costs. Indeed, a general equilibrium analysis which included all externalities associated with all substitutes and complements could lead to a somewhat different result than this paper. However, the result would probably not be significantly different, given the relatively small value of the remaining environmental and social costs.

The environmental and social costs in program area i, E_i, equal

$$E_i = \sum_{k=1}^{s} \sum_{t=1}^{n} \left[\frac{E_{ikt}}{(1+r)^t} \right] \qquad \textbf{\textit{(2)}}$$

where:

E_{ikt} = the cost to society of the kth environmental or social externality occurring in program area i in year t.

MMS calls the net economic rent from OCS production "net social value." This is a misnomer because it does not include consumer surplus benefits. Nevertheless, net economic rent from program area i (NSV_i) is

$$NSV_i = NEV_i - E_i \qquad \textbf{\textit{(3)}}$$

In addition to net economic rent, OCS oil also contributes to society's consumer surplus. In figure V (which is similar to figure III), without OCS oil production, consumer surplus declines as shown by the shaded areas bounded by P_1, E_1, E_0, and P_0. This occurs because when the upward sloping supply curve shifts to the left, it intersects the demand curve at a new, higher price (P_1). The higher price is somewhat closer to the maximum price consumers would be willing to pay and thus their consumer surplus is lower.

However, that portion of diminished consumer surplus shaded in black in figure V is not lost to the U.S. economy. It is a transfer from consumers to domestic onshore producers who add it to their economic rent.

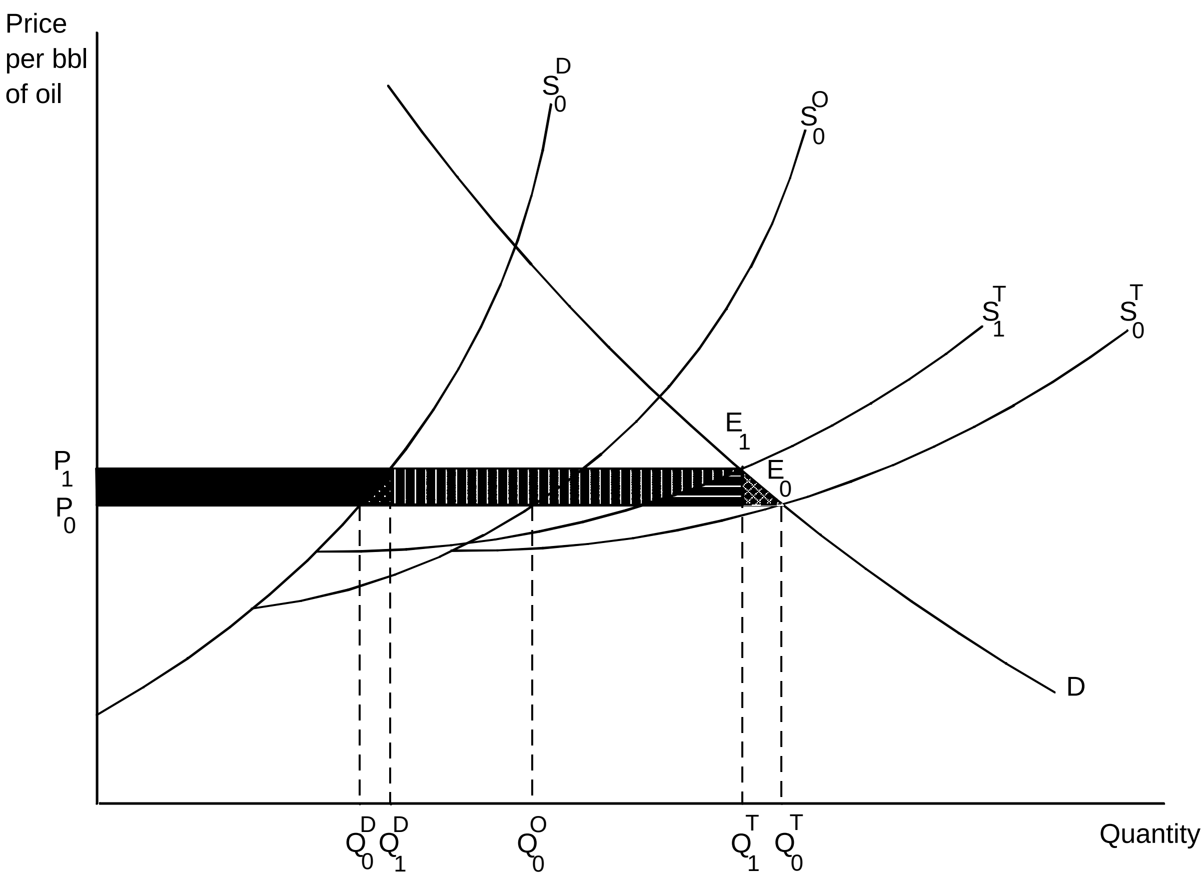
Thus, the consumer surplus loss to the U.S. economy equals the area shaded in stippling, vertical lines, horizontal lines, and crosshatching. The stippled triangle represents the additional cost to producers of increased domestic onshore production, the vertically shaded area represents the economic rent transferred to foreign producers of imported oil, the horizontally shaded area represents the additional cost of increased foreign production, and the crosshatched triangle designates the net global loss of consumer surplus.

Assuming a constant elasticity demand function of the form

$$Q_i^D = aP^{\eta} \qquad \textbf{\textit{(4)}}$$

where a is a constant and η is the elasticity of demand and a constant elasticity of supply function of the form

$$Q_i^S = bP^{\xi} \qquad \textbf{\textit{(5)}}$$



the black shaded area = the transfer from consumers to domestic onshore producers
the stippled triangle = the additional cost of domestic onshore production
the vertically shaded area = the economic rent tranferred to foreign producers of imported oil
the horizontally shaded area = the additional cost of increased foreign production
the crosshatched triangle = the net global loss of consumer surplus

Figure V. Without OCS Oil Production: The Effect on Consumer Surplus.

where *b* is a constant and ξ is the elasticity of supply for domestic onshore oil, the consumer surplus loss to the U.S. economy (*L*) can be expressed as

$$L_i = \int_{P_0}^{P_1} (aP^{\eta} - bP^{\xi})\,dP \qquad \textbf{\textit{(6)}}$$

where the first term inside the parentheses represents the total lost consumer surplus (the shaded areas in figure V) and the second term represents the economic rent transferred to onshore oil producers (the black area). Solving equation 6 yields

$$L_i = \frac{a}{\eta+1}(P_1^{\eta+1} - P_0^{\eta+1}) - \frac{b}{\xi+1}(P_1^{\xi+1} - P_0^{\xi+1}) \qquad \textbf{\textit{(7)}}$$

which is the formula for calculating consumer surplus benefits.

As explained earlier, losses in the “without OCS case” represent the benefits of OCS production. Thus, the net microeconomic benefits from OCS resources in program area i (T_i) equal the net economic rent plus the consumer surplus. Or,

$$T_i = NSV_i + L_i \qquad \textbf{\textit{(8)}}$$

II.B Macroeconomics

Cost-benefit analysis usually ignores macroeconomic impacts arising from the decision under analysis. In most cases this is appropriate because the investment or policy under consideration will have such a small impact on total national product and product prices that its effect can be ignored. However, exceptions exist. For instance, the focus of the analysis, tax policy for example, may be macroeconomic by its very nature. Alternatively, the decision could influence the price of a commodity that constitutes a sizeable percentage of the Nation's total consumption. This may be the case with some oil-related policies.

While the costs higher oil prices impose on the macroeconomy should be transitory, they may be significant nonetheless. For instance, economic growth may be retarded when industries which use oil as a major input cannot implement offsetting technological changes immediately. Labor and other resources idled by higher oil prices may incur frictional costs when they cannot return to work instantly. Furthermore, higher oil prices, through their depressing effect on real domestic income, tend to decrease the domestic savings rate thereby reducing funds available for investment. Higher oil prices can contribute to inflation. Policies to combat inflation usually lead to additional unemployment exacerbating problems of idle resources and lost production. Finally, the increased cost of imports may lead to a decline in the value of the dollar, further raising the cost of imported goods and reducing consumers' welfare. This last effect is usually called the "terms of trade effect."

Two alternative methods for calculating macroeconomic benefits from OCS oil and natural gas production come to mind. The first would be a model, such as an input-output model of the U.S. economy, that includes a sector for the OCS oil and natural gas industry. This type of model either follows or accounts for flows of influence through rounds of feedback and leakage. Unfortunately, such a model is not available at this time.

The second alternative method would be a model which estimates the macroeconomic impact directly through its net effect on national income. To construct such a model one might assume that the relationship between national income (N) and the price of oil (P) at time 0 fits locally a constant elasticity function of the form

$$N_0 = \alpha P_0^{\zeta} \qquad \textbf{\textit{(9)}}$$

where α is a constant and ζ is the oil price-national income elasticity.

The problem is to measure how a change in the price of oil influences national income. In this case, without the OCS contribution the oil market would clear at a new, higher price (P_1). If the assumption of a locally constant elasticity function holds,

$$N_1 = \alpha P_1^{\zeta}. \tag{10}$$

Subtracting N_1 from N_0 gives

$$\begin{aligned} N_0 - N_1 &= \alpha P_0^{\zeta} - \alpha P_1^{\zeta} \\ &= \alpha (P_0^{\zeta} - P_1^{\zeta}). \end{aligned} \tag{11}$$

Using equation 11 to estimate macroeconomic benefits involves acceptance of the strong assumption represented by equation 9. For one thing, there is some question whether an oil price-national income elasticity even exists. The argument for its existence depends on oil being such an important input to the U.S. economy that a change in its price leads to a measurable macroeconomic effect.

Another question is whether an oil price-national income elasticity maintains stability. Some observers believe measurable impacts on the macroeconomy only occur in response to notable price shocks and not from incrementally higher prices in the long run. In other words, a macroeconomic effect would occur only in the case where there was a massive shutdown of the OCS or a sudden boom of a kind seldom experienced.

In addition, even if one accepts the accuracy of an oil price-national income elasticity estimate, that estimate only applies to a single state of technology. The technology of energy substitution is in a continuing state of transition.

Furthermore, a portion of an empirically observed impact from a change in oil price on national income might be a microeconomic income effect that is counted already as economic rent and consumer surplus. Finally, comparability on the short-term, long-term continuum may be inconsistent between the microeconomic and macroeconomic estimates.

Several investigators have tested the existence and stability of the relationship between national income and changes in oil prices.[1] In a recent article, Lee et al (1995) provide strong evidence for a specific relationship between oil price shocks and national income. However, their work replicates the finding of Mork (1989) that a simple relationship between national income and oil prices loses its statistical

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[1]These empirical investigations include those by Burbidge and Harrison (1984), Darby (1982), Hamilton (1983), Loungani (1986), Mork (1989), and Mory (1993).

significance after 1986. They demonstrate that an oil-price shock variable normalized by a measure of price variability is significant for positive price shocks, but insignificant for negative shocks, over the 1950-92 period. In other words, an increase in oil price will have a greater impact on national income during a period of price stability than during a period of relative price instability. A fall in oil price was shown to have a statistically insignificant effect regardless of the level of price stability. Lee et al (1995) point out the relative instability of oil prices since 1986 which explains their initial results as well as those of Mork.

For this investigation the work of Lee et al (1995) strongly implies that in the present market, characterized as it is by price instability, the existence and stability of a macroeconomic relationship between oil prices and national income cannot be supported empirically. Thus, this paper takes the position that the macroeconomic benefits attributable to OCS oil and natural gas production cannot be estimated accurately at this time.

III. Assumptions and Input Data

Considerable uncertainty surrounds future production from the OCS and resulting impacts on the economy. A broad range of future conditions can result from a lease sale schedule. To be useful an analysis must be both specific and realistic, which is difficult in the face of uncertainty. Price expectations play an especially important role in estimating the value of program alternatives. Industry will be much more likely to develop hydrocarbon resources in frontier areas if future prices turn out to be higher than those clearing markets at the present time. In response to this price uncertainty, the MMS has chosen to identify a pair of likely scenarios of the future. One is a low-to-moderate price scenario that might be thought of as the most likely. In other words, no other scenario is more likely than this one, and, indeed, most other scenarios appear to be less likely. The second scenario is a plausible high-price situation for which the Department of the Interior must be prepared.

Scenarios must also be consistent. The MMS ensures consistency by using identical input assumptions in calculating each component of the economic analysis. The analysis in the environmental impact statement (EIS) that accompanies the program decision document also uses the same set of assumptions as the program alternative valuation. Four subsets make up the full assumption set for the economic analysis:

- oil and natural gas prices
- the discount rate
- anticipated production
- exploration and development scenarios

III.A Oil and Natural Gas Prices

To capture the effects of alternative price paths and volatility throughout the 1997 to 2037 analysis period, the MMS developed both a low-to-moderate (most likely) and a high-price scenario. The most-likely oil price selected was $18 per barrel (bbl). This price is consistent with actual worldwide levels following the Persian Gulf War. The price of West Texas Intermediate crude oil averaged about $17.25 per bbl in 1994, while the refiner acquisition cost of imported crude averaged $15.51. The high-oil price ($30 per bbl) is consistent with supply and demand conditions just before the 1985/86 price decline. Then, the benchmark Saudi Arabian Light crude was selling for $34 per bbl.

The MMS set the natural gas wellhead price at 60 percent of the oil price on a British thermal unit-equivalent basis. The most likely natural gas wellhead price is $1.92 per mcf and the high price is $3.20 per mcf. In both cases, inflation-adjusted, or "real," prices are assumed to remain constant throughout the productive life of all leases resulting from the new 5-year program.

III.B The Discount Rate

The MMS reviewed recent studies to determine an appropriate discount rate to use. Trends over the last 10 years have indicated that the real discount, as exemplified by rate of return obtained by industry, has been declining. Thus, based on the studies discussed below as well as the rationale presented in the *Outer Continental Shelf Natural Gas and Oil Resource Management Comprehensive Program 1992-1997,* a discount rate of 7 percent was chosen for the 1997-2002 program analysis.

A study completed by A.T. Guernsey (1990) for Shell Oil Company entitled “Profitability Study: Crude Oil and Natural Gas Exploration, Development, and Production Activities in the USA, 1959-1988" concluded that profitability has fluctuated along with industry's ability to anticipate the future economic environment. The real (after-tax) rate of return (ROR) averaged about 4 to 7 percent per annum from 1959-79. The economic environment for the years 1980-88 is now perceived to have been poorer than contemplated at the time investments were made, resulting in a ROR averaging between a negative 3.5 percent and a positive 0.5 percent per annum. This study suggests that real, after-tax discount rates for the industry currently average between 4 and 8 percent.

A December 1992 National Petroleum Council Report entitled “The Potential for Natural Gas in the United States” reference case used a 4 percent real after-tax marginal ROR. The Council's example after-tax equity ROR's for integrated companies fell between 4 and 6 percent, and between 3 and 5 percent for independents. These minimum ROR's were an extension of the work by Guernsey.

In March 1995, William L. Randol of Salomon Brothers International testified before the U.S. Senate, Committee on Energy and Natural Resources, regarding the flight of capital from the U.S. petroleum industry. Randol's investigation showed a 5-year average return on investment (ROI) for a representative group of seven major oil companies to be 7.3 percent during the period 1989-93. If Atlantic Richfield is excluded, the 5-year average ROI for the remaining six companies drops to 6.3 percent. This suggests that a discount rate around 7 percent is reasonable.

III.C Anticipated Production

As a part of the 5-Year Program process, the MMS constructs a series of alternative schedules for OCS lease sales called the program alternatives. Department of the Interior decisionmakers and, ultimately, the Secretary of the Interior consider these alternatives prior to making a decision on the final OCS lease sale schedule. The following alternatives are being considered for the 5-Year Program 1997-2002:

Alternative 1 -- The Program Proposal

- Western Gulf of Mexico -- annual sales
- Central Gulf of Mexico -- annual sales
- Eastern Gulf of Mexico -- sale in 2001
- Beaufort Sea -- sales in 1998 and 2000
- Chukchi Sea and Hope Basin -- sale in 2002
- Cook Inlet -- sale in 1999
- Gulf of Alaska -- sale in 2001

Alternative 2 -- No Action

Alternative 3 -- Slow the Pace of Leasing

- Western Gulf of Mexico -- sales in 1997, 1999, and 2001
- Central Gulf of Mexico -- sales in 1998, 2000, and 2002
- Eastern Gulf of Mexico -- sale in 2001
- Beaufort Sea -- sale in 2000
- Chukchi Sea and Hope Basin -- sale in 2002
- Cook Inlet -- sale in 1999
- Gulf of Alaska -- sale in 2001

Alternative 4 -- Exclude Some Planning Areas

- Western Gulf of Mexico -- annual sales
- Central Gulf of Mexico -- annual sales
- Eastern Gulf of Mexico -- no sale

- Beaufort Sea -- sales in 1998 and 2000
- Chukchi Sea -- sale in 2002
- Hope Basin -- no sale
- Cook Inlet -- sale in 1999
- Gulf of Alaska -- no sale

Alternative 5 -- Lease Additional Areas

- Western Gulf of Mexico -- annual sales
- Central Gulf of Mexico -- annual sales
- Eastern Gulf of Mexico -- sales in 1999 and 2001
- Beaufort Sea -- sales in 1998 and 2000
- Chukchi Sea and Hope Basin -- sale in 2002
- Cook Inlet -- sale in 1999
- Gulf of Alaska -- sale in 2001
- Mid-Atlantic -- sale in 2000

Alternative 5 may include either one or two sales in expanded Eastern Gulf of Mexico Program areas. If only one sale is held, it will be a deep-water sale only. If two sales are held, the second sale will be deep water plus a strip of lease tracts along the western boundary of the planning area.

The valuation of program alternatives is based on anticipated production, which is the estimated quantity of oil and natural gas that will be produced as a result of the lease sales included in any of the program alternatives. The estimates, along with the exploration and development scenarios, are included in table 1 for the proposed action (Alternative 1) and table 2 for Alternatives 3 and 5.

MMS uses the following information to develop estimates of anticipated production:

- data derived from the MMS National Oil and Natural Gas Resource Assessment and other resource assessment procedures,
- models that estimate the number of blocks expected to be leased,
- past statistics and analytical reasoning regarding the number of leased blocks that will be drilled,
- analysis of the number of drilled blocks that will yield discoveries, and
- analysis of the proportion of expected discoveries large enough to be commercially viable.

Experienced personnel in the MMS regions take all this information into account in formulating subjective estimates of production anticipated from each of the specific program options in each of the program areas.

III.D Exploration and Development Scenarios

Associated with various levels of production are activities and facilities related to exploring for and developing oil and gas resources. The list of these activities and facilities is called an exploration and development scenario. It is these activities and facilities that produce oil and gas, cost money, and cause environmental and social impacts. Table 1 shows the combined anticipated production and associated exploration and development scenario for the moderate and high cases in each program area included in the program proposal (Alternative 1). The production profiles (schedules) are not shown because they are lengthy and of limited interest. Table 2 shows the anticipated production and associated exploration and development scenarios for program areas where they changed in Alternatives 3 and 5.

IV. Models and Results

The total net microeconomic benefits from OCS production include net economic rent and consumer surplus for both oil and natural gas. Section II of this paper refers primarily to benefits from oil. This simplifies the discussion since similar analysis applies to natural gas. Empirically, however, differences arise between the two resources. The differences are identified below.

IV.A Net Economic Rent

Following equation 3, net economic rent consists of the gross economic rent minus the environmental and social costs associated with production. Graphically, net OCS economic rent is represented by the vertically shaded area in figure IV.

IV.A.1 Net Economic Value

Net economic value (NEV) is the difference between the discounted gross market value of anticipated production and the discounted real cost of exploring, developing, producing, and transporting the product to market (except for transfers to the Government). For each program area considered in the various alternatives, the NEV was calculated using the anticipated production and exploration and development scenarios shown in tables 1 and 2 and related production profiles. The U.S. Government (the lessor) collects a portion of the NEV as transfer payments in the form of cash bonuses, rentals, royalties, and taxes. The remainder of the NEV is retained by the lessees (private firms) as economic profits.

The NEV of the various program alternatives is calculated using a discounted cash-flow model called NEVPLUS. NEVPLUS calculates the gross value of anticipated production in a program area based on expected oil and gas prices. The gross value of the production is then discounted so that values can be expressed in terms of a

Table 1. The Proposed Action (Alternative 1) - Anticipated Production and Exploration and Development Scenario.

	GULF OF MEXICO			ALASKA			
Variables	***Western***	***Central***	***Eastern***	***Beaufort***	***Chukchi /Hope***	***Cook Inlet***	***Gulf of Alaska***
# of sales	5	5	1	2	1	1	1
Anticipated production-oil (BBO)	0.03 - 0.43	0.76 - 2.19	0.02 - 0.05	0.50 - 2.70	0.30 - 1.50	0.10 - 0.30	0.20 - 0.40
Anticipated production-gas (Tcf)	2.83 - 9.67	7.65 - 21.93	0.40 - 1.28	none	none	none	none
Years of activity	40	40	40	33	37	25	25
# of platforms	10 - 40	70 - 210	5 - 8	2 - 11	1 - 5	2 - 5	2 - 4
# of expl & delin wells	20 - 115	185 - 540	10 - 30	6 - 32	5 - 25	4 - 13	7 - 10
# of devel & prod wells	65 - 355	515- 1495	20 - 30	56 - 396	36 - 180	28 - 84	42-106
Pipeline miles	550-1150	650-1450	100- 300	250 - 480	550-600	75- 150	75-200
# of landfalls	5	5	0	4	2	1	1
# of shore bases	6[1]	7[2]	0	4	2	1	1

[1]Gulf of Mexico Region - shore facilities; 1 Gas processing plant, 4 oil pipeline shore facilities and 1 waste disposal facility.
[2]Gulf of Mexico Region - shore facilities; 4 oil pipeline shore facilities and 3 waste disposal facilities.

1997 program starting date. Likewise, the costs of exploration, development, production, and transportation (excluding transfer payments) are calculated and discounted back to 1997. The discounted costs are then subtracted from the discounted gross production value. This difference represents the NEV, as of 1997, for the program areas included in the program alternatives.

Table 2. Alternatives 3 and 5 - Anticipated Production and Exploration and Development Scenario.

	Alternative 3			Alternative 5		
	GULF OF MEXICO		ALASKA	GULF OF MEXICO		ATLANTIC
Variables	Western	Central	Beaufort	Eastern (a)	Eastern (b)	Mid-Atlantic
No. of sales	3	3	1	1	2	1
Anticipated production-oil (BBO)	0.02 - 0.26	0.46 - 1.31	0.30 - 2.00	0.02 - 0.05	0.02 - 0.06	0.00 - 0.01
Anticipated production-gas (Tcf)	1.58 - 5.80	4.59 - 13.16	none	0.42 - 1.44	0.46 - 1.76	0.88 - 2.82
Years of activity	40	40	33	40	40	40
No. of platforms	6 - 25	45 - 125	1 - 10	6 - 8	7 - 9	2 - 3
No. of exploration & development wells	15 - 70	110 - 325	4 - 28	20 - 30	20 - 30	10 - 15
No. of development & production wells	40 - 215	310 - 900	50 - 300	25 - 30	30 - 40	20 - 25
Pipeline miles	330 - 690	390 - 870	185 - 355	100 - 350	150 - 500	200 - 300
No. of landfalls	3	3	3	0	0	1
No. of shore bases	3	3	1	0	0	1

Oil estimates are expressed in billions of barrels (BBO); natural gas estimates are expressed in trillions of cubic feet (Tcf).

Table 3 includes NEV's for program areas in the proposed action and alternatives 3 and 5 (for those program areas where the NEV's are different than the proposed action). Table 4 includes the sums of the NEV's for each of the program alternatives.

IV.A.2 Environmental and Social Costs

The net economic value assessment considers the private costs, except for transfer payments to the Government, incurred by the firms that discover and develop OCS oil and natural gas resources. In addition, society incurs environmental and social costs from the activities and facilities associated with OCS oil and natural gas production. These costs take a variety of forms and the MMS has organized the environmental and social costs associated with OCS activities into the following 14 categories:

- Air Quality
- Water Quality
- Spill Avoidance and Response
- Infrastructure
- Fishing Ground Preemption and Gear Loss
- Wetlands
- Property Values
- Oil-Spill Control and Cleanup
- Recreation and Tourism
- Commercial Fisheries
- Wildlife
- Subsistence
- Legal
- Administrative and Research

The categories are not logically parallel because they were chosen to highlight issues the public identified as important with respect to the OCS leasing program.

Costs associated with oil spills constitute the major portion of the total costs that society can be expected to bear. The environmental effects of oil spills and the costs associated with those effects vary widely depending on variables such as the amount and type of oil spilled, the location of the spill, whether the spill hits shore, the sensitivity of the ecosystem affected, weather, season, etc.

Fortunately, the environmental and social costs associated with several oil spills have been relatively well documented so there is a reasonable basis for oil-spill cost modeling in the literature. Nevertheless, modeling efforts are usually limited to assessing the effects of an "average" event like an oil spill. In the case of the analysis performed for this report, the estimates are for the aggregate costs of all the spills that the model suggests would most likely result from anticipated production. This approach cannot and does not try to measure the effects of any individual spill, nor does it take into account the unlikely event of a catastrophic spill of unprecedented proportions.

If OCS oil and, to a lessor extent, natural gas are not produced, imports of foreign oil will increase substantially. Most of this oil would be imported by tanker, entailing risks of oil spills and environmental costs. The environmental costs associated with these increased imports are subtracted from the environmental costs associated with OCS production to arrive at an estimate of the net environmental and social costs associated with OCS activities. To ensure consistency, the market simulation model is used to estimate imports that would substitute for OCS production. This is the same model used to estimate consumer surplus benefits, to develop the no action scenario, and to support the energy alternatives evaluation.

The MMS has adopted the General Purpose Environmental Cost Model (GPECM) for estimating environmental and social costs associated with OCS activities. As the name implies, the GPECM is designed to perform several functions: estimate environmental and social costs of OCS activities, estimate environmental and social costs of imports that would substitute for OCS production, and estimate the OCS-related environmental and social costs that planning areas (and nearby coastal areas) would incur even if the development occurred elsewhere.

The GPECM is designed to model the impact of typical activities associated with OCS production and typical oil spills occurring on the OCS. This model is not designed to represent the impacts of catastrophic events nor impacts on unique resources such as endangered species. The reader is referred to the EIS accompanying this document for assessment of catastrophic effects and impacts on unique resources. Decisionmakers are cautioned that the environmental and social costs included in this analysis are not necessarily all the costs that might be associated with the proposed action and other options, although the MMS attempted to assess accurately costs that could reasonably be expected.

The GPECM is a 14-sector spreadsheet model. The 14 sectors are the same as those listed above as the categories of environmental and social costs. The model uses anticipated production, exploration and development scenarios, and economic inputs as the basis for its calculations. For the 5-Year Program for 1997-2002, some of the variables and parameters were updated on the basis of recently published reports about oil spills and environmental costs.[2]

Both the gross environmental and social costs and the costs of replacement imports have been allocated to the program areas on the basis of production. The rationale for this decision is twofold. First, all benefits are allocated to the program areas where the production occurs; therefore, it would be inconsistent to do otherwise for costs. Second, and more importantly, if benefits and costs are not allocated to the area of

[2]Anyone interested in additional information about the GPECM should see, A. T. Kearney. Estimating the Environmental Costs of OCS Oil and Gas Development and Marine Oil Spills: A General Purpose Model. June 1991; available from the Minerals Management Service, Technical Communication Services. The GPECM itself, along with the model documentation, is also available to those who want to test the model.

production, it would be nearly impossible to maintain the cause-and-effect link between a decision to lease in a specific program area and the costs and benefits likely to result from that decision. The "regional cost" discussion in the equitable sharing section of the 5-Year Program shows an allocation of costs to the planning areas where they are expected to be incurred.

Table 3 includes net environmental and social costs for program areas in the proposed action and Alternatives 3 and 5. Table 4 includes the sums of the net environmental and social costs for each of the program alternatives.

The GPECM does not include loss of passive enjoyment value. Passive enjoyment value, also called passive use or non-use, is the benefit people derive from: (1) knowing a natural resource continues to exist in a specific condition, (2) retaining the option to use that resource in the future, and (3) being able to pass the resource to future generations (which may be a subset of (2)). Passive enjoyment value represents an important component of the value of natural resources; however, it is very difficult and extremely expensive to measure accurately. Some economists question whether it can ever be measured accurately. Exacerbating the difficulty and expense of estimating passive enjoyment is the complication imposed on measurement by the vast extent of territory, many program areas, and great diversity of natural resources covered by this program. No reliable estimate of potential passive enjoyment value loss associated with OCS activities exists.

IV.B Consumer Surplus

The MMS calculates consumer surplus benefits associated with anticipated production using the market simulation model. To maintain consistency, this same model with the same assumptions is used for other portions of the 5-Year Program analysis. The market simulation model includes submodels for oil and natural gas.

IV.B.1 Consumer Surplus -- Oil

Consumer surplus attributable to OCS production is represented graphically by the areas shaded in stippling, vertically, horizontally, and crosshatching in figure V. Equation 7, which is the basis for the oil submodel in the market simulation model, includes a shift in oil price analogous to the price change in figure V. Oil prices are set on a world market. Simulating a shift in world oil market equilibrium entails a simultaneous model with multiple sectors of demand and supply. However, obtaining information from many different sources compounds the data compatibility problem in an effort such as this one. Thus, this paper limits input data to the anticipated production estimate; the U.S. Department of Energy, Energy Information Administration *Annual Energy Outlook 1995* (DOE (1995)); and a set of demand and supply elasticity estimates from ICF Resources Incorporated (ICF (1991)).

DOE (1995) reports international oil production for five groups of countries and oil consumption for seven groups. The five groups on the production side were combined to form three: United States, OPEC, and Rest of World. The U.S. estimate was divided into OCS and onshore domestic to make a total of four production sectors. The consumption estimates were combined to form United States, Other OECD, OPEC, and Rest of World. Thus, the model contains four production and four consumption sectors for which ICF (1991) provides elasticity estimates. Retaining the constant elasticity functional form of equation 4 for the demand sectors and equation 5 for the supply sectors, the world market is represented by simultaneous system 12

$$
\begin{aligned}
Q^{OCSS} &= b^{OCSS} P_0^{\xi^{OCSS}} \\
Q^{ODOMS} &= b^{ODOMS} P_0^{\xi^{ODOMS}} \\
Q^{OPECS} &= b^{OPECS} P_0^{\xi^{OPECS}} \\
Q^{ROWS} &= b^{ROWS} P_0^{\xi^{ROWS}} \\
Q^{USD} &= a^{USD} P_0^{\eta^{USD}} \\
Q^{OECDD} &= a^{OECDD} P_0^{\eta^{OECDD}} \\
Q^{OPECD} &= a^{OPECD} P_0^{\eta^{OPECD}} \\
Q^{ROWD} &= a^{ROWD} P_0^{\eta^{ROWD}} \\
Q^{OCSS} + Q^{ODOMS} + Q^{OPECS} + Q^{ROWS} &= Q^{USD} + Q^{OECDD} + Q^{OPECD} \quad Q^{ROWD}.
\end{aligned}
\qquad \textbf{\textit{(12)}}
$$

where the first four equations are the sectoral supply equations, the second four are the sectoral demand equations, and the last is the world market equilibrium equation.

The first step in calculating consumer surplus is to solve for the sectoral constants (a^s and b^s) in each of the demand and supply equations. Input to these equations consists of oil price, production quantity, and consumption quantity projections in 5-year intervals from DOE (1995), plus the elasticity estimates from ICF (1991).

The model then introduces the sectoral constants back into system 12, sets Q^{ocss} to zero, and solves the system using a manually triggered iterative convergence algorithm. The products of the solution are a new price without OCS production (P_1) and a new set of sectoral quantity estimates. The model next calculates consumer surplus using equation 7 where the *a* and the η are from the *USD* equation and the *b* and the ξ are from the *ODOMS* equation. It interpolates between the 5-year estimates to get a consumer surplus estimate for each year in the analysis period. The yearly estimates are allocated to program areas on the basis of the anticipated production in each program area in that year. Finally, the model takes the net present value of each vector of consumer surplus estimates allocated to each program area.

IV.B.2 Consumer Surplus -- Natural Gas

The natural gas submodel uses the same sources of input data as the oil submodel. However, unlike oil, imports constitute a relatively small fraction of U.S. natural gas consumption. As a result, the natural gas submodel includes only three production sectors (OCS, onshore domestic, and imports) and only a single domestic consumption sector. A second difference with oil is that the wellhead price of gas drives production while the delivered price drives consumption and the trends in these two prices may diverge. Therefore, the U.S. natural gas market can be represented by system 13

$$
\begin{aligned}
Q^{OCSS} &= b^{OCSS} P_{W0}^{\xi^{OCSS}} \\
Q^{ODOMS} &= b^{ODOMS} P_{W0}^{\xi^{ODOMS}} \\
Q^{IMPRTS} &= b^{IMPRTS} P_{W0}^{\xi^{IMPRTS}} \\
Q^{USD} &= a^{USD} P_{D0}^{\eta^{USD}} \\
Q^{OCSS} + Q^{ODOMS} + Q^{IMPRTS} &= Q^{USD} \\
P_{D0} &= P_{W0} + \lambda
\end{aligned}
\qquad \textbf{\textit{(13)}}
$$

where the first three equations are the sectoral supply equations, the fourth is the U.S. demand equation, the fifth is the market equilibrium equation, and the last is the price reconciliation equation in which λ equals the difference between wellhead and delivered natural gas prices.

The natural gas submodel follows the same steps as the oil submodel. The market simulation model adds the totals from oil and natural gas submodels to get total consumer surplus benefits by program area which are included in table 3. Table 4 includes the total consumer surplus benefits for each of the program alternatives.

V. Valuation of Program Alternatives

The ultimate purpose of the economic analysis for the new 5-Year Program is to help the Secretary select the best schedule of proposed sales. Those program areas with positive net benefits are appropriate for inclusion in the leasing program from an economic point of view. It should be remembered that decisionmakers can and should bring to their decisions other valid points of view besides economics. In other words, positive net benefits ought not be the sole criterion for selecting any particular option or for including or excluding a program area from the leasing schedule.

Table 3 shows the estimates of net benefits for program areas in the proposed action and Alternatives 3 and 5, as well as the totals for each of the categories of benefits and costs that went into calculating the net benefits. Only those program areas in

Alternatives 3 and 5 that are different from the proposed action are shown.

Table 4 shows the estimates of total net benefits for each of the program alternatives as well as the totals for each of the categories of benefits and costs that went into calculating the net benefits. Because each of the categories of benefits for each alternative is calculated in comparison to the No Action Alternative (Alternative 2), the No Action Alternative has no benefits or costs listed in the benefit categories. While Alternative 2 does have positive net benefits in the environmental and social costs category, these benefits are not shown because they have been included as costs under the other alternatives.

Alternative 1 -- The Proposed Action

In Alternative 1, Gulf of Mexico Program Areas have especially high net benefits regardless of the price scenario examined. Although the Alaskan Program Areas have relatively low net benefits in the $18 per barrel oil price scenario, they may be of interest to industry if higher oil prices are expected in the future—as indicated by the $30 per barrel estimates.

These results suggest that the Gulf of Mexico Program Areas should be considered for inclusion in the program regardless of future price expectations. In addition, the four Alaska OCS Program Areas are still relatively good candidates for inclusion in the program because they are expected to contain large resource volumes and are estimated to have high net benefits at increased price levels.

Alternative 2 -- No Action

The selection of Alternative 2 would result in forgoing the opportunity to produce any resources from the program areas considered in Alternative 1 and thus forfeiting the associated net benefits as well. The production that would not occur because of selection of a "No Action" alternative would be replaced by other sources, with imports likely contributing the majority of the forgone oil production and about a third of the gas energy.

Alternative 3 -- Slow the Pace of Leasing

Alternative 3 slows the pace of leasing so that there would be only three sales each in the Central and Western Gulf of Mexico Program Areas and only one sale in the Beaufort Sea Program Area while maintaining one sale each in the Chukchi/Hope, Gulf of Alaska, and Cook Inlet Program Areas . Elimination of sales in the Central and Western Gulf of Mexico is estimated to decrease anticipated production by about 40 percent. The reduction in anticipated production under this alternative for the Beaufort Sea, high-price scenario, would be about 25 percent.

Table 3. Valuation of Program Area Net Benefits in the Proposed Action and Alternatives 3 and 5.

Program Areas	***Net Economic Value***	***Environmental & Social Costs***	***Net Social Value***	***Consumer Surplus Benefits***	***Net Microeconomic Benefits***
Alternative 1					
Western Gulf of Mexico	970 9,020	-0.6 -0.6	969.4 9,019.4	146 1,173	1,115.4 10,192.4
Central Gulf of Mexico	4,720 26,180	-18.5 -39.2	4,701.5 26,140.8	908 4,235	5,609.5 30,375.8
Eastern Gulf of Mexico	50 740	-5.3 -8.1	44.7 731.9	21 95	65.7 826.9
Beaufort Sea	* 1,990	* -27.9	* 1,962.1	* 3,475	* 5,437.1
Chukchi Sea/Hope	* 340	* -9.5	* 330.5	* 1,355	* 1,685.5
Cook Inlet/ Shelikof Strait	* 260	* -1.2	* 258.8	* 520	* 778.8
Gulf of Alaska	* 290	* -9.4	* 280.6	* 519	* 799.6
Alternative 3					
Western Gulf of Mexico	530 5,410	-0.4 -0.2	529.6 5,409.8	85 724	614.6 6,133.8
Central Gulf of Mexico	2,840 15,700	-10.8 -22.0	2,829.2 15,678.0	560 2,603	3,389.2 18,281.0
Beaufort Sea	* 1,500	* -19.8	* 1,480.2	* 2,588	* 4,068.2
Alternative 5					
Eastern Gulf of Mexico (a)	60 820	-5.6 -8.1	54.4 811.9	21 101	75.4 912.9
Eastern Gulf of Mexico (b)	60 990	-8.2 -10.0	51.8 980.0	22 123	73.8 1,103.0
Mid-Atlantic	* 410	* -3.6	* 406.4	* 127	* 533.4

All figures in the table are in millions of 1997 dollars. In each cell, base case estimates ($18 per barrel and $1.92 per mcf are shown on top and high case estimates ($30 per barrel and $3.20 per mcf) are on the bottom. * = negligible.

Table 4. Valuation (Net Benefits) of Program Alternatives.

Program Areas	***Net Economic Value***	***Environmental & Social Costs***	***Net Social Value***	***Consumer Surplus Benefits***	***Net Microeconomic Benefits***
Alternative 1 (Proposed Action)	5,740 38,820	-36.2 -95.9	5,703.8 38,724.1	1,879 11,372	7,582.8 50,096.1
Alternative 2 (No Action)	0.0 0.0	0.0 0.0	0.0 0.0	0.0 0.0	0.0 0.0
Alternative 3 (Slow the Pace of Leasing)	3,420 24,240	-24.4 -69.0	3,395.6 24,171.0	1,317 8,407	4,712.6 32,578.0
Alternative 4 (Exclude Some Program Areas)	5,690 37,790	-27.0 -78.1	5,663.0 37,711.9	1,694 10,738	7,357.0 48,449.9
Alternative 5a (Lease Additional Areas)	5,750 39,310	-39.9 -99.5	5,710.1 39,210.5	1,904 11,499	7,614.1 50,709.5
Alternative 5b (Lease Additional Areas)	5,750 39,480	-42.5 -100.6	5,707.5 39,379.4	1,905 11,520	7,612.5 50,899.4

All figures in the table are in millions of 1997 dollars. In each cell, base case estimates ($18 per barrel and $1.92 per mcf are shown on top and high case estimates ($30 per barrel and $3.20 per mcf) are on the bottom.

Analysis of Alternative 3 shows that the Central and Western Gulf of Mexico Program Areas would continue to have high net benefits regardless of the price scenario examined. However, the net benefits would be much lower than those attributed to Alternative 1. Although the net benefit estimate for the Beaufort Sea Program Area is lower than its Alternative 1 value, it still ranks as the highest valued Alaskan Program Area in the $30 price scenario.

Alternative 4 -- Exclude Some Planning Areas

Alternative 4 eliminates sales in the Eastern Gulf of Mexico and Gulf of Alaska Program Areas and excludes the Hope Basin from the Chukchi Sea/Hope Basin Program Area. Because the Hope Basin is thought to be gas prone and unlikely to produce economic quantities of oil or gas, the estimated benefits of this alternative would be the same as Alternative 1, less the estimated net benefits for the Eastern Gulf of Mexico and the Gulf of Alaska.

Alternative 5 -- Lease Additional Areas

Alternative 5 considers leasing in larger program areas in the Eastern Gulf of Mexico and in a program area in the Mid-Atlantic in addition to the areas included in the proposed action. The larger Eastern Gulf Program Area would include 384 additional blocks located in deep water and would be scheduled for either one sale (in 2001) or two sales (in 1999 in the deep-water portion only and 2001 in an expanded area). The Mid-Atlantic component of Alternative 5 is the same as the leasing proposal that was analyzed for that planning area in the Draft Proposed Program -- a sale in 2000 in a small program area encompassing the former Hudson Canyon Unit off New Jersey, limiting the number of blocks offered at the time of the sale to 50.

The expected net social value of either Alternative 5a (one sale) or Alternative 5b (two sales) for the Eastern Gulf of Mexico would be higher than that of the program proposal. The expected net benefits of the Mid-Atlantic option would be negligible under the base case.

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