Appendix II

Appendix II

The Presidential Energy Initiatives: Some Policy Considerations

The recent Presidential Energy Message to Congress has raised a number of varied and important issues. The ongoing debate over the proper course for public policy would be enhanced, however, if additional information and quantitative analyses were available. The purpose of this paper is to move toward this end with respect to three diverse, but major, areas of concern. They include:

1. Estimates of the price elasticity of supply (supply response to price changes) for petroleum and natural gas from future discoveries in the Outer Continental Shelf (OCS) and Alaska.
2. Estimates of the impact of deregulated domestic petroleum prices on energy industry profits and capital financing requirements.
3. Estimates of the number and location of future coal mine developments necessary to meet stipulated consumption levels and sulfur constraints.

Price elasticity of supply

Major portions of the undiscovered oil and natural gas resources in this country have been forecast to lie in the public domain, either in the OCS or in Alaska (USGS, 1975). Because energy discoveries in these areas tend to be more expensive to produce than those in traditional areas and because of their potential magnitude, the impact of market prices on their development takes on special significance.

Any forecast of price response must be tentative, given the host of factors which can influence the actual outcome. For that reason, it is valuable to simulate possible impacts using models which require all necessary assumptions to be clearly specified. Results can then be duplicated or recomputed using alternative assumptions and comparisons can be made.

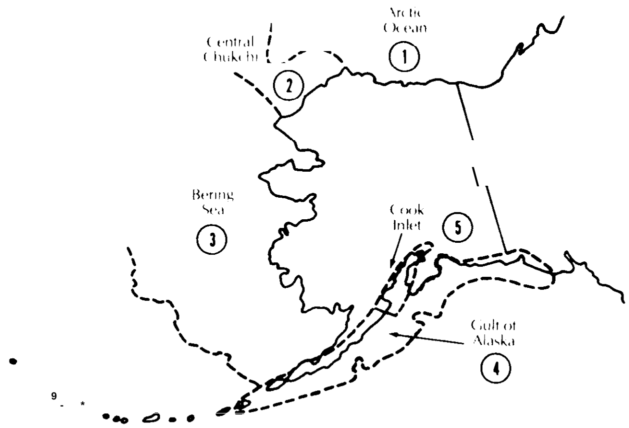
That is the approach used here. A simulation model of private sector behavior under public domain leasing arrangements provides the basis for analysis. Developed over a 4-year period under National Science Foundation funding, the approach has been widely utilized for policy analysis in the past (Kalter and Tyner, 1975a; 1975b; 1975c; Kalter *et al.* 1975). Using concepts of probability theory and Monte Carlo techniques, uncertainty in a number of variables which influence production outcomes can be handled.

For this analysis, potential hydrocarbon discoveries in 13 offshore provinces serve as the focus.[1] Figures II-1 and II-2 outline the areas covered. Appendix A details the input data and assumptions used in the analysis. In general, however, U.S. Geological Survey forecasts of hydrocarbon resources and historical data were used as a basis for deriving field size distributions and the expected number of fields in each OCS subregion. Investment and operating cost data were developed from National petroleum Council information which allowed estimates to be made for individual reservoir sizes in five separate cost regions. Then, the geologic and cost information developed was used in conjunction with

[1] Time was Insufficient to develop the necessary statistical information for an in-depth analysis of the onshore Alaskan situation. However, the results obtained here can be generalized to cover such areas. We will return to this point below.

Figure II-1 Aggregated OCS Provinces Surrounding the Conterminous Lower 48 United States

Figure II-2. Aggregated OCS Provinces Surrounding Alaska



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the Monte Carlo simulation model at alternative levels of expected price. The results of these simulations, when coupled with the field number forecasts by size range, provided the basis for the supply price elasticity calculations.

Oil price levels of $11.64 per barrel (the current upper tier regulated price), $13.75 per barrel (approximately the current landed price for imports), $17.00 per barrel, and $22.00 per barrel were simulated. Natural gas prices of $1.40 per thousand cubic feet (Mcf) (approximately the current regulated price for new gas), $1.75 per Mcf (the President's proposed new price level), and $2.25 per Mcf were tested. The current world oil price is equivalent to a $2.43 per Mcf natural gas price.

The results are summarized in table 11-1. Arc elasticity values for various price ranges are displayed for both oil fields (with associated natural gas) and nonassociated natural gas fields (with associated natural gas liquids). The analysis assumed that a competitive leasing system, similar to the current cash bonus approach, would be used to allocate public domain lands to the private sector for development and that development would not occur if the chance of a less than normal profit falls below 50 percent.[2]

The elasticity values calculated are startling but perhaps, on reflection, not surprising. For oil, supply is highly inelastic above $11.64 per barrel in all but the high-cost regions of the OCS.[3] In these regions (Arctic Ocean, Central Chukchi, Bering Sea, and Cook inlet), some price elasticity is exhibited up to a $17.00 per barrel price. But even then, only the highest cost areas (Arctic Ocean and Central Chukchi) require prices of $17.00 per barrel to foster development. Most production in high-cost regions will take place at prices equivalent to current world market prices ($1 3.75 per barrel). Small oil reservoirs (less than 50 million barrels) usually cannot be profitably developed in high-cost areas even at $22.00 per barrel, whereas medium- and large-size reservoirs are developable at prices below $17.00 per barrel. Overall, supply is price elastic in the $11.64 to $13.75 per barrel range only, with moderate inelasticity between $13.75 and $17.00 per barrel and high inelasticity over $17.00 per barrel.

Thus, supply availability from the OCS appears more dependent on the pace of Federal leasing and the size of resource discoveries than on price (assuming that price is allowed to reflect inflationary impacts over time).[4] Higher prices for the produced product would merely be reflected in higher bids for OCS leases if the leasing system were competitive and methods are devised to reduce risk to the private sector developer (such as greater use of contingency payments in lieu of the cash bonus).

[2] Nelther assumption, however, appears critical to the results. Supplemental analysis showed that permitting development whenever after-tax net present values were positive (regardless of the probability of loss) actually lowered the elasticity values in the few situations where development was affected. Using a profit share form of leasing system had little impact on the results.

[3] That is, a given percentage increase in oi1 prices will result in a small percent change in production. An elasticity value of one implies that the percentage change in price equals the percentage change in production. A value greater than one means a greater percentage increase in production (elastic supply) and conversely for a value less than one (inelastic supply),

[4] Note that the results shown assume real prices and relate to total net production. Thus, they give no indication of the sensitivity of production profiles (or timing) to price changes.

Table II-1 .—Supply Price Elasticity Values by OCS Province Based on Monte Carlo Simulation[a]

Province	Oil				Natural Gas		
	$11.64-13.75 bbl.	$13.75-17.00 bbl.	$17.00-22.00 bbl.	$11.64-22.00 bbl.	$1.40-1.75/Mcf	$1.75-2.25/Mcf	$1.40-2.25/Mcf
1. Arctic Ocean	0.68	2.74	0.45	1.81	—	0,29	0.29
2. Central Chukchi	—	2.99	0.24	1.76	—	0.32	0.32
3. Bering Sea	6,23	0.46	0.20	2.60	4.08	0.41	2.60
4. Gulf of Alaska	0.04	0.04	0.18	0.12	0.09	0.02	0.06
5. Cook Inlet	4.28	0.51	0.20	1.92	0.25	4.24	2.7.5
6. North Pacific	0.83	0.24	0.05	0.41	0.00	0.00	0.00
7. Santa Cruz	0.20	0.10	0.02	0.12	0.05	0.06	0.12
8. S. California	0.19	0.05	0.03	0.10	0.08	0.03	0.06
9. Central and Western Gulf	0.33	0,04	0.02	0.13	0.00	0.00	0.00
10. MAFLA	0.20	0,08	0.04	0.12	0.03	0.04	0.04
11. North Atlantic	0.08	0.03	0.48	0.27	0.00	0.00	0,00
12. Central Atlantic	0.04	0.64	0.14	0.35	0.04	0.04	0.04
13. South Atlantic	0.18	0.08	0.04	0.11	0.00	0.69	0.41
Overall	1.85	0.81	0.20	1.17	1.00	0.13	0.62

[a]See Appendix II for input data and assumptions used.

The situation for nonassociated natural gas is similar to that for oil. If anything, supply is even more inelastic to price changes. However, development of gas in high-cost regions will not commence below $1.75 per Mcf. Small- and medium-size finds (below 600 Bcf) in many of these regions would not be developed at prices as high as $2.25 per Mcf. Potential finds in the Bering Sea and Cook Inlet, however, appear price responsive over the range simulated. Overall, a unitary price elasticity is exhibited in the range of $1.40 to $1.75 per Mcf (due to additional reservoirs that would be developed in the Bering Sea), but supply is moderately inelastic between $1.75 and $2.25 per Mcf.

With respect to onshore Alaska, the results shown for higher cost OCS regions will probably bracket the actual situation. Geological Survey estimates (1975) indicate that the bulk of Alaska's undiscovered crude oil and natural gas deposits occur in the North Slope region, with small amounts of resources in the south adjacent to the Gulf of Alaska and Cook Inlet. Exploration and production costs on the North Slope are roughly equivalent to those in the Bering Sea and Cook Inlet. For example, exploration costs per well are now approaching 10 million dollars in the NPR-4 area, whereas

Table II-2.—Cumulative Production by OCS Province Based on Monte Carlo Simulation

Province	Oil (million barrels)				Natural Gas (billion cubic feet)		
	$1 1.64/ bbl.	$1 3.75/ bbl.	$1 7.00/ bbl.	$22.00/ bbl.	$1 .40/ Mcf	$1 .75/ Mcf	$2.25/ Mcf
1. Artic Ocean . , ...	2167.33	2391.90	3643.27	4018.64	—	4973.57	5293.26
2. Central Chukchi.	—	2018.94	3174.43	3349.21	—	3905.40	4185.24
3. Bering Sea.	1685.56	3298.11	3589.41	3749.66	3457.22	6278.61	6856.00
4. Gulf of Alaska ... , ...	1612.46	1623.45	1634.53	1702.92	3415.61	3478.30	3496.61
s. Cook Inlet.	327.24	542.01	594.97	622.58	643.62	675.63	1312.70
6. North Pacific.	586.43	587.46	614.73	621.26	3124.67	3127.19	3129.24
7. Santa Cruz	273.07	281.47	286.79	288,06	463.12	467.92	474.53
8. S. California	2081.77	2142.32	2161.32	2176.35	1580.30	1607.09	1619,03
9. Central and Western Gulf...	2275.37	2391.74	2409.55	2418.00	35494.89	35494.89	35494.89
10. MAFLA	1014.49	1045.46	1061.09	1069.65	1734.94	1746.15	1761.87
11. North Atlantic . . .	916.46	927.13	932.69	1034.80	4430.18	4430.18	4430.18
12. Central Atlantic.	1552.15	1560.97	1752.31	1806.55	3773.77	3802.27	3837.34
13. South Atlantic . . .	792.99	815.43	828.14	835.68	1242.84	1243.65	1434.15
overall.	15285.32	19626.39	22683.23	23693.36	59361.16	71230.85	73325.04

those in the Bering Sea are estimated at 8.5 million dollars (Kalter et al., 1975). Thus, by analogy, price impacts on supply for similar sized reservoirs in the North Slope can be compared with those of the Bering Sea or Cook Inlet. Similarly, conditions in southern Alaska may be comparable, with regard to costs, to those in the Gulf of Alaska or the North Atlantic.

The results discussed above are basically confirmed by actual experience. Current oil prices are apparently adequate to foster competitive bidding for OCS areas like Cook Inlet, the Gulf of Alaska, and the Atlantic. This is apparent from the results of recent lease sales in those areas. Prudhoe Bay development is occurring on Alaska's North Slope and plans are contemplated to extend this activity offshore. The only issue appears to be what reservoir sizes will be developed once discovery occurs. This analysis suggests that prices between $17.00 and $22.00 per barrel (in real terms) will have little impact on this question.

However, the analysis also suggests (see table II-2) that hydrocarbon resources may be in short supply relative to demands Therefore, if continued price regulation is contemplated as one means of reducing the economic rent (excess profits) resulting from hydrocarbon development, taxes should be substituted to make up the difference between the controlled price and the market clearing level. Only in this manner can a situation of excess demand, like that which has plagued the natural gas market since the 1960's, be avoided.

It must be recognized, however, that unless price elasticity is actually zero, any form of price regulation will lead to some degree of inefficiency. This will occur even with the imposition of an adequate tax to bring consumer prices up to the world price level. Without a tax, inefficiencies will result under all conditions of price elasticity. The question that must be resolved is whether the equity aspects of the problem outweigh any resulting losses in economic efficiency and whether the price regulation-taxation approach is the "best" means of treating the equity problem.

Oil price deregulation impacts

Currently, the wellhead prices for domestic crude oil production are regulated by the Federal Energy Administration. Production is divided into three components—old oil, new oil, and stripper-well production. Old oil is priced at the so-called lower tier ceiling which is the sum of the posted field price on May 15, 1973 and $1.35 per barrel. The national average price for old oil was $5.17 per barrel in December of 1976. New oil was priced at $11.64 per barrel and stripper production (from wells producing less than 10 barrels per day) was priced at $13.30 per barrel (the stripper price has since risen to world oil price levels).

The exact amount of old and new oil being produced is somewhat difficult to determine for a given reservoir or field, In essence, all oil which is not new oil is old oil. New oil, however, has changed definition somewhat over the past several years and its current definition is difficult to apply without historical information on a field's production. Perhaps the best working proxy for purposes of policy analysis is to classify all production which commenced after May 15, 1973 as new oil. Although this definition ignores so-called "released" oil (old oil no longer controlled at the lower tier price due to previous Government action), the bias introduced is in underestimating the amount of oil currently commanding upper tier prices. Overall, approximately 50 percent of domestic crude oil production was sold as old oil in December of 1976, with 36 percent as new and 14 percent as stripper oil.

Aggregate values, such as these, or values applying to one point in time are, however, of little value in ascertaining the impact of a policy which would deregulate domestic crude oil prices. For that purpose, knowledge of future production profiles and the division of those profiles among regulation categories is needed. Only with that level of detail can accurate impacts on industry profits and capital financing requirements be assessed.

'For example, the simulations indicated that a maximum of 15 billion barrels of additional oil could be expected from the OCS at $11.64 pet barrel prices and less than 24 billion barrels at $22.00 per barrel, The value at current world 011 prtces approached 20 billion barrels. This is roughly a 3.2 year's supply for the United States at the consumption rate of 17 million barrels per day (just under the actual rate in 1976).

Similarly, natural gas availability at $1.40 per Mcf just exceeds 59 trillion cubic feet and Increases to 73 trillion cubic feet at $2.25 per Mcf. The President's proposal of $1,75 per Mcf resulted in 71 trillion cubic feet, just about 3.5 year's supply at last year's consumption rate.

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Knowledge of production profiles and their division implies the availability of detailed information on a field by field basis so that proper account can be taken of production decline rates, the timing of production changes between regulatory categories (i.e., old or new oil to stripper), and the exhaustion of primary-secondary production in a reservoir. Apparently, information of this type is not publicly available from Government agencies or the industry.

For this evaluation, then, information had to be independently developed. As a basis, a computerized reservoir data file was used, covering **835** oil reservoirs (385 fields) in 19 States. This data base was originally developed, for the Government, by Lewin and Associates, Inc., as part of a study on enhanced oil recovery technology (1 977). From that data base, the following information can be derived for each reservoir:

1. The volume of in-place oil yet to be produced by primary and secondary techniques (the FEA has proposed that tertiary production receive world prices).
2. The actual production in 1974.
3. The reservoir decline rate.
4. The number of producing wells located in the reservoir.
5. The year in which the reservoir was first produced.

The data cover approximately 52 percent of the known remaining oil in place in the United States and 47 percent of actual 1974 domestic production. By 1976, this figure had dropped to 40 percent if the decline rates given are accurate.

Although caution must be used in interpreting the data (due to the use of numerous sources leading to potential inconsistencies and the need to often estimate certain values like decline rates), this file is probably the best available at the present time. Given that qualification, the following steps were taken with the data to analyze the price deregulation issue.

1. For each reservoir, 1974 actual production, the decline rate and remaining primary-secondary reserves were used to derive a future production profile. It was assumed, as is conventional, that field production would decline exponentially (Roe-at) through time (Newendrop, 1975). Cumulative production was constrained so as not to exceed available reserves.
2. Based upon the year when field production commenced, the resulting production profile was then initially assigned to either a new or old oil category.
3. Annual production was then divided by the number of producing wells to ascertain if and when production from the field should be assigned to the stripper category. If this was called for, the assignment was made at the proper point in the production time horizon.
4. Finally, production profiles in the three price categories (old, new, and stripper) were multiplied by assumed values for regulated and deregulated prices in each category. December 1976 price values ($5.1 7 per barrel for old oil and $11.64 per barrel for new oil) were used for the regulation scenario and $13.75 per barrel was used for stripper production and for the case of deregulation.

The results are summarized in tables II-3, II-4, and II-5 for both onshore and offshore

Table n-3.-Annual Oil Production by Price Category from Selected Known 1974 Onshore and Offshore Reservoirs for the Period 1977-94

(million barrels per year)

Year	Onshore Production				Offshore Production				Total Production			
	Old Oil	New Oil	Stripper Oil	Total*	Old Oil	New Oil	Stripper Oil	Total*	Old Oil	New Oil	Stripper	Total
1977	890.8	3.3	105.1	999.2	67.2	3.5	0.1	70.8	958.0	6.8	105.2	1070.0
1978	764.8	2.9	99,9	867.6	55.9	3.1	0.1	59.0	820.7	6.0	100.0	926.7
1979	623.5	2,6	101.7	727.8	46.7	2.7	0.1	49.6	670.2	5.3	101.8	777.3
1980	533.5	2.3	92,4	628.2	35.4	2.3	0.2	37,9	568.9	4.6	92.6	666.1
1981	439.1	2.1	86.4	527.6	26.2	2.0	0.1	28.3	465.3	4.1	86.5	555.9
1982	356.7	1.8	81.7	440.2	20.7	1.7	0.2	22.5	377.4	3.5	81.9	462.8
1983	282.4	1.6	78.1	362,1	14.6	1.5	0,2	16.3	297.0	3.1	78.3	378.4
1984	239.1	1.4	71.2	311.7	12.4	1.4	0.2	13.9	251.5	2.8	71.3	325.6
1985	196.5	1.3	69.4	267.2	9.4	1.2	0.3	10,8	205.9	2.5	69.7	278.1
1986	165.4	1,1	66.0	232.5	8.1	1.1	0.4	9.6	173.5	2.2	66.4	242.1
1987	138.0	1.0	61.6	200.6	7.1	1.0	0.4	8.5	145.1	2.0	62.0	209.1
1988	111.0	0.9	62.5	174,5	6.2	0.9	0.4	7,5	117.2	1.8	62.9	181.9
1989	99.0	0.8	56.3	156.2	5.5	0.8	0.4	6.7	104.5	1.6	56.7	162.8
1990	87.4	0.7	50.0	138.1	4.3	0.7	0.6	5.8	91.7	1.4	50.6	143.7
1991	75.0	0.6	47.1	122,7	3.8	0.7	0.5	5,0	78.8	1.3	47.6	127.7
1992	63.4	0.6	43.7	107,7	2.4	0.6	0,5	3.5	65.8	1.2	44.2	111.2
1993	56.0	0.5	41.0	97,5	2.0	0,6	0.4	3.0	58.0	1.1	41.4	100.5
1994	50.4	0.4	37.5	88.3	1.8	0.5	0.3	2.7	52.2	0.9	37.8	90.9
Total* . .	**.5171.9**	26.1	1251.5	6449.5	329.7	26.2	5.5	361.3	5501.6	52.3	1257.0	6810.9

"Details may not add to totals due to rounding

fields. Table II-3 displays the resulting production profiles through 1994.[6] Table II-4 shows the gross revenue received by the oil industry under the price regulation assumptions and table II-5 indicates the same information for deregulation.

These values need to be read with several notes of caution, however. First, the production numbers indicate that 90 percent of the reservoir sample output is initially (1 977) classified as old oil, while less than 1 percent is new oil and almost 10 percent is derived from stripper production. Although the sample pertains to less than 40 percent of total 1977 production, this allocation among price categories is substantially different than the December 1976 value for total domestic production of 50 percent old oil, 36 percent new oil, and 14 percent stripper production. Obviously, new oil discoveries since 1974 would account for some of this difference. But major portions may also be due to our inability to distinguish between price categories with complete accuracy given the information in the data base. A portion of the distinction may also

[6] Continued price regulation would actually result in some control well into the next century but the amounts affected would rapidly decline and become inconsequential (relative to the total energy economy).

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Table n-4.-Annual Gross Revenue Under Continued Price Regulation by Price Category from Selected Known 1974 Onshore and Offshore Reservoirs for the Period 1977-94

(million dollars)

Year	Onshore Productlon				Offshore Production				Total Production			
	Old Oil	New Oil	Stripper Oil	Total*	Old Oil	New Oil	Stripper Oil	Total.	Old Oil	New Oil	Stripper Oil	Total
1977	4605.6	38.4	1445.0	6089.1	347.4	40.2	1.8	389.4	4953.0	78.6	1446.8	6478.5
1978	3953.9	34.1	1373.1	5361.1	288.8	35.6	1.6	326.0	4242.7	69.7	1374.7	5687.1
1979	3223.3	30.3	1398.8	4652,4	241.5	31.6	1.8	275.0	3464.8	61.9	1400.6	4927.4
1980	2758.3	26.9	1269.8	4055.1	182.8	27.2	3.2	213.2	2941.1	54.1	1273.0	4268.3
1981. , . .	2270.1	23.9	1188.6	3482.6	135.3	22.8	2.0	160.1	2405.4	46.7	1190.6	3642.7
1982	1844.0	21,3	1123.3	2988.6	106.8	-19.3	2.3	128.4	1950.8	40.6	1125.6	3117.0
1983	1460.2	18.9	1073.4	2552.5	75.2	17.4	3.1	95.7	1535.4	36.3	1076.5	2648.2
1984	1236.0	16.8	978.3	2231.1	63.8	15.6	2.3	81.8	1299.8	32.4	980.6	2312.9
1985	1016.1	15.0	954.1	1985.1	48.4	14.1	3.7	66.2	1064.5	29.1	957,8	2051.3
1986	855.1	13.3	907.3	1775.6	41.9	12.8	5.2	59.9	897.0	26.1	912.5	1835.5
1987	713.3	11.8	847.1	1572.2	36.8	11.5	5.3	53.7	750.1	23.3	852.4	1625.9
1988	574.2	10.5	859.5	1444.2	31.8	10.5	5.6	48.0	606.0	21.0	865.1	1492.2
1989	512.0	9.3	774.5	1295.8	28.4	9.5	5.5	43.4	540.4	18.8	780.0	1339.2
1990	452.0	8.3	687.6	1147.8	23.2	8.6	8.3	40.1	475.2	16.9	695.9	1187.9
1991	387.5	7.3	647.8	1042.7	19.6	7.9	7.2	34.7	407.1	15.2	655.0	1077.4
1992	327.8	6.5	600.8	935.1	12.4	7.2	6.7	26,3	340.2	13.7	607.5	961.4
1993	289.3	5.8	564.0	859.0	10.5	6.6	5.0	22.1	299.8	12.4	569.0	881.1
1994 .., .	260.5	5.2	515.0	780.5	9.5	6.0	4.6	20.1	270.0	11.2	519.6	800.6
Total” . .	.26738.9	303.7	17208 .0	44205.7	1704.5	304.7	75.2	2084.4	28443.4	608.4	17283 .2	46290.1

‘Details may not add to totals due to rounding

be due to the known reservoirs, which are not included in the data file, having a substantially different distribution of production among price categories. For example, the sample includes most major fields and reservoirs. The smaller field not included may therefore contain a greater portion of the stripper production or “released old” oil. In any case, the direction of any analytical bias that results from these data problems appears to be toward overestimating the financial impact of price deregulation for the sample.

On the other hand, the deregulation revenues shown result from the assumption that all oil prices would rise to the current world level (1 3.75) and remain at that *real* value throughout the analytical time period. This is probably a conservative judgment with the probability of higher real prices through time being greater. The result would be an underestimation of deregulation impacts which becomes relatively more severe through the time profile.

With these points in mind, one would like to obtain an aggregate view of the impacts resulting from deregulation. If we restrict our evaluation to known *1974* reservoirs, a range of impacts can be approxi-

Table II-5.—Annua[Gross Revenue Under 'Price Deregulation by Price Category from Selected Known 1974 Onshore and Offshore Reservoirs for the Period 1977-1994

(million dollars)

Year	Onshore Product Ion				Offshore Production				Total Production			
	Old Oil	New Oil	Stripper	Total*	old Oil	New Oil	Stripper Oil	Total*	Old Oil	New Oil	Stripper Oil	Total
1977	12249.0	45.3	1445.0	13739.4	924.0	47,5	1.8	973.3	13173.0	92.8	1446.8	14712.7
1978	10515.6	40.3	1373.1	11929.0	768.1	42.1	1.6	811.8	11283.7	82.4	1374.7	12740.8
1979	8572.6	35.8	1398.8	10007.2	642.5	37.4	1.8	681.7	9215.1	73.2	1400.6	10688.9
1980	7335.9	31.8	1269,8	8637.6	486.3	32.2	3.2	521.6	7822.2	64.0	1273.0	9159.2
1981	6037.4	28,3	1188.6	7254.3	359.8	26.9	2.0	388.7	6397.2	55.2	1190.6	7643.0
1982	4904.2	25.1	1123.3	6052.6	284.0	22.8	2.3	309.2	5188.2	47.9	1125.6	6361.8
1983	3883.4	22.3	1073.4	4979.2	200.0	20.5	3.1	223.7	4083.4	42.8	1076.5	5202.9
1984	3287.1	19.8	978.3	4285.3	169.7	18.5	2.3	190.5	3456.8	38.3	980.6	4475.8
1985	2702.3	17.6	954.1	3674.0	128.7	16.7	3.7	149.1	2831.0	34.3	957.8	3823.1
1986	2274.1	15.7	907.3	3197.1	111.4	15.1	5.2	131.7	2385.5	30.8	912.5	3328.8
1987	1897.1	13.9	847.1	2758.1	98.0	13.6	5.3	116.9	1995.1	27.5	852.4	2875.0
1988	1527.1	12.4	859.5	2399.0	84.7	12.4	5.6	102.7	1611.8	24.8	865.1	2501.7
1989	1361.7	11.0	774.5	2147.1	75.6	11.2	5.5	92.3	1437.3	22.2	780.0	2239.4
1990	1202.0	9.8	687.6	1899.4	61.8	10.2	8.3	80.3	1263.8	20.0	695.9	1979.7
1991, . . .	1030.6	8.7	647.8	1687.1	52.2	9.3	7.2	68.7	1082.8	18.0	655.0	1755.8
1992	871.8	7.7	600.8	1480.3	32.9	8.5	6.7	48.1	904.7	16.2	607.5	1528.4
1993. , . .	769.4	6.9	563.9	1340.2	27.9	7.8	5.0	40.8	797.3	14.7	568.9	1381.0
1994	692.7	6.1	514.9	1213.7	25.3	7.1	4.6	37.0	718.0	13.2	519.5	1250.7
Total" . . .	71114.2	358.8	17208	.088681.04533.2		359.9	75.2	4968.3	75647.4	718.1	17283	.293649.3

"Details may not add to totals due to rounding

mated.[7] Assuming that the reservoir sample will continue to reflect 47 percent of the production from 1974 reservoirs impacted by price regulation and that the decline rate of the remaining 53 percent is similar to that of the sample, the overall impacted production profile can be approximated.

It is unlikely that the distribution of this additional production among price categories would be more heavily weighted toward old oil than that of the sample. Thus, one extreme of the impact range can be that all production not in the sample is classified as stripper oil.

Table II-6 summarizes these results for two price scenarios. The first assumes a constant deregulated price of *$13.75* per barrel, while the second permits price to compound at *5* percent per year. The total impacted production profile as well as the range in net income (after taxes) to producers is shown for each deregulation situation.[8]

"If all discoveries since 1974 were permitted to obtain market price for production, the coverage of the analysis would be complete. To the extent this is not allowed under continued regulation, deregulation impacts would be understated. The extent depends on the price level permitted for this production, the reserves Involved and the associated decline rates.

[8] It was assumed that 48 percent of the gross revenue addition resulting from deregulation would accrue to the Federal Government as taxes, with an additional 4 percent (on average) going to the States. This implies that all producer tax deductions, credits, and exemptions had been used to offset income taxes on the regulated portion of gross revenue,

Table n-6.-Net Revenue Gain to Energy Producers from Oil Price Deregulation of Known 1974 Reservoirs for the Period 1977-94
(million dollars)

Year	Total Production (million barrels)	$13.75 Deregulated Price	Annual 5-Percent Compound Price Growth
1977.	2276.6	$ 3952.3- 8409.2	$ 3952.3- 8409.2
1978	1971.7	3386.4- 7204.4	3656.5- 7784.8
1979	1653.8	2765.0- 5884.1	3216.3- 6856.4
1980.	1417.2	2347.5- 4994.9	2936.1- 6264.4
1981	1182.8	1920.4- 4086.1	2577.8- 5506.6
1982.	984.7	1558.3- 3314.5	2440.4- 4792.3
1983.	805.1	1226.3- 2609.2	1885.3- 4042.4
1984.	692.8	1038.8- 2209.8	1706.1- 3663.6
1985.	591.7	850.8- 1809.6	1489.3- 3206.7
1986.	515.1	716.8- 1525.0	1336.1- 2885.3
1987.	444.9	599.6- 1275.8	1188.7- 2574.8
1988.	387.0	484.3- 1030.9	1017.6- 2217.9
1989.	346.4	431.7- 919.1	964.2- 2104.9
1990. ......,..	305.7	378.2- 806.5	897.8- 1964.4
1991	271.7	325.7- 693.3	818.1- 1795.5
1992.	236.6	272.5- 579.2	723.3- 1594.3
1993.	213.8	240.4- 510.6	674.9- 1492,3
1994. ......,.,	193.4	215,7- 459.3	641.6- 1422.6
Total	14491.3	$22732.7 -48320.8	$32122 .4-68578.4
Present Value Total	—	$15186.3 -32311.4	$19317 .4-41083.2

The annual impacts range as high as $8.4 billion per year in 1977 to a low of $216 million in 1994 for the $13.75 price scenario with all reservoirs not in the sample assumed to be under stripper production. The absolute impact over the 18 year period could range from a low of *$22.7* billion to a high of $68.6 billion, with a present value impact (at a 10 percent discount rate) which ranges from $15.1 billion to $41.1 billion.

These values can be compared to capital requirements of the industry which have been forecast over similar periods of time. The impact of a "plowback" provision as part of any deregulation policy can then be evaluated. For example, the 1976 National Energy outlook (FEA) forecasts the most likely capital requirements of the petroleum industry between 1975 and 1984 as $147.6 billion.[9] This is an average of $15 billion per year. FEA estimated that this could range be-

[9] This forecast is in 1975 dollars, pertains only to the exploration, development and production phases of the industry and exludes lease acqulstion costs. Note that It does not extend to the last 11 years of our analysis.

tween **$9** billion and $19 billion per year. The forecast of *maximum* net revenue gain from deregulation is, therefore, just over 56 percent of the average capital requirement in the best year (1 977). However, for the reference case, deregulation could result in as little as 26* percent of capital requirements in the best year. These values decline to between 7 percent and 24 percent by 1984, Using the $9 billion and $19 billion range for capital requirements, rather than the reference case, results in a 21- to 93-percent value for 1977 and a 5- to 41 -percent value for 1984.

Coal mine developments

A substantial increase in the use of coal by 1985, as called for by the President's plan, will necessitate the establishment of new mining facilities. Moreover, if air quality standards are to be met, low sulfur coal deposits will need to be the object of these new facilities. Such deposits are often located in areas which are not traditionally producers of large quantities of coal. Thus, for both national and regional planning purposes, information on the number, size, and general location of these new facilities would be useful. This type of information is necessary if evaluations of labor force issues, reclamation problems, transportation system adequacy, and the ability to meet air quality standards are to be made.

For this evaluation, a multiperiod spatial allocation model of the United States coal industry (LeBlanc, 1976) was used as the basis for determining future mine developments through 1985, The model uses exogenous forecasts of consumption in 49 regions and determines the least-cost set of coal shipments from 33 supply regions which will satisfy those forecasts given sulfur, resource, transportation, and market constraints, as well as production and transportation economics. More specifically, the effect of the contract-spot market aspects of coal sales on delivery and development patterns over time is considered, along with quality differences among supply regions in coal sulfur and Btu content. Model runs take place in a recursive fashion to permit solutions through time which take account of past contracts and reserve depletion. Both underground and surface mining possibilities (with different resource bases and production costs) are incorporated. Alternative levels of sulfur emission and coal consumption can be investigated. Rail, barge, and mine-mouth electricity generation (and subsequent transportation of electrical energy rather than fossil fuel) are evaluated as possible transportation modes, although coal transshipment and modal capacity limitations resulting in possible transportation bottlenecks are incorporated. Additional detail on the model, the data sources used, and the assumptions specified can be found in LeBlanc (1 976).

Figures II-3 and II-4 display the demand and supply regions, along with their central nodes, used for this analysis. Tables II-7 and II-8 list these regions. For this evaluation, it was assumed that 1.164 billion normal tons.[10] (24 million Btus per ton) of coal would be consumed by 1985. This is slightly less than the President's new goal of 1.279 billion normal tons.[11] We assumed an exponential increase in demand from current

[10] Because a ton of coal trom differlng supply nodes may vary in heat content (ie., Btus per ton), a normaltzatlon of values must occur which places all tons In equivalent units.

[11] Note that the White House recently increased the actual tonnage requirements under the energy plan to 1.235 billion tons per day from the previously announced 1,070 billion tons (Wall Street Journal, June 2, 1977),

Figure II-3. Model Demand Regions and Central Nodes

Figure II-4. Model Supply Regions and Central Nodes

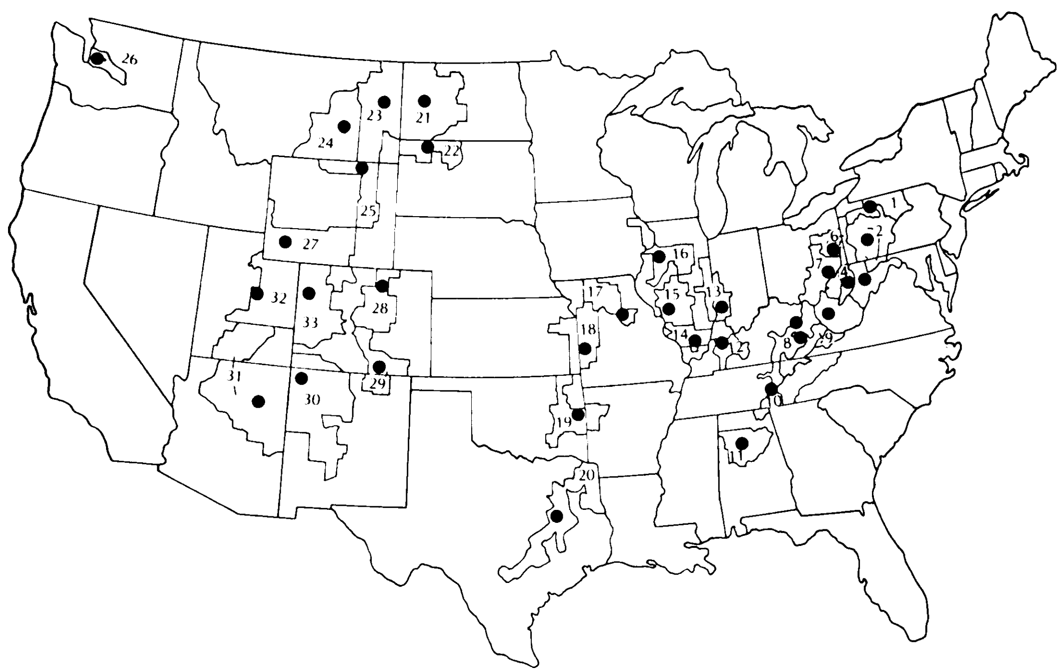

Table II-7.—Demand Regions

State	Region	Centroid Location Latitude (Degrees)	Centroid Location Longitude (Degrees)
Alabama	01	33.23	87.05
Arizona	02	36.05	110.59
Arkansas	03	34.92	92.76
Colorado	05	39.27	105.20
Connecticut	06	41.28	72.44
Delaware	07	38.37	75.19
District of Columbia	08	38.53	77.07
Florida	09	28.50	83.50
Georgia	10	33.30	84.10
Illinois	12	40.07	89.00
Indiana	13	39.38	86.32
Iowa	14	41.52	92.56
Kansas	15	38.46	95.11
Kentucky	16	37.41	86.08
Louisiana	17	30.36	93.06
Maryland	19	38.55	76.42
Massachusetts	20	42.05	71.22
Michigan	21	42.39	83.46
Minnesota	22	45.45	93.35
Mississippi	23	30.28	89.02
Missouri	24	38.33	91.39
Montana	25	46.10	107.22
Nebraska	26	41.17	96.28
Nevada	27	36.13	115,02
New Hampshire	28	43.09	71.28
New Jersey	29	40.23	74.29
New Mexico	30	36.41	108.28
New York	31	42.35	77.08
North Carolina	32	35.41	80.12
North Dakota	33	47.15	100.57
Ohio	34	40.00	81.59
Oklahoma	35	34.40	98.22
Pennsylvania	37	40.30	78.25
South Carolina	39	33.28	80.37
South Dakota	40	44.36	99.46
Tennessee	41	36.04	86.10
Texas	42	31.53	96.14
Utah	43	40.04	111.22
Vermont	44	44.29	73.13
Virginia	45	37.23	78.12
Washington	46	46.42	122.58
West Virginia	47	39.10	80.51
Wisconsin	48	43.22	88.38
Wyoming	49	42.23	108.02

levels (using information on likely additions to electrical generating capacity for *1980)* allocated among demand regions in the same ratio as recent forecasts by Johnson (Gordon, 1975). Table II-9 displays these allocations (in normal tons) by demand region for 1980 and 1985. Johnson used commitments of planned electrical utilities as his basis and estimated coal's share of new capacity as a function of price.

The model was then run for *1980* and 1985 under two different sets of supply constraints. First, for States east of the Mississippi (regions 1 through 20), logistical constraints were imposed in each region which limited surface and underground development, separately, to 5 million tons per year or 10 percent of 1973 production, whichever is greater. Only the existing reserve base constrained other regions. The rationale for this scenario is to restrict new mine openings in the smaller Eastern supply regions to practical limits of manpower and land availability. Normally, the 5-million ton

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Appendix II

constraint was the operational restriction. Second, it was assumed that the only constraint on new mine development in a given supply region was the adequacy of reserves to meet long-term (20-year) contracts. Both scenarios considered the entire reserve base, including coking coal, for the analysis. Coking coal is low in ash and sulfur and high in Btu content and usually commands a premium price because of these characteristics. Also, both cases assumed that national standards on the amount of sulfur oxide emissions from the consumption of coal would apply. This standard is now set at 1.2 pounds of SO_2 per million Btus of energy derived and was used for the time period analyzed. [12]

[12] Stack- scrubber technology to remove sulfur after burning was not assumed for this analysis since great technological and logistical uncertainty surround its Introduction.

Table n-8.-Supply Regions

State[a]	Region	Centroid Latitude (Degrees)	Location Longitude (Degrees)
NW Pennsylvania.	01	41.30	78.14
SW Pennsylvania .	02	40.47	79.10
NE West Virginia .	03	39.10	80.03
N West Virginia . .	04	39.02	80.28
S West Virginia. . .	05	38.00	81.30
Ohio-Pennsylvania	06	40.28	80.55
SE Ohio	07	39.45	81.32
E Kentucky.	08	37.28	83.31
Kentucky-Tennessee-Virginia	09	37.06	82.48
Central Tennessee	10	35.45	85.28
Alabama	11	33.30	86.40
W Kentucky-Indiana.	12	37.46	87.07
Central Indiana-Illinois	13	40.00	87.30
S Illinois.	14	37.54	88.55
Central Illinois. . . .	15	39.33	89.18
N Illinois-Indiana. .	16	41.07	90.10
N Missouri.	17	39.25	92.27
Missouri-Kansas. . .	18	37.50	94.22
Oklahoma-Arkansas	19	35.28	94.48
Texas	20	31.45	96.10
W North Dakota. .	21	47.21	102.28
NW South Dakota	22	45,30	102.00
E Montana.	23	46.48	105.20
SE Montana.	24	45.54	106.37
NE Wyoming.	25	44.27	105.22
Washington.	26	47.54	121.32
SW Wyoming-Colorado	27	41.36	109.13
NE Colorado	28	40.25	104.42
SE Colorado-New Mexico	29	37.10	104.30
NW New Mexico-Colorado	30	36.34	108.12
Arizona-Utah.	31	34.54	110.09
NW Utah.	32	39.35	110.48
W Colorado	33	39.32	107.48

‘N W= Northwest, SW= Southwest, NE= Northeast, N= North, S= South, SE= Southeast, E= East, W= West.

Table II-9.—Exogenous Consumption Allocation Among Demanding Regions for 1980 and 1985

Region	1980 Allocation (thousand normal tons)	1985 Allocation (thousand normal tons)
Alabama	23037	33743
Arizona	5856	8577
Arkansas	4200	6285
Colorado	4572	6425
Connecticut	179	269
Delaware	1557	2288
District of Columbia	638	942
Florida	14758	21617
Georgia	39954	58523
Illinois	44000	50000
Indiana	44895	65760
Iowa	6668	15576
Kansas	48722	71512
Kentucky	39787	58278
Louisiana	13568	19874
Maryland	19931	29201
Massachusetts	4129	6056
Michigan	44895	65760
Minnesota	3939	3939
Mississippi	5219	7645
Missouri	23717	17114
Montana	5964	8736
Nebraska	2996	8614
Nevada	7916	11595
New Hampshire	1281	1884
New Jersey	3486	5114
New Mexico	13338	19536
New York	11019	16148
North Carolina	40854	59841
North Dakota	4255	6232
Ohio	92746	135851
Oklahoma	5466	8153
Pennsylvania	49604	72666
South Carolina	10079	15936
South Dakota	1186	1737
Tennessee	29696	43497
Texas	44000	64548
Utah	8598	12594
Vermont	50	73
Virginia	16378	23989
Washington	10288	15069
West Virginia	46507	68122
Wisconsin	8079	5754
Wyoming	6288	9210
Total	814295	1164283

As a result of these two scenarios, model runs produced a range of results for the 1980 and 1985 time periods. Table II-10 presents these production values for the various constraints, supply regions, mining conditions (surface and underground), and years. The tonnages shown are in physical rather than normal, tons. The results indicate marked shifts in the location of new production facilities are likely under various constraint levels. This confirms the results of previous analyses (LeBlanc, 1976). For exampie, in LeBianc's study, imposition of national sulfur standards resulted in major production shifts toward the Western States (given the eastern logistical constraint). Here the situation is similar until the logistical constraint is removed. The total cumulative new eastern development (in tons per year) for the case with logistical constraints was only 29 percent of the total, whereas it rose to 76 percent when these constraints

Table 11-10.—Incremental Production Capacity Required by Region, Mine Type, and Year (thousand physical tons)

Region	Eastern Logistical Constraints				Reserve Constraints			
	1980		1985		1980		1985	
	Surface	Underground	Surface	Underground	Surface	Underground	Surface	Underground
NW Pennsylvania	5000	88	3821		—	50	—	—
SW Pennsylvania	7000	—	5000	—	28514	—	1	—
NE West Virginia,	5000	4985	5000	5015	39965	—	1	—
N West Virginia. .,	5000	5000	5000	—	20269	—	1	—
S West Virginia	7000	7000	5000	5000	20279	—	147774	—
Ohio-Pennsylvania	5000	—	5000		2000	—	6908	—
SE Ohio	5000	—	—	—	2000	—	—	—
E Kentucky	7000	7000	5000	5000	81918	43897	1	—
Kentucky -Tennessee-Virginia	9000	11000	5000	5000	4000	—	104976	—
Central Tennessee.	4237	—	—	—	2000	—	2338	—
Alabama.	305	7000		5000	729	—	1	—
W Kentucky-Indiana	9600	—		—	4600	—	—	—
Central Indiana-Illmols	5000	—	5000	—	9525	—	22398	—
S Illinois	5000	—	5000	—	2200	—	—	—
Central Illinois	2123	—	1	—	2123	—	—	—
N Illinols-Indiana	5000	—		—	2000	—	—	—
N Missouri	3586	—		—	6783	—	—	—
Missouri-Kansas	2145	—	—	—	2000	—	—	—
Oklahoma-Arkansas	7000	—	5000	—	30289	—	1	—
Texas	22770	—	7011	—	14182	—	3780	—
W North Dakota'	—	—		—	—	—	—	—
NW South Dakota	2091	—	2991	—	2091	—	—	—
E Montana	—	—	14259	—	27	—	3541	—
SE Montana-NE Wyoming	47819	—	244921	—	5140	—	42393	—
Washington	—	—		—	—	—	—	—
SW Wyoming-Colorado	8236	—	1284?	—	8669	—	11159	—
NE Colorado	—	—	—	—	—	—	—	—
SE Colorado-New Mexico	—	—		—	—	—	—	—
NW New Mexico-Colorado	60213	—	47492	—	7014	—	32593	—
Arizona-Utah	—	—		—	—	—	—	—
NW Utah	1000	—	1	—	1000	—	1	—
W Colorado	1787	—	—	—	1787	—	—	—

● These two supply regions have been combined because of their similar geologic and coal characteristics, as well as the nearly identical production and transportation costs involved.

were removed. In the West, new development is concentrated in Montana, Wyoming, and the Northwest New Mexico-Colorado regions. In the East, however, low-sulfur, high-Btu coal in Eastern Kentucky, Tennessee, Virginia and Southern West Virginia receive the greatest call for new development. It should be noted that these are precisely the deposits whose characteristics make them valuable for coking coal. If these deposits are difficult to burn in utility boilers, expensive to mine, and command a premium price for steel making, as is often argued (Gordon, 1976), the likelihood of achieving the result shown will be remote. However, as indicated above, the two cases should bracket the range of actual results.

With that in mind, we can convert the requirements for new additions in productive capacity for 1980 and 1985 to an estimate of new mining facilities. The model assumed (for production cost purposes) that surface mines would be either 1 million or 5 million ton per year facilities and that underground mines would be 1 million or 3 million ton per year operations. For purposes of analysis, we have assumed that new western surface mines will average 5 million tons per year capacity, while eastern surface mines will average only 1 million tons per year. All underground facilities were sized at 1 million tons per year. Table II-11 displays the cumulative new mine developments, by region, which would be required by 1985 to approximate the President's production goal.

The number of new mine developments required range from 300, in the situation where logistics restrict access to eastern deposits, to 585, when only the availability of reserves restricts new development. In either case, new development is concentrated in surface mining operations (78 to 92 percent of the new facilities). Thus, any increase in the average eastern surface mine size could substantially impact the number of new mines required (but not the total production involved). For example, if all new surface mines average 5 million tons per year capacity, the number of new developments would be reduced to between 180 and 192 (the higher number in the case of the eastern logistical constraint where somewhat more underground production occurs).

Cumulative new development by 1985 must reach approximately 700 million tons (a capacity greater than total 1976 production). Since the bulk of this amount is surface mine development (due to lower production costs), the degree of land disruption involved will heavily depend on the new mine locations. Western areas, with thicker and more contiguous coal seams, could be developed with substantially less disruption and, perhaps, with more easily accomplished reclamation practices. On the other hand, development of hundreds of new strip mines by 1985 may constrain equipment suppliers and prohibit achievement of the Presidential goal. In any case, the number of new developments that would be required in such a short time period has no antecedent in our history.

Table 11-11 .—Number of New Mine Developments Required by Region and Mine Type*

Region	Eastern Logistical Constraints			Reserve Constraints		
	Surtace	Underground	Total	Surface	Underground	Total
NW Pennsylvania	8 8	01	8.9	—	0.1	0.1
SW Pennsylvania	120	—	12.0	28,5	—	28.5
NE West Virginia	100	100	200	40,0	—	40.0
N West Virginia	10.0	5,0	150	20.3	—	20.3
S West Virginia	120	120	24.0	1681	—	168 1
Ohio-Pennsylvania	10.0	—	10.0	8.9	—	8.9
SE Ohio	5 0	—	50	2.0	—	2.0
E Kentucky	120	120	24.0	81.9	43.9	125.8
Ken.-Tenn.-Vlr..	14.0	160	300	1090	—	109.0
Central Tennessee	4.2	—	4.2	4.3	—	4.3
Alabama	0.3	12.0	12.3	0 7	—	0.7
W Kentucky-Indiana	9 6	—	9.6	4.6	—	4.6
Central Indiana-IllInols	100	—	100	31.9	—	31.9
S Illinois	100	—	10.0	2.2	—	2.2
Central Illinois	2 1	—	21	2 1	—	2.1
N Illinois-tndiana	5 0	—	5.0	2,0	—	2.0
N MIssouri	0,7	—	07	1 4	—	1.4
Missouri-Kansas	0.4	—	04	0.4	—	0.4
Oklahoma-Arkansas	2.4	—	2.4	6 1	—	6 1
Texas	6 0	—	60	3.6	—	3.6
W North Dakota	—	—	—	—	—	—
NW South Dakota	1.0	—	10	0.4	—	0.4
E Montana	2 9	—	2.9	0 7	—	0 7
SE Montana-NE Wyoming	58.6	—	58.6	9.5	—	9.5
Washington	—	—	—	—	—	—
SW Wyoming-Colorado	4.2	—	4.2	4.0	—	4.0
NE Colorado	—	—	—	—	—	—
SE Colorado-New Mexico	—	—	—	—	—	—
NW New Mexico-Colorado	21.5	—	21.5	7.9	—	7.9
Arizona-Utah	—	—	—	—	—	—
NW Utah	0 2	—	0.2	0.2	—	0 2
W Colorado	0.4	—	0.4	0,4	—	0.4
Total	233.3	67.1	300,4	541.1	44.0	585,1

“Assumes 1 million ton per year underground facilities and surface facilities of 5 million tons per year west of the Mississippi and 1 million tons per year east of the Mississippi.

Appendix A
Supply Price Elasticity Analysis: Data Sources and Assumptions

The analytical model used for the Monte Carlo simulation which served as the basis for this evaluation was developed under National Science Foundation funding and is fully detailed in other publications (Tyner and Kalter, 1976). The interested reader should refer to them for further details.

The model, however, requires input data on geologic, cost, and other economic variables. Many of these values must be in the form of probability distributions if the model's full capabilities to consider uncertainty are to be utilized. The basic information on the values used for this analysis were developed by the author in other research (Kalter et al., 1975), A full explanation can be obtained by referring to that publication. What follows will be a summary of the data used.

Input data on assumed field size distributions and the expected number of fields for each OCS subregion are shown in table 11-A-1 for oil and table II-A-2 for natural gas. The information used pertains to water depths out to 200 meters. Exploration, investment and operating cost data were derived from National Petroleum Council (1973) research and modified to reflect 1975 values and our regional format, Cost relationships were then derived which permitted investment costs to be estimated for any size of reserve sample picked by a Monte Carlo iteration. Table II-A-3 displays the five cost regions specified for the analysis and the factors used to determine actual costs in a given region. Table II-A-4 summarizes the oil and natural gas cost values used for selected reservoir sizes. Finally, table II-A-5 displays the values for other geologic, engineering, time, and economic variables assumed for the analysis.

Table 11-A-l .—Oil Field Sizes, Standard Deviations, and Estimated Field Numbers by Field Category and Subregion

Subregion	Category 1 Fields (less than 50 roll. bbls.)			Category 2 Fields (50-100 roll. bbls.)			Category 3 Fields (greater than 100 mil. bbls.)		
	Mean (mil. bbls.)	Std. Dev. (mil. bbls.)	No. of Fields	Mean (mil bbls.)	Std. Dev. (mil. bbls.)	No. of Fields	Mean (mil. bbls.)	Std. Dev. (roil. bbls.)	No. of Fields
1. Arctic Ocean .,	25.8	12.9	80	70.0	49.0	27	158.7	158.7	18
2 Central Chukchi	25.9	12,9	75	69.6	48.7	21	147.3	147.3	17
3. Bering Sea . . . . .,	23.0	11.5	106	69.8	48.9	30	147,4	147,4	14
4. Gulf of Alaska	23.9	11.9	3	73.1	51,2	1	577,9	577.9	3
5. Cook Inlet	17.4	8.7	27	69.9	48.9	4	145.2	145.2	3
6. North Pacific . .	17.4	8.7	2	73.9	51.7	1	567.9	567.9	1
7. Santa Cruz .,	16.2	8.1	6	70.1	49.1	1	144.9	144.9	1
8. S. Cal. Basins .,	17.2	8.6	20	71.9	50.3	4	256.6	256.6	7
9. C. and W. Gulf .,	11,7	5.8	88	70.0	49.0	10	155.8	155.8	6
10, MAFLA ...	12.8	6.4	13	70.8	49.6	1	311.8	311,8	3
11, North Atlantic .,	185	9,2	7	70.2	49.1	1	321.3	321,3	3
12. Central Atlantic.	150	75	18	71,0	49,7	2	320.6	320.6	5
13 South Atlantlc	12.2	6.1	13	49.6	49.6	1	225.7	225.7	3

Table 11-A-2.—Nonassociated Natural Gas Field Sizes, Standard Deviations, and Estimated Field Numbers by Field Category and Subregion

Subregion	Category 1 Fields (less than 300 mil. Mcf)			Category 2 Fields (300-600 mil. Mcf)			Category 3 Fields (greater than 600 mil. Mcf)		
	Mean (mil. Mcf)	Std. Dev. (mil. Mcf)	No. of Fields	Mean (mil. Mcf)	Std. Dev. (mil. Mcf)	No, of Fields	Mean (mil. Mcf)	Std. Dev. (mil. Mcf)	No, of Fields
1. Arctic Ocean . .	154.8	77,4	31	420.0	294.0	10	952.2	952.2	7
2. Central Chukchi.	155.4	77.7	26	417.6	292.3	7	883.8	883.8	6
3. Bering Sea. . .	138.0	69.0	34	418.8	293.2	9	884.4	884.4	5
4. Gulf of Alaska	143.4	71,7	1	438.6	307.0	1	3,467.4	3,467.4	1
5. Cook Inlet	104.4	52,2	7	419.4	293.6	2	871.2	871.2	1
6. North Pacific	104.4	52.2	0	443.4	310.4	0	3,407.4	3,407.4	1
7. Santa Cruz	97.2	48.6	1	420.6	294,4	1	869.4	869.4	0
8 S. Cal, Basins	03.2	51.6	3	431.4	302.0	0	1,539,6	,539.6	1
9. C. and W. Gulf.	70.2	35.1	225	420.0	294.0	24	934,8	934.8	14
10 MAFLA . . . . .,	76.8	38.4	1	424.8	297.4	0	1,870.8	,870.8	1
11 North Atlantic	11.0	55.5	5	421.2	294.8	1	1,927.8	,927.8	2
12. Central Atlantic	90.0	45.0	8	426,0	298.2	1	1,923.6	,923.6	2
13, South Atlantic .	73.2	36.6	3	425.4	297.8	0	1,354.2	1,345.2	1

Table n-A-3.-Cost Regions Used in the OCS Analysis

Region Number	Region Name	Area Used	Exploration Cost Factor	Development Cost Factor
1	moderate	Gulf of Mexico South Atlantic South Pacific	1.0	1.0
2	moderate-severe	Central Atlantic North Pacific	1.4	1.9
3	severe	North Atlantic Gulf of Alaska	1.8	2.8
4	ice laden	Bering Sea, Alaska	2.3	3.7
5	severely ice laden	Chukchi Sea Arctic Ocean	4.6	4.6

Table n-A-4.-Exploration, Investment, and Operating Costs for Oil and Nonassociated Natural Gas by Reservoir Size and Cost Region

Reservoir Size	Cost Regions 1	2	3	4	5
			oil		
15	$20.96	$38.85	$57.12	$75.41	$94.02
20	15.60	28.91	42.51	56.12	69.97
65	8.98	16.64	24.46	32.29	40.26
175	5.06	9.38	13.79	18.21	22.70
525	2.68	4.97	7.31	9.65	12.03
1050	1.80	3.33	4.89	6.46	8.05
Exp. Costs per well (in millions)	3.121	4.370	5.618	7.179	14.357
Operating costs (initial)	.40	.52	.64	.76	.88
			Nonassociated Natural Gas		
90	$3.28	$6.48	$9.39	$12.31	$15.47
150	2.46	4.86	7.05	9.24	11.62
390	1.44	2.85	4.12	5.40	6.79
1050	.83	1.63	2.36	3.10	3.90
3150	.45	.88	1.28	1.67	2.10
Exp. Costs Per well (in millions)	3.121	4.370	5.618	7.179	14,357
Operating costs (initial)	.04	.0	.06	.08	.09

Appendix H

Table II-A-5.—Common Input Values for Leasing Policy Analysis

Geologic	
Production decline rate, a	.10
Beta (recovery factor), ß	.50
Reserve distributions	lognormal
Price related	
Original oil price, P_o	$11.65, $13.75, $17.00, $22.00
Original gas price, GP_o	$1.40,$1.75,$2.25
Mean of oil price change distribution, RP1 MN	0
Std. dev. of price change distribution, RP1STD	.04
Mean of gas price change distribution, GP1 MN	0
Std. dev. of price change distribution, GP1 STD	.05
Tax related	
Depreciation method, NDEPR	Sum of Years Digits
Depreciaiton lifetime, N	15 years
Percent investment salvageable, a	1 00/0
nvestment tax credit rate, Ω	1 00/0
Federal corporate tax rate, Ø	480/o
Time related	
Minimum production time, TMIN	9 years
Years of flat production plus production build up, FLATP	5 years
Maximum production period, TMAX	40 years
Development and exploration period, LAG	5 years
Exploration period, LAG1	2 years
Production build up period, IBP	2 years
Production build up factors, BPP	
year 1	.5
year 2	.8
Cost *related*	
Working capital factor, WCF	.1
Triangular investment and operating cost contingency distributions	
BMIN, KMIN	– .05
BMODE, KMODE	0
BMAX, KMAX	.1
Rent per acre, RENT	$3.00
Investment cost allocation during development, F	
year 1	0
year 2	.1
year 3	.3
year 4	.4
year 5	.2

Table II-A-5.—Continued

Percent investment each year that is tangible, YZ	
year 1	0
year 2	.7
year 3	.7
year 4	.8
year 5	.8
Exploration cost allocation during exploration, F1	
year 1	.4
year 2	.6
Percent exploration cost tangible each year, YZ1	
year 1	0
year 2	.3
Other *Factors*	
Discount rate	.10
No. of exploratory wells per 1000 acres	.5
No. of acres per tract, ACRES	5760
Bonus factor, BFAC	.75
No. of M. C. iterations, NLOOP	200

Appendix II

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