FEDERAL ENERGY ADMINISTRATION
WASHINGTON, D.C. 20461

OFFICE OF THE ADMINISTRATOR

File

October 31, 1975

The President
The White House
Washington, D. C. 20500

Dear Mr. President:

Enclosed is the final report of the Federal Energy Administration's (FEA) efforts to provide a complete and independent analysis of the Nation's oil and gas resources, reserves, and its capacity to produce oil, gas and major petroleum products as required by Section 15(b) of the Federal Energy Administration Act of 1974 (PL 93-275).

This final report updates and augments the preliminary results submitted in FEA's Initial Report of June 1975. It also includes evaluations of procedures FEA used in this effort as well as recommendations for future efforts.

The Federal Trade Commission was precluded by budgetary constraints from full participation in preparation of this report but was consulted from time to time by the FEA. Liaison has been established between the two Agencies, and both look forward to a continuing relationship in the future in developing information on petroleum reserves and resources.

Respectfully,

Frank G. Zarb
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Administrator

Enclosure

Final Report on Oil and Gas Resources, Reserves, and Productive Capacities

Volume I

Submitted in
Compliance with Public Law
93-275, Section 15(b)

October 1975

Federal Energy Administration
Washington D.C. 20461

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Office of Policy and Analysis
and
Office of Energy
Resource Development

Federal Energy Administration Washington D.C. 20461

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Chapter 1

SUMMARY

An essential element in formulating a National energy policy is the development of a reliable estimate of domestic crude oil and natural gas resources, reserves, and productive capacities. The Federal Energy Administration (FEA) Act directs the FEA to prepare a "complete and independent analysis of actual oil and gas reserves and resources in the United States and its Outer Continental Shelf, as well as of the existing productive capacity and the extent to which such capacity could be increased for crude oil and each major petroleum product each year for the next ten years through full utilization of available technology and capacity. The report shall also contain the Administration's recommendations for improving the utilization and effectiveness of Federal energy data and its manner of collection." The FEA submitted to the President and the Congress in June 1975, an Initial Report on Oil and Gas Resources, Reserves, and Productive Capacities. The initial report provides background information about the methodologies used to accomplish FEA's task as well as resource and preliminary reserve estimates for the United States. Volume I of the final report provides final reserve and productive capacity estimates, compares these estimates with estimates from other sources, projects a U.S. crude oil productive capacity estimate, evaluates the procedures used to develop these estimates, and recommends procedures to be used for future estimates. Volume II of the final report provides summaries of engineering analyses of major domestic oil and gas fields.

Reserve and Productive Capacity Estimates

Based on a survey of all oil and gas field operators in the United States, estimated domestic proved reserves as of December 31, 1974, were 38.0 billion barrels of crude oil and 240.2 trillion cubic feet of natural gas. The American Petroleum Institute (API) report showed comparable crude oil reserves of 34.2 billion barrels, 10 percent less than the FEA survey. The American Gas Association (AGA) estimated comparable natural gas reserves of 233.2 trillion cubic feet (after deducting 3.9 trillion cubic feet which was in underground storage), 2.9 percent less than the FEA survey. These estimates vary no more than might be expected when comparing estimates from different sources.

Both the FEA reserve estimates and the estimates published by industry trade groups define proved reserves as those oil and natural gas resources that have actually been discovered and can be produced under current economic and technological conditions.

The FEA estimate of indicated crude oil reserves--quantities of oil believed to be economically producible from known reservoirs using proven but as yet not installed recovery technology--as of December 31, 1974, was 4.1 billion barrels of crude oil. The API estimated comparable indicated reserves of 4.6 billion barrels, 12 percent higher than the FEA survey.

The survey also indicated that estimated U.S. productive capacity for the 60-day period following December 31, 1974, was 8.7 million barrels per day for crude oil and 63.4 billion cubic feet per day for natural gas.

An explanation of the procedures used in developing the FEA reserve and productive capacity estimates and a listing of these estimates by States are detailed in Chapter 2 of this report.

Recommendations

Drawing upon the experience gained in the development of this study as well as experience as a user of oil and gas resource, reserve, and productive capacity estimates, the FEA has developed recommendations concerning future compilations of such information for each of four subject matter areas:

1. Resources
2. Reserves
3. Current producing capacity
4. Projected producing capacity

Resources

FEA recommends efforts be continued along the course defined in U.S. Geological Survey (USGS) Circular 725. This effort should be augmented by the adoption of a standard set of resource classification and nomenclature, developed by a representative Government-industry task force. A carefully planned exploration of untested geological provinces making optimum use of both Government and private capabilities as well as scientific contributions to improve resource estimates should be encouraged.

Reserves

Accurate and independent evaluations of oil and gas reserves will continue to be an important function of the Federal Government. Periodic Government estimates of oil and gas reserves at the National and State levels of aggregation can be most efficiently generated through direct surveys of field operators. However, these periodic estimates are not required on a three month basis as now mandated, but would be most useful on a biennial basis.

FEA continues to encourage the trade associations to continue their present systems of oil and gas reserves reporting. These efforts provide additional useful information and a valuable cross-check with the independent Federal estimates. The Federal Government should continue to consult with the associations to assure that their information is consistent with Federal efforts and hence of the greatest possible value.

Current Producing Capacity

The definitions of capacity, especially the capacity to produce natural gas, should be reviewed to assure that they meet the data needs of policy makers.

Projected Producing Capacity

FEA recommends continued efforts to improve relevant information, develop reasonable analytical models, and adjust projections based on sound judgment and experience.

Other Information

In addition to reserve and productive capacity estimates and recommendations, this report compares reserve estimates from various sources (Chapter 3), projects a National productive capacity for crude oil during the next ten years (Chapter 4), and evaluates the methodologies investigated during the development of this report (Chapter 5). The report also provides summaries of engineering analyses of major oil and gas fields (Volume II).

Chapter 2

OPERATOR SURVEY

As indicated in the Initial Report on Oil and Gas Resources, Reserves, and Productive Capacities, a survey of oil and gas field operators was selected as the most efficient way to obtain, within the allowed time, a "complete and independent" analysis of oil and gas reserves and capacity as mandated by Section 15(b) of Public Law 93-275.

The initial report described in some detail the procedures used in developing the Operators Survey as well as a summary of how the survey functioned and a sample of the questionnaire.

Data Collection and Editing

Questionnaires were mailed during the third week of December 1974. In February 1975, a reminder letter was sent to nonrespondents. After follow-up letters and telephone calls, survey coverage judged by comparing reported production with benchmark data was good: 97 percent for oil and 95 percent for gas.

To achieve the highest quality of information from this survey, all operator responses were checked for completeness and reasonableness, and a series of mathematical calculations were made regarding the interrelation of reported data. Range limits were prescribed for each relationship, and all relationships found to be out-of-range were reviewed by qualified personnel. These professionals made about 14,000 telephone calls to operators to resolve some 30,000 data omissions and out-of-range situations. Many out-of-range situations were found to be departures from normally expected values, but in most cases data corrections were needed.

Mathematical checks for out-of-range data included checks of:

1. The gas-oil ratio (GOR) of associated natural gas and crude oil.

2. Production decline for crude oil, associated natural gas and nonassociated natural gas.

3. The relationship of average daily productive capacity following December 31, 1974, with the daily average producing rate in 1974.

4. The relationship between proved reserves of crude oil, associated natural gas, and nonassociated natural gas to production in 1974.

5. The relationship between estimated proved reserves to original hydrocarbons in place.

6. The relationship between indicated and secondary recovery reserves to original hydrocarbons in place.

7. The relationship between gross additions to estimated proved reserves in 1974 to estimated proved reserves at year end 1974.

Expansion of Survey Responses to the Universe

Estimated Proved Reserves

Because operators were not required to report reserves for those fields in which an operator produced less than 20,000 barrels of oil or 100 million cubic feet of gas in 1974 and because response was not quite complete, reported information needed to be expanded into U.S. totals. The basis for expanding to the universe was 1973 oil and gas production. Benchmark volumes were based on State data augmented by information provided to the U.S. Bureau of Mines (USBM). Estimates were made for associated gas production for States that did not furnish this information (Illinois, Indiana, Kentucky, Missouri, Nevada, and New York).

The procedure for estimating total reserves for each State was as follows:

1. Production for year 1973 and estimated proved reserves for producing reservoirs were summed for all reports which included both items.

2. For reports which showed production but no estimated proved reserves for producing reservoirs, production was summed on the basis of years of reported production; i.e., 1970-1974, 1971-1974, 1972-1974, 1973-1974, and 1974 only.

3. Reserve calculations for group totals in step 2 were determined as follows. For reports showing 1974 production only, the estimate was based upon 1975 production being equal to that of 1974 and projecting future rates by a hyperbolic curve declining at 10 percent per year for 14 additional years; for the other groups a curve fit was made. Declines greater than 10 percent per year were projected at the calculated rate for 15 years; for lesser declines, a rate of 10 percent was projected for 15 years.

4. The sums of reserves determined in step 1 and those in step 3, excepting the 1974 production-only group, were multiplied by the ratio of State-wide benchmark production in 1973 to correlative sums of production.

5. Reported proved reserves were summed for non-producing reservoirs.

6. Proved reserves were summed from reports which had production in 1974 only and proved reserve estimates.

7. Total state proved reserves were obtained by summing the results of steps 4, 5, and 6 and the reserves determined for the 1974 only group as set forth in step 3.

Productive Capacity

Productive capacity estimates for each State were expanded as follows:

1. Productive capacity data reported by operators were summed.

2. For reports where operators did not provide productive capacity data, 1974 reported production volumes were summed.

3. The total volume in step 2 was divided by 365 and added to the sum found in step 1.

4. Results found in step 3 were multiplied by the ratio of Statewide benchmark production in 1973 to correlative sums of production reported by operators.

Other Data Elements

Indicated secondary and tertiary reserves and 1974 gross additions to estimated proved reserves were not expanded. Original hydrocarbons in place information supplied by operators was incomplete, and there is no known satisfactory means to expand this data element to represent the universe.

Statistical Results

Proved Reserves

Table 1 presents the State-by-State estimates of crude oil reserves as well as National totals. Although relatively small volumes of crude oil and natural gas were produced in the North Slope of Alaska, for statistical purposes these were classed as nonproducing. The volume of crude oil reserves in reservoirs not being produced in 1974 was 10.17 billion barrels, 26.7 percent of U.S. total reserves (Table 1). Alaska accounted for 93 percent of the total. Start up of the Trans-Alaska Pipeline System, scheduled for mid-1977, will permit marketing of North Slope crude oil production. Ranked below Alaska, Louisiana with 3.8 percent and California with 1.5 percent of the National total had the largest volumes of crude oil reserves not being produced. In addition to legal constraint, the lack of transportation and installed equipment facilities, especially in the offshore areas, were the principal factors for non-production.

Table 1--ESTIMATE OF PROVED CRUDE OIL RESERVES*
AS OF DECEMBER 31, 1974

State	Total Reserves (MBbls)	Producing Reservoirs Reserves (MBbls)	Producing Reservoirs Percent of Universe**	Nonproducing Reservoir Reserves (MBbls)
Alabama	102,492	101,106	90	1,386
Alaska	10,047,729	***	100	***
Arkansas	121,104	119,116	89	1,988
California	5,295,792	5,142,708	99	153,084
Colorado	290,490	289,368	97	1,122
Florida	307,145	***	100	***
Illinois	162,342	161,738	82	604
Indiana	29,610	29,495	87	115
Kansas	368,844	367,227	84	1,617
Kentucky	49,569	48,391	80	1,178
Louisiana	4,644,580	4,261,381	98	383,199
Michigan	164,155	157,500	89	6,655
Mississippi	322,730	313,846	96	8,884
Montana	199,380	197,821	97	1,559
Nebraska	35,637	35,637	96	0
New Mexico	652,552	650,641	97	1,911
New York	6,667	6,657	93	10
North Dakota	186,389	186,339	91	50
Ohio	87,349	86,096	75	1,253
Oklahoma	1,345,140	1,307,432	93	37,708
Pennsylvania	35,536	32,599	73	2,937
Texas	12,141,932	12,074,863	98	67,069
Utah	366,048	346,503	99	19,545
West Virginia	27,878	27,785	63	93
Wyoming	1,036,100	1,034,684	97	1,416
Misc.****	10,567	10,567	88	0
Total, U.S.	38,037,757	27,867,151	97	10,170,606

* See definition in Appendix B of Initial Report.

** Percentage of benchmark production reported by operators. Reserves were expanded to the totals shown based upon the methodology described in this report.

*** Reserves are included in totals, but not shown as they would disclose proprietary information.

**** Includes data for the States of Arizona, Missouri, Nevada, South Dakota, and Tennessee.

Table 2 shows proved crude oil reserves in reservoirs not produced in 1974 as a percentage of the total proved reserves in each State.

Table 3 presents the State-by-State estimates of natural gas reserves as well as National totals. Proved reserves of natural gas in reservoirs not produced in 1974 totaled 41.6 trillion cubic feet, 17.3 percent of the Nation's total (Table 3). Alaska has 57.4 percent of the U.S. total, virtually all in the North Slope. Large scale marketing of gas from that area is not expected before 1980. Louisiana and Texas respectively accounted for 25.3 and 11.7 percent of the proved natural gas reserves not produced in 1974. Principal factors contributing to non-production were the same as those for crude oil.

Table 4 shows proved natural gas reserves in reservoirs not produced in 1974 as a percentage of total proved reserves in each State.

Productive Capacity

Productive capacity estimates requested from operators are not the same as those used by API and AGA. The FEA defines productive capacity as the maximum daily average sustainable productive rate for crude oil and natural gas for the 60-day period following December 31, 1974, taking into account the following conditions:

1. No significant reduction in ultimate recovery from the field would result.

2. All economically feasible changes to maximize production would be made to existing wells, well equipment, and surface facilities as well as new drilling and changes in operational practices.

3. No change in constraints on flaring of gas or discharging of brines into water sheds would be made.

4. Productivity would decline at capacity operating conditions.

5. Gas withdrawal from underground storage facilities was not included.

6. Transportation and a market for all production except the North Slope of Alaska would be available.

7. No change in economic conditions, no legal constraints on production, and no changes in ownership equity systems would occur.

The API defines crude oil productive capacity as the maximum daily crude production rate, at the point of custody transfer, that could be achieved in ninety days (following December 31 of any given year) with existing wells, well equipment, and surface facilities - plus work and changes that can be reasonably accomplished within the time period using

Table 2--CRUDE OIL RESERVES IN NONPRODUCING RESERVOIRS
AS A PERCENTAGE OF TOTAL RESERVES

Range (percent)	States
Less than 0.4	Nebraska, North Dakota, Wyoming, New York, New Mexico, West Virginia.
0.4 - 1.0	Illinois, Colorado, Indiana, Kansas, Texas, Montana.
1.0 - 3.0	Ohio, Alabama, Arkansas, Kentucky, Mississippi, Oklahoma, California.
3.0 - 10.0	Michigan, Utah, Florida, Louisiana, Pennsylvania.
More than 10.0	Alaska.

Table 3--ESTIMATE OF NATURAL GAS RESERVES*
AS OF DECEMBER 31, 1974

State	Total Reserves (MMCF)	Producing Reservoirs Reserves (MMCF)	Producing Reservoirs Percent of Universe**	Nonproducing Reservoir Reserves (MMCF)
Alabama	470,644	270,981	68	199,663
Alaska	31,562,606	***	100	***
Arkansas	1,921,392	1,827,644	98	93,748
California	5,434,182	5,194,223	96	239,959
Colorado	2,282,947	2,132,573	95	150,374
Florida	306,918	***	100	***
Illinois	31,002	23,702	41	7,300
Indiana	5,308	2,308	88	3,000
Kansas	12,672,451	12,596,175	95	76,276
Kentucky	535,235	503,499	96	31,736
Louisiana	64,716,007	54,188,654	99	10,527,353
Michigan	1,041,149	996,121	90	45,028
Mississippi	1,132,746	935,027	80	197,719
Montana	733,146	713,487	87	19,659
Nebraska	19,917	19,361	95	556
New Mexico	16,383,957	16,153,986	92	229,971
New York	87,102	63,555	100	23,547
North Dakota	486,371	486,296	92	75
Ohio	1,238,684	1,186,737	68	51,947
Oklahoma	14,478,092	14,054,504	92	423,588
Pennsylvania	878,539	850,392	65	28,147
Texas	75,668,273	70,785,870	94	4,882,403
Utah	1,660,157	1,545,557	61	114,600
West Virginia	2,134,096	1,988,047	66	146,049
Wyoming	4,296,781	4,112,453	94	184,328
Misc.****	53,301	50,783	98	2,518
Total, U.S.	240,231,003	198,633,128	95	41,597,875

* See definition in Appendix B of the Initial Report.
** Percentage of benchmark production reported by operators. Reserves were expanded to the totals shown based upon the methodology described in this report.
*** Reserves are included in totals but not shown as they would disclose proprietary information.
**** Includes data for the States of Arizona, Maryland, Missouri, Nevada, South Dakota, Tennessee, and Virginia.

Table 4--NATURAL GAS RESERVES IN NONPRODUCING RESERVOIRS AS A PERCENTAGE OF TOTAL RESERVES

Range (percent)	States
Less than 2	North Dakota, Kansas, New Mexico.
2 - 4	Montana, Nebraska, Oklahoma, Pennsylvania.
4 - 6	Ohio, Wyoming, Michigan, California, Arkansas, Kentucky.
6 - 10	Texas, Florida, Colorado, West Virginia, Utah.
10 - 20	Louisiana, Mississippi.
20 - 50	Illinois, New York, Alabama.
More than 50	Indiana, Alaska.

present service capabilities and personnel and with productivity declining as it would under capacity operation. The AGA defines natural gas productive capacity as potential production rather than immediate or instantaneous production or open flow potential and is an estimate of the maximum rate of production which can be obtained at any time and from time to time during the heating season of the subject year, estimated to extend about ninety days from January 1, without regard to limitations of markets, transportation and processing facilities. As to be expected, operator survey productive capacity estimates (Table 5) were lower than industry estimates, 2.3 percent for oil and 12.4 percent for gas. (This does not include estimates for the North Slope of Alaska.)

A comparison of the National productive capacity estimate from the Operators Survey with the daily average production in 1974 shows that the capacity estimate was approximately 3.5 percent higher than the daily average production. The USBM average daily crude oil production figure for December 1974 was 8.0 million barrels per day, approximately 8 percent below the FEA capacity estimate.

Operators indicated that there were no constraints on productive capacity in 90.3 percent of the Nation's oil producing fields. Well and lease equipment was the principal constraint in 4.1 percent of the fields. Other constraints and their percentages were: transportation facilities, 0.4; legal (including allowables), 2.2; and unspecified, 3.0.

Estimated productive capacity of 1.062 million barrels per day for California was approximately 178,000 barrels above the daily average production in 1974. This high rate is attributed principally to the Elk Hills Naval Petroleum Reserve. Ranking behind California in unused crude oil productive capacity was Texas with estimated productive capacity of 3.435 million barrels per day, 80,000 barrels higher than daily average production in 1974. Most of this difference can be attributed to East Texas and Yates. Louisiana was indicated to have the most rapid decline in production capability. Estimated productive capacity of 1.709 million barrels per day was about 46,000 barrels less than daily average production in 1974.

Excluding the North Slope of Alaska, estimated productive capacity for natural gas of 63.4 billion cubic feet per day was 7 percent higher than the 1974 daily average production from the Operators Survey. The USBM average daily natural gas production figure for December 1974 was 58.1 billion cubic feet per day, approximately 8 percent below the FEA capacity estimate.

Nationwide there was no indicated productive capacity constraint for 81.3 percent of natural gas fields. Other constraints and their percentages were: lease equipment, 4.4; transportation, 3.1; legal (including allowables), 5.6; and other, 5.6.

Table 5--AVERAGE DAILY PRODUCTION CAPACITY
FOR CRUDE OIL AND NATURAL GAS FOLLOWING DECEMBER 31, 1974

State	Crude Oil (Bbls)	Natural Gas (MCF)
Alabama	32,927	73,330
Alaska*	196,965	703,454
Arkansas	45,708	371,913
California	1,062,536	1,327,666
Colorado	101,568	507,500
Florida	113,728	120,308
Illinois	74,010	4,066
Indiana	13,303	2,909
Kansas	167,862	3,063,300
Kentucky	23,344	180,792
Louisiana	1,709,032	20,756,991
Michigan	76,774	384,224
Mississippi	140,496	341,600
Montana	94,696	176,194
Nebraska	17,847	15,983
New Mexico	260,328	3,503,516
New York	2,392	18,660
North Dakota	61,727	83,882
Ohio	26,427	265,173
Oklahoma	464,299	5,279,054
Pennsylvania	9,825	278,489
Texas	3,435,089	23,887,015
Utah	132,655	302,543
West Virginia	8,975	611,386
Wyoming	393,160	1,083,149
Miscellaneous**	5,817	22,120
Total, United States	8,671,490	63,365,217

* Does not include North Slope.

** Includes for oil Arizona, Missouri, Nevada, South Dakota and Tennessee. Includes for gas Arizona, Maryland, Missouri, Nevada, South Dakota, Tennessee and Virginia.

Estimated productive capacity of natural gas for Texas exceeded average 1974 daily production by more than one billion cubic feet per day while estimated capacity for Kansas and Oklahoma exceeded average 1974 production by more than 500 million cubic feet per day. Nearly the entire difference in Kansas can be attributed to the Hugoton field while a smaller part of the differences in Texas and Oklahoma can be attributed to the same field. The estimated productive capacity for Louisiana exceeded average 1974 production by less than 100 million cubic feet per day.

Indicated Reserves

Indicated secondary and tertiary reserves were defined as the estimated quantities of crude oil and natural gas (other than those defined and reported as proved reserves) that may be economically recoverable using present technology and economic operating conditions as of December 31, 1974, from the following potential sources: known productive reservoirs in existing fields expected to respond to improved recovery techniques where an improved recovery technique has been installed, but its effect cannot be fully evaluated; or an improved technique has not been installed, but knowledge of reservoir characteristics and the results of a known technique installed in a similar situation are available for use in the estimating procedure.

Indicated reserves for crude oil are similarly defined and designated by the API as indicated additional reserves from known reservoirs. Operators reported that these reserves for crude oil totaled 4,128 million barrels, and associated gas was 893 billion cubic feet (Table 6). Texas and California had the largest volumes of crude oil. Combined, they accounted for about two thirds of the U.S. total.

Indicated additional reserves from known reservoirs estimated by API totaled 4.6 billion barrels of crude oil, about 0.5 billion barrels higher than the operator estimate. This difference offsets slightly the higher proved reserve estimates from the Operators Survey. The largest difference was for Texas where operators estimated 1,372 million barrels as compared with the API estimate of 2,033 million barrels. The results for California differed by about 1 percent; operators' estimates totaled 1,335 million barrels, and the API figure was 1,349 million barrels.

Operators also provided information concerning recovery methods expected to be utilized in producing these reserves. As anticipated, the leading method was waterflooding which accounted for slightly more than half the total. Thermal methods, primarily in California, accounted for 22.6 percent. Gas injection was listed for 8.9 percent of the reserves. Polymer, emulsion, miscible, and combination type methods were the principal recovery mechanisms for the remainder of the reserves.

Table 6--INDICATED SECONDARY AND TERTIARY RESERVES
AS OF DECEMBER 31, 1974

State	Secondary and Tertiary Reserves Crude Oil (MBbls)	Associated Gas (MMCF)
Alabama	5,213	2,096
Alaska	3,695	2,797
Arkansas	26,839	2,758
California	1,334,672	20,588
Colorado	45,154	4,047
Florida	20,936	21,030
Illinois	93,659	184
Indiana	3,821	2
Kansas	90,682	2,207
Louisiana	200,891	313,790
Michigan	31,314	5,906
Mississippi	50,357	5,679
Montana	67,479	464
Nebraska	2,528	0
New Mexico	365,171	108,814
New York	1,910	0
North Dakota	8,284	3,482
Oklahoma	158,919	33,615
Pennsylvania	10,915	730
Texas	1,372,027	338,762
Utah	8,122	1,326
West Virginia	1,200	0
Wyoming	199,330	22,537
Miscellaneous*	15,792	0
Total, United States	4,127,677	893,284

* Includes Arizona, Missouri, Nevada, South Dakota, and Tennessee.

Gross Additions to Proved Reserves

Gross additions to proved reserves are the volumes of crude oil, associated natural gas, and nonassociated natural gas proved reserves added in 1974, including additions to reserves in shut-in reservoirs. These additions (shown in Table 7) include extensions, upward revisions, new field discoveries, and new reservoir discoveries in old fields.

Assessment of Data Quality

The discussion which follows analyzes nonresponse and presents results of a special audit of operator responses.

Analysis of Nonresponse

To survey all known oil and gas operators in the United States, lists were obtained by contacting different State agencies, associations, and private companies. More than 22,000 questionnaires were mailed beginning on December 18, 1974. The final response was as follows:

Status	Number of Responses
Usable schedules	11,946
Out of business or out of scope	5,008
Nonrespondents	2,177
Post Office returns - addressee unknown	1,563
Unusable schedules or late receipts	1,470
Total	22,164

Data from usable schedules were processed and compared with State benchmark production records for 1973. Comparisons indicate that usable schedules accounted for 97 percent of the crude oil production and 95 percent of the natural gas production.

FEA contracted with National Analysts to follow up on operators who were classified as nonrespondents or whose questionnaires had been returned as undeliverable. National Analysts selected a random sample of 100 operators from each of these groups. They were able to contact 57 of the 100 operators for nonrespondents by using secondary source material and intensive research. Thirty of the 57 operators contacted said that they were not operating as of October 31, 1974. Levels of oil and gas production for the 57 companies contacted are given below:

Table 7--GROSS ADDITIONS TO PROVED RESERVES IN 1974

State	Crude Oil (MBbls)	Natural Gas (MMCF)
Alabama	19,214	62,222
Alaska	59,647	175,683
Arkansas	8,330	124,740
California	355,845	304,985
Colorado	11,557	98,233
Florida	236,267	283,268
Illinois	16,712	377
Indiana	1,566	55
Kansas	25,991	469,979
Kentucky	5,111	44,849
Louisiana	372,185	3,906,464
Michigan	53,038	359,589
Mississippi	25,029	61,908
Montana	15,535	23,350
Nebraska	1,234	4,826
New Mexico	81,091	2,150,241
New York	685	10,452
North Dakota	7,124	10,994
Ohio	6,402	46,315
Oklahoma	90,147	2,374,147
Pennsylvania	5,445	54,193
Texas	772,016	4,944,379
Utah	36,944	48,023
West Virginia	2,300	97,462
Wyoming	128,561	346,351
Miscellaneous*	2,685	3,273
Total, United States	2,340,661	16,006,318

* Includes for oil Arizona, Missouri, Nevada, South Dakota and Tennessee. Includes for gas Arizona, Maryland, Missouri, Nevada, South Dakota, Tennessee and Virginia.

Crude Oil*	Number	Natural Gas**	Number
none	31	none	40
1 - 2,999	9	1 - 14	7
3,000 - 5,999	3	15 - 29	2
6,000 - 19,999	4	30 - 99	2
20,000 - 99,999	2	100 - 299	1
100,000 or more	1	300 or more	2
Don't know	4	Don't know	0
Refused	3	Refused	3
Total	57	Total	57

* 1974 production (Bbls)
** 1974 production (MMCF)

National Analysts contacted 18 of the operators whose questionnaires had been returned by the Post Office. Seven of these 18 operators said that they were operating on October 31, 1974. Results for these operators are as follows:

Crude Oil*	Number	Natural Gas**	Number
none	13	none	15
1 - 2,999	1	1 - 14	0
3,000 - 5,999	0	15 - 29	0
6,000 - 19,000	0	30 - 99	0
20,000 - 99,000	3	100 - 299	1
100,000 or more	0	300 or more	1
Don't know	0	Don't know	0
Refused	1	Refused	1
Total	18	Total	18

* 1974 production (Bbls)
** 1974 production (MMCF)

Expansion from the results of the sample would indicate that the nonrespondents and Post Office returns accounted for annual production of approximately 12.5 million barrels of crude oil and 41 billion cubic feet of natural gas. This indicates that identified nonrespondents accounted for less than 1 percent of both crude oil and natural gas production.

There were 1,470 operator responses that were not included in survey results. These responses were principally the smaller ones that were given a low priority to upgrade into usable information and those few responses received too late for processing. Those responses that were not included in survey results likewise accounted for less than one percent of both crude oil and natural gas production.

The mailing lists used by FEA were incomplete and omitted operators accounted for the remaining production which is about 1 percent for crude oil and 3 percent for natural gas.

The usable schedules have been expanded to benchmark totals to account for nonresponses, unusable schedules, and the incomplete mailing list.

Special Audit of Operator Responses

FEA realized early in the survey procedure that the quality of response from operators was below expectation. A computer editing procedure was established and telephone calls were made by engineers, geologists, and junior professionals to operators to clarify and validate out-of-range responses.

FEA determined that it should conduct a more intensive examination of operator responses to better assess the quality of data being submitted. National Analysts worked with FEA in selecting a sample of operator field reports for special field-audit. A tabulation indicated that there were 14,451 operator field reports indicating the operator produced over 20,000 barrels of crude oil or 100 million cubic feet of natural gas in 1974.

From these reports National Analysts chose a sample of 1,806 units The sampling procedure is described in Appendix C of the initial report.

Time and available resources precluded personal interviews and an alternative procedure was adopted. FEA selected 32 large operators to be visited by FEA auditors. These 32 operators accounted for 729 of the 1,806 sample units. FEA contracted with Control Data Corporation to survey the remaining operators by telephone.

Noteworthy results of the special field audit are indicated below:

Question: Were the estimates of proved reserves made by an engineer or geologist?

Ninety-four percent of the crude oil, 96 percent of the associated gas, and 95 percent of the nonassociated gas estimates of proved reserves were made by engineers or geologists. These estimates were prepared by updating an earlier reserves estimate in about 80 percent of the cases.

Question: What was the principal methodology used to make the reserve estimate?

Fifty-seven percent of the audit reserve estimates were made by using decline curve analysis, 31 percent by the volumetric method, 7 percent by material balance calculations, and 5 percent by other methods.

Question: Were there any additions to proved reserves for properties operated by you in this field in 1974?

Thirty-eight percent of the reports indicated additions to proved reserves in 1974. The basis for these additions was usually additional drilling.

Question: Were crude oil production volumes reported on FEA P-301-S-0 for 1973 and 1974, the same as those reported to the State agency (or agencies)?

Eighty-four percent of the reports indicated that operators reported the same figures to FEA and State agencies. Reported figures differed in several instances because operators included lease condensate produced fron nonassociated gas wells as crude oil production to the State agencies.

Question: Were crude oil properties being produced at productive capacity at year end 1974?

Ninety-two percent of the reports indicated that crude oil properties were being produced at productive capacity.

Question: Were the same natural gas production volumes reported to the State agency and to the FEA on forms P-301-S-0 for 1973 and 1974?

Sixty-two percent of the reports for associated gas and 67 percent for nonassociated gas indicated that operators reported the same figures to FEA and the State agencies. Several States have a pressure base for reporting gas different from the 14.73 psia used by FEA. This is the reason for most of the differences.

Question: In what volume units did you report yearly natural gas production on FEA P-301-S-0?

Natural gas was reported in millions of cubic feet in 84 percent of the reports. Most of the remaining operators reported annual production in thousands of cubic feet. This incorrect reporting (thousands of cubic feet) necessitated numerous telephone calls by FEA personnel in the editing process.

Question: In what volume units did you report natural gas average daily capacity after December 31, 1974, on FEA P-301-S-0?

Natural gas was reported correctly in thousands of cubic feet in 89 percent of the reports. The remaining operators reported productive capacity in either millions of cubic feet or in cubic feet. These errors also required several telephone calls to obtain correct data.

Question: Were natural gas properties being produced at productive capacity at year-end 1974?

Eighty-one percent of the reports indicated that natural gas properties were being produced at productive capacity.

Question: On properties that you operated in this field in 1974, were there proved reserves of crude oil or natural gas in reservoirs that were not produced?

Four percent of the crude oil, 2 percent of the associated gas, and 7 percent of the nonassociated gas reports indicated nonproducing reservoirs.

Question: Did you report indicated secondary or tertiary reserves as of December 31, 1974?

Fourteen percent of the reports indicated secondary or tertiary reserves. About one-sixth of these indicated reserves were the result of a project installed in 1974 while the remaining were based upon projects that were expected to be installed at a future date.

Chapter 3

COMPARISONS OF RESERVE ESTIMATES

Reserve estimates derived by the same method for a reservoir are unlikely to agree precisely because of the:

1. Number of factors which must be quantified in preparing reserve estimates.

2. Quantifications which must be determined from widely spaced samples and/or incomplete reservoir data.

3. Judgments which must be made by each estimator based on his own experience.

Alternative methods of reserve estimation also usually result in different estimates. The range of estimates is dependent upon the ability and integrity of the estimator and is also related to completeness and accuracy of available data and the geological and physical complexity of the reservoir.

FEA cautions the reader against comparing estimates from various sources without a thorough knowledge and understanding of how the estimates were developed and what definitions and assumptions were involved.

Comparisons of reserve estimates from various sources are presented in this chapter.

Operators Survey Estimates Compared with the Major Field Studies Estimates

Reserves

The totals for proved reserves and indicated secondary or tertiary reserves, obtained from the Operators Survey and from the Major Field Studies, are shown in Table 8 below:

Table 8--COMPARISON OF OPERATORS SURVEY AND FIELD STUDIES

	Proved Reserves		Indicated Secondary and Tertiary Reserves	
	Crude Oil (MMBbls)	Natural Gas (BCF)	Crude Oil (MMBbls)	Natural Gas (BCF)
Operators Survey	19,891	67,485	1,469	211
Major Field Studies	19,416	68,300	1,479	377
Difference as a percent of Field Studies Estimates	2.4%	1.2%	0.7%	44.0%

The totals above are for 60 different field entities. The San Juan Basin gas fields are considered to be two separate fields. Although the comparisons for proved reserves are very close, an examination of the individual field proved reserves points up considerable differences, as Tables 9 and 10 indicate. The very close comparison in the case of indicated secondary and tertiary reserves of crude oil is coincidental. The Operators Survey lists such reserves for 37 fields; the Field Studies list such reserves for 18 fields; only 15 fields have these reserves on both lists. The natural gas reserves in the indicated secondary and tertiary category are too small for meaningful statistical comparison.

Table 9--COMPARISON OF CRUDE OIL RESERVES, OPERATORS SURVEY VERSUS MAJOR FIELD STUDIES

Survey Est. as a Percent of Field Studies Est.	No. of Fields	Field Studies Reserves (MMBbls)	Survey Reserves (MMBbls)
Under 50%	3	776.3	337.6
50% - 79%	5	1,106.5	655.6
80% - 89%	5	1,431.7	1,181.5
90% - 99%	13	1,439.9	1,338.4
100% - 109%	16	12,087.6	12,928.6
110% - 119%	3	1,058.8	1,188.1
120% - 149%	7	1,092.3	1,422.5
150% and over	8	422.4	838.3
Total	60	19,415.5	19,890.6

Table 10--COMPARISON OF NATURAL GAS RESERVES, OPERATORS SURVEY VERSUS MAJOR FIELD STUDIES

Survey Est. as a Percent of Field Studies Est.	No. of Fields	Field Studies Reserves (BCF)	Survey Reserves (BCF)
Under 50%	2	445.8	155.7
50% - 79%	6	2,625.2	1,693.7
80% - 89%	3	44,896.2	37,372.7
90% - 99%	9	3,164.3	3,032.0
100% - 109%	9	4,610.0	4,837.1
110% - 119%	5	985.1	1,130.9
120% - 149%	7	3,574.9	4,874.8
150% and over	19	7,998.8	14,388.1
Total	60	68,300.3	67,485.0

Crude Oil Proved Reserves. A short discussion of the 23 instances in which crude oil reserves from the Operators Survey and Major Field Studies differ by more than 20 percent follows:

1. In nine of the 23 "high percentage difference" fields, (Bay de Chene, Carthage, Chocolate Bayou, Coyanosa, Dollarhide, Dune, LaGloria, Tijerina-Canales-Blucher, and Timbalier Bay) the difference in proved reserves, regardless of percent, was a small absolute amount. These nine fields had differences ranging from 0.1 to 16.6 million barrels. By way of comparison, the average proved crude oil reserve for 59 listed fields (excluding Prudhoe Bay) is about 180 million barrels.

2. There are differences as to when qualified estimators, acting on the same data, will decide that indicated secondary and tertiary reserves should be classed as proved. Examination of the field listings showed five fields (Dos Cuadras, Hawkins, San Ardo, Spraberry Trend, and Wasson) in which this sort of problem appeared to be responsible for the recorded differences.

When proved and indicated reserves were combined, differences which had ranged from 34 to 90 percent were narrowed to 5 to 26 percent. The individual field amounts cannot be listed because three of the five fields are dominated by one or two operators and the Operators Survey volumes cannot be set out separately. The proved and indicated reserve estimates for the five combined fields are shown in Table 11.

3. Four of the remaining "high percentage difference" fields have sufficiently broad based ownership that the Operators Survey proved reserves may be identified separately. The crude oil reserves statistics for these fields are indicated by Table 11.

Table 11--COMPARISON OF PROVED AND INDICATED RESERVES

Field	Field Studies Proved (MMBbls)	Field Studies Indicated (MMBbls)	Field Studies Total (MMBbls)	Operators Survey Proved (MMBbls)	Operators Survey Indicated (MMBbls)	Operators Survey Total (MMBbls)
Five combined fields*	1,580	197	1,777	1,445	420	1,865
Cat Canyon	54	---	54	81	90	171
Greater Altamont	39	---	39	186	---	186
Midway Sunset	644	224	868	279	179	458
Tom O'Connor	216	---	216	264	1	265

* Dos Cuadras, Hawkins, San Ardo, Spraberry Trend, and Wasson.

The Greater Altamont and Midway-Sunset fields appear to be instances of somewhat extreme interpretations of production decline curves in the FEA field studies. At Altamont the field study reflects an extreme position concerning high operating costs, high economic limits of production, and continuation of the severe rates of production decline. At Midway-Sunset the field study has extended the very low primary production decline rates so as to yield a primary ultimate recovery of 15% of the oil originally present, supplemented by further recovery of 6% by thermal methods. At Altamont the proper interpretation will be evident soon; at Midway-Sunset, however, many years will be required before differences cited above can be resolved.

At Cat Canyon, FEA's consultant was impressed with the many operating problems and the questionable economics of various development and recovery schemes which are applicable. These possibilities were cited in the report, but the consultant elected not to place additional reserves in either the proved or indicated categories. The time required for resolution of this uncertainty will be several years.

At Tom O'Connor, the FEA study team elected to reduce estimates of net pay thickness and to increase estimates of connate water saturation from amounts which had been previously reported.

4. The remaining five "high percentage difference" fields are each dominated by one operator and the Operators Survey reserves numbers cannot be cited separately.

Two of these fields are quite complicated geologically. The operators did not discuss interpretative or proprietary information with the consultant firm. The FEA study reports are extremely brief and generally undocumented. In the absence of additional data, a choice cannot be made as to which estimate best reflects actual reserves.

In the case of a third field study, the volumetric data were based upon very old published information. The operator quite possibly has more recent and more reliable data and interpretations.

In the case of a fourth field, an instance of questionable methodology in the field study could account for the difference between the two proved reserves estimates.

The last field report was prepared in considerably less time than the other studies. Therefore, this report cannot be subjected to a critical review.

These last five fields are Caillou Island, Cogdell, Hastings, Oregon Basin, and West Cote Blanche Bay.

Natural Gas Proved Reserves. A short discussion of the 34 instances in which natural gas reserves from the Operators Survey and the Major Field Studies differ by more than 20 percent follows:

1. In sixteen of the gas fields in the "high percentage difference" category, the proved reserves differences, regardless of percent, were low in absolute amount. The recorded differences were each less than 90 BCF, and in thirteen instances, 45 BCF or less. By way of comparison, the average proved gas reserves for 58 fields (excluding Prudhoe Bay and Hugoton) are about 415 BCF for the studied fields and about 528 BCF for the surveyed fields.

2. Possible explanations for the proved reserves differences in seven fields are apparent from review of the field studies. Proved reserves data for six of these fields are listed in Table 12.

Table 12--COMPARISON OF NATURAL GAS PROVED RESERVES

Field	Operators Survey (BCF)	Field Study (BCF)
Altamont	388	40
Brown Bassett	341	203
Carthage	345	465
East Texas	364	226
San Juan - Basin Dakota	2,807	2,064
San Juan - Blanco	6,458	3,358

At Altamont the natural gas reserves problem parallels the crude oil reserves analysis. At Brown-Bassett, Basin Dakota, and Blanco fields there are problems in each of the field studies which are mentioned in the field summaries (see Volume II). The proved reserve estimates for any of these three reports may be somewhat inexact. At Carthage, FEA's contractor placed most emphasis on quite old reservoir pressure data for reserves in the major zones. Current production decline trends indicate a lower reserve nearer the Operators Survey estimate. In East Texas, almost 13 gallons of natural gas liquids per thousand cubic feet are being recovered at gas processing plants. The contractor reduced gas reserves volumes by 47 percent to account for the extraction loss. Many of the operators reporting for this large field quite possibly failed to make this correction. The seventh field (dominated by one operator and not listed above) is Kelly Snyder. As discussed in the FEA field summary, the FEA field study has overstated gas reserves.

3. The reasons for the proved reserves differences for the remaining eleven "high percentage difference" fields were not possible to determine. These fields are Anahuac, Bastian Bay, Bay de Chene, Coyanosa, Conroe, Gomez, Grand Isle Block 43, Main Pass Block 41, Seminole, Spraberry Trend, and West Delta Block 30. Six of these fields are each dominated by one or two operators. Seven of the FEA reports for these fields are poorly documented. The proved gas reserves estimates from the remaining four FEA field studies appear generally reasonable. The logic and assumptions behind the estimates from the Operators Survey are of course unknown.

Productive Capacity

Tables 13 and 14 display summaries of a field by field comparison between the Major Field Studies estimates of productive capacity and those from the FEA Operator Survey.

There are 51 oil fields for which comparisons can be made for crude oil productive capacity. There were 27 fields with average daily productive capacity of 1.5 million barrels where the field study estimates were within 5 percent of the Operators Survey. Field Study estimates were within 15 percent of the Operators Survey estimates for 46 fields with 93 percent of the productive capacity audited by these means. The aggregate productive capacity totals for the 51 oil fields indicate that the field study figures are 0.7 percent higher than those of the Operators Survey.

Table 13--COMPARISON OF CRUDE OIL PRODUCTIVE CAPACITY ESTIMATES, MAJOR FIELD STUDIES VERSUS OPERATORS SURVEY

Field Studies Est. as a percent of Survey Est.	No. of Fields	Fields Studies Prod. Cap. (MBbls/day)	Survey Prod. Cap. (MBbls/day)
Under 85	2	65.7	86.6
85 - 89	6	459.3	521.9
90 - 94	7	303.1	328.4
95 - 99	14	717.4	738.8
100 - 104	13	784.0	771.5
105 - 109	3	120.7	114.6
110 - 114	3	135.4	120.1
115 and over	3	222.3	107.7
Total	51	2,807.9	2,789.6

Table 14--COMPARISON OF NATURAL GAS PRODUCTIVE CAPACITY ESTIMATES, MAJOR FIELD STUDIES VERSUS OPERATORS SURVEY

Field Studies Est. as a percent of Survey Est.	No. of Fields	Fields Studies Prod. Cap. (MCF/day)	Survey Prod. Cap. (MCF/day)
Under 60	4	68.1	129.3
60 - 69	4	252.2	402.0
70 - 79	7	910.0	1,211.0
80 - 89	9	771.4	928.0
90 - 99	7	805.6	864.0
100 - 109	14	2,170.6	2,056.0
110 - 119	5	1,820.1	1,607.0
120 - 129	0	0	0
130 - 139	3	389.4	287.0
140 and over	3	5,407.2	2,964.0
Total	56	12,594.6	10,448.0

There are 56 fields for which comparisons can be made for natural gas productive capacity. Field Study productive capacity estimates were within 30 percent of operator estimates for 42 fields that accounted for 64 percent of the productive capacity audited by this means. In three fields that contained 28 percent of productive capacity audited by this means, field study estimates were over 40 percent higher than from the Operators Survey. The field study estimate for the Hugoton field, which has the highest average daily productive capacity of any field in the United States, was 83 percent higher than the estimate from the Operators Survey. The aggregate average daily productive capacity for the 56 fields indicates that the field study figures are 20.5 percent higher than those of the Operators Survey. This difference is due to the variance in the estimates for the Hugoton field. The aggregate average daily productive capacity for 55 fields (excluding Hugoton) indicates that the field study figures are 2.0 percent lower than those of the Operator Survey.

As indicated in Chapter 6 of this report, an exact definition of current producing capacity is difficult to draft and even more difficult to persons who use the definition. The FEA field study for Hugoton estimated that the field could produce at the tested deliverability rate on a continuous basis without significant loss to ultimate recovery. This rate does not take into account outlets from the field, the seasonality of consumer demand, or legal constraints. There is also the possibility that high rates of production would encourage water encroachment in portions of the field. Production at these high rates could only be maintained for a short duration before the field would be producing at or below current levels. Although information is not available regarding the operators' response, the survey productive capacity estimate appears to be more of a practical production rate rather than a potential rate.

Trade Associations Estimates Compared with FEA Estimates

Historically, the most prevalent source of data concerning proved reserves has been the annual report prepared jointly by the API and the AGA. A comparison of these trade association estimates with the FEA estimates has been prepared. The FEA, under the guidance of the General Accounting Office, solicited additional information from the trade associations to upgrade the quality of the comparisons. By publication time, the trade associations were unable to provide complete information about definitional consistency for the 100 largest oil fields and 50 largest gas fields in the United States, but some major discrepancies were corrected.

API Estimates Compared with FEA Estimates

Operators Survey Comparisons. The FEA survey indicated that there were 38.0 billion barrels of proved crude oil reserves in the United States as of December 31, 1974. The API report showed comparable reserves of 34.2 billion barrels, approximately 10 percent less than the FEA survey. The API also published data this year for the 100 fields in the United States with the largest proved reserves of crude oil. Table 15 is a summary of a field by field comparison between the API estimates and those from the FEA Operators Survey. Definitional consistency has not been confirmed for all fields.

Table 15--COMPARISON OF CRUDE OIL PROVED RESERVES, API VERSUS OPERATORS SURVEY

API Est. as a Percent of Survey Est.	No. of Fields	API Reserves* (MMBbls)	Survey Reserves (MMBbls)
Under 50	4	474.5	1,593.2
50 - 69	14	1,170.5	1,978.1
70 - 89	30	4,775.2	6,106.2
90 - 109	26	14,500.8	14,425.4
110 - 129	12	1,021.1	874.0
130 - 149	4	307.1	222.8
150 and over	10	2,144.0	1,345.8
Total**	100	24,391.9	26,545.4

* Reserves for Elk Basin and Spraberry Trend have been corrected for portions of each field previously omitted.

** Individual entries may not add to totals because of rounding.

The API estimates were lower than the Operators Survey estimates for 60 of the 100 fields. Based on the FEA survey there were 26 fields with 14.4 billion barrels of crude oil reserves where the API estimate was within 10 percent of the Operators Survey. The API estimate was within 30 percent of the Operators Survey for 68 fields with 21.4 billion barrels of crude oil reserves. The aggregate reserve totals for the 100 fields indicate that the API figures were 8.1 percent lower than those of the survey.

Major Field Studies Comparisons. Thirty-six of the fields which were studied by FEA are also included on the API list of proved reserves for their 100 largest oil fields. Table 16 lists the reserves for each of the 36 fields. In order to permit proper comparison, the API estimate for Elk Basin has been increased to include the Montana portion of the field, and the Spraberry Trend estimate has been increased to include the Texas Railroad Commission District 8 portion of the field. These revised reserve estimates have been furnished by the API. Also the FEA estimates for Hastings have been reduced to include only the West Hastings field; the Seminole Complex estimates have been reduced to include only the Seminole San Andres zone; and the Yates estimates have been reduced to include only the Yates-Grayburg-San Andres zone. These reductions were necessary to permit more valid comparison. In addition, the API list has been supplemented with estimates of indicated secondary and tertiary reserves in 18 of the more important fields.

The total proved reserve estimate for 36 FEA field studies was 18.9 billion barrels, about 2.8 percent more than the comparable field total of API estimates of proved reserves.

Table 16--COMPARISON OF CRUDE OIL RESERVES, API VERSUS MAJOR FIELD STUDIES

Field	Proved Reserves: Field Studies (MMBbls)	Proved Reserves: API (MMBbls)	Indicated Reserves: Field Studies (MMBbls)	Indicated Reserves: API* (MMBbls)
Anahuac	54.3	56.4	0.0	----
Bay de Chene	39.1	47.1	0.0	----
Bay Marchand Block 2	154.6	126.1	0.0	0.0
Caillou Island	202.8	205.1	0.0	----
Cogdell	85.8	76.0	0.0	----
Conroe	200.7	196.8	0.0	----
Dos Cuadras	61.8	73.0	35.7	25.0
East Texas	1,250.2	1,287.2	0.0	----
Elk Basin	114.7	80.2	0.0	0.0
Eunice-Monument	60.9	62.0	0.0	100.0
Fairway	87.3	89.9	0.0	----
Grand Isle, Block 43	107.7	119.8	7.4	----
Greater Altamont	39.2	112.7	0.0	----
Hastings-West	179.5	253.2	0.0	----
Hawkins	535.0	304.8	0.0	175.0
Huntington Beach	124.6	121.5	45.5	50.0
Jay	255.6	257.9	0.0	----
Kelly Snyder	565.3	477.0	0.0	231.0
Kern River	1,087.0	250.5	0.0	355.0
Main Pass, Block 41	82.5	74.8	35.1	----
McElroy	266.3	49.0	0.0	52.0
Midway Sunset	644.0	303.8	224.0	50.0
Oregon Basin	132.2	61.3	131.0	0.0
Prudhoe Bay	8,759.0	9,598.5	0.0	----
San Ardo	385.0	101.1	0.0	60.0
Seminole-San Andres	200.8	162.0	0.0	75.0
Slaughter	402.0	349.0	153.0	0.0
Sooner Trend	62.6	64.1	0.0	----
Spraberry Trend	90.2	81.8	75.0	75.0
Tom O'Connor	216.2	314.7	0.0	----
Wasson	508.0	636.0	86.0	30.5
West Cote Blanche Bay	75.9	103.1	0.0	----
West Delta Block 30	102.8	110.1	0.0	----
West Ranch	99.2	96.3	0.5	----
Wilmington	886.0	705.4	0.0	82.0
Yates-Grayburg-San Andres	825.6	1,398.0	544.8	0.0
Total	18,944.4	18,416.2	1,338.0	----

* Data not available for all fields.

The differences in proved reserve estimates were within 10 percent of the field study estimates for 14 fields. These fields are:

Anahuac	Fairway	Sooner Trend
Caillou Island	Huntington Beach	Spraberry Trend
Conroe	Jay	West Delta Block 30
East Texas	Main Pass Block 41	West Ranch
Eunice-Monument	Prudhoe Bay	

The largest variance was for the Prudhoe Bay field where the proved reserve difference amounted to 833 million barrels, almost the entire difference of the 14 field group. All proved reserves at Prudhoe Bay are based upon either simulation studies or very early assumptions. This 10 percent difference in estimates of proved reserves should not be alarming, in view of the early stage of the reserve estimates. Indicated secondary or tertiary reserves are similar in 12 of the 14 instances; the difference is of an obscure category at Eunice-Monument and the difference could distort the comparison at Main Pass Block 41.

The reserves differences in five fields (Dos Cuadras, Hawkins, Wasson, Wilmington and Yates) mainly can be attributed to timing as to when indicated secondary reserves should be classified as proved. An examination of Table 16 indicates differences in proved reserves for these five fields to range from 18 to 69 percent. When proved plus indicated reserves are considered, the differences range from 0.5 percent to 12 percent.

There are four fields in South Louisiana (Bay de Chene, Bay Marchand Block 2, Grand Isle Block 43, West Cote Blanch Bay) in which the proved reserves estimates differ from 11 to 36 percent. The total reserve difference in these fields is about 5 percent. The FEA field studies had the benefit of a later date of preparation, ranging from 5 to 8 months. The total of reserves from these fields, where the reserves situation is somewhat fluid, may be generally valid in either case, although some changes in individual field reserves might be necessary in subsequent estimates.

For the following field groupings, the introduction of the Operators Survey estimates tends to support either the FEA field study estimates or the API estimates. However, the extent to which the operators survey can be considered an independent check on the API reserve estimates in these next groups of fields is not clear. Ten of the 13 fields are dominated by one or two operators, and one might presume that these operators influence both the API and the Operators Survey estimates to a significant extent. Also the operators may have influenced the field study estimates through contractor interviews.

1. The first group is two fields in California where indicated thermal recovery reserves are important. These fields are Kern River and San Ardo. The FEA contractor tended to recognize more thermal reserves and to classify them as proved. The reserve estimates are summarized below:

Source	Proved Reserves (MMBbls)	Indicated Reserves (MMBbls)	Total Reserves (MMBbls)
Field Study	1,472	---	1,472
API	352	415	767
Operators Survey	1,094	287	1,381

In the absence of further data, the Operators Survey estimates tend to agree with the field study estimates, and the API estimates appear somewhat conservative.

2. The second group includes three fields (Elk Basin, McElroy, and Slaughter). The reserve estimates are summarized below:

Source	Proved Reserves (MMBbls)	Indicated Reserves (MMBbls)	Total Reserves (MMBbls)
Field Study	783	153	936
API	478	52	530
Operators Survey	684	202	886

In the absence of further data the Operators Survey estimates again tend to agree with the field study results, and the API estimates appear somewhat conservative.

3. The third group includes Kelly Snyder and Tom O'Connor. The reserve estimates of these fields are summarized below:

Source	Proved Reserves (MMBbls)	Indicated Reserves (MMBbls)	Total Reserves (MMBbls)
Field Study	782	---	782
API	792	231	1,023
Operators Survey	872	46	918

The API and the field study estimates straddle the Operators Survey estimates and neither appears preferable in the absence of additional data.

4. The last six fields (Cogdell, Greater Altamont, Hastings-West, Midway-Sunset, Seminole, and Oregon Basin) are subdivided into two groups. The reserves data are tabulated below:

Source	Proved Reserves (MMBbls)	Indicated Reserves (MMBbls)	Total Reserves (MMBbls)
Field Study	862	355	1,217
API	441	50	491
Operators Survey	402	204	606

Source	Proved Reserves (MMBbls)	Indicated Reserves (MMBbls)	Total Reserves (MMBbls)
Field Study	420	---	420
API	528	75	603
Operators Survey	671	53	724

Within this six-field grouping, the field study estimates for Cogdell, Midway-Sunset, and Oregon Basin appear higher than the corresponding API and Operator Survey estimates while those for Greater Altamont, Hastings-West, and Seminole appear lower than the corresponding estimates. In the absence of further data, the Operators Survey estimates tend to support the API estimates.

AGA Estimates Compared with FEA Estimates

Operators Survey Comparisons. The FEA survey indicated that there were 240.2 trillion cubic feet of proved natural gas reserves as of December 31, 1974. The AGA comparable proved reserves were 233.2 trillion cubic feet (after deducting 3.9 trillion cubic feet which was in underground storage). The AGA figure is approximately 2.9 percent less than that of the FEA survey. The AGA also published data this year for the 50 fields in the United States with the largest proved reserves of natural gas. Table 17 is a summary of a field by field comparison between the AGA committee estimates and those from the FEA Operators Survey. Definitional consistency has not been confirmed for all fields.

The AGA estimates were higher than the Operators Survey estimates for 23 of the 50 fields. Based on the FEA survey there were 20 fields with 57.0 trillion cubic feet of natural gas reserves where the AGA estimate was within 10 percent of the Operators Survey. The AGA estimate was within 30 percent of the FEA survey for 38 fields with 88.7 trillion cubic feet of natural gas reserves. The aggregate reserve totals for the 50 fields indicate that the AGA figures are 0.4 percent higher than those of the survey.

Table 17--COMPARISON OF NATURAL GAS PROVED RESERVES, AGA VERSUS OPERATORS SURVEY

AGA Est. as a Percent of Survey Est.	No. of fields	AGA Reserves (BCF)	Survey Reserves (BCF)
50 - 69	2	2,805	4,532
70 - 89	13	18,782	23,984
90 - 109	20	58,578	56,950
110 - 129	5	8,603	7,228
130 - 149	2	1,541	1,107
150 and over	8	6,895	3,036
Total	50	97,204	96,837

Major Field Studies Comparisons. Sixteen of the fields which were studied by FEA are also included on the AGA list of proved reserves for their 50 largest gas fields. Table 18 lists the reserves for each of the 16 fields.

The total proved reserve estimates for 16 FEA field studies were 60.6 TCF, about 3.2 percent more than the comparable 16 field total of AGA estimates of proved gas reserves.

The differences in proved reserve estimates were within 10 percent of the field study estimates for five fields (Bateman Lake, Caillou Island, Gomez, Puckett, and San Juan-Basin Dakota).

At Hugoton and Coyanosa, the differences in proved reserves can be attributed to the assumed reservoir pressure at the time of abandonment. In the case of Hugoton, the FEA field study assumes an abandonment reservoir pressure of 25 psia as compared to 55 psia reported by the AGA. As discussed in the field summary in Volume II, this would cause the FEA proved reserve estimate to be 2.3 TCF higher than the AGA estimate. The actual difference in proved reserve estimates is 2.6 TCF. In the case of Coyanosa, the FEA contractor selected quite high abandonment reservoir pressures ranging from 1,000 to 1,500 psia as compared to an AGA selection in the 350-375 psia range. This difference would account for the FEA estimate being 271 BCF lower than the AGA estimate. The actual difference in the estimates is 301 BCF. The Operators Survey proved reserves, 13.0 TCF at Hugoton and 1.0 TCF at Coyanosa seemed to support the AGA gas reserves for both of these fields.

Table 18 -- COMPARISON OF PROVED NATURAL GAS RESERVES
AGA VERSUS MAJOR FIELD STUDIES

Field	Field Studies (BCF)	AGA (BCF)
Bastian Bay	1,068.2	1,313
Bateman Lake	1,485.7	1,481
Caillou Island	1,235.0	1,216
Carthage	465.6	1,154
Coyanosa	669.9	1,000
Eumont	485.0	715
Gomez	2,327.0	2,165
Grand Isle Block 43	638.7	819
Hugoton	15,187.0	12,538
LaGloria	198.8	852
Main Pass Block 41	579.8	884
Prudhoe Bay	29,082.0	25,994
Puckett	1,183.0	1,065
San Juan-Basin Dakota	2,064.0	2,130
San Juan-Blanco	3,358.0	4,610
Wasson	527.0	700
Total	60,554.7	58,636

At Carthage, the FEA field study estimate of proved gas reserves is 466 BCF, about 40 percent of the AGA estimate. The AGA, at FEA's request, reviewed the Carthage situation, and reported, based upon information developed since their last estimate, that reserves might be reduced by about 230 BCF. The remaining difference seems caused by variation in projections of production decline trends. The AGA reports an exponential extrapolation would tend to confirm the field study estimate, while the AGA reserve estimate presumes a flattening of future rates of production decline.

At LaGloria, the FEA field study estimate of proved gas reserves is 199 BCF, about 23 percent of the AGA estimate. The AGA also reviewed the LaGloria situation, and reported that recent data indicate a downward revision to the AGA reserve estimates may be necessary. The AGA's cumulative net gas production records from the cycled reservoirs appear to be considerably more than the amounts furnished to FEA's contractor by the operator. This would lead to excessive estimates of ultimate recovery and proved reserves on the part of AGA.

The Operators Survey proved reserve estimates tend to confirm the FEA's field study estimates at both Carthage and LaGloria as indicated below:

Source	Proved Reserves (BCF)
Field Study	664
AGA	2,006
Operators Survey	547

At Eumont, the AGA reports cumulative gas production to be 153 BCF higher than shown in the FEA field study. The Eunice Area cumulative gas production estimates were especially developed by the AGA because they believed the records on official file to be under-reported. This possibility was pointed out to the contractor during FEA's review of the field study but could not be corrected. In this situation, an understatement of cumulative production would lead to an under estimate of both ultimate recovery and proved reserves. The AGA believes the entire five-field Eunice Area cumulative gas production, shown as 6.2 TCF on the field study, should be 9.0 TCF.

At Prudhoe Bay, the FEA field study is 29.1 TCF, about 10.6 percent greater than the AGA estimate. The AGA estimate of ultimate gas production has not been revised since it was initially recorded on December 31, 1970. The FEA estimate is based upon considerably more recent data. The difference in proved gas reserve estimates of about 10 percent should not be regarded as serious at this early stage of the field development.

The Blanco gas field in the San Juan Basin presents a difficult reservoir analysis problem. The data for a volumetric determination of gas in place are inadequate because of heterogeneous reservoir conditions. The reservoir pressures are not diagnostic because of low permeability and inadequate pressure buildup. The spacing pattern in the principal Mesaverde reservoir has recently been changed from 320 acres per well to 160 acres. The amount this will increase ultimate recovery as opposed to only accelerating production is somewhat controversial. The field study estimate of proved reserves is 3.4 TCF, about 1.2 TCF less than the AGA estimate. The field study was based entirely upon extrapolation of pressure trends and, in this situation, would be expected to be somewhat conservative. The Operators Survey estimate of proved reserves of 6.5 TCF, about 1.8 TCF more than the AGA estimate, is indicative of the range of opinion in this difficult and changing analysis situation.

At Wasson, there is a low permeability problem which renders the pressure measurements for material balance calculations somewhat suspect. Also reservoir heterogeneity makes volumetric determinations very difficult. Finally, cumulative gas production, according to some accounts, is 200 BCF low in the FEA field study. The problems of low permeability and gas accounting would each lead to conservative estimates of hydrocarbons originally in place and proved reserves. The various proved gas reserve estimates at Wasson are:

Source	Proved Reserves (BCF)
Field Study	527
AGA	700
Operators Survey	597

The remaining three fields (Bastian Bay, Grand Isle Block 43, and Main Pass Block 41) are in South Louisiana. The AGA reported that their reserve estimate for one of the fields includes some untested reserves which should possibly be removed. They also reported that a recent study of another of these fields indicates the advisability of a considerable downward revision to their estimate. The proved reserves for these three fields are listed below:

Source	Proved Reserves (BCF)
Field Study	2,287
AGA	3,016
Operators Survey	2,322

Decline Curve Analysis Estimates Compared With Other FEA Estimates

The FEA contracted with the USGS to utilize decline curve analyses to calculate proved reserves of crude oil for selected fields where production histories tended to conform to machine processing. In all but three States, Kansas, Oklahoma, and Texas, the latest production data readily available for this project were for 1973. Therefore, comparisons can only be attempted for these three States where 1974 production data were included in the analysis.

As explained in the critique of decline curve analysis, the FEA has observed certain shortcomings in applying a computer program to process rapidly field data for determining reserves from decline curve analysis. The most critical limitation is the accumulation of accurate input data for the many variables in each field. Unless a detailed field by field, reservoir by reservoir determination of the validity of data is performed, machine-processed decline curve analyses tend to develop suspect reserve estimates. Such a detailed search and confirmation of data would tend to defeat the purpose of rapid machine processing for determining reserve estimates.

Operators Survey Comparisons

Reserve estimates of crude oil developed by decline curve analysis for 88 fields in Kansas, Oklahoma, and Texas were compared with the appropriate estimates from the Operators Survey for the same fields. These estimates were for fields with decline curve reserves in excess of two million barrels in Kansas and Oklahoma and in excess of five million barrels in Texas. Table 19 indicates the results of field by field comparison of reserves.

Table 19--COMPARISON OF CRUDE OIL RESERVE ESTIMATES, DECLINE CURVE ANALYSIS VS. OPERATORS SURVEY

Decline Curve Est. as a Percent of Survey Est.	No. of Fields	Decline Curve Reserves (MMBbls)	Survey Reserves (MMBbls)
Under 50	7	56.9	139.0
50 - 89	14	265.3	354.7
90 - 109	7	112.1	116.2
110 - 149	17	281.3	222.4
150 and over	43	749.8	363.0
Total	88	1,465.4	1,195.3

As Table 19 illustrates, the reserve estimates from decline curve analysis tended to be higher than those from the Operators Survey. The aggregate reserve totals for the 88 fields indicate that the decline curve figures were 20.8 percent higher than those of the Operators Survey while the aggregate reserve totals for the 47 Texas fields were only 9.5 percent higher. A small part of this can be explained by the fact that prior to 1971, Texas production was affected by Statewide allowables. Therefore, there were insufficient significant data available to project hyperbolic declines for any Texas fields, and only exponential declines were projected. The hyperbolic projections used for some fields in Kansas and Oklahoma tend to compute more optimistic reserve estimates because of the flatting of the curve.

Major Field Studies Comparisons

Only three of the fields studied by FEA that were amenable to decline curve analysis had comparable 1974 reserve estimates. The reserves from the decline curves were 19 percent higher than the corresponding reserves from the engineering studies.

One of the cautions of this exercise of decline curve analysis was that the lack of production data by producing horizon could cause an erroneous value to be used for the average depth figure. Thus, when applying the average depth data to the number of wells, an erroneous abandonment rate would be used in determining the reserves.

Table 20 shows a comparison of the fields from the decline curve analysis of field production histories and the Major Field Studies.

Table 20--COMPARISON OF CRUDE OIL ESTIMATES, DECLINE CURVE ANALYSIS VS. FIELD STUDIES

Field	Decline Curve (MMBbls)	Major Field Studies (MMBbls)	Decline Curve as a Percent of Major Field Studies Est.
Cogdell Area	127.3	85.8	148
Dune	40.3	33.1	122
Sooner Trend	48.7	62.6	78
Total	216.3	181.5	119

In States where reservoir data were available, a number of fields had reservoirs which were adaptive to decline curve analysis, but the total field was not adaptive. This helps to provide some more insight into the nonadaptability of determining field reserves by machine processing. Theoretically, decline curve analysis should be applicable for depletion drive reservoirs and not for waterdrive or waterflood reservoirs. However, some depletion curve reservoirs in a field may influence the field production and indicate that the total field is amenable to decline curve analysis. As can be seen from the field summaries in Volume II, all three of the fields compared in Table 20 have waterdrive or waterflood projects for portions of the fields. In the case of Cogdell, the field, which originally had depletion drive, has been unitized and is under waterflood.

State Agency Estimates Compared with FEA Estimates

Operator Survey Comparisons

State reserve estimates were provided by 14 State agencies. Because of differences in definitions and incompleteness, comparability is limited. Nevada and Virginia provided reserves for the only field in each State. To avoid disclosure of proprietary information, reserves have been combined for these States and South Dakota and Missouri.

Although both oil and gas reserves were submitted by Alabama, the estimate did not include new fields and included some secondary reserves. Thus, the estimates did not have a common base with the Operators Survey. Estimates for California did not include the Federal offshore leases, therefore no comparison was made. The crude oil reserve estimate provided by Colorado was as of January 1, 1974, and the Operators Survey was as of December 31, 1974. North Dakota provided an estimate of crude oil, technically recoverable with no economic limitations, which again was noncomparable.

Crude oil data for the States identified individually in Table 21 range from close agreement to widespread differences between State and Operators Survey estimates. These comparisons reemphasize the subjective nature of reserve estimating and the widespread difference in results that can be expected.

Table 21--COMPARISON OF PROVED CRUDE OIL RESERVE ESTIMATES, STATE AGENCIES VS. OPERATORS SURVEY

State	Crude Oil (MMBbls) State Estimate	Operator Survey	State Est. as a Percent of Survey Est.
Arkansas	363.1	121.1	300
Florida	363.8	307.1	118
Illinois	164.4	162.3	101
Michigan	173.7	164.2	106
Montana	310.0	199.4	155
New Mexico	600.0	652.6	92
Others	8.6	4.3	200
Total	1,983.6	1,611.0	123

Major Field Studies Comparisons

Only California and Florida prepared independent reserve estimates for individual fields which FEA studied. California provided reserve estimates for the six fields, Cat Canyon, Huntington Beach, Kern River, Midway-Sunset, San Ardo, and Wilmington. Florida provided reserve estimates for the Jay field.

California law prohibits the publication of individual field reserve estimates prepared by the State. Therefore, fields have been divided into two groups for comparison purposes. One group consists of fields producing heavy oil. These fields are Cat Canyon, Kern River, Midway-Sunset, and San Ardo. The other group consists of Huntington Beach and Wilmington, two fields in the Los Angeles Basin. The comparisons of crude oil reserve estimates are indicated by Table 22.

Table 22--COMPARISON OF PROVED CRUDE OIL RESERVE ESTIMATES, STATE AGENCIES VS. MAJOR FIELD STUDIES

State	Field	State Agency (MMBbls)	Major Field Studies (MMBbls)	State Est. as a Percent of Field Studies Est.
Calif.	Heavy Oil Fields	1,395.4	2,189.9	63.7
	Los Angeles Basin Fields	759.0	1,010.6	75.1
Fla.	Jay	273.1	255.6	106.8

A comparison of the State reserve estimates and those of the Major Oil and Gas Field Studies indicated significant differences. In California, State crude oil reserve estimates tended to be lower than the estimates from the field studies. California reported proved reserves only. The State may classify some additional reserves as indicated which could significantly alter the comparisons. Florida's Jay field crude oil reserve estimate was marginally higher than the corresponding estimate from the engineering study.

Chapter 4

PRODUCTIVE CAPACITY

Projections of future capacities to produce oil and gas under several sets of assumptions were analyzed and published as a part of Project Independence Blueprint. FEA is making a greater "in depth" analysis of various facets of Project Independence, including productive capacity and plans to publish its findings in the near future. However, to fulfill the mandate to analyze productive capacity, statistical projections, tempered with judgements based upon experience, were made. Projections presented herein have been made independently and incorporate assumptions and subjective judgements that may or may not be compatible with the Project Independence Blueprint update. The results, therefore, are not expected to be in complete agreement.

Productive capacity for the major petroleum products was presented in the preliminary report in June and is not repeated.

To analyze the productive capacity of crude oil each year for the next ten years, domestic production was apportioned into four segments.

1. Production from proved reserves in the United States excluding the North Slope of Alaska.

2. Production from proved reserves in the North Slope of Alaska.

3. Production from initially estimated proved reserves for new field and new pool discoveries and extensions.

4. Production from revisions in proved reserves.

Crude oil productive capacity projections in this report are FEA's evaluations of the maximum sustainable rates of output that could be obtained and marketed. In making these projections, FEA assumed the existence of economically favorable and stable conditions and desirable drilling prospects that will foster increased drilling activity and utilization of improved recovery techniques. Discoveries of unusually large reservoirs, e.g., Prudhoe Bay Field in Alaska, have not been anticipated.

The following assumptions were made.

1. No significant reduction in ultimate recovery from any field would result.

2. All economically feasible changes to maximize production would be made to existing wells, well equipment, and surface facilities as well as new drilling and changes in operational practices.

3. No change in constraints on flaring of gas or discharging of brines into water sheds would be made.

4. Productivity would decline at capacity operating conditions.

5. Transportation and a market for all crude oil production in the lower 48 States would be available, and the Trans-Alaska Pipeline System would be completed and operated at announced schedules.

6. No change in economic conditions, no legal constraints on production, and no changes in ownership equity systems would occur.

7. Production from the Elk Hills Naval Petroleum Reserve will be increased annually and attain a maximum production rate of 200 thousand barrels daily in Government Fiscal Year 1980.

Production from Proved Reserves in the United States Excluding the North Slope of Alaska

During 1973 and 1974, crude oil production from this segment of proved reserves has been virtually at capacity. A projection of production from these reserves was made using a hyperbolic curve that declined at the rate of 10 percent per year.

Production from Proved Reserves in the North Slope of Alaska

Latest revised schedule is for a start up of the Trans-Alaska Pipeline System in mid-1977 at a rate of 600,000 barrels per day increasing to 1.2 million barrels per day by yearend 1977. Increase in transportation capability to 1.5 million barrels per day in 1979 and ultimately to 2.0 million barrels per day is projected. Estimated proved reserves at yearend 1974 in the North Slope of Alaska are sufficient to support a production rate of 1.5 million barrels per day beyond 1985. New field and new pool discoveries, extensions, and revisions in proved reserves are expected to provide production for expanded pipeline capacity.

Production from Initially Estimated Proved Reserves for New Field and New Pool Discoveries and Extensions

Production of crude oil in the United States except the North Slope of Alaska was virtually at capacity in 1974. For this production, the proved reserves (as determined from the FEA operator survey) to production ratio was 9.35 to 1. Projected production for this sector was based upon a continuation of proved reserve to production ratio.

From yearly drilling statistics of the American Association of Petroleum Geologists, Inc., and reserves data for new field and new pool discoveries and extensions of the API, an average of the estimated proved reserves per well drilled was calculated. Although erratic, a downward trend is discernible, especially for 1973 and 1974. The decrease for 1973 and 1974 is attributed partially to the changes in economic conditions and regulations that encouraged the drilling of developmental wells and low risk exploratory prospects previously considered marginally profitable.

The economic conditions that encourage the drilling of developmental wells and low risk prospects that previously were unprofitable are assumed to continue and have a downward influence on proved reserves added per well drilled. However, the backlog of known low risk prospects is being eliminated. Based on this elimination of low risk prospects, FEA assumed that the downward trend in reserves added per well will be partially arrested because of factors tending to increase reserves added per well such as wider well spacing. Improved engineering capability to eliminate the drilling of unnecessary wells and the trend toward unitization that should result in more efficient drilling patterns and geological and geophysical methods could reduce the percentage of dry holes drilled. FEA also assumed that the average proved reserve additions initially estimated for new field and new pool discoveries and extensions per well drilled throughout the forecast period will decline at a rate of 2 percent per year, about half the rate of decline experienced during the past decade. The average additions for the past 4 years were used as the starting base for these reserve additions.

With stable and favorable economic conditions, a National policy of selfsufficiency in energy and an adequate number of economically attractive prospects, an increase in the number of wells drilled is expected. We have assumed that a two percent annual increase from an estimated base of 35,800 wells in 1975 can be attained. At this increase 43,640 wells will be drilled in 1985, more than have been drilled in any year since 1962.

Production from Revisions in Estimated Reserves

These revisions are based upon the 29-year series of API reserve estimates and are principally changes to earlier estimates resulting from new information and increases in proved reserves from utilizing improved recovery techniques. Initial proved reserve estimates are normally lower than final reserve estimates due to definitions. Virtually all secondary and tertiary projects improve recovery. Thus, revisions to reserves constitute a large portion of the annual increases. Since a discernible trend was not apparent from the data, FEA assumed that the average for the past 29 years (1.17 billion barrels per year) will be added as revisions in each of the next 10 years.

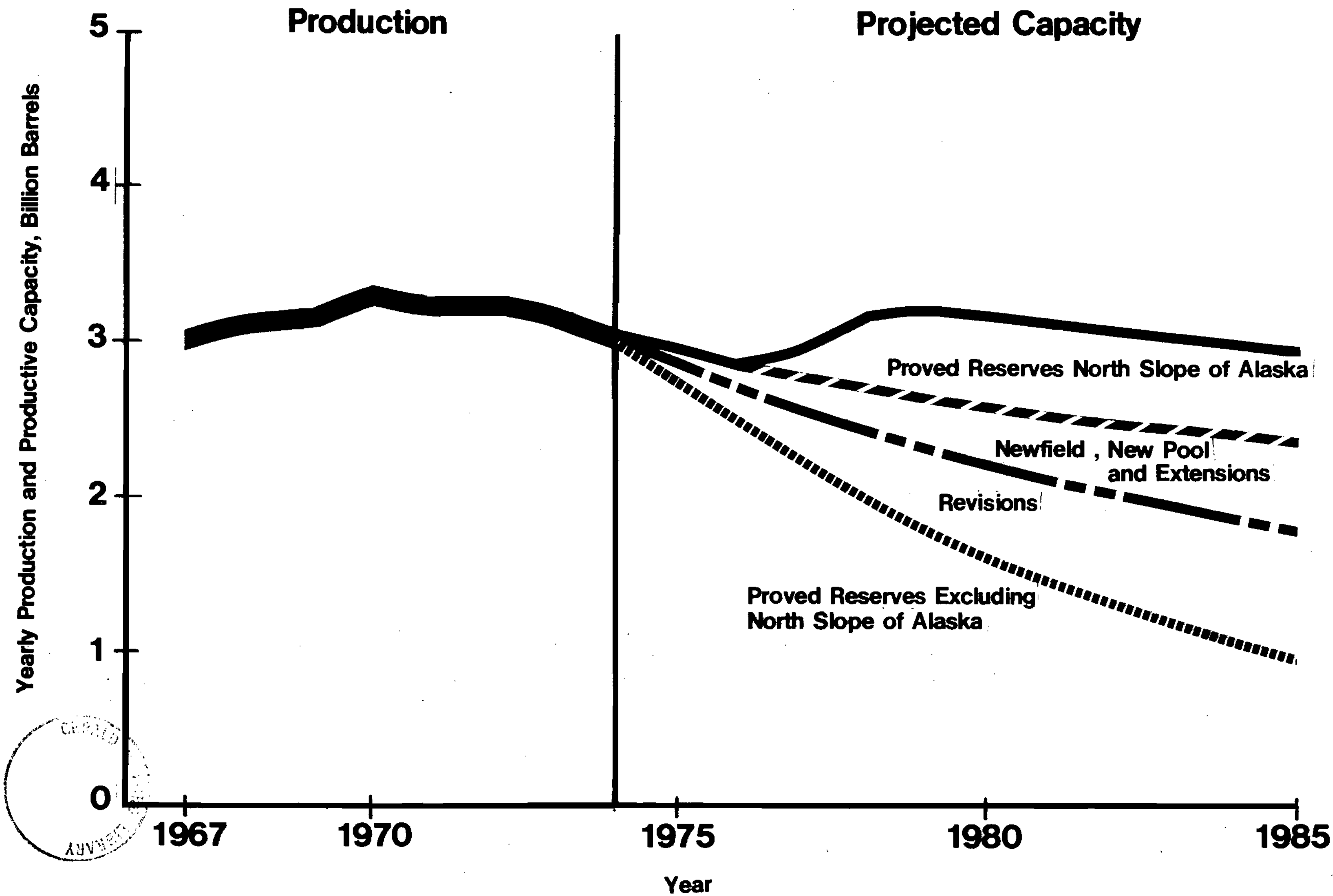
Results

Results of this analysis, shown in Table 23 and the illustration that follows, indicate that crude oil productive capacity in 1985 will approximate 1975 production.

Table 23--CRUDE OIL PRODUCTIVE CAPACITY PROJECTION FROM YEAREND 1974 (Million Barrels)

	Proved reserves					
Year	Excluding North Slope of Alaska	North Slope of Alaska	Revisions	New Field, New Pool, and Extensions	Total	Daily Average
1975	2753	2	125	92	2972	8.14
1976	2478	3	237	175	2893	7.90
1977	2230	164	337	249	2980	8.16
1978	2007	438	426	315	3186	8.73
1979	1807	548	506	373	3234	8.86
1980	1626	548	577	426	3177	8.68
1981	1463	548	641	473	3125	8.56
1982	1317	548	697	514	3076	8.43
1983	1185	548	748	552	3033	8.31
1984	1067	548	793	585	2993	8.18
1985	960	548	834	614	2956	8.10

Crude Oil Production and Projected Productive Capacity in the United States



Chapter 5

CRITIQUE OF METHODOLOGIES

The API and the AGA have prepared estimates of proved reserves of crude oil, natural gas, and natural gas liquids annually since 1945. Disruption of imports in late 1973 and early 1974 and allocation programs served as catalysts for increased investigating and questioning of the petroleum industry. One area that received considerable Congressional attention and concern was reserve estimates provided by industry associations. The law that created FEA incorporated the mandate to ". . . . provide a complete and independent analysis of actual oil and gas reserves and resources in the United States and its Outer Continental Shelf . . . ." FEA realized the magnitude of this assignment and immediately began evaluating alternative procedures to comply with the mandate.

The USGS has prepared and published several estimates of oil and gas resources in recent years. Their estimates employed two divergent approaches, a mathematical extrapolation based upon historic data and estimates based upon volumetric-yield methods. FEA employed the USGS to prepare an analysis of oil and gas resources utilizing volumetric-yield techniques and scholars at four universities to calculate oil and gas resources using mathematical approaches. Details on methodologies, approaches and personnel were presented in the "Initial Report on Oil and Gas Resources, Reserves, and Productive Capacities."

The more viable approaches considered to comply with the oil and gas reserve portion of the mandate included having:

1. Government personnel work with API and AGA reserves subcommittees and committees.

2. Government teams prepare reserves for a sampling of fields and prepare a report based on these estimates.

3. Decline curve computer models developed to calculate reserves.

4. Operators provide estimates of proved reserves and audit their responses.

After discussing the methods of complying with the mandate with Senate and House members, the FEA concluded that having Government personnel work with API and AGA subcommittees to prepare reserve estimates would not be widely acceptable as an "independent" source of estimates.

Having Government teams prepare estimates for a sampling of fields and prepare a report based upon these estimates was deemed to be the most "independent" but least "complete" method because of the lack of available technically competent manpower to make reserve estimates. Technical manpower requirements are monumental. The API has 24 subcommittees that provide inputs to their annual reserves update. The AGA has a similar but smaller organizational structure to provide reserve data for natural gas and natural gas liquids. FPC estimated that it would require a staff of up to 400 people to provide reserve data on a continuous basis for natural gas.

The FPC Natural Gas Reserves Study, published in 1973, was a sample of about 200 of some 6,400 known gas fields. Including management, engineers, geologists, statisticians, consultants, and sub-professionals, about 100 people worked on this study over a 2-year period. About half of the U.S. gas reserves were quantified on an individual reservoir basis. As more than 100 of the fields included in the sample were the "giants" (fields having reserves greater than 400 billion cubic feet), the required manpower for making reserve estimates for the numerous smaller fields not included in the original study would be significantly higher. As the FEA mandate also included crude oil and, as the ratio of oil fields to gas fields is about 4 to 1, this approach was not deemed to be satisfactory for meeting the "complete" requirement within the allotted time. The number of engineers experienced in oil and gas reserve calculations, geologists and other required technicians to do a complete and independent analysis (in terms of 100 percent coverage on an individual reservoir basis) of oil and gas reserves and resources within 1 year was not available in Government. Thus, an alternative method was needed.

Using decline curves was not considered acceptable because only about one-third of the crude oil reserves were in reservoirs that exhibited characteristics considered favorable for estimating proved reserves by decline-curve analysis. An even lesser volume of gas reserves could be estimated reliably from analyses of decline curves.

As other methods did not satisfy the Congressional mandate, FEA elected to survey oil and gas operators by requesting estimates of proved reserves and auditing their responses.

Critique of the Operators Survey

The Operators Survey provides the only comprehensive National estimates of crude oil and natural gas proved reserves, indicated secondary and tertiary reserves, and productive capacity available other than those prepared by the industry trade associations.

Operator Response and Accuracy

Of paramount importance in FEA's survey of oil and gas field operators were the ability of operators to supply the data and capability of FEA to process, evaluate, and analyze operator responses within the imposed time constraints.

Initial response to the questionnaire was slow and data quality was substantially below expectations. FEA reacted to these situations by mailing a reminder letter to nonrespondents; in a later effort all nonrespondents having 1973 production of at least 5,000 barrels of oil or 100 million cubic feet of gas were again reminded of their noncompliance by telephone. The additional efforts were deemed successful in that coverage of the survey as measured by production data benchmarks was 97 percent for crude oil and 95 percent for gas. Operators who submitted forms that were incomplete or contained data considered out-of-range of normal expectancy were telephoned. More than 14,000 calls were made to upgrade operator responses.

The screens used to determine out-of-range data were initially too fine, and the rejection rate was larger than considered reasonable. Subsequent widenings of the screens were necessary to achieve a balance between resources--man-hours and time necessary to validate the responses--and data quality. Further improvement in data quality could perhaps have been obtained by adjusting screen sizes, but this was not practical due to resource limitations.

Operators in many instances indicated that they did not have basic data needed to make accurate estimates of original hydrocarbons in place. This was especially noticeable for older fields and in situations where ownership had changed.

An audit of a stratified statistical sample of responses indicated that 94 percent of the crude oil and 95 percent of the nonassociated gas reserve estimates were made by either an engineer or a geologist.

Although there were good correlations in total gas reported by operators and benchmark data, distributions of gas into associated and nonassociated classes were not satisfactory. Thus, gas data have been tabulated by totals for this report.

Misinterpretation of Instructions

The largest deficiencies in operator responses were failure to designate the principal constraint on productive capacity and the reporting of gas production and reserve volumes in thousands instead of millions of cubic feet. Two mathematical interrelationships were incorporated in computerized auditing procedures to identify incorrect units of information and operators were telephoned to obtain consistent data.

Misinterpretation of instructions or definitions which were not flagged by the screen could distort estimates. In the case of natural gas estimates being reported in thousands instead of millions of cubic feet, the estimate would tend to be overstated.

Field Identification and Delineation

To compare operator responses to a known base, FEA obtained 1973 crude oil and gas production by fields from all States in which this information was available. However, in many instances, validation and delineation of fields to compare State production, operator production, field study production, decline curve production, and the 100 oil fields and 50 gas fields for which the API and AGA published reserve estimates required data tabulations by hand. This resulted from inexact labeling of data entries into the benchmark system, inexact labeling of field names provided by operators, and grouping of previously individually designated and named fields into areas, trends, and other fields.

Through the use of auxiliary information purchased for 15 principal oil and gas producing States including operator production by field and State allowable schedules, the FEA was able to identify satisfactorily and delineate virtually all fields for which API, AGA, and FEA field studies reserve data were available.

The expansion of reserves for those responses that did not provide the data at a field level by using the ratio of reserve to production would have provided a more precise estimate than the State level expansion and the application of theoretical decline curves to calculate reserves. However, the delineation problems mentioned would have greatly increased the time and manpower requirements.

Manpower Constraints

There were insufficient technically qualified personnel available within FEA to complete the study in the allotted time. A total of 25 professionals from three offices of the USBM, one office of Energy Research Development Administration and two FEA Offices assisted in the processing, analyzing and obtaining of additional information from operators. The work of these professionals contributed significantly to improvements in data quality. A sufficient number of personnel were made available to process, edit, encode, keypunch, and verify data submissions; develop computerized systems; and process the data. At peak periods in April and May between 65 and 70 persons worked on the operator survey portion of this project.

Production Information Not Surveyed

The Operator Survey questionnaires did not request information to make analyses of the manner and rates at which oil and gas resources have been and will be converted into proved reserves. These analyses deal with the efficiencies and rates of exploration, development and recovery of oil and gas resources. To obtain all the data needed to perform economic analyses of petroleum supply from operators of oil and gas wells was deemed impractical for the following reasons:

1. Only a small number of operators have the capability to provide such data.

2. Adherence to a number of complex definitions would have been necessary. Uniform interpretations and adherences probably could not be achieved.

3. Time constraints imposed by P.L. 93-275 and availability of qualified Government personnel to collect, validate and analyze the data precluded a timely and quality product.

Critique of Major Oil and Gas Field Studies

The objective of the Major Oil and Gas Field Studies was to provide a check on the Operators Survey results by means of independent engineering analyses.

A completely independent field study would start with basic data concerning wells, logs, production and various mandatory surveys which are in the public files or available from commercial reporting services. The contractor or Government agency would process the information, produce its own interpretations of the geological and reservoir situations and formulate its own conclusions. This is a considerable undertaking. A completely independent field study for a large and complicated field could require several man-years of technical effort and considerable staff support. In addition to the generally available information cited above, a proper field study requires other information such as geophysical surveys, core analyses, reservoir fluid analyses, results of special research investigations, and laboratory or mathematical model studies. This sort of information often does not reach a public file and is generally regarded by its owner as interpretative and proprietary. Because of the requirement of accessibility and considerable cost, duplication of this sort of information without the cooperation of the operators is usually not possible.

The FEA studied 65 separate field entities. Two of the original 50 fields selected by FEA contained seven separate field entities which were studied separately and one field was studied twice. An additional nine fields were selected for study after the original selection. The FEA field study program involved the preparation of 47 field reports by six contractors and 18 field reports by three Government agencies. Forty-five days were allowed for the preparation of 56 of the reports and 90 days were allowed for the preparation of nine of the reports. Neither the contractors nor the Government agencies had appreciable spare staff standing by awaiting commencement of the FEA field study program. Accordingly, most of the FEA field studies are not of the completely independent category discussed above. Perhaps a half dozen of the reports demonstrate thorough basic original work.

Much is known and has been written about the large oil and gas fields of the United States. This information is in the form of technical papers which have been presented before professional societies or published in trade journals. Many large fields have been extensively reviewed and exhibited before various regulatory bodies. Many private field studies have received some outside distribution. Very often, large fields are studied by committees of technical people for the purpose of developing unitized operating plans in the secondary recovery category. When these fields involve many operators and hundreds of mineral owners, the committee studies are generally accessible to those wishing to maintain extensive libraries. Finally, most of those working on the field studies have had at least some experience working for employers who have dominate positions in some of the larger fields.

Most of the FEA field studies were prepared after extensive reviews of all of the available interpretative information mentioned above. Those preparing the reports usually updated these reviews to whatever extent seemed practicable. In most instances, the principal operators were visited and additional factual information was obtained. In some instances, the operators were not averse to discussing the interpretive aspects of reservoir behavior. The authors then composited the various items of information, carried out spot checks to the extent considered advisable, and estimated the required hydrocarbon volumes.
Thus, the FEA field studies in most instances should be classed as independently prepared summary reviews of available literature and data, supplemented as necessary with original work to make the study reasonably complete. Problems arose when a field which had never been extensively reviewed in the literature was dominated by one or two operators who declined to discuss interpretive or proprietary information. These

instances usually resulted in the production of very brief undocumented reports which are less than completely satisfactory. The time constraints would not permit the preparation of a more complete report in these circumstances.

All of the reports were reviewed by FEA staff who checked for proper methodology, internal consistency, reasonableness, and compliance with definitions. Many of the reports lacked polish in these four respects. This was generally attributed to shortness of time, additional time lost establishing data gathering procedures with operators, reluctance of some operators to reveal interpretive information, poor communications regarding definitions and reporting format, and lack of time to review reports carefully after preparation. In addition, there was a considerable amount of carelessness and some incompetence.

The contractors and Government agencies generally were concerned about these shortcomings when they were pointed out. Complete, new reports were voluntarily issued for 14 fields. Over 250 revised pages were issued for 30 reports. Oral or written corrections were supplied for 12 reports. All of this resulted in significant numerical changes to hydrocarbon volumes shown on the summary tables of 47 reports. Fourteen of these 47 instances were primarily caused by definition problems, although, over 40 of the report authors failed to follow prescribed definitions. This suggests that the definitions themselves could be clarified. The definitional problem areas were in the category of proved shut-in reserves, indicated secondary and tertiary reserves, short-term productive capacity, and shrinkage of gas volumes caused by extraction of natural gas liquids. Eight of the changes in summary volumes resulted from corrections of improper methodology. A half dozen instances of improper procedures which have not been corrected are mentioned in the various FEA report summaries. All of the remaining changes to summary volumes resulted from corrections of numerical mistakes, in addition to corrections in the definition category. These corrections have brought most all reports up to satisfactory levels of acceptability.

Because of the exigencies of time and other practical considerations, not many of the FEA reports are particularly scholarly. However, they are, for the most part, practical documents. As such, they have generally accomplished their objectives of serving as a useful check on the Operators Survey. Completely unacceptable and unjustified levels of expenditure, both in time and money, would have been necessary if completely original and independently prepared reports of a thorough and basic nature had been attempted.

Critique of Decline Curve Analysis

The initial report discussed the methodology of decline curve analysis and the fundamental mathematical relationships of graphic declines curves to actual oil production decline rates. A number of data problems encountered in the first coarse pass at determining reserves from decline curve analysis were cited. Efforts continued on a modest scale to apply needed refinements to the screening and analytical procedures and to use decline curve analysis to check and to augment reserve estimates from other sources. FEA's tentative judgment was that mass machine processing of data did not offer a promising means of developing estimates of reserves and production capacities for a significant number of domestic fields. Subsequent refinements have not materially changed this viewpoint. In effect, each field must be verified for data input and then evaluated using the proper parameters. Variances to general parameters are more the rule than they are the exception.

Methodology

A brief explanation and update about certain features of hyperbolic decline curve projections is warranted before this method is evaluated.

Data Files. The data files are computer based magnetic tapes containing field and reservoir identification, depth, production by year, and number of producing wells. This information is fairly complete except for the number of wells which is important in determining the estimated economic limit. All of this information is displayed on the computer printout for quick assessment of data errors.

Economic Limit. Economic limit is that point at which the producing property becomes uneconomic to operate. This limit will vary with many factors including depth and geographic location. When the current production rate is appreciably greater than the economic limit, the reserves determined are only slightly affected. When the current production rate is near the economic limit, reserves can vary appreciably. This point may be emphasized by wells currently producing, due to price incentives, that were previously shut in. Price changes could possibly double those field reserves overnight. The economic limits used in the computer program were derived from field experience and may not be germain for any given field. The economic limit of fields on the North Slope of Alaska, with its many problems associated with weather and geography, will have a much different economic limit than a field in Illinois with shallow depths and mild climate. Abandonment rates can vary from about 50 barrels per day per well in Alaska to less than one barrel per day in the older fields of the Midcontinent or Appalachian area.

The yearly volumes that were assumed to be the abandonment rate per well for this analysis are listed below:

Producing Depth (feet)	Economic Limit (bbl/yr/well)
0 - 3,000	365
3,001 - 4,500	540
4,501 - 6,500	730
6,501 - 8,000	1,000
8,001 - 10,000	1,000
10,001 - Greater	2,500

A field abandonment level was determined by multiplying the number of producing wells by the appropriate abandonment rate.

Three-Year Running Average. Prior to fitting a hyperbolic decline curve to the data, a 3-year running average test was used. The application of this test in screening data was that the production for 1973, 1972, and 1971 was less than for 1972, 1971 and 1970, etc. This screen ensured that the data were consistently declining.

The decline program observed only that portion of consecutive production which meets the 3-year running average test. If between 4 and 6 data points met the test, only an exponential curve was used. For more than 6 points, both exponential and hyperbolic curves were used. For less than 4 points, no calculations were performed. Prior to 1971, Texas production was affected by Statewide allowable regulations. Thus, there were insufficient significant data available to project hyperbolic declines, and only exponential declines were used for Texas production.

Hyperbolic Curve Fit Routine. A hyperbolic curve is generally accepted within the petroleum industry as a useful tool for determining future reserves. The use of this method is basically empirical but does have fundamental foundation.

The hyperbolic curve fit program determined the hyperbolic curve which "best" represented the data. An exponential curve fit was also determined. An exponential curve is a hyperbolic curve in which the change in slope with respect to time is zero. The "best" curve fit was determined by the statistical procedure of "least squares."

Except for the determination of the shift factor, the curve fit program was essentially identical to the described program in articles by A. W. McCray and A. G. Comer.* McCray and Comer use a curve fit

*McCray, A. W. and Comer, A. G., "Statistical Basis for Choice Among Hyperbolic Decline Curves and Computer Application in Calculating Confidence Limits of Reserve Predictions," AIME, Inc., SPE Paper No. 1930, 1967.

relating residuals versus shift factors to determine the statistical best shift while the contractor used a trial and error converging iteration to determine the unknown constant.

The hyperbolic decline program was tested against known test data which ensured accuracy of the program. Calculations on portions of actual data followed and the results were examined to ensure proper execution of the program.

Reserves. Once a declining trend was established by the curve fit routine, reserves to the economic limit were calculated by summing the volumes under the curve.

Data Screens. Certain situations were encountered where decline curve evaluation was rejected for analysis. These are listed below:

Situation	Screen
1. No production reported in most recent year.	1973 production greater than zero.
2. Production not declining.	Three-year running average.
3. Less than 4 points to determine curve.	Three-year running average.
4. Confidence level of 95 percent not met.	Table of values for 95 percent confidence level.
5. Projected production declined less than a 2 percent rate.	Slope less than 0.02.
6. Calculated reserves greater than 25 times the latest year's production.	Reserves 25 times greater than 1973 production.

Evaluation

The expertise gained from the decline curve analysis has revealed certain shortcomings in applying a computer program to rapidly process field data for determining reserves.

The production input data (number of producing wells and unimpeded production rates) must be accurate or the results will be faulty.

Arbitrary abandonment rates based only on depth are not realistically valid. The economic abandonment rate for each field at the same depth can vary widely because of surface operating cost differences. For example, in Pennsylvania some wells are still producing at averages of less than 1/2 barrel per day while wells in the Alaskan Cook Inlet offshore area may be uneconomic at greater than 35 barrels per day. To refine abandonment rates to meet these objections would require a more rigorous screening procedure that could approach a field by field investigation. Such a procedure would rule out the rapid treatment of a machine computing program.

In multireservoir fields not all reservoirs are produced by the same type of drive mechanism. Individual depletion drive reservoirs may influence production data for an entire field to be amenable to analysis while the reservoirs not produced by depletion drive may distort the results of such analysis.

Reconciliation of invalid production data would require State-by-State investigation of how a producing well is defined and reported. The same procedure would apply to average depth of field reporting. Some data on production well count and depth as in the case of Pennsylvania, Ohio and West Virginia were not available on a field-by-field basis. Therefore, utilization of a computer program designed to mass process production data to determine reserve estimates is restricted to a less than significant number of fields in the United States and cannot be used statistically to extend coverage to any significant number of fields.

The following tabulation describes in summary form the results obtained by the computer program decline curve analysis. It describes quantitatively the fields that were adaptive to decline curve analysis on a State-by-State basis. In cases where reservoir data were available, if some reservoirs in fields were amenable to analysis and others were not, the total field was rejected. Therefore, more production may be amenable to decline curve analysis than calculated by the computer program for these cases. Table 24 reveals that only 38 percent of the producing fields in the United States are adaptive to decline curve analysis for reserve determination. These adaptive fields have 43 percent of the producing wells but only 25 percent of the production.

The tabulations of the reserves determinations applied to adaptive fields are iterations of the results using the parameters and screens described previously. Table 25 shows the relationship of reserves determined by hyperbolic decline analysis vs. exponential decline analysis. In all cases, hyperbolic analysis indicated greater reserves than exponential analysis.

Critique of the Trade Associations

The initial report describes the evolution of the API and AGA reserve and productive capacity estimates. API and AGA began publishing annual estimates of crude oil, natural gas, and natural gas liquids on a definitionally consistent basis in 1946. In response to data needs defined in a Federal interagency effort, the API and AGA greatly

Table 24--NUMBERS OF FIELD PRODUCTION HISTORIES ADAPTIVE TO DECLINE CURVE ANALYSIS - 1973

State	No. of Adapt. Fields	Percent, Adapt. Fields of Total Fields	No. of Adapt. Wells	Percent, Adapt. Wells of Total Wells	Annual Prod., Adapt. Fields (MMBbls)	Percent, Adapt. Prod. of Total Prod.
Texas**	3,043	35	74,893	47	215.6	18
Louisiana	275	42	6,305	22	170.2	25
California	238	49	19,131	34	148.9	28
Oklahoma**	421	30	23,664	30	68.0	37
Wyoming	155	40	3,050	39	53.9	36
New Mexico	223	47	5,696	43	32.3	34
Kansas**	813	48	19,159	63	31.3	56
Illinois	142	43	18,897	78	25.3	85
Alaska	3	43	90	54	22.7	31
Mississippi	199	46	1,224	36	19.8	22
Utah	30	52	608	48	12.0	39
Montana	65	49	1,446	43	11.6	31
North Dakota	68	58	854	60	7.9	40
Arkansas	106	40	3,690	36	7.6	26
Michigan	61	33	2,135	53	5.0	39
Colorado	180	46	812	30	4.6	8
Indiana	58	32	2,143	58	3.3	68
Nebraska	184	63	724	66	3.1	45
Kentucky	87	37	1,532	57	2.6	58
Arizona	2	67	21	70	0.7	94
Alabama	4	29	83	15	0.6	5
Florida	1	11	15	11	0.6	2
Tennessee	1	7	1	1	***	1
Total*	6,359	38	186,173	43	847.5	25

* No field production history for Nevada, New York, Ohio, Pennsylvania, South Dakota, Virginia, West Virginia, and Missouri.
** Based on 1974 production.
*** Less than 0.05.

Table 25--RESERVES FROM FIELDS ADAPTIVE TO DECLINE CURVE ANALYSIS OF FIELD PRODUCTION HISTORIES - 1973

State	Hyperbolic Reserves (MMBbls)	Exponential Reserves (MMBbls)
Alabama	3.3	3.0
Alaska	266.5	262.2
Arizona	4.0	1.9
Arkansas	60.7	55.9
California	1,692.4	1,553.0
Colorado	28.7	22.0
Florida	5.0	5.0
Illinois	185.6	150.2
Indiana	21.4	20.0
Kansas*	226.4	208.0
Kentucky	13.4	11.9
Louisiana	1,568.8	1,492.5
Michigan	55.4	50.6
Mississippi	143.8	131.4
Montana	124.6	110.7
Nebraska	18.8	16.4
New Mexico	283.9	271.5
North Dakota	85.5	75.0
Oklahoma*	498.7	476.6
Tennessee	**	**
Texas*	***	1,534.2
Utah	98.1	94.9
Wyoming	652.7	628.5

* Based on 1974 production.
** Less than 0.05.
*** Texas production affected by Statewide allowable regulations, thus there were insufficient significant points available to project a hyperbolic decline.

expanded the details of their joint 1966 report. Federal observers have attended all annual API/AGA meetings since 1966.

Neither the range nor the detail of reserve estimates included in the API and AGA reports is available from any other source. These consistent historical records were essential to recent U.S. energy studies such as Project Independence Blueprint and the National Petroleum Council's Energy Outlook.

For more information about the API and AGA procedures, refer to their joint publication entitled "Reserves of Crude Oil, Natural Gas Liquids and Natural Gas in the United States and Canada and United States Productive Capacity as of December 31, 1974," Volume 29, May 1975.

Critique of State Agencies

The initial report contained a review and evaluation of the capabilities to perform reserve and productive capacity estimates. Since no new information has been received from the States since the initial report, the complete discussion will not be repeated for this report, but major points will be highlighted.

In order to determine the States' capabilities to develop reserve and productive capacity estimates, all member and associate member States of the Interstate Oil Compact Commission and other States with histories of oil and gas production were surveyed. The survey had two major objectives. The first objective was to determine the States' capabilities to perform the above tasks within their present Governmental structures. The second objective was to obtain any information that would be of aid in a National reserve study.

The cooperation and effort of the States in response to the survey was excellent. The States not only submitted valuable information about reserves, production, and other data but also provided an insight into their present capabilities to perform reserve evaluations. Most States surveyed did not have agencies which prepared reserve or productive capacity estimates. For those estimates provided by the States which did prepare estimates, the methodologies and definitions varied and prevented consistent aggregation and valid comparisons.

To develop complete estimates prepared by the States, three major obstacles would have to be overcome. First, a common set of criteria or definitions would need to be provided to the States and applied consistently by the States. Second, considerable time would be needed to expand staffing, data, and analytical capabilities to permit valid calculations to be made. And, third, the State agencies responsible for making the necessary calculations would need large increases in funding.

Chapter 6

CONCLUSIONS AND RECOMMENDATIONS

The final section of this report presents to the President and the Congress a set of recommendations concerning future efforts. Four subject matter areas will be addressed separately as each presents unique problems. These are:

1. Resources
2. Reserves
3. Current producing capacity
4. Projected producing capacity

Resources

Measures or estimates of resources delineate the volumes of a material that are potentially available for commercial exploitation. Recoverable volumes are limited by the amount of the material in place in the ground; they are also importantly affected by technology, production costs and selling prices. Resources pass through several levels of identification, ranging from estimates of the total volume of material in place to a restrictive definition of materials which are proved to exist and are recoverable under current technological and economic conditions. These latter resources are known as proved or measured reserves.

To analyze oil and gas resources in the United States, two methods were utilized: a mathematical-statistical approach and a method that made use of geologic-volumetric data and statistical models. Complete descriptions of these methods and results were included in the June 1975 initial report.

Mathematical Approach

FEA engaged four teams of consultants to prepare independent mathematical-statistical estimates of undiscovered crude oil resources in the United States. Two teams concluded that reliable projections of undiscovered resources could not be developed. The other two teams developed projections for explored regions; however, estimates differed widely.

Recommendation. Further efforts to develop improved mathematical and statistical approaches to undiscovered oil and gas resources should be assigned a low priority.

Combined Geologic-Volumetric and Statistical Approach

Through an interagency agreement, FEA funded the maximum effort that USGS could undertake to evaluate undiscovered oil and gas resources in the United States. The results, published as USGS Circular 725 present the most recent and comprehensive set of oil and gas undiscovered resource data for the Nation.

Recommendations. FEA recommends the following:

1. Create a task force from Government and industry to standardize resource classifications and nomenclature. Considerable confusion has arisen because the terms resources and reserves are often used imprecisely and without indication of degree of identification or the extent of recovery implied.

2. Encourage carefully planned exploratory efforts in relatively untested geological provinces. A high proportion of "undiscovered recoverable resources" is presumed to be located in those provinces. Their exploration would reduce some important uncertainties in our national energy planning.

3. Investigate the extent to which changes in economic parameters can be incorporated in resource evaluations.

4. Encourage scientific contributions to Government-wide efforts to improve estimates of oil and gas resources.

Reserves

Accurate and independent evaluations of oil and gas reserves will continue to be an important function of the Federal Government. Periodic Government estimates of oil and gas reserves at the National and State levels of aggregation can be most efficiently generated through direct surveys of field operators. However, these periodic estimates are not required on a three month basis as now mandated, but would be most useful on a biennial basis.

Operators Survey

Useful estimates of proved oil and gas reserves were derived through a survey of oil and gas field operators. The accuracy of operators' estimates was tested by field audits of responses and by comparisons with reserve estimates from other sources.

The quality of the results obtained from the survey depended in large measure on extensive clerical and computerized edits and on telephone followups with respondents -- more than 14,000 telephone calls were made to oil and gas operators to verify or correct questionable information.

FEA's evaluation of the results of the survey indicates that similar surveys in the future would yield useful results. Sample surveys of operators carried out on a biennial basis would provide updated estimates of reserves at a fraction of the cost of the original survey of all operators. The FEA believes that the requirement of P.L. 93-319 for quarterly reports on the reserves of oil and gas is not realistic. Reserves in a 3-months period do not change appreciably and for this reason a biennial report would be sufficient.

Recommendation. If the Federal Government's objective is a periodic inventory of proved oil and gas reserves, FEA recommends that a sample survey of operators be carried out every second year with survey results audited in the same manner as in the survey just completed. Every effort should be made to coordinate these surveys with the work of other Federal agencies.

Industries' Surveys

The API and the AGA surveys which have been developed on a yearly basis since 1946 provide valuable detailed information about reserves. Detailed information includes new additions to reserves; the source from which the additions come, such as new field drilling, exploratory drilling; and the results of the application of enhanced recovery methods.

Recommendation. FEA continues to encourage the trade associations to continue their present systems of oil and gas reserves reporting. These efforts provide additional useful information and a valuable cross-check with the independent Federal estimates. The Federal Government should continue to consult with the associations to assure that their information is consistent with Federal efforts and hence of the greatest possible value.

Major Oil and Gas Fields Studies

Engineering studies of major oil and gas fields provided independent reserve estimates and yielded supplemental information. Because large fields were heavily represented in this sample, this effort yielded independent estimates of fields accounting for 52 percent of the Nation's total crude oil reserves and 28 percent of the natural gas reserves.

Recommendation. Engineering studies of selected fields should be used to confirm the reserve estimates provided by operators. In addition, these engineering studies, carried out over a period of years, would yield reasonably current and detailed information, independent in nature, on the large fields in which the great bulk of the Nation's reserves are found.

Decline Curve Analysis

An attempt was made to estimate aggregate reserve totals by supplementing major field estimates with computer-processed estimates of smaller fields, using decline curve analysis procedures. This proved infeasible in general because decline curves were not applicable to all fields. Decline curve analysis is, however, an efficient method of analysis for certain fields.

Recommendation. FEA should give low priority to efforts to explore the application of decline curve analysis for reserve estimation.

Current Producing Capacity

Accurate reporting on capacity to produce oil and gas calls for precise definitions of the conditions under which production will occur. Such definitions are difficult to draft and even more difficult to convey to respondents and to persons who use the information. In FEA's recent survey, results relating to productive capacity generally were less satisfactory than those relating to reserves.

Currently, virtually all U.S. oil and gas fields are producing at or near capacity and are likely to continue to do so under normal producing conditions. Nonetheless, capacity information is useful in monitoring the current progress of the oil and gas industries, for evaluating market forces and for emergency planning. Most current unused capacity is found in a few very large, identified oil and gas fields. FEA's field studies were useful in identifying this capacity.

Recommendation. Definitions of capacity, especially capacity to produce natural gas, should be reviewed to insure that they meet data needs.

Projected Producing Capacity

Under certain conditions production decline curves are useful in projecting producing capacities of individual fields. This technique can be extended to some entire mature producing areas.

Useful projections of producing capacities must consider current capacities, the rate at which capacities are declining, opportunities to stimulate new recovery from known fields, opportunities for extensions or in-fill drilling in known reservoirs in known fields, and potentials for the discovery and production of oil and gas in new areas. Additionally, projections must take into account a host of other factors which include present and future prices and costs of production, marketability, governmental and other constraints on production, access to resources, the availability of financing, and trends in technologies of exploration, production and transportation.

Project Independence Blueprint illustrates a method which is often followed, but there is no single technique for the projection of producing capacity.

Recommendation. Efforts to improve relevant information, develop reasonable analytical models, and adjust projections on the basis of sound judgment and experience should be continued.

Volume II

Final Report on Oil and Gas Resources, Reserves, and Productive Capacities

Submitted in Compliance with Public Law 93-275, Section 15(b)

October 1975

Federal Energy Administration
Washington D.C. 20461

Final Report on Oil and Gas Resources, Reserves, and Productive Capacities

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Office of Policy and Analysis
and
Office of Energy
Resource Development

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Chapter 1

ENGINEERING ANALYSES OF MAJOR OIL AND GAS FIELDS

An essential element in formulating a National energy policy is the development of a reliable estimate of domestic crude oil and natural gas resources, reserves, and productive capacities. The Federal Energy Administration (FEA) Act directs the FEA to prepare a "complete and independent analysis of actual oil and gas reserves and resources in the United States and its Outer Continental Shelf, as well as of the existing productive capacity and the extent to which such capacity could be increased for crude oil and each major petroleum product each year for the next ten years through full utilization of available technology and capacity. The report shall also contain the Administration's recommendations for improving the utilization and effectiveness of Federal energy data and its manner of collection." The FEA submitted to the President and the Congress in June 1975, an Initial Report on Oil and Gas Resources, Reserves, and Productive Capacities. The initial report provides background information about the methodologies used to accomplish FEA's task as well as resource and preliminary reserve estimates for the United States. Volume I of the final report provides final reserve and productive capacity estimates, compares these estimates with estimates from other sources, projects a U.S. crude oil productive capacity estimate, evaluates the procedures used to develop these estimates, and recommends procedures to be used for future estimates. Volume II of the final report provides summaries of engineering analyses of major domestic oil and gas fields.

As part of FEA's effort to prepare reserve and productive capacity estimates of oil and natural gas, the FEA contracted for and performed engineering analyses of 59 major oil and gas fields in the United States. The initial report describes the procedures used to select and analyze the 59 oil and gas fields. These major oil and gas fields represent 52 percent of the proved reserves of crude oil and 28 percent of the proved reserves of natural gas.

The major oil and gas fields were studied for the following reasons:

1. To serve as an audit of the Operators Survey.

2. To test the feasibility of expanding estimates from the major fields in conjunction with estimates from other sources to develop national reserve and productive capacity estimates.

3. To increase the understanding of reserve and productive capacity estimates of major domestic oil and gas fields.

4. To test the capabilities of Government agencies and private contractors in developing independent field estimates.

Audit of the Operators' Survey

Volume I of the final report compares the reserve estimates from the Major Field Studies with those from the Operators Survey. As indicated by the comparisons, reserve estimates for individual fields varied significantly, but neither the Major Field Studies estimates nor the Operators Survey estimates tended to be consistently higher. The overall difference for crude oil was less than 2.5 percent while the overall difference for natural gas was less than 1.5 percent. Therefore, the Operators Survey would tend to be verified as an acceptable technique of reserve estimation.

Expansion of Major Field Estimates

The expansion of reserve estimates from the Major Oil and Gas Field Studies in conjunction with estimates from other sources was not found to be practical for this report. The only source of complementary, independent estimates would need to be developed by a mass machine application of decline curve analysis. Since the decline curve analysis technique was not found to provide a dependable source of estimates, no attempt was made to expand the estimates from the Major Field Studies to be representative of National estimates.

Understanding of Major Oil and Gas Fields

The Major Oil and Gas Field Studies enhanced the understanding of the reserve and productive capacity estimates of those fields as well as the general knowledge about the fields themselves. The studies provided information on current producing status and state of depletion, reservoir rock and fluid parameters, reservoir structure, and indications of opportunities for enhanced recovery prospects for the Nation's principal oil and gas fields. The information contained in the summaries of the field studies provides insight into the difficulties encountered in developing reserve estimates.

Capabilities of Government Agencies and Contractors

Although few of the field studies represent thorough basic original work because of the lack of adequate time, manpower, and financing to perform such studies, most all of the reports are practical documents providing independent interpretation of available information. Apparently, the accumulation of experience in preparing full field studies has generally been limited to principal operators and some Government agencies. In the routine course of their work, consultant firms have usually not been called upon to prepare complete field studies for domestic clients. There are, of course, exceptions to this generalization.

Chapter 2

SUMMARIES OF ENGINEERING ANALYSES OF MAJOR OIL AND GAS FIELDS

The summaries of the Major Oil and Gas Field Studies were prepared by FEA staff after a careful and thorough review of each report. All of the reports were reviewed for proper methodology, internal consistency, reasonableness, and compliance with definitions. Many of the reports lacked polish in these four respects. This was generally attributed to shortness of time, additional time loss establishing data gathering procedures with operators, reluctance of some operators to reveal interpretive information, poor communications regarding definitions and reporting format, and lack of time to review reports carefully after preparation. In addition to this, there was a considerable amount of carelessness and some incompetence. The consultant firms and Government agencies generally were concerned about correcting the various shortcomings when they were pointed out. Many of the reports were extensively revised and these revisions have brought most all reports up to satisfactory levels of acceptability.

The reserve and capacity estimates shown in these summaries, and the factors evaluated in arriving at those estimates are in each case those submitted by the contractor. FEA has noted those relevant factors which are highly judgmental, and those evaluations which are based on limited information. Where possible, the sensitivity of reserve and capacity estimates to those factors has been noted. FEA advises the reader to review the critique of the Major Oil and Gas Field Studies contained in Chapter 5, Volume I of this report and to read each summary carefully before attempting to use any data contained in the field summaries.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
ANAHUAC FIELD

	Crude Oil (MMBbls)	Lease Condensate[1] (MMBbls)	Natural Gas: Assoc. (BCF)	Natural Gas: Non-Assoc. (BCF)	Natural Gas: Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	487.3	0.3	869.3	146.1	
Proved ultimate recovery	297.8	0.2	671.9	113.1	
Cumulative production	243.5	0.2	312.6	81.2	
Proved reserves	54.3	NA	359.3	31.9	
			(Dry Basis)		
Proved reserves			348.6	31.9	4.7
Reserves in shut-in reservoirs	0	NA	0	0	0
Indicated secondary and tertiary reserves	0		0		
Production					
Year 1973 (total)	11.0	NA	42.6	11.7	1.1
Year 1974 (total)	8.8	NA	31.2	11.8	0.9
Long-term projection of production (annual total)					
1975	7.9	NA	22.3	8.6	
1976	6.8	NA	20.8	6.3	
1977	5.8	NA	19.1	4.6	
1978	5.1	NA	17.8	3.5	
1979	4.4	NA	16.3	2.6	
1980	3.8	NA	14.9	1.8	
1981	3.3	NA	13.7	1.4	
1982	2.8	NA	13.0	1.0	
1983	2.4	NA	12.4	0.8	
1984	2.1	NA	11.5	0.5	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	22.8	0.1	80	24	2.4
Short-term productive capacity (60-day basis)	22.9	0.1	86	26	

[1]Lease condensate reserves and production volumes are insignificant.

The Anahuac oil and gas field is located in Chambers County, Texas, about 50 miles east of Houston in the Oligocene belt of the Texas Gulf Coast.

The most important reservoir at Anahuac is the Main oil reservoir at about 7,000 feet. It consists of Marginulina sands of the Anahuac Series which are Upper Oligocene in age and upper Frio sands which are Middle Oligocene in age. Below the Main reservoir, there are 17 lower Frio oil reservoirs and 10 lower Frio gas reservoirs extending to 8,800 feet. Above the Main oil reservoir, there are 6 Marginulina and 2 Discorbis gas reservoirs in the Anahuac Series and 17 Miocene age gas reservoirs in the Fleming Series extending upward to 1,350 feet. About 99 percent of the oil reserves and 91 percent of the gas reserves at Anahuac are in the Main oil reservoir.

Anahuac is a domal uplift associated with deep seated salt movement. The field has been complexly faulted. The Main reservoir sands are blanket in nature and extend across the structure; the shallow Miocene gas reservoirs appear to be stratigraphic; and the other Marginulina, Discorbis, and lower Frio reservoirs are combination structural and stratigraphic situations. In addition to structure, lenticularity, and faulting, bottom water further delineates the accumulations in most instances. Anahuac has 7,000 productive acres (11 square miles).

Hydrocarbons originally in place in the Main oil reservoir were determined by the volumetric analysis method. The report is documented with structure and isopach maps, cross sections, and listings of reservoir rock and fluid parameters in the various fault segments. The calculations are demonstrated. Detailed data were not available for the minor reservoirs, so hydrocarbons originally in place were inferred from ultimate recovery estimates and recovery efficiency factors.

The crude oil in the Main oil reservoir was initially saturated and a large gas cap existed. There is a very active water drive. The large gas cap was cycled from about 1957-71 to recover liquid products and to prevent shrinkage of the gas cap and loss of oil to the gas cap area. Subsequently, a large portion of produced gas has been reinjected into the gas cap in order to maximize oil recovery prior to blow-down of the gas cap. In recent years, there has been a considerable reduction in reservoir pressure and increase in gas oil ratio as Texas market demand factors have been increased. A strenuous remedial work program has been carried out during the past two years and the consultant firm has assumed that this rework program can be continued. Most all of the other reservoirs at Anahuac have apparent strong water drives.

Ultimate recovery and proved reserves estimates in most all of the Anahuac reservoirs have been based upon analysis of production decline trends. Additionally, water cut versus cumulative oil production relationships were utilized for the Main oil reservoir.

The FEA report on the Anahuac Field was prepared by James A. Lewis Engineering under Contract No. CO-05-50181-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
BASTIAN BAY FIELD

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas: Assoc. (BCF)	Natural Gas: Non-Assoc. (BCF)	Natural Gas: Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	42.3	155.1	71.5	4261.3	
Proved ultimate recovery	19.0	52.6	32.9	2946.9	
Cumulative production	17.5	42.0	30.6	1881.0	
Proved reserves	1.5	10.6	2.3	1065.9	
			(Dry Basis)		
Proved reserves			2.3	1065.9	NA
Reserves in shut-in reservoirs	0	0.7	0	86.0	NA
Indicated secondary and tertiary reserves	0		0		
Production					
Year 1973 (total)	0.4	1.8	0.6	124.1	NA
Year 1974 (total)	0.4	1.6	0.5	114.1	NA
Long-term projection of production (annual total)					
1975	0.4	1.4	0.5	110.0	
1976	0.3	1.2	0.4	100.0	
1977	0.2	1.1	0.4	96.0	
1978	0.2	1.0	0.3	90.0	
1979	0.1	0.8	0.2	84.0	
1980	0.1	0.8	0.2	80.0	
1981	0.1	0.7	0.1	74.0	
1982	---	0.6	---	70.0	
1983	---	0.6	---	66.0	
1984	---	0.5	---	62.0	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	1.1	3.7	1.7	273	NA
Short-term productive capacity (60-day basis)	1.1	3.7	1.7	273	

The Bastian Bay gas field is located in Plaquemines Parish, Louisiana, in the Onshore Miocene Belt about 50 miles southeast of New Orleans.

The producing sands are in a thick sand-shale sequence of Miocene age. There are 10 oil reservoirs from 8,700 to 14,130 feet and 43 nonassociated gas reservoirs from 5,100 to 15,000 feet.

Bastian Bay is an east-west trending faulted anticline. There are east and west closures separated by a structural saddle. Almost all of the accumulations occur in the south and down thrown block of a major east-west fault which traverses the northern portion of both closure areas. Bottom water is present in most reservoirs. Some of the sands are lenticular and shale-out in the East Bastian area. The East and West Bastian areas total about 9,000 productive acres (14 square miles).

Hydrocarbons originally present in the nonassociated gas reservoirs were estimated by the volumetric analysis method. The various reservoir measurements and rock and fluid parameters were listed in the report for each zone. The hydrocarbons originally present in the oil reservoirs were inferred from estimates of ultimate production and estimates of recovery efficiency.

Almost all of the reservoirs at Bastian Bay produce with partial water drives. Two of the gas reservoirs in the western portion of the field produce predominately with a depletion mechanism.

Ultimate recovery and proved reserves in the oil reservoirs were estimated generally by analysis of production decline trends. In the nonassociated gas reservoirs, recovery efficiency factors were assigned to the estimates of hydrocarbons originally present, based upon performance in each reservoir. This latter method was also applied to one of the oil reservoirs.

The FEA report on the Bastian Bay Field was prepared by Geoscience Consulting Services International, Inc., under Contract No. CO-05-50188-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
BATEMAN LAKE FIELD

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas Assoc. (BCF)	Natural Gas Non-Assoc. (BCF)	Natural Gas Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	105.4	52.5	1053.4	2537.3	
Proved ultimate recovery	41.8	30.1	682.0	1812.4	
Cumulative production	31.3	16.6	160.5	807.2	
Proved reserves	10.5	13.5	521.5	1005.2	
			(Dry Basis)		
Proved reserves			506.9	978.8	27.7
Reserves in shut-in reservoirs[1]	0	2.6	5.6	300.1	0
Indicated secondary and tertiary reserves	0		0		
Production					
Year 1973 (total)	1.5	1.8	8.9	108.5	2.7
Year 1974 (total)	1.4	1.6	9.0	123.0	2.5
Long-term projection of production (annual total)					
1975	1.2	1.4	10.0	130.2	
1976	1.1	1.3	11.0	130.5	
1977	1.0	1.2	14.0	120.8	
1978	0.9	1.0	18.0	106.9	
1979	0.8	0.7	23.0	90.6	
1980	0.7	0.6	28.0	79.7	
1981	0.6	0.6	32.0	68.9	
1982	0.6	0.5	37.0	58.0	
1983	0.5	0.4	41.0	53.5	
1984	0.4	0.4	46.0	44.4	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	3.1	3.4	22.0	343.0	6.8
Short-term productive capacity (60-day basis)	3.1	3.8	22.0	377.0	

[1] Reserves in the shut-in reservoirs are for 61 nonassociated gas reservoir units and for 3 gas caps in oil reservoir units. These reserves are included in the proved category.

The Bateman Lake gas field is located in St. Mary Parish of southern Louisiana in the onshore Miocene belt. The field is 75 miles southwest of New Orleans.

The producing formations consist of some 30 Miocene sands which are encountered at depths ranging from 3,150 feet to below 14,000 feet.

The Bateman Lake structure is a highly faulted anticline which overlies a deep seated salt dome. There are 121 different reservoir units resulting from the numerous faults and many sands. Some 101 of the reservoir units contain nonassociated gas and lease condensate. Twenty of the reservoir units contain associated gas and relatively small amounts of crude oil. Bottom water is present in most reservoir units. Bateman Lake has 9,000 productive areas (14 square miles).

Hydrocarbons originally in place at Bateman Lake were estimated by volumetric analysis of each of the 121 reservoir units. The consultant firm checked maps, data, and figures which were furnished by the operators in the field.

The recovery mechanism was reported as a water drive in virtually all of the gas reservoirs at Bateman Lake. The oil reservoirs produce with both water drives and solution gas drives. The judgment of the consultant was employed in the selection of recovery factors which average 69 percent for gas and 40 percent for crude oil (expressed as a portion of hydrocarbons originally present).

The production history or the performance characteristics at Bateman Lake were not reviewed extensively. Such a review would be helpful in understanding the selection of the recovery efficiency factors and the forecast production trends.

There are some errors in methodology in the report. The consultant has corrected some of these and the corrections are reflected in the Summary Table. The others are not particularly significant.

The FEA report on the Bateman Lake Field was prepared by Geoscience Consulting Services, Inc., under Contract No. CO-05-50185-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
BAY DE CHENE FIELD

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas: Assoc. (BCF)	Natural Gas: Non-Assoc. (BCF)	Natural Gas: Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place----------------------	190.9	2.5	167.2	124.9	
Proved ultimate recovery-----	114.5	1.5	117.1	87.4	
Cumulative production--------	75.4	1.1	76.8	54.4	
Proved reserves--------------	39.1	0.4	40.3	33.0	
			(Dry Basis)		
Proved reserves--------------			39.1	32.1	1.8
Reserves in shut-in reservoirs----------------	18.1	0	18.1	0	0
Indicated secondary and tertiary reserves---------	0		0		
Production					
Year 1973 (total)---------	6.9	0.3	6.2	14.8	0.5
Year 1974 (total)---------	5.5	0.1	3.7	9.6	0.3
Long-term projection of production (annual total)					
1975-------------------	4.8	0.1	4.8	8.2	
1976-------------------	4.2	0.1	4.2	6.9	
1977-------------------	3.7	0.1	3.7	5.4	
1978-------------------	3.2	---	3.2	3.9	
1979-------------------	2.9	---	2.9	2.8	
1980-------------------	2.5	---	2.5	1.9	
1981-------------------	2.2	---	2.4	1.4	
1982-------------------	1.9	---	1.9	0.9	
1983-------------------	1.7	---	1.7	0.5	
1984-------------------	1.5	---	1.5	---	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production-----	15.1	0.5	9.0	45.0	1.4
Short-term productive capacity (60-day basis)---	14.7	0.5	9.0	43.0	

The Bay De Chene oil and gas field is located in Jefferson and Lafourche Parishes on the coast line in extreme southern Louisiana. The field is in the onshore Miocene belt, 35 miles south of New Orleans.

The producing formations at Bay De Chene are sands in a thick sand-shale sequence of Pliocene and Upper Miocene age. Depth to the producing sands varies from 4,500 feet to 13,000 feet.

The Bay De Chene field is related to a shallow piercement type salt dome. The highest occurrence of salt is at 7,950 feet. There are numerous faults around the dome. The accumulations are structural in some instances, as the shallower sands carry over the top of the dome. In other reservoirs the sands are truncated by salt or shale, associated with upward salt movement. The depositions of some sands pinch out as they approach the salt. Faulting and bottom water play important roles in reservoir delineation. The field has about 3,550 acres (6 square miles). Over 200 separate reservoir units are believed present in the field.

Hydrocarbons originally in place were estimated by carrying out a broad--so called "coarse" volumetric analysis. A sampling of well logs was examined and net oil and gas sand thicknesses were determined. A "composite type" isopach map was prepared for the field and average reservoir and fluid properties were selected. An analysis in this degree of detail was apparently all that could be carried out in the time period allowed for study.

The determination of ultimate recovery at Bay De Chene utilized an interesting logic. The ultimate production was estimated from the "broad" and "coarse" volumetric analysis work mentioned above and by selection of average recovery efficiency factors of 60 percent for oil and 70 percent for gas. The predominate recovery mechanism is a water drive, though several water floods are in operation. Reserves and ultimate recovery in the developed producing category were estimated by extrapolation of production history. The difference between total proved reserves and proved producing reserves was placed in the proved but shut-in category. These amounted to 46 percent of proved reserves, and would require the drilling of 15 - 20 additional wells which seemed supported by the magnitude of the operator's ongoing development program. An estimate of shut-in reserves, prepared in an ideal manner, would have required an analysis of the geological and reservoir characteristics of each of the many reservoir segments in the field. This has previously been explained as beyond the time limitation for study. The ingenuity of this approach, under the circumstances, is commendable; however, the method does have the weakness of allocating to the proved shut-in reserves category, the algebraic total of all errors which may have been accumulated in prior steps in the field study.

The FEA report on the Bay De Chene Field was prepared by Keplinger and Associates, Inc., under Contract No. CO-05-50184-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974

BAY MARCHAND BLOCK 2 FIELD

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas: Assoc. (BCF)	Natural Gas: Non-Assoc. (BCF)	Natural Gas: Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	1258.7	NA	698.0	128.1	
Proved ultimate recovery	574.2	NA	489.1	97.8	
Cumulative production	419.6	NA	365.5	11.6	
Proved reserves	154.6	NA	123.6	86.2	
			(Dry Basis)		
Proved reserves			121.0	84.5	2.1
Reserves in shut-in reservoirs[1]	0	NA	0	15.1	0.2
Indicated secondary and tertiary reserves	0		0		
Production					
Year 1973 (total)	32.8	NA	30.8	---[2]	---[3]
Year 1974 (total)	32.1	NA	28.2	---	---
Long-term projection of production (annual total)					
1975	28.3	NA	24.9	2.9	
1976	24.9	NA	22.8	5.0	
1977	22.1	NA	20.9	6.3	
1978	19.6	NA	16.0	8.5	
1979	15.6	NA	12.0	9.5	
1980	11.1	NA	8.2	9.5	
1981	8.5	NA	5.0	8.8	
1982	6.1	NA	3.2	7.4	
1983	4.2	NA	2.0	5.4	
1984	2.9	NA	1.5	3.8	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	79.5	NA	77	---[2]	---[3]
Short-term productive capacity (60-day basis)	79.5	NA	77	---	

[1]Shut-in reserves included with proved reserves.

[2]Included with associated gas volumes.

[3]Data not available.

The Bay Marchand Block 2 field is located just offshore from Lafourche Parish in southern Louisiana about 60 miles south of New Orleans in the offshore Miocene belt.

There are more than 125 individual sand members at Bay Marchand in a thick sand-shale sequence of predominately Miocene age. They occur from 1,200 feet to 16,000 feet.

The structure at Bay Marchand is related to a shallow piercement type salt dome which is one of the largest in the world (about nine miles in diameter at the 18,000 foot level). The field is highly faulted. The combination of faults and numerous sands has caused more than 500 individual stratigraphic or fault block reservoirs in the field. Some are superdomal at the crest; others are controlled by salt or shale truncation; and still others are sand pinchout situations. Faulting plays a major part in the delineation of the reservoirs. Most segments are underlain by bottom water. The field has about 13,900 production acres (22 square miles).

A volumetric analysis to determine hydrocarbons originally in place in each of the many individual reservoir segments was not practical. However such calculations were made for reservoirs which were being water flooded on the east, south, and west flanks of the field. Also, volumetric analyses were carried out for the nonassociated gas reservoirs at Bay Marchand.

The primary producing mechanisms are combinations of dissolved gas drive, gas cap drive, and partial water drive. In addition, numerous segments are being water flooded. The consultant firm estimated ultimate recovery by the process of interpretation of production decline, well test, and water/oil ratio data in the reservoir segments not being water flooded. In the other reservoir segments (including nonassociated gas reservoirs), reserves were estimated by assigning recovery efficiency factors to estimates of hydrocarbons originally in place, and then by adjusting the predictive data to the various production decline curves. This appears to be a very reasonable and practical manner of handling a most tedious situation in the time span allotted. The overall recovery efficiencies came down to 46 percent of oil and 71 percent of gas originally in place.

The FEA report on the Bay Marchand Block 2 Field was prepared by Keplinger and Associates, Inc., under Contract No. CO-05-50184-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
BROWN-BASSETT FIELD[1]

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas[2] Assoc. (BCF)	Natural Gas[2] Non-Assoc. (BCF)	Natural Gas[2] Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	NA	NA	NA	560.4	
Proved ultimate recovery	NA	NA	NA	508.0	
Cumulative production	NA	NA	NA	304.8	
Proved reserves	NA	NA	NA	203.2	
			(Dry Basis)		
Proved reserves			NA	203.2	NA
Reserves in shut-in reservoirs	NA	NA	NA	0	NA
Indicated secondary and tertiary reserves	NA		NA		
Production					
Year 1973 (total)	NA	NA	NA	25.9	NA
Year 1974 (total)	NA	NA	NA	28.1	NA
Long-term projection of production (annual total)					
1975	NA	NA	NA	38.2	
1976	NA	NA	NA	28.9	
1977	NA	NA	NA	22.8	
1978	NA	NA	NA	18.4	
1979	NA	NA	NA	14.9	
1980	NA	NA	NA	12.1	
1981	NA	NA	NA	10.3	
1982	NA	NA	NA	8.9	
1983	NA	NA	NA	7.7	
1984	NA	NA	NA	6.7	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	NA	NA	NA	76	NA
Short-term productive capacity (60-day basis)	NA	NA	NA	104	

[1] Includes the principal Ellenburger zone and the Silurian, Pennsylvanian, and Permian Zones which contain about 6 percent of the reserves.

[2] Ellenburger gas volumes have been reduced (54 percent by volume) for removal of CO_2.

The Brown-Bassett gas field is located in Terrell County, Texas, in the Val Verde Basin.

The principal producing formation is the Ellenburger dolomite of Ordovician age. The Ellenburger reaches about 1,500 feet in thickness at Brown-Bassett and is encountered at a depth of about 14,000 feet. There are minor amounts of gas in the Silurian, Pennsylvania-Strawn, and Permian-Wolfcamp Formations.

The structure at Brown-Bassett is a highly faulted anticline. Bottom water controls the lower limits of production. The Ellenburger productive area is about 18,000 acres (28 square miles).

The bottom water in the Ellenburger appears limited in its activity and the gas is believed to be produced through the process of pressure depletion. The raw gas produced is about 54 percent CO_2 by volume.

Ultimate recovery and gas originally in place were estimated by extrapolating a pressure data versus cumulative production trend to an abandonment reservoir pressure of 500 psia and to a pressure of absolute zero respectively. The study team encountered several problems in this analysis which could affect the results. The highly faulted nature of the Ellenburger structure seriously restricts pressure communication throughout the field. The average pressure trend for the reservoir does not extrapolate backwards to the correct original pressure--the difference being 1,300 psia or about 20 percent. Accordingly there is some risk that the incorrectly positioned line might not extrapolate forward to the correct ultimate recovery. Finally there is a problem of water production in the Ellenburger gas stream, which was not investigated because of time restrictions.

The FEA report on the Brown-Bassett Field was prepared by the U.S. Bureau of Mines, Department of Interior, under Interagency Agreement CG-05-50058-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
CAILLOU ISLAND FIELD

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas: Assoc. (BCF)	Natural Gas: Non-Assoc. (BCF)	Natural Gas: Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	1306.2	61.7	2148.0	1644.0	
Proved ultimate recovery	718.4	43.9	1503.6	1233.0	
Cumulative production	515.6	28.6	915.5	548.0	
Proved reserves	202.8	15.3	588.1	685.0	
			(Dry Basis)		
Proved reserves			570.5	664.5	25.7
Reserves in shut-in reservoirs	---[1]	---[1]	---[1]	---[1]	---[1]
Indicated secondary and tertiary reserves	0		0		
Production					
Year 1973 (total)	24.7	3.0	78.7	81.5	---[1]
Year 1974 (total)	17.4	2.2	56.6	81.3	---
Long-term projection of production (annual total)					
1975	13.0	2.1	36.6	71.8	
1976	12.0	1.9	33.8	71.8	
1977	12.0	1.8	33.8	71.8	
1978	13.0	1.6	36.6	71.8	
1979	14.0	1.6	39.4	71.8	
1980	16.0	1.4	45.0	67.9	
1981	17.0	1.2	47.8	58.2	
1982	18.0	1.0	50.6	48.5	
1983	18.0	0.8	50.6	38.8	
1984	18.0	0.6	50.6	29.1	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	41.7	4.7	133	190	---[1]
Short-term productive capacity (60-day basis)	41.0	4.5	133	190	

[1] Data not available.

The Caillou Island oil and gas field is located in the extreme southern portion of Terrebonne Parish in southern-most Louisiana, in the onshore Miocene belt.

The producing zones at Caillou Island are sands, ranging from Miocene to Pleistocene in age, in a very thick sand-shale sequence. Producing depths range from about 3,000 feet to possibly 18,000 feet.

The structure at Caillou Island is controlled by a shallow piercement type salt dome. The reservoirs are highly faulted; the combination of numerous sands and numerous fault segments causes over 400 separate reservoir units. Some are purely structural such as the shallow sands which carry over the top of the salt dome. Others are caused by truncation of the sand by salt or shale as the salt intruded. Some sands which were deposited around the structural high pinch out stratigraphically as deposition approaches the salt. The many faults, which are generally radial, further delineate the accumulations. Bottom water controls the lower limits of the accumulation in most segments. The field has about 20,200 productive acres (32 square miles).

Hydrocarbons originally in place at Caillou Island were calculated using volumetric analysis procedures. These procedures were not practical on an individual reservoir segment basis. Instead, the consultant carried out a composite type of analysis which utilized generalized average reservoir parameters based upon sampled data throughout the field. This approach seems reasonable in view of the tremendous amount of effort which otherwise would be required. Also the situation at Caillou Island would seem to lend itself to this gross type of averaging technique without introduction of serious error.

Most all types of recovery mechanisms are active in various segments at Caillou Island. Most of the oil segments have limited water drives which are being supplemented by water injection in some instances. The nonassociated as zones are produced by combinations of pressure depletion and partial water drive.

Ultimate recovery at Caillou Island was estimated by the production decline curve extrapolation method in some reservoir segments and by assigning a recovery efficiency percentage in others. The basis for the estimated recovery efficiency was by analogy with the overall performance characteristics of water drive fields in the area. The ultimate recovery efficiencies are estimated as 55 percent for oil and 72 percent for the combined associated and nonassociated gas volumes.

A considerable portion of the proved reserves at Caillou Island are not on production currently, but will be produced in the future as a result of continuous re-completion and drilling operations which are underway in the field. A determination of the specific shut-in and producing portions of proved reserves would have required a detailed analysis of the various individual reservoir segments which was not possible in the time allotted.

The FEA report on the Caillou Island Field was prepared by Keplinger and Associates, Inc., under Contract No. CO-05-50184-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
CARTHAGE FIELD

			Natural Gas		
	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Assoc. (BCF)	Non-Assoc. (BCF)	Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	NA	NA	NA	7181.6	
Proved ultimate recovery	NA	NA	NA	6678.9	
Cumulative production	NA	NA	NA	6190.6	
Proved reserves	NA	NA	NA	488.3	
			(Dry Basis)		
Proved reserves			NA	465.6	17.9
Reserves in shut-in reservoirs	NA	NA	NA	0	0
Indicated secondary and tertiary reserves	NA		NA		
Production					
Year 1973 (total)	NA	NA	NA	74.3	2.9
Year 1974 (total)	NA	NA	NA	64.4	2.5
Long-term projection of production (annual total)					
1975	NA	NA	NA	58	
1976	NA	NA	NA	52	
1977	NA	NA	NA	48	
1978	NA	NA	NA	42	
1979	NA	NA	NA	38	
1980	NA	NA	NA	34	
1981	NA	NA	NA	31	
1982	NA	NA	NA	28	
1983	NA	NA	NA	25	
1984	NA	NA	NA	22	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	NA	NA	NA	169	6.5
Short-term productive capacity (60-day basis)	NA	NA	NA	169	

The Carthage gas field covers most of Panola County and extends into Harrison County, Texas, and is located on the extreme edge of the East Texas Basin just west of the Sabine uplift.

The principal producing zones are the Upper and Lower Pettit limestones and the Travis Peak sandstones, which are Lower Cretaceous in age. The drilling depth to the Upper Pettit is 5,600 feet. There are other minor gas accumulations in other sandstones and limestones of Cretaceous age and in the Cotton Valley Sand of Jurassic age.

The Carthage field is a pronounced nose plunging southwest off the Sabine uplift. Permeability pinchouts delineate the reservoir to the north and east. Edge water limits the reservoirs to the south and west. The productive acreage totals 282,000 acres (440 square miles). The reservoir is classed as a stratigraphic trap.

All of the zones at Carthage are produced by means of pressure depletion and are in the later stages of production. About 90 percent of the reserves, in five zones, have been estimated by extending pressure decline trends. However, the pressure surveys have been discontinued for over seven years. Current production decline data tend to substantiate lower reserves than indicated by the older pressure data. Another nine percent of the reserves, in eight zones, were estimated from production decline trends. The remaining one percent of the reserves was estimated by somewhat arbitrary methods.

The FEA report on the Carthage Field was prepared by Geoscience Consulting Services International, Inc. under Contract No. CO-05-50185-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
CAT CANYON FIELD

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas Assoc. (BCF)	Natural Gas Non-Assoc. (BCF)	Natural Gas Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	2692.5	NA	107.7	NA	
Proved ultimate recovery	269.3	NA	98.0	NA	
Cumulative production	215.4	NA	71.1	NA	
Proved reserves	53.9	NA	26.9	NA	
			(Dry Basis)		
Proved reserves			26.9	NA	NA
Reserves in shut-in reservoirs	0	NA	0	NA	NA
Indicated secondary and tertiary reserves	0		0		
Production					
Year 1973 (total)	6.8	NA	3.9	NA	NA
Year 1974 (total)	6.7	NA	3.7	NA	NA
Long-term projection of production (annual total)					
1975	6.2	NA	3.1	NA	
1976	5.6	NA	2.8	NA	
1977	5.0	NA	2.5	NA	
1978	4.5	NA	2.2	NA	
1979	4.0	NA	2.0	NA	
1980	3.6	NA	1.8	NA	
1981	3.2	NA	1.6	NA	
1982	2.9	NA	1.4	NA	
1983	2.6	NA	1.3	NA	
1984	2.4	NA	1.2	NA	

	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	17.6	NA	9.9	NA	NA
Short-term productive capacity (60-day basis)	17.6	NA	9.8	NA	

The Cat Canyon oil field is located in Santa Barbara County, California, in the Santa Maria Basin eight miles south of the town of Santa Maria.

The producing formations consist of fine grained unconsolidated Sisquoc sands of Pliocene age from 2,000 to 4,500 feet and very hard fractured Monterey shales of Miocene age from 3,500 to 7,000 feet.

The Cat Canyon structure is a northwest-southeast trending anticline containing about 7,400 productive acres (12 square miles). The Sisquoc sand-shale series contains highly lenticular sand bodies which shale-out irregularly. The Monterey shale received its permeability through fracturing and faulting prior to Pliocene time. There is very little natural porosity in this zone. Better reservoir conditions are observed in proximity to known major faults. Bottom water has been observed in some reservoirs.

The Pliocene reservoirs at Cat Canyon were discovered in 1908, and extensive data concerning reservoir rock character were not gathered. The geometry of the fracture system in the more recently discovered Monterey reservoirs is not amenable to analysis. An analysis to determine hydrocarbons originally in place was not carried out. The volumes shown on the summary table were inferred by assigning estimated recovery efficiencies to the estimates of ultimate production.

The crude oil at Cat Canyon is generally of low gravity and high viscosity. Operations have historically been beset with problems relating to use of diluent systems to pump and transport oil, desanding operations, high temperature oil treatment, and high temperatures and pressures necessary for steam injection for thermal recovery projects. These pressures and temperatures have resulted in severe metallurgical problems. The deeper Monterey wells have required stimulation in the form of solvent washes and acid treatments. The operating problems have been historically paired with low well head values for the very heavy crude. The consultant anticipates that present price levels should encourage additional activity which could dampen the productive decline trends somewhat for the next two years.

The report treats separately nine different producing entities and mentions that the several reservoirs produce with various degrees of dissolved gas drive, water drive, and gravity drainage, which is particularly important in the thick Monterey formation. At the end of 1974 there were three active water injection projects, five cyclic steam projects and various well stimulation experiments. These activities should be expanded somewhat.

Proved reserves are based upon a future oil decline rate of 10 percent yearly. The forecast decline rates are also shown for the nine producing groupings. Generally, the decline trends selected are not yet firmly established. The assumptions of future production rates and the failure to allow for new thermal recovery projects, either in proved or indicated reserves, appear generally conservative.

The FEA report on the Cat Canyon Field has been prepared by James A. Lewis Engineering under Contract No. CO-05-50181-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
CHOCOLATE BAYOU FIELD

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas Assoc. (BCF)	Natural Gas Non-Assoc. (BCF)	Natural Gas Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	118.9	93.7	103.5	2217.7	
Proved ultimate recovery	40.9	41.9	47.5	1724.5	
Cumulative production	38.0	41.4	40.1	1662.2	
Proved reserves	2.9	0.5	7.4	62.3	
			(Dry Basis)		
Proved reserves			6.9	58.4	2.9
Reserves in shut-in reservoirs	0	0	0	0	0
Indicated secondary and tertiary reserves	7.6		5.7		
Production					
Year 1973 (total)	0.4	0.1	0.8	11.2	0.3
Year 1974 (total)	0.4	0.1	0.8	7.9	0.4
Long-term projection of production (annual total)					
1975	0.5	0.1	1.4	8.1	
1976	0.4	0.1	1.5	7.3	
1977	0.3	0.1	1.2	6.4	
1978	0.3	0.1	0.9	5.8	
1979	0.2	---	0.6	5.4	
1980	0.2	---	0.4	5.0	
1981	0.2	---	0.2	4.1	
1982	0.1	---	0.2	3.4	
1983	0.1	---	0.1	2.9	
1984	0.1	---	0.1	2.4	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	1.3	0.2	3.0	22.0	1.0
Short-term productive capacity (60-day basis)	1.3	0.2	4.0	22.0	

The Chocolate Bayou oil and gas field is located in east central Brazoria County, Texas, about 25 miles south of Houston in the onshore Oligocene belt of the Texas Gulf Coast.

The producing formations are Frio sands of Oligocene age, ranging in depth from 8,600 to 15,200 feet. There are five major and 10 minor oil reservoirs generally above 10,000 feet. There are seven major and 28 minor gas reservoirs, generally between 10,000 and 12,500 feet.

Chocolate Bayou is a faulted anticline with about 10,000 productive acres (16 square miles). A NE-SW central fault separates the field into two areas. The eastern fault block is down-thrown and produces from a closed anticlinal structure. The western up-thrown fault block produces from closure against the dividing fault. Other smaller faults do not have significant trapping effect. The various Frio sands are over-lain and under-lain by inter bedded shales. Bottom water controls the productive limits in almost all instances.

The nonassociated gas reservoirs at Chocolate Bayou are producing by pressure depletion. The bottom water has apparently not been active. One nonassociated gas reservoir--now depleted--produced with a partial water drive. The oil reservoirs are producing with various combinations of solution gas drive, gas cap expansion drive and partial water drive. Secondary recovery reserves are indicated for one project under current study.

Hydrocarbons originally in place in the nonassociated gas reservoirs were determined by examination of trends of pressure data versus cumulative production. The volumetric analysis method was utilized in the case of the oil reservoirs. Documentation of these analyses, both in the report and from supplemental material, appears excellent.

Ultimate recovery and proved reserves of nonassociated gas were estimated from the pressure data versus cumulative production trends and from production decline trends. Ultimate recovery and proved reserves in the oil reservoirs were estimated from production decline curve analyses. Here again, the documentation in the report is excellent.

The FEA report on the Chocolate Bayou Field was prepared by James A. Lewis Engineering, under Contract No. CO-05-50181-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
COGDELL FIELD[1]

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas: Assoc. (BCF)	Natural Gas: Non-Assoc. (BCF)	Natural Gas: Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	530.1	NA	425.1	NA	
Proved ultimate recovery	275.4	NA	243.2	NA	
Cumulative production	189.6	NA	185.3	NA	
Proved reserves	85.8	NA	57.9	NA	
			(Dry Basis)		
Proved reserves			52.1	NA	4.1
Reserves in shut-in reservoirs	0	NA	0	NA	0
Indicated secondary and tertiary reserves	0		0		
Production					
Year 1973 (total)	12.1	NA	9.9	NA	0.7
Year 1974 (total)	10.9	NA	6.6	NA	0.5
Long-term projection of production (annual total)					
1975	13.0	NA	7.9	NA	
1976	11.1	NA	6.7	NA	
1977	9.5	NA	5.8	NA	
1978	8.1	NA	4.9	NA	
1979	6.9	NA	3.6	NA	
1980	5.9	NA	3.1	NA	
1981	5.0	NA	2.6	NA	
1982	4.3	NA	2.2	NA	
1983	3.7	NA	1.9	NA	
1984	3.1	NA	1.6	NA	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	38.2	NA	22	NA	NA
Short-term productive capacity (60-day basis)	38.0	NA	22	NA	

[1] Includes Canyon reef plus insigifnicant reserves in San Andres, Fuller and Strawn reservoirs.

The Cogdell oil field is in Scurry and Kent Counties of West Texas, on the eastern side of the Midland Basin.

The principal producing formation is the Canyon fossiliferous limestone reef of Pennsylvanian age. The highest occurrence of the reef is about 6,100 feet and the water level is at 6,800 feet. There are insignificant reserves in the San Andres (Permian), the Fuller (Upper Pennsylvanian), and in the Strawn (Lower Pennsylvanian).

The reservoir at Cogdell is an eroded reef structure. The upper seal is caused by impervious Pennsylvanian shales. The lower limits are controlled by bottom water, when porosity is developed. The productive area is about 14,000 acres (22 square miles).

The crude oil was initially undersaturated. The bottom water was not active. The reservoir initially produced by means of fluid expansion and later by dissolved gas drive. Subsequently, virtually all of the field was unitized and pressure maintenance, by means of a peripheral type water injection program, was commenced. As oil producers water out, they are converted to water injections. Currently about 75 percent of the reservoir volume is behind the advancing water front. Injection has balanced or exceeded reservoir withdrawals and pressure appears to be currently maintained at levels equal to or exceeding the original saturation pressure.

The Operators' Engineering Committee carried out detailed volumetric analyses of hydrocarbons originally in place - prior to unitization. In the Cogdell report the consultant firm summarized and accepted these estimates. The report stated that the Engineering Committee confirmed the volumetric estimates by the material balance method, though this analysis is not documented.

The proved reserves from the Canyon reef at Cogdell have been estimated by extrapolating the movement of the peripheral water front as it encroaches through the oil reservoir. This indicated that recovery efficiency would amount to over 48 percent of the oil originally present. The consultant has added an additional 4 percent recovery efficiency to account for prolonged production at very high water cuts, though the logic in this particular instance appears erroneous. This limestone reservoir has been developed on a 40 acre pattern and the effectiveness of the water displacement or of infill development have not been thoroughly evaluated. The total recovery efficiency of almost 53 percent has also been "confirmed" by extrapolation of production curves (versus time and versus cumulative production). However, these trends are not yet well established--having been in evidence for only about 2 years. A production decline, caused by a gradual reduction in the number of producers, is probably not an independent check on reservoir flood-out calculations.

Cogdell is probably one of the largest limestone reservoirs with a peripheral artificial water drive situation. As is the case for most very large unitized operations, the project has been very carefully engineered. Considerable data are available - usually in processed and interpreted form.

The FEA report on Cogdell Field has been prepared by Keplinger and Associates, Inc., under Contract No. CO-05-50184-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
CONROE FIELD

	Crude Oil (MMBbls)	Lease[1] Condensate (MMBbls)	Natural Gas: Assoc. (BCF)	Natural Gas: Non-Assoc. (BCF)	Natural Gas: Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place----------------------	1368.0	2.7	1378.9	NA	
Proved ultimate recovery-----	737.4	1.8	970.7	NA	
Cumulative production--------	536.7	1.2	629.3	NA	
Proved reserves--------------	200.7	0.6	341.4	NA	
			(Dry Basis)		
Proved reserves--------------			316.5	NA	15.7
Reserves in shut-in reservoirs----------------	0	0	0	NA	0
Indicated secondary and tertiary reserves---------	0		0		
Production					
Year 1973 (total)---------	21.7	NA	30.2	NA	2.2
Year 1974 (total)---------	21.7	NA	33.9	NA	2.2
Long-term projection of production (annual total)					
1975-------------------	21.9	NA	29.1	NA	
1976-------------------	21.9	NA	29.6	NA	
1977-------------------	18.6	NA	26.0	NA	
1978-------------------	15.8	NA	22.9	NA	
1979-------------------	13.4	NA	20.1	NA	
1980-------------------	11.4	NA	17.8	NA	
1981-------------------	9.7	NA	15.7	NA	
1982-------------------	8.3	NA	14.0	NA	
1983-------------------	7.0	NA	12.5	NA	
1984-------------------	6.0	NA	11.1	NA	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production-----	59.7	NA	93	NA	6.7
Short-term productive capacity (60-day basis)---	60.0	NA	93	NA	

[1] Lease condensate production volumes are insignificant.

The Conroe oil field is located in Montgomery County, Texas in the Eocene belt of the Texas Gulf Coast.

The principal producing members are in the Yegua Formation of the Claiborne Group of Eocene age. These are the Upper Cockfield sand at 4,750 feet and the Main Conroe sands at 5,000 feet.

The structure at Conroe is a highly faulted, broad, ovate anticline which is underlain by a deep seated salt dome. The productive sands are overlain and separated by shale members. Bottom water is present. The productive area is somewhat in excess of 17,000 acres (27 square miles).

The Upper Cockfield sand had a large gas cap--having an area some five times the oil rim. It produced under the influence of a dissolved gas drive and an expanding gas cap. Water influx into the Upper Cockfield is limited. The Main Conroe sands had original gas caps. However, an active water drive is in effect for these zones. The reservoir pressure in the Upper Cockfield has been reduced considerably by production from gas wells. This has caused migration of oil from the Main Conroe sands to the overlying gas caps up through fault planes and through the reservoir. In an attempt to control this situation, oil rates have been increased recently; gas production has been reduced considerably; and efforts are underway to unitize the field. Water and gas will be injected to maintain pressure and to prevent oil migration.

Hydrocarbons originally in place have been calculated using the volumetric method. Although the field was discovered in 1932, there have been many infilling wells drilled recently to improve upon structural position in the various fault segments and to prevent oil migration up the fault planes. The modern data so obtained have aided considerably in understanding the geometry of the reservoir and the rock properties of the producing sands. Material balance analyses to determine hydrocarbons in place have been inconclusive because of complex geology, migration of hydrocarbons, numerous blow-outs, and lack of early gas and water production records.

The oil recovery efficiencies have been estimated as 52.5 percent and 57 percent in the Upper Cockfield and Main Conroe sands respectively. Following oil depletion the gas caps will be rapidly blown down and a 70 percent gas recovery efficiency has been assumed.

The FEA report on the Conroe Field has been prepared by the U.S. Bureau of Mines, Department of Interior, under Interagency Agreement CG-05-50058-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
COYANOSA FIELD[1]

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas Assoc.[2] (BCF)	Natural Gas Non-Assoc. (BCF)	Natural Gas Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	16.9	133.0	495.8	1651.2	
Proved ultimate recovery	5.4	42.3	341.6	1323.9	
Cumulative production	3.3	29.1	(20.2)	972.5	
Proved reserves	2.1	13.2	361.7	351.4	
			(Dry Basis)		
Proved reserves			322.5	344.4	19.3
Reserves in shut-in reservoirs	0	0	0	0	0
Indicated secondary and tertiary reserves	0		0		
Production					
Year 1973 (total)	0.5	2.0	(4.8)	90.5	----[3]
Year 1974 (total)	0.4	1.8	(5.9)	72.0	----[3]
Long-term projection of production (annual total)					
1975	0.4	1.9	(7.0)	77.3	
1976	0.3	2.0	(8.2)	60.4	
1977	0.3	1.7	(7.9)	48.7	
1978	0.3	1.5	(7.6)	39.6	
1979	0.2	1.7	31.0	31.6	
1980	0.1	1.1	31.8	26.2	
1981	0.1	0.8	32.3	22.4	
1982	0.1	0.5	29.9	18.0	
1983	0.1	0.4	27.2	10.2	
1984	---	0.3	24.3	9.0	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	1.0	5.0	(18)	233	5.2
Short-term productive capacity (60-day basis)	1.0	5.2	NA	242	

[1]Includes nonassociated gas in Mississippi, Devonian, and Ellenburger. Includes oil, lease condensate, and associated gas in the Wolfcamp.

[2]The associated gas in the Wolfcamp reservoir has been cycled. Make up gas from the nonassociated Devonian and Ellenburger reservoirs has resulted in net injection of 20 BCF to date. Net injection of 31 BCF is forecast during 1975-78. Blow down of the gas cap is forecast to start in 1979.

[3]Data not available.

The Coyanosa gas field is located in Pecos County of West Texas, in the Delaware Basin, some 200 miles east of El Paso.

The producing formations are the Wolfcamp conglomerate of Permian age, and dolomites of Mississippian, Devonian, and Ellenburger-Ordovician age. The depths to the various formations are 9,400; 10,500; 11,800; and 15,000 feet respectively.

Coyanosa is a deep seated anticlinal structure containing 14,700 productive acres (23 square miles). The Pre-Permian reservoirs are structural traps with down dip water and minor faulting. The Wolfcamp conglomerate build-up is completely enclosed by impermeable shale.

The bottom water in the Pre-Permian reservoirs is not active and the gas is produced by means of pressure depletion. The Wolfcamp gas originally contained 217 barrels of lease condensate per million cubic feet. A small oil rim was on the east side. For this reason, the Wolfcamp gas has been classed as associated. The Wolfcamp gas has been cycled to prevent retrograde condensation in the reservoir. In order to maintain pressure, some make-up gas from the Devonian and Ellenburger formations has also been injected into the Wolfcamp.

Nonassociated gas originally in place and proved ultimate recovery for the Mississippian, Devonian, and Ellenburger formations have been estimated from analysis of reservoir pressure data versus cumulative production relationships. The consultant firm has selected an abandonment reservoir pressure of 1,500 psi in the Mississippian, 1,000 psi in the Devonian, and 1,100 psi in the Ellenbruger. The pressure data versus cumulative production plots, which have been furnished as supplementary material, appear very satisfactory for this purpose. The hydrocarbons originally in place in the Wolfcamp formation were estimated after review of material balance analyses carried out by the operators. This analysis is not disucssed in the report. Proved oil reserves from the Wolfcamp formation have been estimated from continuation of established production trends. Proved reserves of Wolfcamp associated gas and lease condensate are based upon continuation of cycling until the end of 1978, followed by blow down.

The FEA report on the Coyanosa Field was prepared by Ryder Scott Company under Contract No. CO-05-50189-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY,[1] DECEMBER 31, 1974
DOLLARHIDE FIELD[1]

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas: Assoc. (BCF)	Natural Gas: Non-Assoc. (BCF)	Natural Gas: Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	703.5	NA	537.6	NA	
Proved ultimate recovery	221.6	NA	337.7	NA	
Cumulative production	172.7	NA	307.0	NA	
Proved reserves	48.9	NA	30.7	NA	
			(Dry Basis)		
Proved reserves			27.6	NA	2.6
Reserves in shut-in reservoirs	0	NA	0	NA	0
Indicated secondary and tertiary reserves	0		0		
Production					
Year 1973 (total)	7.0	NA	3.9	NA	0.4
Year 1974 (total)	6.7	NA	3.6	NA	0.3
Long-term projection of production (annual total)					
1975	5.6	NA	3.0	NA	
1976	4.9	NA	2.6	NA	
1977	4.3	NA	2.3	NA	
1978	3.8	NA	2.1	NA	
1979	3.4	NA	1.9	NA	
1980	3.1	NA	1.8	NA	
1981	2.7	NA	1.5	NA	
1982	2.3	NA	1.3	NA	
1983	2.0	NA	1.1	NA	
1984	1.8	NA	1.0	NA	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	17.3	NA	7.2	NA	0.7
Short-term productive capacity (60-day basis)	17.3	NA	7.2	NA	

[1] Includes the Queen, Leonard, Devonian, Silurian, and Ellenburger in Texas and New Mexico. Does not include Dollarhide, East or Northeast.

The Dollarhide field is in Andrews County, of West Texas, and Lea County, of Southeastern New Mexico, on the northwestern edge of the Central Basin Platform.

The producing formations are the Queen sand in the Guadalupe Series of the Middle Permian age, the Tubb and Clearfork dolomites in the Leonard Series of the Lower Permian age and the Devonian, Fusselman-Silurian, and Ellenburger-Ordovician dolomitic limestones. These reservoirs occur from 3,650 feet to 10,000 feet.

Dollarhide is an anticlinal structure with a northwest-southeast trending axis. There are about 9,000 productive acres (14 square miles). The Queen sand reservoir is controlled by stratigraphic variations in development of porosity and permeability. The reservoir is developed only on the New Mexico side of the field. The Leonard reservoir is controlled both by structure in the Lower Permian and by porosity and permeability development. The Pre-Permian reservoirs are controlled by structure and by faulting. There is a structural saddle in the state line vicinity which divides the Silurian and Ellenburger reservoirs into separate New Mexico and Texas portions. In addition to the reservoir control mentioned above, there is bottom water in all formations.

The Queen sand, the Leonard, and Devonian accumulations first produced with fluid expansion and dissolved gas drive. They are now under active water flood. The Silurian and Ellenburger reservoirs were generally highly undersaturated. They produced by means of fluid expansion and by combination of dissolved gas drive and partial water drive. On the Texas side, these reservoirs are currently under pressure maintenance by water injection.

Hydrocarbons originally in place were estimated by means of volumetric analysis. The report listed average reservoir rock and fluid parameters, and the calculations were documented for each reservoir.

Ultimate recovery and proved reserves were estimated by extrapolation of established production decline curves. In those units where water flood production has not yet reached a peak and commenced a decline, the production forecast was prepared by analogy with other units, more advanced in the depletion cycle. Although some of the selected decline rates are not firmly established, the estimates of proved reserves appear reasonable.

The FEA report on Dollarhide Field was prepared by James A. Lewis Engineering under Contract No. CO-05-50181-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
DOS CUADRAS FIELD

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas[2] Assoc. (BCF)	Natural Gas[2] Non-Assoc. (BCF)	Natural Gas[2] Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	582.0	NA	74.5	NA	
Proved ultimate recovery	178.6	NA	----	NA	
Cumulative production	116.8	NA	----	NA	
Proved reserves[1]	61.8	NA	13.9	NA	
			(Dry Basis)		
Proved reserves			13.9	NA	NA
Reserves in shut-in reservoirs	0	NA	0	NA	NA
Indicated secondary and tertiary reserves	35.7		0		
Production					
Year 1973 (total)	16.7	NA	7.7	NA	NA
Year 1974 (total)	14.9	NA	5.9	NA	NA
Long-term projection of production (annual total)					
1975	13.9	NA	4.9	NA	
1976	12.9	NA	---	NA	
1977	10.0	NA	---	NA	
1978	7.7	NA	---	NA	
1979	6.0	NA	---	NA	
1980	4.6	NA	---	NA	
1981	3.6	NA	---	NA	
1982	2.8	NA	---	NA	
1983	2.2	NA	---	NA	
1984	1.4	NA	---	NA	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	41.0	NA	14.9	NA	NA
Short-term productive capacity (60-day basis)	41.0	NA	14.9	NA	

[1]Reserves do not include inferred reserves of about 14 MMB.

[2]Cumulative production and proved utlimate associated gas volumes are not available. An associated gas production forecast was not prepared.

The Dos Cuadras oil field is located about 6 miles offshore from Santa Barbara County, California, in the offshore Ventura Basin. The field has been developed from three platforms in about 180 feet of water.

The producing formations are sands in a thick sand-shale sequence in the Repetto series of Lower Pliocene age. The sands occur from about 400 to 3,800 feet.

Dos Cuadras is an east-west trending anticline, with relatively steep dips. There is a major thrust fault, striking east-west, which divides the field into two principal fault blocks. There are additional minor normal faults which further delineate the various reservoirs. There is considerable lenticularity and many sands shale-out from east to west. Bottom water is also present. The reservoirs have been divided into nine groups of layered sands. The largest group extends over 736 acres and the smallest group covers only 24 acres.

Hydrocarbons originally in place were determined by the volumetric analysis method. The report is somewhat documented with cross sections, structure and isopach maps; and average values for reservoir rock and fluid parameters are cited. Other reports prepared on this field were also utilized in the analysis. Because of the shallow depth of the principal sands, the outer fringes of the reservoirs cannot be reached from the existing platforms. The lateral extent of the field has not been established, especially to the west.

The producing mechanism at Dos Cuadras appears to be a dissolved gas drive aided by a partial water drive. The effectiveness of water influx is indicated to be greater on the western side of the field. Water injection operations started in January, 1974, with nine wells injecting.

Ultimate recovery and proved reserves at Dos Cuadras were estimated by means of production decline curve analysis and by use of oil recovery efficiency factors determined by empirical methods. The various production decline curves have flattened considerably during the last one, two, or three years, possibly as a result of water influx or, in some cases, as a result of the water injection. The extrapolations, which presume a return to the steeper production decline rates, may be somewhat pessimistic. Secondary reserves are indicated for that portion of the field in which natural water influx has been less pronounced.

The FEA report on the Dos Cuadras Field has been prepared by the U.S. Geological Survey, Department of Interior, under Interagency Agreement CG-05-50059-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
DUNE FIELD[1]

	Crude Oil (MMBbls)	Lease[2] Condensate (MMBbls)	Natural Gas Assoc. (BCF)	Natural Gas Non-Assoc. (BCF)	Natural Gas Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	622.0	NA	201.6	11.6	
Proved ultimate recovery	156.7	NA	130.5	8.7	
Cumulative production	123.6	NA	110.6	3.5	
Proved reserves	33.1	NA	19.9	5.2	
			(Dry Basis)		
Proved reserves			16.3	4.3	2.3
Reserves in shut-in reservoirs	0	NA	0	0	0
Indicated secondary and tertiary reserves	77.0		18.9		
Production					
Year 1973 (total)	9.1	NA	3.8	0.5	0.5
Year 1974 (total)	7.4	NA	3.5	0.4	0.4
Long-term projection of production (annual total)					
1975	6.1	NA	3.2	0.4	
1976	5.4	NA	2.9	0.4	
1977	4.2	NA	2.6	0.4	
1978	3.5	NA	2.4	0.3	
1979	2.9	NA	2.2	0.3	
1980	2.3	NA	1.8	0.3	
1981	1.9	NA	1.6	0.2	
1982	1.6	NA	1.5	0.2	
1983	1.4	NA	1.3	0.2	
1984	1.1	NA	1.2	0.2	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	18.2	NA	8.6	1.1	1.1
Short-term productive capacity (60-day basis)	18.3	NA	9.2	1.2	

[1]Includes Grayburg-San Andres formation and minor reserves in the Wolfcamp.
[2]Lease condensate volumes are insignificant.

The Dune oil field is in the northeast Crane County of West Texas, on the eastern edge of the Central Basin Platform.

The principal producing formation is the Grayburg-San Andres of the Middle Permian age. These are dolomites containing relatively large amounts of anhydrite and gypsum. They are interbedded with anhydrite and black shale. Average depth to the top of the pay is about 3,300 feet. Gross thickness of the producing members is about 300 feet. There are insignificant reserves in the Wolfcamp formation of the lower Permian.

The Dune field is on an asymmetrical anticline with a northwest-southeast axis. The field is on the eastern limb of the anticline, which dips about 500 feet per mile. Up dip and down dip (west and east), the productive limits are controlled by variations in development of porosity and permeability. To the north and south the Dune boundaries are generally arbitrary separations from adjoining fields. The Dune boundary includes about 30,000 acres (47 square miles).

The crude oil was initially undersaturated, but pressures were quickly reduced in the vicinity of producing wells because of the generally low order of permeability. The primary producing mechanism was fluid expansion and dissolved gas drive. Perhaps half of the reservoir has been or is under water flood. The floods have had only partial success. The principal problem is premature water break-through because of the highly heterogenous, lenticular, and fractured nature of the rock. Also there is a very high interstitial water saturation.

Hydrocarbons originally in place have been estimated from data submitted by operators to the Texas Railroad Commission when various water flood units were being considered. The consultant firm then expanded these analyses by analogy to the total field area. None of these details are mentioned in the report. The Summary Table shows a small accumulation of Grayburg-San Andres "nonassociated gas." The consultant firm has not located these wells nor determined if the gas is truly associated or nonassociated. However, this should not detract seriously from our understanding of the reserves situation at Dune.

The remaining reserves at Dune were estimated by extrapolation of production decline curves. These curves indicated the ultimate recovery would amount to about 25 percent of oil originally in place. The indicated secondary reserves of 77 million barrels represent an additional 13 percent of the 590 million barrels originally present in the Grayburg-San Andres formation. These are dependent upon improved water flooding techniques and are considered to be somewhat doubtful by the consultant firm.

The FEA report on the Dune Field has been prepared by Keplinger and Associates, Inc., under Contract No. CO-05-50184-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
EAST TEXAS FIELD

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas: Assoc. (BCF)	Natural Gas: Non-Assoc. (BCF)	Natural Gas: Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	7116.7	NA	2597.6	NA	
Proved ultimate recovery	5494.4	NA	1889.3	NA	
Cumulative production	4244.2	NA	1464.2[1]	NA	
Proved reserves	1250.2	NA	425.1	NA	
			(Dry Basis)		
Proved reserves			225.9	NA	130.9
Reserves in shut-in reservoirs	0	NA	0	NA	0
Indicated secondary and tertiary reserves	0		0		
Production					
Year 1973 (total)	75.5	NA	13.6	NA	7.9
Year 1974 (total)	72.2	NA	13.1	NA	7.6
Long-term projection of production (annual total)					
1975	70.6	NA	12.8	NA	
1976	67.2	NA	12.1	NA	
1977	65.6	NA	11.9	NA	
1978	64.0	NA	11.6	NA	
1979	62.4	NA	11.3	NA	
1980	60.7	NA	11.0	NA	
1981	58.9	NA	10.7	NA	
1982	57.1	NA	10.3	NA	
1983	55.3	NA	10.0	NA	
1984	53.6	NA	9.7	NA	

	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	192.8	NA	32	NA	19.8
Short-term productive capacity (60-day basis)	200.0	NA	36	NA	

[1]Estimate based upon cumulative gas oil ratio of 345 SCF/B.

The East Texas oil field is located in Gregg, Rusk, and Upshur Counties, Texas. The Smith and Cherokee County portions are now depleted and abandoned. The field is on the eastern side of the East Texas Basin and on the western slope of the Sabine uplift.

The producing formation at East Texas is the Woodbine Sand of Upper Cretaceous age. The Woodbine Sand thickens to about 1,000 feet in the center of the basin some 50 miles west of the field. The sand becomes finer and increases in shale percentage from north to south. The depth is about 3,600 feet.

East Texas is a stratigraphic trap. The Woodbine Sand is overlain unconformably by the Austin Chalk (and in some places the Eagle Ford Shale). The downdip limits of the accumulation are controlled by bottom or edge water. The updip limits are controlled by the complete erosional truncation of the sand. Within the field, the gross oil sand thickness ranges from 0 to 125 feet. The field is over 40 miles in length from north to south and varies in width from 4 to 12 miles. The originally productive area was 130,400 acres (204 square miles).

The recovery mechanism at East Texas is a waterdrive. In 1942, a salt water disposal company was organized. Presently almost all of the produced water is returned to the Woodbine Sand through 85 injection wells. The natural rate of water influx into East Texas is sufficient to replace oil withdrawals at the 86 percent market demand factor and pressure is thus being maintained well above the gas saturation level. The current oil rate is almost 200,000 barrels daily.

Hydrocarbons originally in place at East Texas were calculated by the volumetric method. Structure and isopach maps were carefully prepared. The gross thickness intervals were adjusted to net productive sand thickness by allowing for shale content in the sand in each of 425 three dimensional block compartments of the field (17 areal districts times 25 contour intervals of 10 feet each). Oil in place amounts to 1,324 barrels per net acre-foot or 7.1 billion barrels for the field.

Ultimate recovery has been estimated by very close monitoring of the movement of bottom and edge water as it encroaches through the field. In 1939, there was a maximum of 26,000 producing wells at East Texas; by January 1, 1975, 13,000 were still producing--thus providing many points to observe the local water situation. Periodically, maps are prepared to show the current position of the advancing water front and the area which has been completely flooded out. As of January 1, 1975, these studies indicate that 4.2 million net acre-feet of Woodbine Sand have been flooded out, which is about 79 percent of the entire amount in the field. During this time, 4.2 billion barrels have been produced for a recovery factor of 1,003 barrels per net acre-foot of sand flooded. This is 75.75 percent of the oil originally in place. The advancing water has now cut the field in two near the Kilgore townsite--

an area of relatively heavy oil withdrawals in the past. The same calculation procedure was used to estimate reserves and the future production schedule, as the remaining 20 percent, or so, of oil sand is watered out. The future life could amount to about 50 years at the 86 percent market demand factor. Half of the remaining reserves should be produced in the next ten years. This is probably the best documented and classic water encroachment and oil displacement situation anywhere in the world. East Texas is the largest oil field in the contiguous continental United States.

On a long term basis, the productive capacity of the field is essentially at the current rate, because of the necessity to maintain pressure to prevent loss of ultimate recovery. For a short term emergency period, the consultant estimates that a 350,000 barrel daily rate could be maintained for a 60 day period without serious damage to ultimate recovery from the field.

The FEA report on the East Texas Field was prepared by H. J. Gruy and Associates, Inc., under Contract No. CO-05-50180-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
ELK BASIN FIELD[1]

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas: Assoc. (BCF)	Natural Gas: Non-Assoc. (BCF)	Natural Gas: Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	1051.0	NA	295.4	NA	
Proved ultimate recovery	546.2	NA	219.8	NA	
Cumulative production	431.5	NA	128.3	NA	
Proved reserves	114.7	NA	91.5	NA	
			(Dry Basis)		
Proved reserves			91.5	NA	NA
Reserves in shut-in reservoirs	0	NA	0	NA	NA
Indicated secondary and tertiary reserves	0		0		
Production					
Year 1973 (total)	11.6	NA	17.8	NA	NA
Year 1974 (total)	9.1	NA	15.4	NA	NA
Long-term projection of production (annual total)					
1975	8.0	NA	12.6	NA	
1976	7.0	NA	10.0	NA	
1977	6.3	NA	8.3	NA	
1978	5.6	NA	6.3	NA	
1979	5.1	NA	5.1	NA	
1980	4.8	NA	4.4	NA	
1981	4.5	NA	3.7	NA	
1982	4.2	NA	3.3	NA	
1983	3.9	NA	2.8	NA	
1984	3.6	NA	2.5	NA	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	24.2	NA	44	NA	NA
Short-term productive capacity (60-day basis)	24.0	NA	44	NA	

[1]Includes the Frontier, Phosphoria-Tensleep, Madison, and Big Horn-Jefferson reservoirs.

The Elk Basin oil field is located in Park County, Wyoming, and Carbon County, Montana, in the northwestern portion of the Big Horn Basin. The field is about 55 miles east of Yellowstone National Park.

The producing formations at Elk Basin consist of the Torchlight and Peay sands of the Frontier Series of Lower Cretaceous age, at 1,300 and 1,500 feet; the Embar or Phosphoria dolomite of Permian age, and the Tensleep sand of Pennsylvanian age, both at about 4,500 feet; the Madision dolomite of Mississippian age, at 4,800 feet; the Jefferson dolomite of Devonian age, at 5,400 feet; and the Big Horn dolomite of Ordovician age, at 5,900 feet. The lower Peay sand probably accounts for over 90 percent of the Frontier oil. The Phosphoria and the Tensleep zones are produced as one reservoir. The oil attributed to the Phosphoria is very minor. The Madison reservoir is produced separately. The Big Horn and Jefferson zones are commingled and accounted for as one reservoir.

Elk Basin field is a highly faulted, elongated anticline. The structure is about 8 miles long in a northwest-southeast direction and about 3 miles wide. The southwest flank of the structure dips from 10 to 24 degrees, while dips up to 50 degrees are measured on the northeast flank. The faulting is most apparent in the Frontier formation but seems to die out in the lower zones. Bottom water is present in all of the reservoirs. The Elk Basin Field has about 6,400 productive acres (10 square miles).

Hydrocarbons originally in place were estimated by the volumetric analysis method. The various volumetric, reservoir rock, and fluid parameters were listed in the report for each reservoir. About 52 percent of the oil originally in place is attributed to the Phosphoria-Tensleep, and about 41 percent to the Madison reservoir. The crude oil in each reservoir was undersaturated and no original gas caps existed. The original solution gas/oil ratio was somewhat less than 300 standard cubic feet per barrel.

The Frontier reservoir produced originally by means of fluid expansion, dissolved gas drive and partial water drive. The reservoir has been unitized and a water flood is in operation. The proved reserves are not large, but they do indicate a considerable future life at low oil rates and with high water cuts. This zone was discovered in 1915.

The bottom water in the Phosphoria-Tensleep reservoir was not active. Some form of pressure maintenance appeared necessary. The reservoir was unitized in 1946. Flue gas was injected into the crest of the structure from 1949 until 1972. Water is also being injected below the oil/water contact, which should enhance recovery of the oil from the lowermost portions of the reservoir. Planned production from the lower gas/oil ratio wells has permitted the gravity drainage mechanism to operate. The Phosphoria-Tensleep reservoir appears over 90 percent depleted and remaining proved reserves were estimated from study of production decline trends. This reservoir was discovered in 1942.

The Madison reservoir is subdivided into four members. The upper three produced with fluid expansion and a dissolved gas drive while the lowermost zone had an active water drive. The reservoir has been unitized and a water flood is in operation. The Madison carbonate is very heterogeneous in development of porosity and permeability. The producing section is quite thick. The original spacing was 80 acres per well. The spacing has been reduced to about 40 acres, and a few wells have been drilled on 20 acre spacing. The study team has estimated that proved reserves resulting from future infill development should be 40 million barrels in addition to the 45 million barrels assigned to existing wells. This results in the Madision reservoir having almost three-fourths of the Elk Basin proved oil reserves. This zone was discovered in 1946.

The Big Horn and Jefferson reservoirs have an active water drive. The reservoir is almost 90 percent depleted. The water cut is about 94 percent; the produced water is being used for shallower water floods. Proved reserves were estimated from analysis of production decline curves and water cut trends. This reservoir was discovered in 1961.

About three-fourths of the natural gas reserves are in the Phosphoria-Tensleep reservoir. This gas has a low heat of combustion of about 500 BTU's per standard cubic foot, caused by previous pressure maintenance by flue gas injection. Some of the gas is bieng sold after H_2S removal but without further treatment, to a pipe line company who uses it as a dilutent to higher quality gas from other fields. Because the low BTU gas is marketable, no adjustment has been made to the reserve volumes for the nonhydrocarbon content. The proved reserves of natural gas liquids, recoverable from that portion of the produced gas which is processed, have not been estimated in the report.

The FEA report on the Elk Basin Field has been prepared by the U.S. Bureau of Mines, Department of the Interior, under Interagency Agreement CG-05-50058-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
EUGENE ISLAND BLOCK 32 FIELD

	Crude Oil (MMBbls)	Lease Condensate[1] (MMBbls)	Natural Gas: Assoc. (BCF)	Natural Gas: Non-Assoc. (BCF)	Natural Gas: Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	68.0	11.8	261.6	984.2	
Proved ultimate recovery	32.5	4.3	177.7	656.3	
Cumulative production	20.0	4.2	66.2	553.0	
Proved reserves	12.5	0.1	111.5	103.3	
			(Dry Basis)		
Proved reserves			105.9	98.1	2.5
Reserves in shut-in reservoirs	3.4	0.1	8.4	50.1	0.7
Indicated secondary and tertiary reserves	4.8		6.7		
Production					
Year 1973 (total)	1.4	NA	2.5	10.9	0.1
Year 1974 (total)	1.1	NA	1.5	9.8	0.1
Long-term projection of production (annual total)					
1975	1.0	NA	1.8	10.7	
1976	1.8	NA	4.0	9.4	
1977	2.2	NA	6.3	6.1	
1978	2.0	NA	8.8	5.1	
1979	1.6	NA	11.4	4.3	
1980	1.3	NA	13.2	9.3	
1981	0.9	NA	13.6	8.6	
1982	0.6	NA	13.1	8.2	
1983	0.4	NA	11.3	7.7	
1984	0.2	NA	8.1	6.4	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	2.7	NA	3.6	25.5	----[2]
Short-term productive capacity (60-day basis)	2.7	NA	3.6	36.8	

[1]Lease condensate production volumes are insignificant.
[2]Data not available.

The Eugene Island Block 32 oil and gas field is located 15 miles offshore from St. Mary Parish of southern Louisiana in 16-20 feet of water. The location is 95 miles west southwest of New Orleans in the offshore Miocene belt.

The producing formations consist of 21 separate sands in a thick Miocene sand-shale sequence at depths from 6,400 to 12,800 feet.

The structure at Eugene Island Block 32 field is a slightly elongated dome with an east west axis. The dome was caused by deep seated salt intrusion. The Jurassic Louann salt has been encountered at about 17,000 feet. There are several northeast southwest faults that cross the field which, together with partial withdrawal of the salt, have caused a series of graben blocks over the center of the dome. The sands are overlain and underlain by shale, and bottom water is present in most reservoirs. A tendency for some of the sand members to shale-out provides additional reservoir delineation. There are 17 productive and 4 depleted oil reservoirs occurring from 6,400 to 10,400 feet. There are six productive and three depleted nonassociated gas reservoirs from 10,100 to 12,800 feet. The productive area of the field is 2,000 acres (3 square miles).

Hydrocarbons originally in place were estimated by the volumetric analysis method. The report is very well documented with structure and isopach maps as well as with reservoir rock and fluid parameters for the important zones. The study team, in some instances, could not determine the exact position of the gas/oil contact in reservoir segments containing original gas caps.

The oil reservoirs produce with combinations of water drive and gas cap drive. A water injection project is active in one reservoir and secondary recovery reserves are indicated for five reservoirs. The nonassociated gas reservoirs produce with combinations of pressure depletion and water drive.

Ultimate recovery and proved reserves at Eugene Island Block 32 field have been estimated by determination of recovery efficiency factors based on empirical methods, with adjustments based upon judgment of the study team. The report mentions that there is a higher probability of the estimates being optimistic than pessimistic. Furthermore, the report mentions that the production of the proved reserves will require workovers, recompletions, drilling of new wells, and secondary recovery projects--the economics of which have not been considered. Again, the report states that recoveries from some of the smaller reservoirs may be overly optimistic. The recovery from the nonassociated gas reservoirs, producing with pressure depletion, was determined from study of pressure data versus cumulative production relationships.

The FEA report on the Eugene Island Block 32 field has been prepared by the U.S. Geological Survey, Department of the Interior, under Interagency Agreement CG-05-50059-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
EUGENE ISLAND BLOCK 175 FIELD

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas: Assoc. (BCF)	Natural Gas: Non-Assoc. (BCF)	Natural Gas: Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	114.9	2.9	119.1	93.7	
Proved ultimate recovery	--61.2[1]--		--117.5[2]--		
Cumulative production	--36.9[1]--		-- 53.0[2]-		
Proved reserves	23.6	0.7	27.8	36.7	
			(Dry Basis)		
Proved reserves			26.6	35.1	1.5
Reserves in shut-in reservoirs	3.9	0.1	2.5	11.3	0.3
Indicated secondary and tertiary reserves	8.5		6.7		
Production					
Year 1973 (total)	9.4	0.1	7.7	4.8	0.3
Year 1974 (total)	7.5	0.2	7.1	7.2	0.4
Long-term projection of production (annual total)					
1975	5.9	0.2	6.5	10.2	
1976	3.7	0.3	5.1	11.2	
1977	2.2	0.1	3.8	5.0	
1978	3.1	0.1	3.9	1.9	
1979	2.7	---	2.7	0.4	
1980	2.1	---	1.8	0.5	
1981	1.6	---	1.2	1.2	
1982	1.2	---	0.9	1.7	
1983	0.6	---	0.4	2.5	
1984	0.3	---	0.3	0.5	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	18.9	0.8	19.9	32.3	1.0
Short-term productive capacity (60-day basis)	17.8	0.8	18.0	30.0	

[1] Cumulative production and proved ultimate recovery volumes are combined crude oil and lease condensate.

[2] Cumulative production and proved ultimate recovery volumes are combined for associated and nonassociated gas.

The Eugene Island Block 175 field is located 45 miles offshore from Iberia Parish, Louisiana, in the Offshore Pliocene Belt. The water depth is 80 feet.

The producing formations are sands in a thick sand-shale sequence of Middle and Lower Pliocene age from 5,000 to 14,000 feet.

Eugene Island Block 175 is a shallow piercement type salt dome. Shallowest salt is about 200 feet. There are numerous radial faults. The sands pinchout a short distance from the salt or are truncated by the salt. Most sands are underlain by extensive aquifers in the synclinal portions of the structure. The various combinations of faulting, salt truncation, sand pinchout, and bottom water have resulted in 125 separate reservoirs. The field has 1,700 productive acres (3 square miles).

Hydrocarbons originally in place were calculated by the volumetric analysis method. The report lists reservoir measurements, and rock and fluid parameters for each reservoir. Structure and isopach maps were prepared for the more important reservoirs. Porosity data are from sidewall cores, water saturation data are from wire line logs, and fluid parameters were obtained from empirical correlations.

Most of the reservoirs at Eugene Island Block 175 produce with at least a partial water drive. Others produce with various combinations of partial water drive , gas cap drive, and dissolved gas drive. There are some water injection and attic oil recovery projects.

Ultimate recovery and proved reserves were estimated by assigning recovery efficiency factors to each reservoir. These assignments were obtained by empirical correlation methods, by decline curve analysis, gas/oil ratio plots, water/oil ratio plots, and analysis of well position in the various reservoir segments.

The FEA report on the Eugene Island Block 175 Field was prepared by the U.S. Geological Survey, Department of the Interior, under Interagency Agreement CG-05-50059-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
EUGENE ISLAND BLOCK 276 FIELD

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas: Assoc. (BCF)	Natural Gas: Non-Assoc. (BCF)	Natural Gas: Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	117.6	2.1	162.3	43.2	
Proved ultimate recovery	---65.4[1]---		---173.8[2]---		
Cumulative production	---48.0[1]---		---110.3[2]---		
Proved reserves	17.0	0.4	43.1	20.4	
			(Dry Basis)		
Proved reserves			41.8	19.8	1.7
Reserves in shut-in reservoirs	0	0	0	0	0
Indicated secondary and tertiary reserves	0		0		
Production					
Year 1973 (total)	5.8	0.2	13.5	7.2	0.5
Year 1974 (total)	4.7	0.1	----[3]	----[3]	0.5
Long-term projection of production (annual total)					
1975	4.2	0.1	11.3	4.6	
1976	3.3	0.1	7.5	4.6	
1977	2.5	0.1	5.3	4.3	
1978	1.6	0.1	4.0	3.3	
1979	1.1	---	1.7	2.8	
1980	0.7	---	0.9	0.2	
1981	0.5	---	0.6	---	
1982	0.4	---	0.5	---	
1983	0.3	---	0.3	---	
1984	0.2	---	0.2	---	

	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	11.9	0.4	----[3]	----[3]	1.7
Short-term productive capacity (60-day basis)	16.0	0.6	38	14	

[1]Consultant was unable to furnish cumulative production volumes. The volume shown (which includes crude oil and lease condensate) was furnished by the USGS.

[2]Consultant was unable to furnish cumulative production volumes. The volume shown (which includes associated and nonassociated gas) was furnished by the USGS.

[3]Data not available. Consultant reports 1974 total gas production was about 15 BCF, and that December 1974 total gas production was about 53 MMCF/D.

The Eugene Island Block 276 oil and gas field is located about 75 miles offshore from St. Mary Parish in southern Louisiana. The field is in the offshore Pliocene and Pleistocene belt some 130 miles southwest of New Orleans in water depth of about 170 feet.

There are 23 sands producing in a basal Pleistocene and Upper Pliocene sand-shale sequence from 6,500 to 12,500 feet in depth.

Eugene Island Block 276 is a shallow piercement type salt dome. The flanking sediments are complexly faulted into numerous small reservoirs. To the north of the salt plug, there is a long northeast trending low relief anticlinal structure possibly caused by a shale or salt ridge. The reservoirs associated with the plug vary from 15 to 125 acres with from 1 to 4 wells each. The reservoirs associated with the anticline are less complexly faulted and contain from 10 to 740 acres with from 1 to 15 wells each. There are 73 known reservoirs. Most reservoirs contain bottom water.

The hydrocarbons originally in place were determined by the volumetric analysis method when data were available. In other reservoirs, the hydrocarbons originally in place were inferred from the estimate of ultimate recovery and average recovery efficiency factors. None of this work is documented in the report.

Most of the reservoirs have produced by water drive. There are four large reservoirs on the anticlinal portion of the field where water injection operations are being carried out to maintain pressure. Attic oil recovery projects in the salt plug area have not been successful because of the slowness of the gravity drainage mechanism. The report contains almost no discussion or exhibits concerning the production history. Only the production for 1973 and 1974 from the various reservoirs is cited.

The proved reserves were estimated by extrapolation of past performance, by analogy, and by empirical calculations of recovery factors. None of this work is discussed in the report. The report tabulates proved reserves and production forecasts for forty separate reservoir units which add to the totals shown on the summary table. There are several numerical inconsistencies or instances in which the proved reserves and production forecasts do not appear related. The most important of these concerns the largest reserve unit in the field which appears seriously in error. The consultant firm has elected not to correct this situation.

The consultant estimates the current oil production rate to be about 3/4 of capacity because of downtime relating to sand production, paraffin accumulations, work overs, compressor failures, etc. To the extent that these are normal recurring problems, the productive capacity estimate would appear excessive.

The FEA report on the Eugene Island Block 276 Field has been prepared by Scientific Software Corporation under Contract No. CO-05-50182-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
EUNICE AREA[1]

	Crude[2] Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas Assoc.[2] (BCF)	Natural Gas Non-Assoc. (BCF)	Natural Gas Liquids[2] (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place----------------------	3040.5	NA	7879.9	NA	
Proved ultimate recovery-----	670.5	NA	7360.6	NA	
Cumulative production--------	560.9	NA	6210.3	NA	
Proved reserves--------------	109.6	NA	1150.3	NA	
			(Dry Basis)		
Proved reserves--------------			1080.6	NA	66.1
Reserves in shut-in reservoirs----------------	0	NA	0	NA	0
Indicated secondary and tertiary reserves---------	33.2		0		
Production					
Year 1973 (total)---------	9.5	NA	141.9	NA	8.7
Year 1974 (total)---------	9.8	NA	136.6	NA	8.4
Long-term projection of production (annual total)					
1975------------------	10.1	NA	123.6	NA	
1976------------------	9.7	NA	109.1	NA	
1977------------------	8.9	NA	97.2	NA	
1978------------------	8.2	NA	87.0	NA	
1979------------------	7.3	NA	78.0	NA	
1980------------------	6.5	NA	70.0	NA	
1981------------------	5.7	NA	63.0	NA	
1982------------------	5.1	NA	56.8	NA	
1983------------------	4.6	NA	51.3	NA	
1984------------------	4.1	NA	46.5	NA	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production-----	27.6	NA	378	NA	23.1
Short-term productive capacity (60-day basis)---	27.6	NA	357	NA	

[1]Includes Eumont, Eunice-Monument, Eunice South, Jalmat, and Langlie-Mattix Fields.
[2]Individual field totals may not add to the area total due to independent rounding.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
EUMONT FIELD

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas: Assoc. (BCF)	Natural Gas: Non-Assoc. (BCF)	Natural Gas: Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	275.7	NA	2392.3	NA	
Proved ultimate recovery	73.9	NA	2247.1	NA	
Cumulative production	65.8	NA	1730.3	NA	
Proved reserves	8.1	NA	516.8	NA	
			(Dry Basis)		
Proved reserves			485.0	NA	29.7
Reserves in shut-in reservoirs	0	NA	0	NA	0
Indicated secondary and tertiary reserves	8.8				
Production					
Year 1973 (total)	1.1	NA	66.9	NA	4.1
Year 1974 (total)	0.9	NA	65.9	NA	4.0
Long-term projection of production (annual total)					
1975	0.9	NA	59.8	NA	
1976	0.8	NA	53.2	NA	
1977	0.7	NA	47.9	NA	
1978	0.6	NA	43.1	NA	
1979	0.6	NA	38.8	NA	
1980	0.5	NA	34.9	NA	
1981	0.5	NA	31.4	NA	
1982	0.4	NA	28.3	NA	
1983	0.4	NA	25.4	NA	
1984	0.3	NA	22.9	NA	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	2.5	NA	199	NA	12.2
Short-term productive capacity (60-day basis)	2.5	NA	178	NA	

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
EUNICE-MONUMENT FIELD

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas Assoc. (BCF)	Natural Gas Non-Assoc. (BCF)	Natural Gas Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	1888.7	NA	1498.5	NA	
Proved ultimate recovery	377.7	NA	1423.6	NA	
Cumulative production	316.8	NA	1119.0	NA	
Proved reserves	60.9	NA	304.6	NA	
			(Dry Basis)		
Proved reserves			286.3	NA	17.5
Reserves in shut-in reservoirs	0	NA	0	NA	0
Indicated secondary and tertiary reserves	0		0		
Production					
Year 1973 (total)	4.3	NA	21.3	NA	1.3
Year 1974 (total)	4.1	NA	21.2	NA	1.3
Long-term projection of production (annual total)					
1975	4.0	NA	18.9	NA	
1976	3.8	NA	17.7	NA	
1977	3.5	NA	16.7	NA	
1978	3.3	NA	15.7	NA	
1979	3.1	NA	14.7	NA	
1980	2.9	NA	13.8	NA	
1981	2.8	NA	13.0	NA	
1982	2.6	NA	12.2	NA	
1983	2.4	NA	11.5	NA	
1984	2.3	NA	10.8	NA	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	11.1	NA	51	NA	3.1
Short-term productive capacity (60-day basis)	11.0	NA	51	NA	

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
EUNICE SOUTH FIELD

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas: Assoc. (BCF)	Natural Gas: Non-Assoc. (BCF)	Natural Gas: Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	225.8	NA	448.7	NA	
Proved ultimate recovery	29.3	NA	403.9	NA	
Cumulative production	23.0	NA	394.2	NA	
Proved reserves	6.3	NA	9.7	NA	
			(Dry Basis)		
Proved reserves			9.1	NA	0.6
Reserves in shut-in reservoirs	0	NA	0	NA	0
Indicated secondary and tertiary reserves	5.9		0		
Production					
Year 1973 (total)	0.2	NA	5.0	NA	0.3
Year 1974 (total)	0.3	NA	4.4	NA	0.3
Long-term projection of production (annual total)					
1975	0.5	NA	3.1	NA	
1976	0.7	NA	2.1	NA	
1977	0.8	NA	1.4	NA	
1978	0.8	NA	0.9	NA	
1979	0.7	NA	0.6	NA	
1980	0.6	NA	0.4	NA	
1981	0.5	NA	0.3	NA	
1982	0.4	NA	0.2	NA	
1983	0.4	NA	0.1	NA	
1984	0.3	NA	0.1	NA	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	1.0	NA	10	NA	0.6
Short-term productive capacity (60-day basis)	1.1	NA	10	NA	

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
JALMAT FIELD

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas: Assoc. (BCF)	Natural Gas: Non-Assoc. (BCF)	Natural Gas: Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place----------------------	313.3	NA	2203.5	NA	
Proved ultimate recovery-----	87.8	NA	2082.7	NA	
Cumulative production--------	68.8	NA	1792.7	NA	
Proved reserves--------------	19.0	NA	290.0	NA	
			(Dry Basis)		
Proved reserves--------------			272.6	NA	16.7
Reserves in shut-in reservoirs----------------	0	NA	0	NA	0
Indicated secondary and tertiary reserves---------	12.4		0		
Production					
Year 1973 (total)---------	0.8	NA	39.8	NA	2.4
Year 1974 (total)---------	1.0	NA	36.8	NA	2.3
Long-term projection of production (annual total)					
1975------------------	1.5	NA	34.0	NA	
1976------------------	1.8	NA	30.4	NA	
1977------------------	1.8	NA	27.2	NA	
1978------------------	1.8	NA	24.4	NA	
1979------------------	1.6	NA	21.8	NA	
1980------------------	1.3	NA	19.3	NA	
1981------------------	1.2	NA	17.2	NA	
1982------------------	1.0	NA	15.4	NA	
1983------------------	0.9	NA	13.7	NA	
1984------------------	0.7	NA	12.3	NA	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production-----	3.1	NA	95	NA	5.8
Short-term productive capacity (60-day basis)---	3.2	NA	94	NA	

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
LANGLIE-MATTIX FIELD

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas: Assoc. (BCF)	Natural Gas: Non-Assoc. (BCF)	Natural Gas: Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	337.1	NA	1337.0	NA	
Proved ultimate recovery	101.8	NA	1203.3	NA	
Cumulative production	86.5	NA	1174.1	NA	
Proved reserves	15.3	NA	29.2	NA	
			(Dry Basis)		
Proved reserves			27.4	NA	1.7
Reserves in shut-in reservoirs	0	NA	0	NA	0
Indicated secondary and tertiary reserves	6.1		0		
Production					
Year 1973 (total)	3.2	NA	9.0	NA	0.5
Year 1974 (total)	3.4	NA	8.4	NA	0.5
Long-term projection of production (annual total)					
1975	3.2	NA	7.9	NA	
1976	2.6	NA	5.7	NA	
1977	2.1	NA	4.1	NA	
1978	1.7	NA	2.9	NA	
1979	1.3	NA	2.1	NA	
1980	1.1	NA	1.5	NA	
1981	0.9	NA	1.1	NA	
1982	0.7	NA	0.8	NA	
1983	0.5	NA	0.6	NA	
1984	0.4	NA	0.4	NA	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	10.0	NA	23	NA	1.4
Short-term productive capacity (60-day basis)	9.8	NA	23	NA	

The Eunice Area includes the Eumont, Eunice-Monument, Eunice South, Jalmat, and Langlie-Mattix Fields located in extreme southeastern Lea County, New Mexico, on the northwestern edge of the Central Basin Platform.

The producing formations in this group of fields, ranging from youngest to oldest, are the Yates, Seven Rivers, Queen, Grayburg, and San Andres. All of these formations are of the Guadalupe Series of the Middle Permian age. The Yates and Queen formations are predominately sandstones with varying degrees of interbedded limestone, dolomite, anhydrite, and red shale. The Seven Rivers, Grayburg, and San Andres formations are mostly dolomitic limestone with varying amounts of anhydrite and sandstone--generally decreasing with depth. The overall thickness of the entire section is about 1500 feet which includes approximately the top 200 feet of the San Andres formation.

These fields cover an area about 50 miles from north to south and average about 9 miles from east to west. In the southern 30 miles of the area, the fields lie on the western flank or limb of the Central Basin Platform. The dip is predominately west into the Delaware Basin. Down dip and to the west the productive limits are controlled by bottom water. Up dip and to the east, the facies changes to a more sandy back reef or lagoonal environment with productive limits stratigraphically controlled by diminishing porosity and permeability. There is some reversal of dip on the eastern edge. In the northern 20 miles of the area, the structure rises 500 to 700 feet and there is closure on all sides of an anticlinal feature. Water controls the lower limits of this reservoir. There is a tendency for gravity stabilization of reservoir fluids in the entire section. There was a large original gas cap, an oil zone, and bottom water. Although there are variations caused by erratic porosity and permeability development, the gas/oil and oil/water contacts tend to cut across formation interfaces when porosity and permeability are sufficiently developed.

The division of this area--laterally and vertically--into the five fields is arbitrary. In the north 20 miles the Yates, Seven Rivers, and Queen formations are called Eumont; while the Grayburg and San Andres formations are called Eunice-Monument. Eumont has a large gas cap and an oil rim. Eunice-Monument has a continuation of the same gas cap and an underlying oil zone. In the southern 30 miles, the Yates and all except the lower 100 feet of Seven Rivers is called Jalmat. Jalmat has a large gas cap and an underlying oil column on the western edge. The lower-most 100 feet of Seven Rivers and the Queen formations are futher subdivided into the Eunice South and Langlie-Mattix Fields. Eunice South covers the north 6 miles and Langlie-Mattix the southern 24 miles of the lower 30 miles of the trend.

There was an active water drive along the western Capitan reef front in the southern 30 miles of the area. This affected only the western several rows of wells. In the back reef eastern areas and in the Eunice-Monument anticline to the north, the producing mechanism has been a dissolved gas drive. The large associated gas caps at Eumont and Jalmat are being produced by means of pressure depletion.

The consultant firm estimates that secondary oil recovery by water flood should amount to 60 percent of primary recovery at Langlie-Mattix and Jalmat and 50 percent of primary recovery at Eunice South and Eumont. Also the contractor determined that portions of the producing areas actively under flood are 50 percent at Eunice South, 67 percent at Jalmat, 68 percent at Eumont, and 85 percent at Langlie-Mattix. The Summary Tables list indicated secondary reserves for further activities in the presently unflooded portions. At Eunice-Monument, the only water flood project in the Grayburg and San Andres apparently demonstrated premature water break through and poor oil response. Indicated secondary reserves are not yet listed for Eunice-Monument, though residual oil saturation at primary depletion should amount to some 1.5 billion barrels.

Ultimate oil recovery in these five fields was estimated by determining primary ultimate by means of extrapolation of appropriate portions of the production decline trends and then by addition of secondary recovery amounts as discussed above. At Eumont, both production decline trends and pressure decline trends were utilized to estimate gas reserves. Production decline trends were used to estimate gas reserves in the other four fields.

Hydrocarbons originally in place were estimated generally by process of comparing estimated primary ultimate recovery with estimated primary recovery efficiency factors. The primary recovery efficiency factors selected by the consultant firm are as follows: Oil at Eunice South-10 percent; oil in other four fields-20 percent, gas cap at Eumont-96 percent; gas cap at Jalmat-95 percent; other associated gas in all five fields-90 percent.

The fields in the Eunice Area were discovered in 1929 and are thus over 45 years old. Much information concerning reservoir rock or fluid properties was not obtained in the early days. Cumulative production records of water and gas are not reliable. Data collections and storage have been adversely affected by the many nomenclature complications relating to changing field combinations and boundaries. Time constraints precluded a thorough review of these situations.

The FEA reports on the Eumont, Eunice-Monument, Eunice South, Jalmat, and Langlie-Mattix Fields were prepared by Keplinger and Associates, Inc., under Contract No. CO-05-50184-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
FAIRWAY FIELD[1]

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas Assoc. (BCF)	Natural Gas Non-Assoc. (BCF)	Natural Gas Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place[2]	438.1	NA	629.0	NA	
Proved ultimate recovery[2]	207.4	NA	377.4	NA	
Cumulative production[2]	120.1	NA	68.1	NA	
Proved reserves	87.3	NA	309.3	NA	
			(Dry Basis)		
Proved reserves			263.0	NA	26.0
Reserves in shut-in reservoirs	0	NA	0	NA	0
Indicated secondary and tertiary reserves	0		0		
Production					
Year 1973 (total)	17.0	NA	10.2	NA	3.5
Year 1974 (total)	13.6	NA	9.0	NA	3.8
Long-term projection of production (annual total)					
1975	11.1	NA	9.4	NA	
1976	9.4	NA	10.2	NA	
1977	7.8	NA	10.5	NA	
1978	6.5	NA	10.7	NA	
1979	5.3	NA	10.7	NA	
1980	4.4	NA	10.6	NA	
1981	3.6	NA	10.3	NA	
1982	3.0	NA	9.9	NA	
1983	2.5	NA	9.3	NA	
1984	2.0	NA	8.2	NA	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	34.2	NA	25	NA	10.2
Short-term productive capacity (60-day basis)	34.2	NA	25	NA	

[1]Includes the James Lime reservoir and minor reserves in the Rodessa, Pettit, and Massive Anhydrite.
[2]James Lime Formation only.

The Fairway oil field is located in Henderson and Anderson Counties, Texas, in the East Texas Basin.

The principal producing zone is the James Limestone which is of Lower Glenrose-Cretaceous age. The depth to the top of the pay is about 9,900 feet.

The structure at Fairway, principally a reef growth, is a southeasterly plunging nose. Flank faults, permeability pinch outs and edge water complete the trap. The productive area is about 23,000 acres (36 square miles).

The crude oil at Fairway was initially undersaturated. The initial reservoir pressure exceeded the saturation pressure by some 1,200 psi. Although the bottom or edge water has not been active, the reservoir pressure has always been maintained above the saturation level. Initially the field produced under fluid expansion drive. In 1965, some five years after discovery, the field was unitized and in the following year an alternating gas-water miscible displacement program was begun. Subsequently, injection has exceeded or equaled reservoir withdrawals. The reservoir pressure first rose and has since been generally maintained.

The hydrocarbons originally in place were calculated using the volumetric method. The data obtained in relatively recent years should permit a reliable calculation of reservoir volumes. However, the James Lime is very heterogenous and stratified. The attempts at material balance calculations of oil originally in place were discounted because of difficulties in determining the average pressure in the low permeable carbonate reservoir. Also all of the history has been in the highly sensitive undersaturated phase of fluid expansion.

The field operator had determined from displacement tests, numeric model studies and calculations from depleted sections of the field that a 50 percent oil recovery efficiency would be representative of the more important zones and that a 40 percent oil recovery efficiency would be representative of the lesser important zone. (47 percent weighted total). These factors were accepted by the study team. The production forecast was based upon a production decline trend which has become manifest since mid 1972. The production forecast appears somewhat inconsistent with the proved reserves estimate, which was based on the recovery efficiency factors. The proved reserves appear too high if the production trend is valid. A few more years of production history will be necessary to clarify this matter. The most important uncertainties concerning recovery efficiency relate to the combination of the wide-160 acre spacing and the extreme lack of uniformity in the carbonate reservoir.

The FEA report on the Fairway Field was prepared by the U.S. Bureau of Mines, Department of the Interior, under Interagency Agreement CG-05-50058-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
GOMEZ FIELD[1]

	Crude Oil (MMBbls)	Lease[2] Condensate (MMBbls)	Natural Gas Assoc. (BCF)	Natural Gas Non-Assoc. (BCF)	Natural Gas Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	NA	NA	NA	5255	
Proved ultimate recovery	NA	NA	NA	4370	
Cumulative production	NA	NA	NA	2043	
Proved reserves	NA	NA	NA	2327	
			(Dry Basis)		
Proved reserves			NA	2327	NA
Reserves in shut-in reservoirs	NA	NA	NA	0	NA
Indicated secondary and tertiary reserves	NA		NA		
Production					
Year 1973 (total)	NA	NA	NA	408	NA
Year 1974 (total)	NA	NA	NA	383	NA
Long-term projection of production (annual total)					
1975	NA	NA	NA	368	
1976	NA	NA	NA	313	
1977	NA	NA	NA	266	
1978	NA	NA	NA	226	
1979	NA	NA	NA	190	
1980	NA	NA	NA	159	
1981	NA	NA	NA	131	
1982	NA	NA	NA	109	
1983	NA	NA	NA	91	
1984	NA	NA	NA	76	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	NA	NA	NA	1050	NA
Short-term productive capacity (60-day basis)	NA	NA	NA	1189	

[1]Includes the principal Ellenburger reservoir (over 99 percent of the reserves) and the Devonian, Fusselman, and Wolfcamp reservoirs.

[2]Lease condensate volumes (Wolfcamp reservoir only) are insignificant.

The Gomez gas field is located in Pecos County, Texas, in the Delaware-Val Verde Basin.

The principal producing formation is the Ellenburger dolomite of Ordovician age. It has a thickness of about 1,600 feet in the field and is encountered at a depth of about 20,000 feet.

The Gomez structure is an anticline with a number of faults--some of which form reservoir boundaires. Porosity and permeability deterioration are also important in determining limits of the reservoir. The lower limits are determined by bottom water. The field has 80,000 productive acres (125 square miles).

The bottom water in the Ellenburger is not active at Gomez. Production is controlled by pressure depletion. Because of the numerous faults in the reservoir, which hinder pressure equalization throughout the field, reserves and gas originally in place were determined on an individual well basis. The method was generally through analysis of trends of pressure data versus cumulative production. In some instances, production decline trends were utilized.

Because of the 20,000 foot producing depth, the consultant firm selected a relatively high abandonment reservoir pressure of about 900 psia. The sensitivity of change in ultimate production to a change in abandonment pressure, at this range, is roughly 1 BCF/psi.

The FEA report on the Gomez Field was prepared by Ryder Scott Company under Contract No. CO-05-50183-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974

GRAND ISLE BLOCK 43 FIELD

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas: Assoc. (BCF)	Natural Gas: Non-Assoc. (BCF)	Natural Gas: Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place----------------------	562.8	20.4	865.5	894.4	
Proved ultimate recovery-----	271.9	12.3	514.9	631.4	
Cumulative production--------	164.2	5.5	266.1	228.5	
Proved reserves--------------	107.7	6.8	248.8	402.9	
			(Dry Basis)		
Proved reserves--------------			243.8	394.9	12.8
Reserves in shut-in reservoirs----------------	0	0	0	0	0
Indicated secondary and tertiary reserves---------	7.4		18.0		
Production					
Year 1973 (total)---------	21.4	1.4	40.5	45.6	1.7
Year 1974 (total)---------	21.2	2.4	43.1	61.0	2.1
Long-term projection of production (annual total)					
1975------------------	19.1	1.6	39.1	53.2	
1976------------------	16.5	1.2	34.2	45.9	
1977------------------	13.7	1.0	29.3	40.8	
1978------------------	11.6	0.8	25.3	35.6	
1979------------------	9.7	0.6	21.6	30.9	
1980------------------	7.8	0.4	17.9	25.5	
1981------------------	6.3	0.3	14.8	20.4	
1982------------------	5.1	0.2	12.3	17.0	
1983------------------	4.2	0.1	10.1	14.1	
1984------------------	3.4	0.1	8.4	11.2	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production-----	52.8	3.8	105	192	5.9
Short-term productive capacity (60-day basis)---	54.0	4.8	116	154	

The Grand Isle Block 43 oil and gas field is about 20 miles offshore from Plaquemines and Jefferson Parishes in southern Louisiana. The location is in the offshore Miocene belt, some 65 miles south-southeast of New Orleans in water depths from 105-160 feet.

Some 54 producing sands have been identified in a thick sand-shale sequence of Upper Miocene to Middle Pliocene age at depths from 3,500 to 13,000 feet. The most important reservoirs are in the Miocene from 9,000 to 12,000 feet.

The Grand Isle Block 43 structure is a NW-SE oriented anticline, cut by normal faults which generally trend E-W. No well has penetrated salt and the consultant has not established if the anticline is related to salt diapirism. Blanket sands generally are not present, and some traps are principally stratigraphic. Further reservoir delineation is provided by numerous fault intersections. Bottom water is present in most instances. In addition to the 54 separate sands, there are 12 separate fault segments. The consultant has not established the number of separate reservoir entities. The field has a productive area of 19,600 acres (31 square miles).

Hydrocarbons originally in place at Grand Isle Block 43 were estimated by pseudo-volumetric analysis methods in eleven sands which contain about two-thirds of the oil and gas reserves. Most logs were examined; oil and gas pay was counted; isopach maps were prepared; and average reservoir rock and fluid parameters were selected. In the remaining sands, ultimate recoveries were estimated from production history and decline curve analysis, and hydrocarbons originally in place were inferred by assuming oil and gas recovery efficiency factors. None of this work is documented in the report.

The oil recovery mechanisms were reported as various combinations of solution gas drive, gas cap drive, and partial water drive. The non-associated gas recovery mechanisms are pressure depletion and partial water drive. Beyond this generalized statement, the details of reservoir behavior, even in the principal sands, were not discussed. There are no water floods currently operating, though secondary reserves are indicated for two sands.

Ultimate recovery and proved reserves in most sands were estimated by means of analysis of production history and production decline curves. In some of the larger reservoirs, which are not in production decline, ultimate recovery and proved reserves were estimated from combination of the volumetric analysis work and selection of recovery efficiency factors. The consultant reports that the production decline extrapolations would include the weighted effect of future recompletions. This is an undocumented but possible situation. The report includes graphs for each sand showing a few years' recent production history as well as a forecast for the next ten years. The projections, many of which are not straight forward, are not discussed in the report.

The FEA report on the Grand Isle Block 43 Field was prepared by Keplinger and Associates, Inc., under Contract No. CO-05-50187-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974

GREATER ALTAMONT FIELD[1]

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas: Assoc. (BCF)	Natural Gas: Non-Assoc. (BCF)	Natural Gas: Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	698.0	NA	712.0	NA	
Proved ultimate recovery	87.2	NA	88.5	NA	
Cumulative production	48.0	NA	48.1	NA	
Proved reserves	39.2	NA	40.4	NA	
			(Dry Basis)		
Proved reserves			40.4	NA	NA
Reserves in shut-in reservoirs	0	NA	0	NA	NA
Indicated secondary and tertiary reserves	0		0		
Production					
Year 1973 (total)	13.8	NA	14.6	NA	NA
Year 1974 (total)	22.1	NA	23.2	NA	NA
Long-term projection of production (annual total)					
1975	20.5	NA	21.8	NA	
1976	10.4	NA	10.5	NA	
1977	4.3	NA	4.2	NA	
1978	2.2	NA	2.2	NA	
1979	1.1	NA	1.1	NA	
1980	0.4	NA	0.5	NA	
1981	0.2	NA	0.2	NA	
1982	---	NA	---	NA	
1983	---	NA	---	NA	
1984	---	NA	---	NA	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	57.1	NA	58	NA	NA
Short-term productive capacity (60-day basis)	64.6	NA	69	NA	

[1]Includes Altamont, Bluebell, Cedar Rim, and Sink Draw areas.

The Greater Altamont Field, in Duchesne and Uintah Counties of northeastern Utah includes the Altamont, Bluebell, Cedar Rim, and Sink Draw areas. The field is in the Uinta Basin, some 80 miles southeast of Salt Lake City.

The producing formations include the Green River and Wasatch zones of Eocene age. Completion depths range from 8,000 to 14,000 feet. The Green River intervals are Tertiary lake deposits of black shale and silt. The Wasatch is a series of red sands and shales.

The regional structure in the Green River and Wasatch zones dips gently to the north by about 3 degrees. The producing members are very lenticular and the accumulations are stratigraphically controlled. Bottom water occurs in some intervals. The field extends some 50 miles in an east-west direction and is up to 13 miles wide. The productive area is about 237,000 acres (370 square miles).

The pay zone consists of a very low porosity siltstone which has a very low matrix permeability. Fracture development contributes to well productivity. The crude was initially undersaturated and a fluid expansion drive is contemplated. The bottom water is not active. The consultant does not expect significant production at pressures below the saturation point. The crude has a very high pour point of 105° F; downhole and surface heating of facilities is necessary to prevent solidification. The consultant firm has estimated hydrocarbons originally in place by assuming that ultimate recovery would be approximately 12.5 percent of the volumes initially present.

Ultimate recovery and proved oil reserves have been estimated by study of production decline trends of every lease in the field. Spacing is generally on a 640-acre per well basis, though some of the older areas were drilled on 160-acre spacing. Ultimate recoveries from some of the more recent wells were estimated by analogy. The consultant firm estimates that about ten of the some 300 wells will recover more than 1 million barrels each, while somewhat more than one-half of the wells will produce 250,000 barrels or less. The tendency is for the older wells to be better, which has been attributed to initial wide drainage through the fracture system.

The FEA report on the Greater Altamont Field has been prepared by Ryder Scott Company under Contract No. CO-05-50189-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
HASTINGS FIELD[1]

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas: Assoc. (BCF)	Natural Gas: Non-Assoc. (BCF)	Natural Gas: Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	1004.9	NA	647.2	NA	
Proved ultimate recovery	663.9	NA	472.9	NA	
Cumulative production	481.5	NA	284.9	NA	
Proved reserves	182.4	NA	188.0	NA	
			(Dry Basis)		
Proved reserves			178.6	NA	2.9
Reserves in shut-in reservoirs	0	NA	0	NA	0
Indicated secondary and tertiary reserves	0		0		
Production					
Year 1973 (total)	22.6	NA	14.1	NA	0.3
Year 1974 (total)	27.6	NA	16.2	NA	0.4
Long-term projection of production (annual total)					
1975	28.0	NA	16.0	NA	
1976	27.8	NA	15.9	NA	
1977	26.4	NA	15.2	NA	
1978	24.3	NA	14.2	NA	
1979	19.2	NA	10.6	NA	
1980	15.4	NA	8.1	NA	
1981	12.2	NA	6.2	NA	
1982	9.6	NA	5.0	NA	
1983	7.7	NA	4.0	NA	
1984	6.1	NA	3.3	NA	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	76.0	NA	45	NA	1.1
Short-term productive capacity (60-day basis)	79.4	NA	47	NA	

[1] Does not include shallow Miocene gas reservoirs.

Hastings oil field is located in Brazoria and Galveston Counties, Texas, within the Oligocene belt of the Texas Gulf Coast.

The principal producing zones are the Upper and Lower Frio sandstones which are of Oligocene age. They are found at depths from 5,500 to 6,000 feet.

The anticlinal structure at Hastings is highly faulted and overlies a deep seated salt dome. The area of the field is about 4,600 acres (7 square miles).

The oil recovery mechanism is a strong water drive aided by expansion of an original gas cap in the eastern part of the field and by expansion of a secondary gas cap in the western part of the field.

Hydrocarbons originally in place were estimated using the volumetric method. However, the early discovery date of the field (1934) precludes the availability of much reservoir data of the sort now obtained by utilizing modern methods. The study team relied upon previously published information, modified by their examination of more recent data obtained while drilling infilling wells. Attempts to calculate hydrocarbons in place using material balance methods were not generally noteworthy because of poor water production records in the early days and questionable quality of the pressure-volume-temperature data.

The production from the more important western portion of the field has not yet established a predictable decline pattern. Also, the combination of time constraints and generally inadequate data in the oil field did not permit a thorough analysis of the oil displacement mechanism, as water encroaches through the oil reservoir. However, data from considerable infill drilling has indicated a relatively good water sweep efficiency in the flooded out portions of the reservoir. The study team estimated that oil recovery efficiency should approximate 69 percent in the western part of the field based upon empirical correlation methods and from residual oil saturation data from cores. A production decline has been in existence for some years in the eastern and poorer part of the field. There, an oil recovery efficiency of about 54 percent is indicated.

The FEA report on the Hastings Field was prepared by the Region VI Office of the Federal Energy Administration located in Dallas, Texas.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
HAWKINS FIELD[1]

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas: Assoc. (BCF)	Natural Gas: Non-Assoc. (BCF)	Natural Gas: Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	1530	NA	942	NA	
Proved ultimate recovery	1071	NA	800	NA	
Cumulative production	536	NA	262	NA	
Proved reserves	535	NA	538	NA	
			(Dry Basis)		
Proved reserves			479	NA	38.0
Reserves in shut-in reservoirs	0	NA	0	NA	0
Indicated secondary and tertiary reserves	0		0		
Production					
Year 1973 (total)	39.7	NA	26.0	NA	2.3
Year 1974 (total)	39.8	NA	28.8	NA	2.3
Long-term projection of production (annual total)					
1975	39.8	NA	14.2	NA	
1976	39.8	NA	14.2	NA	
1977	39.8	NA	14.2	NA	
1978	39.8	NA	14.2	NA	
1979	39.8	NA	14.2	NA	
1980	37.8	NA	13.5	NA	
1981	35.9	NA	12.8	NA	
1982	34.1	NA	12.1	NA	
1983	32.4	NA	11.5	NA	
1984	30.8	NA	11.0	NA	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	108	NA	78	NA	6.3
Short-term productive capacity (60-day basis)	112	NA	80	NA	

[1] Includes only the Woodbine Sand.

The Hawkins oil field is located in southeast Wood County, Texas, in the East Texas Basin.

The principal producing formation at Hawkins is the Woodbine Sand of Cretaceous age which occurs at 4,200 feet. The Woodbine is composed of the Lewisville and Dexter units which are divided into 10 highly porous and permeable intercommunicative sands. The Dexter (lower 3 of the 10 sands) has 80 percent of the reservoir volume.

Hawkins is a complexly faulted anticline which is underlain by a deep seated salt mass. Except for a major N-S fault, which separated the field into the West and East Segments, the 42 fault segments of the field are intercommunicative. In addition to structure, the accumulation is controlled by a common water table at the base. The Eagle Ford Shale, and sometimes the Austin Chalk provides the upper seal. At the base of the West Segment, there is a heavy asphalt layer ranging in thickness from 50 feet on the north to 100 feet in the south. The productive area is 10,600 acres (17 square miles).

The hydrocarbons originally in place at Hawkins were calculated using the volumetric method. There are considerable core data. The field was heavily studied and reported on prior to unitization.

The crude oil at Hawkins was originally saturated and a large original gas cap existed. The asphaltic layer in the Western Segment has restricted water encroachment into the oil reservoir. The absence of this layer in the Eastern Segment probably accounts for the 15 percent reduction in the original pressure there, which has been attributed to heavy withdrawals from the East Texas field (14 miles away and discovered 10 years earlier). The primary recovery mechanisms include solution gas drive, gas cap drive with gravity drainage, and water drive. In the Western Segment, water drive is limited and the gravity drainage mechanism is considered more important. The opposite situation may prevail to some extent in the Eastern Segment. The field was unitized on January 1, 1975. The operating plan is to inject inert gas near the gas/oil contact to maintain pressure and to prevent migration of oil into the gas cap area (which has occurred to some extent in the past). Even in the Western Segment, a high pressure differential between the oil reservoir and the aquifer can prompt water influx through the thinner portions of the asphaltic layer.

The consulting firm has adopted the oil recovery efficiency which was developed in the operating plan by the engineering unitization committee. This efficiency is 70 percent of the oil originally in place and is reported by the consultant to result from gas cap expansion and gravity drainage recovery mechanisms. At this point in the producing life of the field, the portion of the secondary recovery volume that should be defined as "proved" or as "indicated" is debatable. The gas injection activities had not been commenced as of the index date of the report. Following oil depletion, the large gas cap will be blown down and 85 percent of the gas originally in place will be produced. This appears reasonable.

The FEA report on the Hawkins Field was prepared by James A. Lewis Engineering under Contract No. CO-05-50181-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
HEIDELBERG FIELD

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas Assoc.[1] (BCF)	Natural Gas Non-Assoc. (BCF)	Natural Gas Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	492.5	NA	39.1	1.8	
Proved ultimate recovery	172.0	NA	NA	1.5	
Cumulative production	116.6	NA	NA	0.5	
Proved reserves	55.4	NA	NA	1.0	
			(Dry Basis)		
Proved reserves			NA	1.0	NA
Reserves in shut-in reservoirs	0	NA	NA	0	NA
Indicated secondary and tertiary reserves	3.1		NA		
Production					
Year 1973 (total)	5.3	NA	NA	0.2	NA
Year 1974 (total)	5.1	NA	NA	0.1	NA
Long-term projection of production (annual total)					
1975	4.7	NA	NA	0.1	
1976	4.4	NA	NA	0.1	
1977	4.2	NA	NA	0.1	
1978	3.9	NA	NA	0.1	
1979	3.5	NA	NA	0.1	
1980	3.2	NA	NA	---	
1981	2.9	NA	NA	---	
1982	2.6	NA	NA	---	
1983	2.4	NA	NA	---	
1984	2.2	NA	NA	---	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	13.7	NA	NA	0.1	NA
Short-term productive capacity (60-day basis)	13.6	NA	NA	0.1	

[1]Associated gas reserves and production volumes are insignificant

The Heidelberg oil field is located in Jasper County, Mississippi, in the Cretaceous-Jurassic belt of Mississippi, Alabama, and West Florida. The field is about 65 miles southeast of Jackson.

The producing sands at Heidelberg range from the Selma Chalk of Upper Cretaceous age at 3,900 feet to the Cotton Valley sand of Upper Jurassic age at 11,200 feet. The Eutaw sand series of Upper Cretaceous age is the principal producing group and occurs from 4,600 to 5,000 feet.

Heidelberg is situated over and around a salt dome of intermediate depth. The central part of the field, which overlies the dome, is a highly faulted graben area. There are also east and west flanks on the sides of the dome which are considerably less faulted. The report identifies and treats separately 16 oil reservoirs and one small nonassociated gas reservoir. Bottom water is present in most reservoirs. The field has 9,600 productive acres (15 square miles).

Hydrocarbons originally in place in the oil reservoirs were calculated by the volumetric analysis method. Average reservoir rock and fluid parameters are listed for each reservoir. The analysis of the small nonassociated gas reservoir is based on pressure depletion.

The crude oil at Heidelberg was generally highly undersaturated. Dissolved gas oil ratios were very low. Nine of the oil reservoirs have active water drives and one has a combination water drive and solution gas drive. These ten reservoirs have about 97 percent of the proved oil reserves at Heidelberg. The remaining six oil reservoirs produce with dissolved gas drives. There has been one apparently successful in situ combustion project in the Cotton Valley reservoir. Another in situ combustion project in a naturally watered-out zone has not shown production response. A conventional waterflood pilot operation in a third small reservoir appears noncommercial. Secondary reserves are indicated for a fourth reservoir which has been unitized preparatory to a water injection program.

Ultimate recovery and proved reserves were estimated based on extrapolations of productive decline curves and recovery factors determined from field performance for each reservoir. The oil production decline trends are not yet firmly established in some of the larger reservoirs.

The FEA report on the Heidelberg Field was prepared by James A. Lewis Engineering under Contract No. CO-05-50181-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974

HUGOTON FIELD

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas: Assoc. (BCF)	Natural Gas: Non-Assoc. (BCF)	Natural Gas: Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	NA	NA	NA	39,305	
Proved ultimate recovery	NA	NA	NA	37,239	
Cumulative production	NA	NA	NA	22,052	
Proved reserves	NA	NA	NA	15,187	
			(Dry Basis)		
Proved reserves			NA	15,187	NA
Reserves in shut-in reservoirs	NA	NA	NA	0	NA
Indicated secondary and tertiary reserves	NA		NA		
Production					
Year 1973 (total)	NA	NA	NA	861.0	NA
Year 1974 (total)	NA	NA	NA	860.4	NA
Long-term projection of production (annual total)					
1975	NA	NA	NA	1921.6[1]	
1976	NA	NA	NA	1568.5	
1977	NA	NA	NA	1305.4	
1978	NA	NA	NA	1103.8	
1979	NA	NA	NA	945.9	
1980	NA	NA	NA	819.7	
1981	NA	NA	NA	717.2	
1982	NA	NA	NA	632.9	
1983	NA	NA	NA	562.5	
1984	NA	NA	NA	503.3	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	NA	NA	NA	2601	NA
Short-term productive capacity (60-day basis)	NA	NA	NA	5264	

[1] Projection represents the field's capacity to produce. Actual production rates are controlled by State and National regulatory agencies.

The Hugoton gas field is located in the Anadarko Basin of western Kansas, the Oklahoma panhandle and the Texas panhandle.

The production is from the Chase Group of dolomites of Wolfcamp--Permian age. The average depth to the top of the pay is about 2,600 feet.

Hugoton is a stratigraphic trap. Westward and updip, porosity and permeability pinch out as the dolomites grade into red shales and silt stones. To the south, the gas is trapped against the igneous uplift of the Amarillo Mountains. Eastward the producing zone contains bottom water. The upper seal is provided by the overlying Wellington Shale. The field stretches some 150 miles from north to south and contains about 4 million productive acres (6,250 square miles).

The recovery mechanism is gas expansion drive (pressure depletion). The edge water is not active.

The gas originally in place (39.3 TCF) was estimated by extrapolating pressure data versus cumulative gas production to a reservoir pressure of absolute zero. Ultimate production (37.2 TCF) was estimated by extending the above mentioned trend to an abandonment reservoir pressure of 25 psia. After deduction of cumulative production of 22 TCF, reserves of 15.2 TCF are indicated.

The estimates of ultimate recovery and reserves are sensitive to the estimate of reservoir pressure at the time of abandonment. This is controlled by future economic factors. In this very large field, 75-80 BCF of gas are produced for each one psi drop in pressure. A change in the estimate of reservoir pressure at abandonment of 13 psi will cause a change in the recovery estimate of one TCF.

The gas at Hugoton contains about 17 percent nitrogen. However, this does not render the gas unsalable. The heat content of the raw gas ranges from 950-1,000 BTU per cubic foot in spite of nitrogen. Helium content averages about 1/2 of 1 percent.

The original reservoir pressures were 600-700 psi lower than anticipated pressures for the reservoir depth. These compare with current pressures as follows:

State	Original BHP (psia)	Current BHP (psia)	Ultimate Recovery (TCF)
Kansas	457	248	25.6
Oklahoma	451	195	6.0
Texas	454	133	5.6
			37.2

Individual well deliverability is determined from well test data. The wells are flowed approximately 72 hours into the pipeline while maintaining a working well head pressure at 80 percent of the average shut-in well head pressure of the field. The study team has estimated that the field could produce at the deliverability rate on a continuous basis without significant loss of ultimate recovery. The December 1974 production is about one-half of deliverability as shown below:

State	December 1974 Production (MMCF/D)	Deliverability (MMCF/D)	Ratio
Kansas	1,960	4,596	0.43
Oklahoma	399	321	1.24
Texas	242	347	0.70
Total	2,601	5,264	0.49

The FEA report on the Hugoton field was prepared by the U.S. Bureau of Mines, Department of the Interior, under Interagency Agreement CH-05-50058-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
HUNTINGTON BEACH FIELD

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas: Assoc. (BCF)	Natural Gas: Non-Assoc. (BCF)	Natural Gas: Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	4000.0	NA	1000.0	NA	
Proved ultimate recovery	1047.9	NA	791.1	NA	
Cumulative production	923.3	NA	772.1	NA	
Proved reserves[1]	124.6	NA	19.0	NA	
			(Dry Basis)		
Proved reserves			19.0	NA	NA
Reserves in shut-in reservoirs	0	NA	0	NA	NA
Indicated secondary and tertiary reserves	45.5		7.0		
Production					
Year 1973 (total)	20.6	NA	5.1	NA	NA
Year 1974 (total)	19.0	NA	4.7	NA	NA
Long-term projection of production (annual total)					
1975	16.0	NA	4.0	NA	
1976	13.0	NA	3.1	NA	
1977	10.6	NA	2.4	NA	
1978	8.7	NA	1.9	NA	
1979	7.0	NA	1.5	NA	
1980	5.6	NA	1.1	NA	
1981	4.6	NA	0.9	NA	
1982	4.0	NA	0.7	NA	
1983	3.2	NA	0.5	NA	
1984	2.7	NA	0.4	NA	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	50.2	NA	12	NA	NA
Short-term productive capacity (60-day basis)	48.0	NA	12	NA	

[1]Reserves do not include 12.8 MMBbls and 2 BCF in offshore area which will probably not be developed during next ten years.

The Huntington Beach oil field is located in Orange County, California, about 15 miles southeast of the city of Long Beach. The field is in the Los Angeles Basin situated both onshore and offshore.

The producing sands are in an alternating sand-shale sequence principally in the Repetto Series of the Lower Pliocene age and the Puente Series of the Upper Miocene age. Drilling depths range from 1,800 feet to 5,500 feet (true vertical depths).

The field consists of three distinct structural features. One is a simple anticline offshore, to the southwest, that is relatively unfaulted. The second is a complexly faulted central area which lies between the Ocean Avenue and the Inglewood fault systems. The final is a generally northeasterly dipping flank to the northeast of the Inglewood fault system. The accumulations are controlled by structure, by faulting, by interbedded shales, by the overlying Pico shale, and by bottom water. The field has 5,300 productive acres (8 square miles) of which some 2,300 acres lie offshore in State controlled waters.

A number of producing mechanisms are active in the various sand groups and in the different producing areas. The crude appeared to be initially undersaturated. The primary recovery mechanism was principally fluid expansion and dissolved gas drive. An active water drive is present in at least one of the medium sized reservoirs. Most of the major reservoir units are either under active water flood or they have future water flood secondary reserves indicated on the Summary Table. One of the shallow reservoirs, producing heavy crude oil, has responded well to cyclic steam injection and steam drive operations are under study. However, the consultant firm has not yet included steam drive secondary reserves in the indicated category because of failure of the two steam drive projects which have been carried out thus far. Water flooding is not considered possible for some of the reservoir units in the highly faulted areas.

The consultant firm has estimated proved reserves on a reservoir basis for the fourteen most important reservoirs in the various field areas. The future production decline rates are estimated to be quite severe because of the generally advanced nature of most of the active water floods and the likelihood that additional water flood activities and offshore development cannot be carried out in the forecast time span. In the offshore area there are proved reserves which cannot be reached by slant wells from either onshore drilling sites or existing platforms. The consultant firm does not contemplate that the existing environmentalist climate will permit the exploitation of these reserves in the next ten years. Approvals or permissions from 13 different agenices would be required.

A volumetric analysis was not possible in this very old and geologically complicated field. The consultant has estimated hydrocarbons originally in place on an approximate basis by assuming reasonable recovery efficiency factors for the various reservoirs.

The FEA report on the Huntington Beach Field was prepared by James A. Lewis Engineering under Contract No. CO-05-50181-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
JAY FIELD

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas[1] Assoc. (BCF)	Non-Assoc. (BCF)	Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	711.7	NA	906.7	NA	
Proved ultimate recovery	333.2	NA	424.5	NA	
Cumulative production	77.6	NA	98.9	NA	
Proved reserves	255.6	NA	325.6	NA	
			(Dry Basis)		
Proved reserves			325.6	NA	NA
Reserves in shut-in reservoirs	0	NA	0	NA	0
Indicated secondary and tertiary reserves	0		0		
Production					
Year 1973 (total)	30.1	NA	38.4	NA	NA
Year 1974 (total)	33.5	NA	42.7	NA	NA
Long-term projection of production (annual total)					
1975	34.1	NA	43.5	NA	
1976	34.1	NA	43.5	NA	
1977	34.1	NA	43.5	NA	
1978	31.2	NA	39.7	NA	
1979	29.1	NA	37.1	NA	
1980	27.8	NA	35.4	NA	
1981	26.5	NA	33.7	NA	
1982	22.7	NA	28.9	NA	
1983	16.0	NA	20.4	NA	
1984	----	NA	----	NA	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	93.3	NA	119	NA	NA
Short-term productive capacity (60-day basis)	93.3	NA	119	NA	

[1] Gas volumes have been reduced (9 percent by volume) for removal of H_2S.

The Jay oil field is located in the Florida panhandle in Santa Rosa and Escambia Counties. The field laps over a little into Escambia County, Alabama. The field is in the Cretaceous-Jurassic belt of Mississippi, Alabama, and West Florida.

The producing formations are the Smackover dolomite at about 15,500 feet and the Norphlet Sand at 15,950 feet. Both of these formations are Lower Jurassic in age. They are interconnected and are treated as a common reservoir. The Norphlet Sand contains about 2 percent of the hydrocarbons.

The field is a south and southwest plunging nose. The updip limits of the accumulation to the north are determined by porosity and permeability barriers and the lower limits are controlled by bottom water. The field has a productive area of 14,700 acres (23 square miles).

The crude oil at Jay was extremely undersaturated and the primary producing mechanism was by fluid and rock expansion. Movement of the bottom water is not expected. The crude is highly toxic with the dissolved gas containing 9 percent H_2S. Pressure reduction was to be avoided because it would be impractical to pump the corrosive and toxic crude from 15,000 feet. The field was unitized in 1974, less than four years after discovery and water injection was commenced immediately on a "three-to-one" line drive. There is one row of injectors for three rows of producers. Plans call for 27 injection wells. Injection rates have exceeded reservoir withdrawals; the pressure decline has been arrested; and more recently there has been some rise in reservoir pressure.

Hydrocarbons originally in place were calculated by the volumetric method. Every well at Jay was cored. The Smackover Formation was extensively studied prior to unitization. The 1970 discovery date has permitted use of the most modern methods.

Oil recovery efficiency at Jay has been estimated at 47 percent of oil originally in place, based on theoretical model studies of pressure maintenance by water injection. The secondary project had been in operation only ten months until survey time and the classification of the additional recovery as proved might be somewhat premature. There are many areas of concern in a project such as this, including: the great depth; the corrosive nature of the crude with associated metallurgical problems; the difficulties and expense of workovers, well control, etc.; the very wide spacing in the field; and the characteristic lack of uniformity of porosity and permeability in carbonate reservoirs. An alternative disposition of reserves might be to place perhaps 150 million barrels of the proved reserves into the indicated secondary category until the water injection project is fully installed and fully evaluated.

The FEA report on the Jay Field has been prepared by James A. Lewis Engineering under Contract No. CO-05-50181-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
KELLY-SNYDER FIELD

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas: Assoc. (BCF)	Natural Gas: Non-Assoc. (BCF)	Natural Gas: Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	3172.0	NA	2782.0	NA	
Proved ultimate recovery	1319.5	NA	1808.0	NA	
Cumulative production	754.2	NA	747.6	NA	
Proved reserves	565.3	NA	1060.4	NA	
			(Dry Basis)		
Proved reserves			595.5	NA	303.1
Reserves in shut-in reservoirs	0	NA	0	NA	0
Indicated secondary and tertiary reserves	0		0		
Production					
Year 1973 (total)	70.6	NA	37.5	NA	19.7
Year 1974 (total)	76.2	NA	43.5	NA	22.1
Long-term projection of production (annual total)					
1975	73.4	NA	41.2	NA	
1976	65.6	NA	36.8	NA	
1977	59.9	NA	33.6	NA	
1978	52.9	NA	29.7	NA	
1979	45.9	NA	25.8	NA	
1980	41.1	NA	22.9	NA	
1981	34.8	NA	19.5	NA	
1982	29.5	NA	16.6	NA	
1983	25.0	NA	14.0	NA	
1984	21.2	NA	11.9	NA	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	209	NA	119	NA	56
Short-term productive capacity (60-day basis)	209	NA	119	NA	

The Kelly Snyder oil field is in Scurry County, Texas, on the eastern shelf edge of the Midland Basin.

The producing formation is heterogenous dolomite of Canyon-Pennsylvanian age. The depth to the top of the pay varies from about 6,000 feet at the highest point to 6,700 feet at the oil/water contact.

The producing zone is considered to be a shelf edge carbonate deposition with the relief of the producing zone being a structurally controlled erosion remnant. The producing zone is overlain by Wolfcamp clays,and the base of the producing zone is controlled by bottom water.

The closed reservoir originally produced with fluid expansion and dissolved gas drive. The bottom water was not active. The reservoir pressure declined to less than the bubble point. In the mid-1950's a centerline water injection project was started to raise and maintain pressure above the bubble point. In the early 1970's, a nine spot pattern flood with alternating injection of water and CO_2, outside the water front of the centerline project, was commenced. Most all of the field is currently unitized. The secondary activities have succeeded in maintaining the higher pressures. However, the injected fluids have channeled through the highly permeable zones resulting in in premature break throughs and in by-passed oil. Programs and studies are underway to improve the injection profile. Considerable infill drilling is also contemplated.

Hydrocarbons originally in place were calculated using the volumetric method. Although considerable core analysis data are available, there is significant probability that the combination of averages selected for the entire field may not be truly representative of the extremely heterogenous reservoir situation. This applies to the portion of the gross reservoir thickness considered to be productive, as well as to the average values of permeability, porosity, and initial water saturation. The available time did not permit an extensive analysis of zoning or startification of porosity and permeability within the reservoir.

Several attempts to determine hydrocarbons originally in place, using material balance methods, were made. The final such calculation indicated an oil-in-place volume similar to that obtained by the volumetric calculation. However, because the material balance calculation was carried out entirely above the saturation pressure, and the concept of rock compressibility was not introduced, the meaningfulness of this fortunate comparison is not clear.

The 1974 oil production rate at Kelly Snyder is believed near the all time high. The infill drilling program could dampen the future decline during the next three years or so. In any event, a firm estimate of reserves by decline curve analysis is not possible. Oil recovery efficiency, expressed as a percent of oil originally present, in this situation is difficult to estimate. Our state of knowledge of this reservoir does not lead to proper adjustments for less than optimum displacement, sweep, or conformance factors. There are various empirical correlation methods to accomplish this. The study team has chosen a 42 percent oil recovery efficiency for the combination water and CO_2 miscible secondary recovery project. The final infill spacing this will entail or the extent injection profiles will have to be improved upon is not clear. The study team contemplates a final produced water cut of 95 percent.

As shown by the Summary Table, the proved wet gas reserves would indidate an average future gas oil ratio of somewhat over twice the solution gas oil ratio. If the future production operations are successful in maintaining the reservoir pressure above the saturation level, as planned, this estimate of gas reserves would appear excessive.

An experimental CO_2 tertiary miscible injection project in the watered-out zone has not yet proved economic.

The FEA report on the Kelly Snyder Field was prepared by the Region VI Office of the Federal Energy Administration located in Dallas, Texas.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
KERN RIVER FIELD

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas[1] Assoc. (BCF)	Natural Gas[1] Non-Assoc. (BCF)	Natural Gas[1] Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	3582	NA	179	NA	
Proved ultimate recovery	1721	NA	NA	NA	
Cumulative production	634	NA	NA	NA	
Proved reserves	1087	NA	NA	NA	
			(Dry Basis)		
Proved reserves			NA	NA	NA
Reserves in shut-in reservoirs	0	NA	NA	NA	NA
Indicated secondary and tertiary reserves	0		NA		
Production					
Year 1973 (total)	27.9	NA	NA	NA	NA
Year 1974 (total)	26.8	NA	NA	NA	NA
Long-term projection of production (annual total)					
1975	27.7	NA	NA	NA	
1976	28.8	NA	NA	NA	
1977	30.0	NA	NA	NA	
1978	31.2	NA	NA	NA	
1979	32.4	NA	NA	NA	
1980	33.7	NA	NA	NA	
1981	35.1	NA	NA	NA	
1982	36.5	NA	NA	NA	
1983	38.0	NA	NA	NA	
1984	39.5	NA	NA	NA	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	71.6	NA	NA	NA	NA
Short-term productive capacity (60-day basis)	74	NA	NA	NA	

[1]Gas reserves and production volumes are considered insignificant.

The Kern River oil field is located in Kern County, California, in the southeastern portion of the San Joaquin Basin.

The production comes from the Kern River Group of sands of Pliocene-Pleistocene age found from about 500 feet to 1,300 feet in depth. The producing interval is a highly heterogeneous and lenticular sand-shale series. The net productive thickness is about 210 feet. The sand has unusually high porosity and permeability.

The structure at Kern River, as defined by a marker at the base of the sand, is a homocline dipping gently to the southwest. Reservoir trapping is controlled by sand lenticularity--combined updip with a heavy residual tar formation near the surface. Downdip, the reservoir limits are defined by a thick oil/water transition zone. The productive area at Kern River is 10,800 acres (17 square miles).

The hydrocarbons originally in place were calculated by the volumetric method. Porosity determinations are difficult because the sand is highly unconsolidated. Water saturation and net pay thickness are difficult to determine because the interstitual water is fresh and resembles oil on logs. However, the overall calculation appears reasonable.

The crude oil at Kern River is of very low API gravity with extremely high viscosity and a very low dissolved gas content. The recovery efficiency has been estimated at only 11 percent of oil originally in place, by means of primary recovery. The field was discovered in 1899 and there were long periods of production decline in the first half of this century to substantiate this recovery level.

There is a very favorable decrease in viscosity at elevated temperatures. For instance, when the crude oil is heated from the 90° F reservoir temperature to 250° F, the viscosity is reduced from 4,060 to 15 centipoise. Other things being equal, mobility of the crude is inversely proportional to viscosity. In the mid-1950's, bottom hole heaters were used to stimulate production. In the early 1960's, hot water injection techniques were used. In the mid-1960's, cyclic steam injection and production was carried out; and more recently, continuous steam displacement on a 5-spot pattern was started.

Currently, the production rate at Kern River is 50-60 percent more than in the flush production days of 1904.

The ultimate recovery efficiency as a result of pattern continuous steam flooding is estimated as 60 percent of oil originally in place. This recovery efficiency has been confirmed by drilling, coring, and logging in representative areas which have been depleted by steam flooding.

The cumulative production at Kern River amounts to 18 percent of the original oil in place. The report estimates that ultimate production will amount to 31 percent, if no more expansion of the steam displacement operations is carried out. Approximately one-fifth of the field is now under patterned steam drive. If the steam displacement activity is expanded, as planned by the operators, to cover most of the field, the overall efficiency is estimated to be 48 percent. This latter case was considered most reasonable by the investigators. However, they did not allow for the optimistic rate of installation and production build up contemplated by the operators. Instead, the report programs a more reasonable rate of production increase which resembles the recent past trends.

In most instances, oil field and gas processing plant fuel needs are satisfied with a portion of the produced gas volumes. In the case of very heavy crude oil reservoirs, natural gas is usually not available in sufficient volume. In some of these fields, a portion of the produced crude oil is burned to generate steam for thermal recovery operations. The amount of steam required varies with the particular project and its stage of completeness. An approximation of crude oil required as fuel might range between one-fourth and one-third of the incrementally produced thermal oil volumes. As in the case of fuel gas, these oil fuel volumes have not been deducted from the volumes shown on the summary table.

The FEA report on the Kern River Field was prepared by Scientific Software Corporation under Contract No. CO-05-50182-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
LA GLORIA FIELD

	Crude Oil[1] (MMBbls)	Lease Condensate (MMBbls)	Natural Gas Assoc. (BCF)	Natural Gas Non-Assoc. (BCF)	Natural Gas Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	83.3	NA	331.7	1913.2	
Proved ultimate recovery	30.4	NA	204.2	1753.4	
Cumulative production	30.4	NA	202.6	1544.6	
Proved reserves	0.1	NA	1.6	208.8	
			(Dry Basis)		
Proved reserves			1.5	197.3	5.9
Reserves in shut-in reservoirs	0	NA	0	0	0
Indicated secondary and tertiary reserves	0		0		
Production					
Year 1973 (total)	----	NA	1.1	63.8	2.2
Year 1974 (total)	----	NA	0.9	56.9	2.2
Long-term projection of production (annual total)					
1975	----	NA	0.7	49.9	
1976	----	NA	0.5	39.1	
1977	----	NA	0.3	29.5	
1978	----	NA	0	22.1	
1979	----	NA	0	15.5	
1980	----	NA	0	11.0	
1981	----	NA	0	7.7	
1982	----	NA	0	5.9	
1983	----	NA	0	4.2	
1984	----	NA	0	2.9	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	0.1	NA	2.2	142.4	5.3
Short-term productive capacity (60-day basis)	0.1	NA	2.2	142.4	

[1]Crude oil production volumes are insignificant.

The La Gloria gas field is located in Jim Wells and Brooks Counties, of southern Texas, in the Oligocene Belt of the Texas Gulf Coast.

There are 49 reservoirs at La Gloria in Frio and Vicksburg sands of the Middle and Lower Oligocene age. The depth ranges from 5,400 to 8,100 feet. Sands deeper than 7,600 feet are generally in the Vicksburg.

The La Gloria structure is an elongated anticlinal dome with a northeast-southwest trending axis. The structure is relatively unfaulted. Shales in the thick sand-shale sequence provide upper and lower seals for the reservoirs. Bottom water controls the accumulations in most instances; though sand lenticularity controls the accumulations in some reservoirs. There are about 7,500 productive acres (12 square miles).

Twenty of the reservoirs at La Gloria are depleted. Twenty-three still produce by pressure depletion; the bottom water not being active. Six of the remaining reservoirs have partial water drives.

Nonassociated gas originally in place, ultimate recovery, and proved reserves were generally determined by plotting curves of reservoir pressure decline versus cumulative production. The permeability in the Oligocene sands and the unfaulted nature of the reservoirs resulted in very satisfactory observed pressure trends--the most important of which are included in the report. The consultant selected an abandonment pressure of 200 psia for most of these reservoirs. The sensitivity of gas reserves to change in abandonment pressure would be on the order of only 0.8 BCF per psi. From the early 1940's to 1970, about 2 TCF of gas has been recycled. Apparently the unit operator has maintained adequate records of net withdrawals so as to permit proper construction of the pressure cumulative trends for the major reservoirs.

The FEA report on the La Gloria Field was prepared by James A. Lewis Engineering under Contract No. CO-05-50181-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
MAIN PASS BLOCK 41 FIELD

	Crude Oil (MMBbls)	Lease Condensate[1] (MMBbls)	Natural Gas: Assoc. (BCF)	Natural Gas: Non-Assoc. (BCF)	Natural Gas: Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	593.3	0.9	780.3	868.5	
Proved ultimate recovery	224.0	0.6	354.0	594.8	
Cumulative production	141.5	0.2	165.2	173.3	
Proved reserves	82.5	0.4	188.8	421.5	
			(Dry Basis)		
Proved reserves			179.4	400.4	6.2
Reserves in shut-in reservoirs	0.1	0	0.8	33.4	0.4
Indicated secondary and tertiary reserves	35.1		96.1		
Production					
Year 1973 (total)	12.8	NA	13.9	31.1	0.5
Year 1974 (total)	10.9	NA	12.3	24.7	0.4
Long-term projection of production (annual total)					
1975	8.7	NA	9.5	32.2	
1976	7.0	NA	7.8	31.9	
1977	8.1	NA	10.0	33.8	
1978	8.0	NA	10.3	33.1	
1979	7.2	NA	10.0	30.3	
1980	6.0	NA	8.5	28.9	
1981	4.9	NA	7.1	27.1	
1982	4.0	NA	5.8	25.3	
1983	3.3	NA	4.8	21.7	
1984	2.8	NA	3.9	19.7	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	19.6	NA	24.0	72.2	1.0
Short-term productive capacity (60-day basis)	21.7	NA	27.9	80.6	

[1] Lease condensate production volumes are insignificant.

The Main Pass Block 41 field is located 10 miles offshore from Plaquemines Parish in southern Louisiana. The field is 90 miles southeast of New Orleans in the offshore Miocene belt with water depths of 40 to 45 feet.

There are 32 producing sands in a thick sand-shale sequence of Pliocene and Upper Miocene in age. Depths range from 3,500 to 10,000 feet with nonassociated gas reservoirs predominating above 5,500 feet and oil reservoirs occurring below. The Pliocene/Miocene contact is at about 5,000 feet.

Main Pass Block 41 is an anticlinal structure related to a deep seated salt dome. Several faults divide the field into five main fault blocks. The report isolates and treats separately some 53 reservoir units. In addition to structure, faulting, and bottom water, there are several important permeability variations or shale-outs which influence reservoir boundaries. The field has 32,200 productive acres (50 square miles).

The predominate producing mechanism is an active water drive. Water is also being injected to maintain pressure in six of the larger reservoirs. Some reservoirs produce with various combinations of dissolved gas drive and partial water drive.

Hydrocarbons originally in place were estimated by the volumetric analysis method. The report is very well documented with structure and isopach maps, and with reservoir rock and fluid property data.

Ultimate recovery and proved reserves were estimated based upon production performance and recovery efficiency factors, selected by empirical analysis methods or by analogy.

The category of indicated secondary and tertiary reserves includes, possibly to the extent of one-third of the oil and one-half of the gas, other categories of shut-in, behind pipe, or inferred reserves in some of the reservoir segments which probably will not be brought onto production during the forecast time span.

The FEA report on the Main Pass Block 41 Field has been prepared by the U.S. Geological Survey, Department of the Interior, under Interagency Agreement CG-05-50059-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
MCELROY FIELD[1]

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas Assoc. (BCF)	Natural Gas Non-Assoc. (BCF)	Natural Gas Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	2414.5	NA	785.7	NA	
Proved ultimate recovery	682.2	NA	-----[2]	NA	
Cumulative production	415.9	NA	-----[2]	NA	
Proved reserves	266.3	NA	82.8	NA	
			(Dry Basis)		
Proved reserves			63.8	NA	7.4
Reserves in shut-in reservoirs	0	NA	0	NA	0
Indicated secondary and tertiary reserves	0		0		
Production					
Year 1973 (total)	11.0	NA	3.9	NA	0.3
Year 1974 (total)	12.9	NA	5.0	NA	0.5
Long-term projection of production (annual total)					
1975	13.3	NA	3.6	NA	
1976	13.6	NA	3.4	NA	
1977	13.0	NA	3.1	NA	
1978	12.4	NA	2.9	NA	
1979	12.0	NA	2.8	NA	
1980	11.1	NA	2.6	NA	
1981	10.3	NA	2.4	NA	
1982	9.6	NA	2.2	NA	
1983	8.9	NA	2.1	NA	
1984	8.3	NA	2.0	NA	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	35.2	NA	12.5	NA	1.1
Short-term productive capacity (60-day basis)	35.2	NA	9.6	NA	

[1] Includes the Grayburg-San Andres and very minor reserves in the Bend, Devonian, Silurian, and Ellenburger reservoirs.

[2] Gas production records are inadequate.

The McElroy oil field is located in Crane and Upton Counties of West Texas on the eastern edge of the Central Basin Platform.

The principal producing formation is the Grayburg-San Andres dolomitic limestone of the Middle Permian age. The formation contains a relatively large amount of anhydrite and gypsum. The average depth to the top of the pay is 3,000 feet. The field also contains insignificant reserves in the Bend-Lower Pennsylvanian, the Devonian, the Silurian, and the Ellenburger-Ordovician formations.

McElroy is on the eastern limb of an asymmetrical anticlinal structure with a northwest-southeast orientation. To the east, the structure dips into edge water. To the west and south the limits of the accumulations are controlled, generally up dip, by porosity and permeability pinch-outs. To the north, the field is arbitrarily separated from the Dune Field. The field extends over 30,000 acres (47 square miles).

The McElroy crude oil was initially undersaturated. The primary producing mechanism was fluid expansion and dissolved gas drive. The consultant estimates that currently the field is approximately 70 percent under active water flood.

The ultimate recovery from the primary producing mechanism was determined by means of production decline curve analysis for the North Unit, which covers about 40 percent of the field. It was not possible to isolate a diagnostic period of primary production decline for the main, or southern, portion of the field. The procedure of expanding the estimate of primary ultimate to a field total is on a less firm basis.

The consultant firm has estimated that secondary recovery at McElroy should amount to 62 percent of primary recovery. There are some pilot operations, small unit operations, unit operator reports, and model studies which indicate this factor to be reasonable or possibly conservative for application to the McElroy site.

There is a dearth of information at McElroy concerning rock and fluid properties and early gas production records. In part this is because of the early 1926 discovery date. Also, the consultant reports that the waters of hydration associated with the anhydrite and gypsum have clouded the interpretation of core analysis and radioactive logging data. Accordingly, the consultant has estimated oil originally in place by assuming that primary ultimate recovery would represent 17.5 percent of the oil originally present, based upon analogy with similar West Texas reservoirs.

In summary, at McElroy we have a situation in which secondary recovery, total recovery, and oil originally in place are all derived from an estimate of primary recovery, which in itself does not appear firmly established. Although the consultant firm has attempted to apply the various reservoirs analysis techniques, there just do not appear to be separate methods to test the reserves estimates for reasonableness.

The FEA report on the McElroy Field was prepared by James A. Lewis Engineering under Contract No. CO-05-50181-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
MIDWAY-SUNSET FIELD

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas[1] Assoc. (BCF)	Natural Gas[1] Non-Assoc. (BCF)	Natural Gas[1] Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	10,000	NA	1,500	NA	
Proved ultimate recovery	1,871	NA	NA	NA	
Cumulative production	1,227	NA	NA	NA	
Proved reserves	644	NA	NA	NA	
			(Dry Basis)		
Proved reserves			NA	NA	NA
Reserves in shut-in reservoirs	0	NA	NA	NA	NA
Indicated secondary and tertiary reserves	224		NA		
Production					
Year 1973 (total)	35.3	NA	NA	NA	NA
Year 1974 (total)	35.0	NA	NA	NA	NA
Long-term projection of production (annual total)					
1975	34.8	NA	NA	NA	
1976	34.9	NA	NA	NA	
1977	35.0	NA	NA	NA	
1978	35.1	NA	NA	NA	
1979	34.9	NA	NA	NA	
1980	34.6	NA	NA	NA	
1981	33.6	NA	NA	NA	
1982	32.9	NA	NA	NA	
1983	32.4	NA	NA	NA	
1984	31.8	NA	NA	NA	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	97	NA	NA	NA	NA
Short-term productive capacity (60-day basis)	100	NA	NA	NA	

[1] Natural gas at Midway-Sunset is considered insignificant.

The Midway-Sunset oil field is located in Kern and San Luis Obispo Counties of California in the southeastern end of the San Joaquin Basin. Los Angeles is 100 miles southeast of the field.

There are 37 different identified producing zones at Midway-Sunset, occurring from 200 to 5,300 feet in depth. They are sandstones, siltstones, clay stones, and shales of Pleistocene, Pliocene, and Upper Miocene age. The more important reservoirs are in high porosity and permeability sands of Pliocene and Upper Miocene age.

The basic structure at Midway-Sunset is a regional homocline dipping off the east flank of the Temblor Uplift and into the San Joaquin Basin. The homocline is modified by several folds. Faulting within the field limits is minor. Faults in the foot hills to the west and tar seals to the north and south are effective barriers to migration of hydrocarbons. Bottom water is often controlling in the easterly downdip direction. Within the field, there is much sand lenticularity and numerous unconformities which result in sand truncation. The field is 25 miles long in a northwest southeast direction and about 3 miles wide. There are numerous barren inside areas. The productive area is 33,000 acres (52 square miles).

In the early 1800's the Indians used Midway-Sunset tar from surface seeps as an adhesive and caulking material. The early settlers used the crude oil as a lubricant for wagons. The discovery date of the field, in modern terms, was about 1900. Because of this early date, there is a general inadequacy of core data, logs, pressure measurements, fluid analyses, and water or gas production measurements. Therefore, a determination of hydrocarbons originally in place by volumetric analysis or by material balance methods is not possible. Based on broad field averages, the consultant firm has estimated original oil in place as 10 billion barrels. There were some very small localized original gas caps which were rapidly dissipated. Original associated gas in place might approximate 1.5 TCF based upon a solution gas oil ratio of 150 cubic feet per barrel and a negligible gas cap volume. Gas production at Midway-Sunset has never been of economic significance and the gas volumes have been omitted from this field study.

The primary oil producing mechanism at Midway-Sunset appears to be gravity flow. This is because primary and secondary gas caps were dissipated, bottom water drive has not been of great significance, and dissolved gas volumes are not large. The gravity flow mechanism has been enhanced by the high rock porosity and permeability and by the considerable formation dips, ranging from 7 to 60 degrees. The high viscosity of the crude detracts from the effectiveness of gravity flow and has resulted in low production rates, low rates of production decline, and in very long primary production lives. Gas injection and water injection operations have been carried out,but they have not had an appreciable effect on oil recovery. Thermal recovery operations, principally cyclic steam injection and then steam drive on patterns, have been very effective.

The sands are thick with high orders of porosity and permeability. The high oil saturations, shallow depths, and good structural dips are also important. The slope of the temperature-viscosity relationship indicates a general halving of viscosity with only a 15^{o} F temperature rise. Currently, half of the wells are being steamed, principally by the cyclic method. Some six in situ combustion projects are active in the field. The economics of this method, as compared to cyclic steam injection or steam flooding, do not appear firmly proven and the consultant firm does not think in situ combustion will have an appreciable effect on total field recovery.

Primary ultimate recovery has been estimated by analysis of production decline trends before the advent of steam activities in 1963. Secondary or thermal recovery has been estimated by study of various trends of steam generation, oil production/steam injection ratios, numbers of wells injecting, number of wells producing, and production rates per well. The methods, which are practical and empirical, appear generally reasonable. Of the proved reserves shown on the summary tabulation, 420 MMbbls are considered primary and 224 MMbbls are in the thermal category. An additional 224 MMbbls of thermal reserves are placed in the indicated category. About 15 percent of the cumulative production is considered to be thermal production.

In most instances, oil field and gas processing plant fuel needs are satisfied with a portion of the produced gas volumes. In the case of very heavy crude oil reservoirs, natural gas is usually not available in sufficient volume. In some of these fields, a portion of the produced crude oil is burned to generate steam for thermal recovery operations. The amount of steam required varies with the particular project and its stage of completeness. An approximation of crude oil required as fuel might range between one-fourth and one-third of the incrementally produced thermal oil volumes. As in the case of fuel gas, these oil fuel volumes have not been deducted from the volumes shown on the summary table.

The FEA report on the Midway-Sunset Field has been prepared by James A. Lewis Engineering under Contract No. CO-05-50186-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
OREGON BASIN FIELD[1]

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas Assoc. (BCF)	Natural Gas Non-Assoc. (BCF)	Natural Gas Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	1290.0	NA	283.3	NA	
Proved ultimate recovery	372.3	NA	99.4	NA	
Cumulative production	240.1	NA	71.2	NA	
Proved reserves	132.2	NA	28.2	NA	
			(Dry Basis)		
Proved reserves			28.2	NA	NA
Reserves in shut-in reservoirs	0	NA	0	NA	NA
Indicated secondary and tertiary reserves	131.0		28.5		
Production					
Year 1973 (total)	10.3	NA	2.3	NA	NA
Year 1974 (total)	11.3	NA	2.4	NA	NA
Long-term projection of production (annual total)					
1975	10.3	NA	2.2	NA	
1976	9.5	NA	2.1	NA	
1977	8.7	NA	1.9	NA	
1978	8.1	NA	1.8	NA	
1979	7.5	NA	1.6	NA	
1980	6.9	NA	1.5	NA	
1981	6.4	NA	1.4	NA	
1982	5.7	NA	1.2	NA	
1983	5.4	NA	1.2	NA	
1984	5.1	NA	1.1	NA	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	32	NA	7	NA	NA
Short-term productive capacity (60-day basis)	32	NA	7	NA	

[1] Includes Embar, Tensleep, and Madison formations.

The Oregon Basin oil field is located in Park County, Wyoming, in the western part of the Big Horn Basin 60 miles east of Yellowstone National Park.

The producing formations at Oregon Basin are the Embar dolomitic limestone of Permian age found from 3,200-4,000 feet, the Tensleep sandstone of Pennsylvanian age found from 3,500 to 4,500 feet, and the Madison dolomitic limestone of Mississippian age found from 3,700 to 4,400 feet. Shallower small gas sands in the Triassic, Jurassic, and Cretaceous age formations are not included in the study.

Oregon Basin is an anticlinal structure consisting of a north and south dome connected by a slender saddle. The field is about 9 miles from north to south and 2-3 miles in width. The productive area is 10,300 acres (16 square miles). Bottom water is present in all formations. Minor faulting is indicated in all reservoirs on both domes, but it is not considered to be a significant trapping factor.

Hydrocarbons originally in place in the Embar and Tensleep reservoirs were determined by the volumetric analysis method. The study team reviewed the analyses which had been prepared by the operators in conjunction with studies of water-flood activities. They modified the parameters as necessary to account for subsequent field extensions. In the Madison formation, hydrocarbons originally in place were inferred from estimates of ultimate recovery and assumed recovery efficiency factors.

Water influx into the Embar and Tensleep formations was not active and both reservoirs on both domes are currently under water flood. The floods have shown favorable response and secondary reserves are indicated for future expansions to nearly field-wide scale. The Madison reservoir on both domes has had active water influx, but a relatively low recovery efficiency is contemplated, presumably because of an unfavorable permeability distribution.

Ultimate recovery and proved reserves have been estimated by means of extension of oil production trends. The oil production decline rates are quite well established in the Madison reservoirs. The Embar-Tensleep oil production decline rates have been dampened somewhat in recent years because of water flood response. The forecast decline rate selected by the study team is therefore not well established. Over 96 percent of the proved reserves are estimated to be in the Embar-Tensleep reservoirs.

The FEA report on the Oregon Basin Field was prepared by the Region VIII Office of the Federal Energy Administration located in Denver, Colorado.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974

PRUDHOE BAY FIELD

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas: Assoc.[1] (BCF)	Natural Gas: Non-Assoc. (BCF)	Natural Gas: Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	19,245	830	38,318	NA	
Proved ultimate recovery	8,760	379	30,331	NA	
Cumulative production[2]	1	0	6	NA	
Proved reserves	8,759	379	30,325	NA	
			(Dry Basis)		
Proved reserves			29,082	NA	949
Reserves in shut-in reservoirs	8,759	379	29,082	NA	949
Indicated secondary and tertiary reserves	0		0		
Production					
Year 1973 (total)	NA	0	NA	NA	0
Year 1974 (total)	NA	0	NA	NA	0
Long-term projection of production (annual total)					
1975	NA	0	NA	NA	
1976	NA	0	NA	NA	
1977	146.0	0	18.2	NA	
1978	515.4	0	36.5	NA	
1979	547.5	0	36.5	NA	
1980	547.5	0	36.5	NA	
1981	547.5	0	36.5	NA	
1982	547.5	0	220.5	NA	
1983	547.5	0	415.1	NA	
1984	547.5	0	425.7	NA	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	NA	0	NA	NA	0
Short-term productive capacity (60-day basis)	NA	0	NA	NA	

[1]Production volumes for 1973 through 1976, as well as short-term productive capacities, do not include minor amounts of fuel usage.

[2]Cumulative production data from the State of Alaska.

The Prudhoe Bay oil field is located on the northern coastline of Alaska, partly onshore and partly offshore. It is situated midway between Point Barrow and the Canadian border in the Arctic Slope Basin.

The principal producing formation is the Sadlerochit, a massive sandstone containing varying amounts of conglomerates and interbedded shales and ranging up to 500 feet in thickness. The depth of this Permian-Triassic sand varies from about 8,000 feet on the crest of the structure to about 9,100 feet at the water level. The Sag River and Shublic formations of Triassic-Jurassic age occur in the 200 feet interval above the Sadlerochit. The Sag River formation is a sand ranging up to 60 feet in thickness; the Shublic consists of limestones, shales, and sandstones ranging up to 200 feet in thickness. There is very little separation between the Sag River and the Shublic or between the Shublic and the Sadlerochit. These three zones make up the Prudhoe Bay Oil Pool, with the Sadlerochit holding about 97 percent of the oil and 90 percent of the natural gas. The Lisburne limestone and dolomite of Mississippian-Pennsylvanian age reaches a thickness of 2,000 feet and underlies the Sadlerochit formation. The Kuparuk River sands of Jurassic-Lower Cretaceous age reach a thickness of about 400 feet. They occur about 2,500 feet above the Sadlerochit sand.

Prudhoe Bay is a combination structural, fault, and stratigraphic trap. The basic structure is an anticline which plunges to the southwest. The northern and westerly productive limits are controlled by major faulting. The southern limits, and to a lesser extent the northwest limits, are controlled by bottom water. An important erosional unconformity near the base of the Cretaceous dips across the field in a northeasterly direction. It truncates all of the formations discussed above beginning with the Kuparuk River sands in the western part of the field and progresses across to the Lisburne in the east. This unconformity is overlain by an unnamed Lower Cretaceous shale which provides the upper seal on the eastern edge of the field. In the central and western parts of the field, where the Prudhoe Bay Oil Pool zones are not truncated, the upper seal is provided by the Kingak shale of Jurassic age which overlies the Sag River sand. The field measures about 30 miles east-west and up to 13 miles north-south. The oil zone in the Prudhoe Bay Oil Pool covers about 128,000 acres (200 square miles) and the gas zone covers about 60,000 acres (94 square miles). About 20 percent of the gas zone area extends beyond the oil zone; the remainder overlies the oil zone. The Lisburne reservoir in the eastern field area and the Kuparuk River reservoir in the western field area have not yet been defined. The report includes a very small proved reserve allocated to these reservoirs at this time.

The crude oil in the Prudhoe Bay Oil Pool was initially saturated and a very large gas cap existed. The original reservoir volume of the gas cap is about 62 percent as large as the oil zone. Hydrocarbons originally in place in the Prudhoe Bay Oil Pool were determined by the volumetric analysis method. The consultant studied the various wire line logs and core analysis data, most of which are in the public file. Most all of the wells have been extensively logged, and a reasonable amount of core data is available.

Except for a minor amount of production for fuel usage, the Prudhoe Bay Oil Pool has not been produced since its discovery in 1968. Estimates of proved reserves are based upon analyses using a numerical simulation model. The consultant estimates that about 19.3 percent of the oil in place should be recoverable if the reservoir produced by natural depletion, with the aquifer remaining inactive. Next, a finite aquifer averaging 200 feet in thickness, with rock properties the same as the Sadlerochit zone in the field proper, and extending south to outcrops in the Brooks Mountain range was considered. An aquifer of this size did not result in appreciable water influx into the field. Recovery amounted to 20.5 percent of oil originally present. The case involving a full scale pressure maintenance program by water injection to supplement the finite aquifer yielded a recovery of 46.3 percent of the oil originally present. This latter value was selected by the consultant firm. The entire reserve has been considered as proved and in the shut-in category. If the aquifer were larger and more permeable than assumed above, a recovery comparable to the water flood case possibly could be obtained by natural water drive. The division of reserves into the proved or indicated secondary or inferred categories is debatable at this time. A strict compliance with the FEA definitions would suggest that possibly over half of the proved reserves be placed in a different category until the matter of the primary recovery mechanisms is resolved or until secondary water flood operations are installed or a pilot flood tested.

The oil rate projections were based on start up of the Trans-Alaska Oil Pipeline on July 1, 1977 at a 600,000 barrel daily rate. This would be increased to 1.2 million barrels daily by November 1, 1977 and from 1.5 to 1.6 million barrels daily in mid-1978. The gas production during the forecast time span is entirely in the dissolved category. A minor amount of gas is to be used as a fuel. Gas production in excess of fuel needs is programmed to be injected into the gas cap. Starting in mid-1982, this surplus dissolved gas production will be marketed through an Alaska gas transportation sytem which the consultant assumes will be available at that time. Alternatively, the gas injection operations could continue.

The FEA report on the Prudhoe Bay Oil Field has been prepared by James A. Lewis Engineering, under Contract No. CO-05-50186-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
PUCKETT FIELD[1]

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas[2] Assoc. (BCF)	Non-Assoc. (BCF)	Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	NA	NA	NA	3171	
Proved ultimate recovery	NA	NA	NA	3007	
Cumulative production	NA	NA	NA	1824	
Proved reserves	NA	NA	NA	1183	
			(Dry Basis)		
Proved reserves			NA	1183	NA
Reserves in shut-in reservoirs	NA	NA	NA	0	NA
Indicated secondary and tertiary reserves	NA		NA		
Production					
Year 1973 (total)	NA	NA	NA	111.0	NA
Year 1974 (total)	NA	NA	NA	107.1	NA
Long-term projection of production (annual total)					
1975	NA	NA	NA	94.8	
1976	NA	NA	NA	88.1	
1977	NA	NA	NA	81.6	
1978	NA	NA	NA	75.2	
1979	NA	NA	NA	70.3	
1980	NA	NA	NA	64.9	
1981	NA	NA	NA	60.2	
1982	NA	NA	NA	56.3	
1983	NA	NA	NA	50.9	
1984	NA	NA	NA	46.4	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	NA	NA	NA	293	NA
Short-term productive capacity (60-day basis)	NA	NA	NA	317	

[1]Includes Ellenburger and Devonian Formations.

[2]Gas volumes have been reduced (30.8 percent by volume) for the removal of inert gases from the Ellenburger volumes and (3.7 percent by volume) from the Devonian volumes.

The Puckett gas field is located in Pecos County, Texas, in the Delaware-Val Verde Basin.

The principal producing formation at Puckett is the Ellenburger dolomite of Ordovician age. The Ellenburger has a maximum thickness of 1,600 feet and is encountered at 12,400 feet on top of the structure. About 4 percent of the gas reserves at Puckett are in the Devonian reservoir which is encountered at 10,300 feet.

The structure at Puckett is an anticline. There is a large fault on one side of the field, but the productive area appears unfaulted. The limits of the Ellenburger accumulation are controlled by structure and bottom water. The Ellenburger reservoir has 23,000 productive acres (36 square miles).

The bottom water at Puckett is not active and the gas is produced by pressure depletion.

Hydrocarbons originally in place and ultimate recovery were calculated using relationships of reservoir pressure data versus cumulative gas production. This was done on both an individual well basis and a total reservoir basis. The ultimate recoveries were based upon an abandonment reservoir pressure of 375 psia in the Ellenburger and 235 psia in the Devonian. The sensitivity of reserves and ultimate recovery to a change in abandonment pressure is about 400 MMCF/psi in the Ellenburger and 100 MMCF/psi in the Devonian.

The FEA report on the Puckett Field was prepared by the Region VI office of the Federal Energy Administration located in Dallas, Texas.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
QUARANTINE BAY FIELD

	Crude Oil (MMBbls)	Lease[1] Condensate (MMBbls)	Natural Gas Assoc. (BCF)	Natural Gas Non-Assoc. (BCF)	Natural Gas Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	288.0	0.9	333.5	50.3	
Proved ultimate recovery	158.4	0.5	201.9	30.2	
Cumulative production	149.4	0.3	190.8	19.7	
Proved reserves	9.0	0.2	11.1	10.5	
			(Dry Basis)		
Proved reserves			11.1	10.5	NA
Reserves in shut-in reservoirs	0	0	0	0	NA
Indicated secondary and tertiary reserves	NA		NA		
Production					
Year 1973 (total)	3.9	---	5.6	2.4	NA
Year 1974 (total)	3.5	---	4.3	2.5	NA
Long-term projection of production (annual total)					
1975	2.5	---	3.1	2.5	
1976	1.9	---	2.4	2.5	
1977	1.4	---	1.7	2.1	
1978	1.0	---	1.2	1.8	
1979	0.7	---	0.8	1.5	
1980	0.5	---	0.6	---	
1981	0.4	---	0.5	---	
1982	0.3	---	0.3	---	
1983	0.2	---	0.2	---	
1984	0.1	---	0.2	---	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	7.7	---	10.0	4.0	NA
Short-term productive capacity (60-day basis)	8.1	---	10.0	7.0	

[1]Lease condensate production volumes are insignificant.

Quarantine Bay Field is located in Plaquemines Parish on the coast line in extreme southern Louisiana. The field is 50 miles southeast of New Orleans in the onshore Miocene Belt with water depth ranging from 4 to 15 feet.

The producing formations are sands in a thick sand-shale sequence of Upper and Middle Miocene age. Depth to the sands ranges from 5,800 to 11,000 feet.

Quarantine Bay is a low relief anticline associated with a deep seated salt dome. There are numerous faults which also delineate the various reservoirs. There are believed to be 147 different reservoir segments in the field. Bottom water is present in most instances. Most of the reserves are in four major fault blocks. The field has 10,000 productive acres (16 square miles).

The predominate oil producing mechanism is a water drive. The field has been producing at capacity since 1969. Proved reserves and ultimate recovery have been estimated, based upon production trends, water-oil ratio history, and analogy with overall production characteristics of water drive reservoirs. There are four water flood projects in the field--each of which has produced sufficiently to be assessed.

An analysis to determine hydrocarbons originally in place was not carried out. Approximate volumes of oil and gas originally present were determined by assuming an oil recovery efficiency factor of 55 percent and a gas recovery efficiency factor of 60 percent.

The FEA report on the Quarantine Bay Field was prepared by Keplinger and Associates, Inc., under Contract No. CO-05-50184-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
SAN ARDO FIELD

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas[1] Assoc. (BCF)	Natural Gas[1] Non-Assoc. (BCF)	Natural Gas[1] Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	1487	NA	118	NA	
Proved ultimate recovery	659	NA	NA	NA	
Cumulative production	274	NA	NA	NA	
Proved reserves	385	NA	NA	NA	
			(Dry Basis)		
Proved reserves			NA	NA	NA
Reserves in shut-in reservoirs	0	NA	NA	NA	NA
Indicated secondary and tertiary reserves	0		NA		
Production					
Year 1973 (total)	12.6	NA	NA	NA	NA
Year 1974 (total)	12.9	NA	NA	NA	NA
Long-term projection of production (annual total)					
1975	14.7	NA	NA	NA	
1976	16.6	NA	NA	NA	
1977	18.4	NA	NA	NA	
1978	18.3	NA	NA	NA	
1979	18.4	NA	NA	NA	
1980	18.9	NA	NA	NA	
1981	19.6	NA	NA	NA	
1982	20.5	NA	NA	NA	
1983	21.6	NA	NA	NA	
1984	22.9	NA	NA	NA	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	37.2	NA	NA	NA	NA
Short-term productive capacity (60-day basis)	38.5	NA	NA	NA	

[1] Gas reserves and production volumes are considered insignificant.

The San Ardo oil field is located in Monterey County, California, in the Salinas Basin.

The producing formations are the Lombardi and Aurignac sandstones which are of the Monterey Series of the Upper Miocene age. The sands have unusually high porosity and permeability. The Lombardi, which occurs between 1,350 and 1,600 feet, has an average productive thickness of 120 feet. The Aurignac occurs between 1,650 and 1,875 feet, and averages 50 feet in productive thickness. The two sands are separated by an impermeable siltstone and are produced as separate reservoirs.

San Ardo is an anticline formed when sediments were draped over and lapped onto a granitic ridge. In addition to structural control, the lower sand is buttressed against the basement complex on the west, and both sands have permeability pinchout barriers either on the south or to the east. The main portion of the reservoir is not faulted. Both of the sands are generally underlain by water--with the oil/water contact tilted to the north and west. Each reservoir has about 4,600 acres. Because the two productive areas do not coincide the total productive surface area is about 6,200 acres (10 square miles).

Oil originally in place at San Ardo was calculated using the volumetric method. The eastern portions of the reservoirs, which are estimated to contain about 10 percent of the reserves, are not completely developed. The consultant firm felt that this was the principal source of uncertainty in the volumetric calculation. The relatively recent 1947 discovery date of the field should have permitted adequate determination of reservoir properties--utilizing modern methods.

The crude oil at San Ardo is of very low API gravity, with high viscosity and a very low dissolved gas content. There is a very favorable decrease in viscosity and increase in mobility of the crude oil at elevated temperatures. In the mid-1960's, cyclic steam injection and production was started, and in the late 1960's steam displacement on a continuous flood pattern was commenced. More recently, hot water injection has been started in a small portion of the upper reservoir. The flood pattern has typically been nine spots on 20 acres. Recently experiments have been carried out with five spot patterns on five acres, and the consultant reports that the operators intend to develop the flood pattern with five spots on 2 1/2 acres. At present, about 20 percent of the upper reservoir and 42 percent of the lower reservoir is under continuous steam flood--although the spacing of injectors and producers is not close to the density which is ultimately contemplated.

The consultants estimated that primary recovery at San Ardo would have amounted to 20 percent of oil originally in place. Cyclic steam stimulation is estimated to recover about 30 percent. The steam displacement and hot water injection technique were estimated at 45 to 50 percent recovery efficiency. None of these recovery efficiencies were documented in the report as to their bases. The consultant firm reports that the expected recovery efficiencies for all types of recovery processes being attempted at San Ardo are difficult to determine with much confidence.

The cumulative production at San Ardo has amounted to 18 percent of the oil originally present. The consultants estimated that almost 33 percent of the oil would be ultimately produced under an assumption that no more expansions of the steam displacement and hot water injection processes were carried out. If steam displacement and hot water injection processes are expanded, as planned by the operators, to cover most of the reservoir (presumably to the intended density of five spots on 2-1/2 acres), almost 45 percent of the original oil would be produced. This will require the drilling of several thousand additional wells and installation of related steam generating equipment.

The case which presumes no further expansion of facilities is really not a viable case because the future producing life would be unreasonably long. The report considers the higher case to be the most reasonable, in that it reflects the operators' plans which are already underway. The rates at which increased production can be obtained depend on considerable development activity and resolution of some difficult logistical problems which could not be studied thoroughly in the time allowed.

In most instances, oil field and gas processing plant fuel needs are satisfied with a portion of the produced gas volumes. In the case of very heavy crude oil reservoirs, natural gas is usually not available in sufficient volume. In some of these fields, a portion of the produced crude oil is burned to generate steam for thermal recovery operations. The amount of steam required varies with the particular project and its stage of completeness. An approximation of crude oil required as fuel might range between one-fourth and one-third of the incrementally produced thermal oil volumes. As in the case of fuel gas, these oil fuel volumes have not been deducted from the volumes shown on the summary table.

The FEA report on the San Ardo Field was prepared by Scientific Software Corporation under Contract No. CO-05-50182-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
SAN JUAN: BASIN DAKOTA FIELD[1]

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas: Assoc. (BCF)	Natural Gas: Non-Assoc. (BCF)	Natural Gas: Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	NA	75.0	NA	5000	
Proved ultimate recovery	NA	30.4	NA	4589	
Cumulative production	NA	25.2	NA	2439	
Proved reserves	NA	5.2	NA	2150	
			(Dry Basis)		
Proved reserves			NA	2064	58.1
Reserves in shut-in reservoirs	NA	0	NA	0	0
Indicated secondary and tertiary reserves	NA		NA		
Production					
Year 1973 (total)	NA	1.3	NA	176	4.9
Year 1974 (total)	NA	1.2	NA	171	4.8
Long-term projection of production (annual total)					
1975	NA	1.0	NA	168	
1976	NA	0.8	NA	156	
1977	NA	0.7	NA	145	
1978	NA	0.5	NA	135	
1979	NA	0.4	NA	126	
1980	NA	0.3	NA	117	
1981	NA	0.3	NA	109	
1982	NA	0.2	NA	101	
1983	NA	0.2	NA	94	
1984	NA	0.1	NA	88	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	NA	3.3	NA	452	12.7
Short-term productive capacity (60-day basis)	NA	3.1	NA	470	

[1]Includes New Mexico portion of field. Excludes Colorado portion.

The Basin Dakota gas field is located in San Juan and Rio Arriba Counties, of northwest New Mexico, in the San Juan Basin. The field report does not include the Colorado portion of the field.

The producing formation is the Dakota sandstone which is of lowermost Upper Cretaceous in age. The "Dakota" includes the overlying Graneros sandstone. The sand is encountered at about 7,000 feet and averages 60 feet in productive thickness.

The general structure of the Dakota Sand is an asymmetrical depression in the San Juan Basin. The gas is trapped on the flanks and on the bottom of the depression by a combination of permeability variations and strong hydrodynamic forces. The sands are overlain and underlain by impervious shales. Approximately 2,300 wells have been completed in the Dakota on 320 acre spacing. The limits of production have not been established. Step out drilling and infill drilling is continuing.

The producing mechanism is gas expansion or pressure depletion. Gas originally in place at Basin Dakota has been estimated by extrapolation of shut-in well head pressure versus cumulative production trends. The very low permeability in the Dakota (average 0.15 md.) does not allow pressure buildup during the surveys, so the pressure trend studied does not represent the true pressure situation. The incorrect position of the pressure trend on the chart is evidenced by failure of the back extrapolation of the trend to intersect the original pressure. Accordingly the forward extension of this trend to indicate gas originally in place is uncertain. The consultant firm did not make a volumetric analysis of gas originally in place because of lack of time. Also, they considered that such an analysis would probably be unwarranted. If one were to accept the average reservoir parameters quoted in the study, a volumetric analysis would indicate gas originally present to be almost four times the volume indicated by the pressure data.

Proved reserves at Basin Dakota were estimated from the pressure data using an abandonment surface pressure of 100 psig. The sensitivity of reserves to a change in abandonment pressure is about 4 BCF per psi. The reserves were confirmed by method of production decline analysis--using an economic limit of 30 MCF/D per well. The determination of proved economic reserves should not be seriously affected by the pressure measurement problem mentioned above.

The FEA report on Basin Dakota was prepared by Keplinger and Associates, Inc., under Contract No. CO-05-50184-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
SAN JUAN: BLANCO FIELD[1]

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas Assoc. (BCF)	Natural Gas Non-Assoc. (BCF)	Natural Gas Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	NA	26.9	NA	9337	
Proved ultimate recovery	NA	20.6	NA	8318	
Cumulative production	NA	15.9	NA	4820	
Proved reserves	NA	4.7	NA	3498	
			(Dry Basis)		
Proved reserves			NA	3358	94.4
Reserves in shut-in reservoirs	NA	0	NA	0	0
Indicated secondary and tertiary reserves	NA		NA		
Production					
Year 1973 (total)	NA	1.0	NA	274	7.7
Year 1974 (total)	NA	1.1	NA	272	7.6
Long-term projection of production (annual total)					
1975	NA	1.0	NA	264	
1976	NA	0.8	NA	246	
1977	NA	0.6	NA	229	
1978	NA	0.5	NA	214	
1979	NA	0.4	NA	200	
1980	NA	0.3	NA	186	
1981	NA	0.2	NA	174	
1982	NA	0.2	NA	162	
1983	NA	0.2	NA	151	
1984	NA	0.1	NA	141	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	NA	3.1	NA	748	21.0
Short-term productive capacity (60-day basis)	NA	2.9	NA	725	

[1]Includes Mesaverde Group; Pictured Cliffs and Fruitland Sands. Includes New Mexico portion of field. Excludes Colorado portion.

The Blanco gas field is located in San Juan, Rio Arriba and Sandoval Counties of northwest New Mexico, in the San Juan Basin. The field report does not include the Colorado portion of the field.

The principal producing member at Blanco is the Mesaverde Group which contains the Cliff House and Point Lookout sandstones. Smaller amounts of gas are contained in the Pictured Cliffs sandstone and insignificant amounts are contained in the Fruitland sandstone. All of these sandstones are of Upper Cretaceous age. The principal Mesaverde Group is encountered at about 5,000 to 5,400 feet in depth.

The gas reservoirs at Blanco are stratigraphically controlled by the extent to which porosity and permeability are developed. Generally the sands are capped by impervious shales. Bottom or edge water is irregularly present. Large areas have been defined as within the various official pool limits. The approximate size is indicated by the 2,050 Mesaverde wells drilled on 320 acre spacing and the 1,750 Pictured Cliff wells drilled on approximately 160 acre spacing. These two principal pools do not coincide as to productive area but overlap each other somewhat.

The producing mechanism at Blanco is pressure depletion. The bottom or edge water is not active. Gas originally in place has been estimated by study of trends of shut-in well head pressure versus cumulative production. The permeability of the Blanco reservoirs is quite low. The extent to which the pressure data are insufficiently built up during the various pressure surveys is not known. The pressure-cumulative trends do not extrapolate backwards in time to the original pressures. The various pressure points do not fall into a classic linear array. The correctness of the forward extrapolations to gas originally in place is not on a firm basis. The pressure measurement problem is not mentioned or discussed in the report.

An attempt to calculate gas in place by the volumetric method was not carried out because of insufficient time and because of inability to estimate parameters representative of the drainage area of the reservoir. Average reservoir parameters quoted in the report seem to indicate an original gas in place volume in the principal zones almost three times that determined from the pressure data.

Proved reserves at Blanco were estimated by extrapolating the shut in pressure trends to a well head pressure of 100 psig. The sensitivity of reserves to a change in abandonment pressure is about 10 BCF per psi. The inadequacy of the pressure information discussed above is not so much a problem in the proved economic reserves determination. Here the low permeabilities should be expected to influence the reserve estimate adversely. The proved reserves were also confirmed by extrapolating production trends to an economic limit of 30 MCF/D per well. However, the production decline evidence, on a reservoir basis, is not sufficient to establish the future decline rates selected.

The FEA report on the Blanco Field was prepared by Keplinger and Associates, Inc., under Contract No. CO-05-50184-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974

SEMINOLE COMPLEX FIELD[1]

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas: Assoc. (BCF)	Natural Gas: Non-Assoc. (BCF)	Natural Gas: Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	1195.9	NA	1062.1	24.6	
Proved ultimate recovery	457.9	NA	610.0	18.5	
Cumulative production	218.9	NA	362.0	14.9	
Proved reserves	239.0	NA	248.0	3.6	
			(Dry Basis)		
Proved reserves			211.0	3.6	24.2
Reserves in shut-in reservoirs	0	NA	0	0	0
Indicated secondary and tertiary reserves	0		0		
Production					
Year 1973 (total)	16.2	NA	20.0	1.0	1.8
Year 1974 (total)	20.5	NA	20.6	0.9	2.3
Long-term projection of production (annual total)					
1975	23.3	NA	20.3	0.7	
1976	23.3	NA	17.2	0.6	
1977	23.1	NA	15.3	0.5	
1978	23.0	NA	14.2	0.4	
1979	22.5	NA	13.4	0.3	
1980	19.3	NA	11.7	0.3	
1981	16.2	NA	10.2	0.2	
1982	13.7	NA	9.1	0.2	
1983	11.7	NA	8.1	0.1	
1984	9.9	NA	7.3	0.1	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	57.9	NA	54.0	2.0	5.6
Short-term productive capacity (60-day basis)	64.1	NA	57.0	2.0	

[1] Includes Seminole Field and six smaller surrounding fields. Includes principal San Andres zone and Devonian, Pennsylvanian, Lower Permian, and Upper Permian zones.

The Seminole Complex is located in central Gaines County, Texas, on the Central Basin Platform.

The principal producing formation is the San Andres which is an anhydritic dolomite of Permian age. The top of the pay zone occurs about 5,100 feet. In the most important instance, the San Andres oil zone averages 140 feet in gross thickness and is overlain by a gas cap which is 50 feet thick on the crest of the structure. There are very minor amounts of hydrocarbons in other formations at the Seminole Complex.

At the San Andres level, the structure at Seminole is an elongated NW-SE trending unfaulted anticline of some 15,700 productive acres (25 square miles). The entire field is underlain by bottom water. There are six smaller satellite fields surrounding Seminole which are named Seminole West, East, North, Northwest, Southwest, and Southeast. Almost 99 percent of the reserves of the complex are in the San Andres Formation and 84 percent are at Seminole San Andres.

The hydrocarbons originally in place within the San Andres were estimated using the volumetric method of analysis. Seminole, Seminole West, and Seminole East have all been subjected to intensive study prior to their unitization. These engineering analyses were reviewed and accepted by the consultant firm.

The recovery mechanism in the San Andres Formation was primarily a dissolved gas drive. Original gas caps were present at Seminole and Seminole West. The original bottom water has not been active. Following unitization, water flooding has taken place. Also, gas has been injected into the two primary gas caps to maintain pressure. Following initiation of water flooding, oil production rates have increased several fold. Reservoir pressure decline has been arrested and reversed. Producing gas/oil ratios have been reduced considerably. Prior to unitization, the operators' engineering committee estimated that primary oil recovery efficiency would have been 27.5 percent at Seminole San Andres. An additional 12 percent oil recovery efficiency has been assigned to the secondary water flooding activities. The consultant firm has accepted these efficiency factors.

The FEA report on the Seminole Complex was prepared by Keplinger and Associates, Inc., under Contract No. CO-05-50184-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
SLAUGHTER FIELD

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas Assoc. (BCF)	Natural Gas Non-Assoc. (BCF)	Natural Gas Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	3060	NA	1408	NA	
Proved ultimate recovery	998	NA	965	NA	
Cumulative production	596	NA	812	NA	
Proved reserves	402	NA	153	NA	
			(Dry Basis)		
Proved reserves			109	NA	22
Reserves in shut-in reservoirs	0	NA	0	NA	0
Indicated secondary and tertiary reserves	153[1]		0		
Production					
Year 1973 (total)	44	NA	12	NA	2.4
Year 1974 (total)	48	NA	11	NA	2.3
Long-term projection of production (annual total)					
1975	46	NA	12	NA	
1976	44	NA	11	NA	
1977	40	NA	10	NA	
1978	37	NA	10	NA	
1979	33	NA	8	NA	
1980	29	NA	8	NA	
1981	26	NA	7	NA	
1982	23	NA	7	NA	
1983	21	NA	5	NA	
1984	18	NA	4	NA	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	134	NA	33	NA	6.5
Short-term productive capacity (60-day basis)	132	NA	33	NA	

[1] Indicated tertiary reserves are 5 percent of oil in place based upon CO_2 injection in watered-out zones. This process is not yet proved commercial at Slaughter.

The Slaughter oil field is located in Cochran, Hockley, and Terry Counties of West Texas, in the North Basin.

The producing formation at Slaughter is the San Andres dolomite of Permian age. The San Andres thickness is about 800-900 feet. The oil zone is in the lower 50-100 feet and the net pay thickness ranges from 30 to 60 feet. The San Andres includes considerable limestone and anhydrite. The depth to the top of the pay is 5,000 feet.

The field is on a monocline which dips moderately to the south. The porous dolomite grades into anhydrite and shale in the north and western portion of the field. The reservoir is underlain by bottom water which controls the eastern and southern limits of the accumulation. The productive area of the field is 103,000 acres (161 square miles).

The crude oil at Slaughter was initially undersaturated. There was no original gas cap. The bottom water movement has been limited. The primary producing mechanism was fluid expansion and, after pressure reduction to below bubble point, a dissolved gas drive. Since about 1964, the field has been under water flood. There are 54 unitized water injection projects in the field. The typical project is a line drive arrangement with alternating rows of injection and producing wells. The original spacing of the field was about 34 acres per well. The reservoir pressure has been raised and maintained above the saturation point and producing gas/oil ratios have stabilized at low levels.

The hydrocarbons originally in place have been calculated using the volumetric method. The calculations were made for each of the 54 units and then added. The data were as submitted by each operator at the various unitization hearings. Meaningful material balance determinations of hydrocarbons originally in place were not possible because the extremely low permeability of the reservoir prevented the measurement of true reservoir pressures.

Ultimate recovery under the water flood operations was estimated to range from 32 to 38 percent of oil originally in place, using several empirical methods. The study team elected 32.6 percent as the most reasonable determination. Oil production is still increasing, as a result of flooding, in half or more of the units, so the future production schedules and the magnitude of reserves are not firm at this time. The ability to apply empirical water flood recovery calculations successfully to heterogeneous carbonate reservoir situations has not been common.

The FEA report on the Slaughter field was prepared by the Region VI Office of the Federal Energy Administration located in Dallas, Texas.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
SOONER TREND FIELD

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas: Assoc. (BCF)	Natural Gas: Non-Assoc. (BCF)	Natural Gas: Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	1871.4	NA	1684.3	815.0	
Proved ultimate recovery	262.0	NA	1094.8	712.0	
Cumulative production	199.4	NA	719.3	408.5	
Proved reserves	62.6	NA	375.5	303.5	
			(Dry Basis)		
Proved reserves			347.4	279.8	40.4
Reserves in shut-in reservoirs	0	NA	0	0	0
Indicated secondary and tertiary reserves	0		0		
Production					
Year 1973 (total)	11.3	NA	62.7	31.8	5.9
Year 1974 (total)	9.8	NA	54.4	37.6	5.8
Long-term projection of production (annual total)					
1975	8.5	NA	47.3	33.3	
1976	7.3	NA	40.6	31.1	
1977	6.2	NA	34.6	28.3	
1978	5.3	NA	29.3	26.1	
1979	4.6	NA	25.3	23.9	
1980	3.9	NA	21.6	22.2	
1981	3.4	NA	18.6	20.5	
1982	2.9	NA	16.0	18.9	
1983	2.5	NA	14.0	17.2	
1984	2.1	NA	11.7	15.5	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	24.6	NA	137	96	15.5
Short-term productive capacity (60-day basis)	24.8	NA	138	97	

The Sooner Trend oil and gas field is located in Garfield, Kingfisher, and Logan Counties, of central Oklahoma, on the eastern edge of the Anadarko Basin against the Nemaha Ridge.

The producing formations range in age from Siluro-Devonian up through the Middle Pennsylvanian. The prime producing interval is the Osage-Meramec group of limestones and dolomites, which are Mississippian in age. This group accounts for over 50 percent of the wells. Next in importance, with 29 percent of the wells, are the Oswego-Big Lime groups which are Upper Des Moines limestones of Pennsylvanian age. Other producing formations of lesser importance are the Hunton dolomite (Siluro-Devonian), the thin Manning limestome streaks (Upper Mississippian), the Red Fork-Cherokee sandstones (Des Moines-Pennsylvanian) and the Layton sandstone (Missouri-Pennsylvanian). Most all of these intervals are contained within drilling depths from 5500 to 9500 feet.

The Sooner Trend is a combination of 59 different oil and gas fields in an area measuring 50 miles north-south and 35 miles east-west. The structure in the area is a regional southwest dip off the Nemaha Ridge and into the Anadarko Basin. The area is generally devoid of local structure or faulting. Many of the producing members have facies changes due to the regressive and transgressive nature of the seas. Porosity and permeability variations control the limits of the accumulations in most instances. The sandstone reservoirs are referred to as stream channels or near shore bars.

The predominate producing mechanism in the Sooner Trend is a dissolved gas drive. There are some isolated water drive instances in the Hunton formation. The nonassociated gas reservoirs produce by pressure depletion. There are nine pressure maintenance or secondary oil recovery projects in operation. These projects have reached their peak and are declining. Their production represented 25 percent of the 1974 total, and their cumulative represents 20 percent of the field total. The consultant firm does not anticipate any potential for additional wide spread projects.

The oil reserves at Sooner Trend have been estimated by means of extrapolation of production decline trends which seem to be fairly well established. The reserves of nonassociated gas have been estimated by extrapolation of pressure decline trends. These reserves are probably all that have economic significance.

In the case of the oil reservoirs, a volumetric analysis to determine oil originally in place was not carried out. The consultant firm estimated oil originally in place by deciding that ultimate recovery would amount to 14 percent of the oil originally present. This procedure is probably the only practical solution under the circumstances. The use of the pressure plots to determine nonassociated gas originally in place is suspect because the shut-in pressures are less than fully built up pressure, a result of the low permeability problem.

The FEA report on the Sooner Trend was prepared by Keplinger and Associates, Inc., under Contract No. CO-05-50184-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
SOUTH PASS BLOCK 65 FIELD

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas: Assoc. (BCF)	Natural Gas: Non-Assoc. (BCF)	Natural Gas: Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	163.6	NA	111.7	NA	
Proved ultimate recovery	73.5	NA	60.4	NA	
Cumulative production	44.5	NA	34.7	NA	
Proved reserves	29.0	NA	26.7	NA	
			(Dry Basis)		
Proved reserves[1]			25.2	NA	1.7
Reserves in shut-in reservoirs	0	NA	0	NA	0
Indicated secondary and tertiary reserves	0		0		
Production					
Year 1973 (total)	11.2	NA	9.2	NA	0.3
Year 1974 (total)	9.9	NA	9.4	NA	0.3
Long-term projection of production (annual total)					
1975	8.3	NA	6.8	NA	
1976	5.6	NA	4.6	NA	
1977	3.9	NA	3.2	NA	
1978	2.7	NA	2.2	NA	
1979	2.0	NA	1.6	NA	
1980	1.5	NA	1.2	NA	
1981	1.1	NA	0.9	NA	
1982	0.6	NA	0.5	NA	
1983	0.4	NA	0.3	NA	
1984	0.4	NA	0.3	NA	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	25.4	NA	24.1	NA	0.9
Short-term productive capacity (60-day basis)	26.8	NA	25.3	NA	

[1] Proved reserves do not include 1.2 MMBbls of crude oil and 2.6 BCF natural gas in six untested zones or 0.8 MMBbls of crude oil and 1.2 BCF natural gas of shut-in reserves in one reservoir segment from which further production is very doubtful.

The South Pass Block 65 oil field is about 25 miles east of the mouth of the Mississippi River in the Gulf of Mexico. Water depth is about 300 feet. The field lies within the Pliocene belt of offshore Louisiana.

The productive sands are Pliocene in age and range from 6,500 to 8,500 feet in depth. There are ten or so sands in the F, G, and H series. They range from very fine to fine grained and from clean to very shaley. Most of the sands are deltaic river mouth deposits, but some are localized channel sands.

The structure at South Pass Block 65 is caused by a fairly circular deep-seated shale dome. There are numerous normal faults. The accumulations are controlled by the structure, by faults, and by bottom water. One of the principal accumulations is a channel sand which is stratigraphically controlled. There are eleven sands in nine fault blocks or sub segments. Of the total 26 recognized separate reservoir units, 19 are producing, one is shut-in, and six are untested. Over 80 percent of the reserves are in four principal segments. The productive area is 2,600 acres (4 square miles). Eighty-five wells have been drilled from two platforms for 103 zonal-completions.

The hydrocarbons originally in place were calculated using the volumetric method. This requires careful structural and isopach mapping and analyses of core and logging data. These requirements apparently have been met.

One of the major zones and one of the minor zones had original gas caps. All of the other reservoir segments appear to have been undersaturated. The primary oil recovery mechanism in most of the reservoir segments was a water drive; however, the extent of water encroachment was not sufficient to maintain pressure. A few of the reservoir segments, including the channel sand segment were sufficiently isolated from an active aquifer that the primary recovery mechanism was classed as pressure depletion and dissolved gas drive. Pressure is being maintained by water injection into most all of the reservoir segments, including all of the important ones.

Ultimate oil recovery at South Pass Block 65 is estimated at 45 percent of the oil originally in place. About 60 percent of the ultimate recovery has already been produced. Most of the reservoir segments are experiencing oil production decline. The recovery efficiency of gas is estimated at 54 percent of the gas originally in place.

The FEA report on the South Pass Block 65 Field was prepared by the U.S. Geological Survey under Interagency Agreement CG-05-50059-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
SPRABERRY TREND FIELD[1]

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas Assoc. (BCF)	Natural Gas Non-Assoc. (BCF)	Natural Gas Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	7771.9	NA	3885.9	NA	
Proved ultimate recovery	469.0	NA	1261.2	NA	
Cumulative production	378.8	NA	990.7	NA	
Proved reserves	90.2	NA	270.5	NA	
			(Dry Basis)		
Proved reserves[2]			230.0	NA	21.3
Reserves in shut-in reservoirs	0	NA	0	NA	0
Indicated secondary and tertiary reserves	75.0		128.0		
Production					
Year 1973 (total)	19.8	NA	41.7	NA	4.2
Year 1974 (total)	17.6	NA	42.0	NA	4.2
Long-term projection of production (annual total)					
1975	13.8	NA	33.9	NA	
1976	11.0	NA	28.0	NA	
1977	9.2	NA	24.3	NA	
1978	7.8	NA	21.1	NA	
1979	6.8	NA	18.3	NA	
1980	5.9	NA	15.9	NA	
1981	5.1	NA	13.8	NA	
1982	4.5	NA	12.0	NA	
1983	3.9	NA	10.4	NA	
1984	3.4	NA	9.0	NA	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	45.3	NA	105	NA	10.5
Short-term productive capacity (60-day basis)	45.3	NA	105	NA	

[1]Does not include the Clearfork, Wolfcamp, and Devonian zones which would increase the data by about 1 to 2 percent.

[2]Proved reserves do not include 75 MMBbls and 191 BCF of inferred reserves from future extension of field limits.

The Spraberry Trend oil field is located in Upton, Reagan, Irion, Martin, Midland, and Glasscock Counties of West Texas, within the Midland Basin.

The producing formations are the Upper and Lower Spraberry which are Clearfork-Wichita equivalent of Permian age. The underlying Dean Sand is Wolfcamp, also of Permian age. The Upper Spraberry is generally around 400 feet thick; the Lower Spraberry ranges from 500 to 600 feet in thickness; and the Dean Sand is about 120 feet thick. Over most of the area, about 90 percent of the thickness is sand, silt, and shale (mostly shale). The remaining 10 percent or so is limestone and dolomite. The oil is indigenous to the formation. The reservoir rock is extremely low in porosity and permeability, and is a siltstone. Production is made possible by fractures which extend through both the matrix siltstone and the shale. Depth to the top of the Upper Spraberry varies from 6,000 to 8,000 feet.

The oil accumulations in the Spraberry are trapped stratigraphically. The area is virtually devoid of folded or faulted traps. The structure is a general monocline dipping from the eastern shelf into the depths of the Midland Basin. The classic sections grade into limestones and dolomites on the rims of the basin. The productive field, as defined by the Texas Railroad Commission, covers 920,000 acres (about 1,400 square miles). The consultant firm also estimates that an additional 150,000 acres on the fringes of the field may be developed in the future.

The crude oil at Spraberry Trend was initially undersaturated. However, because of low permeability, pressure was quickly reduced in the vicinity of producing wells causing release of gas from solution and high producing gas/oil ratios. The primary producing mechanism was a dissolved gas drive. Bottom water is not active. Oil drains from the siltstone matrix into the fracture system and productivity depends on the effectiveness of this fracture system. The normal spacing is 160 acres per well and over 3,900 wells are currently producing. About 320,000 acres or 35 percent of the presently defined area of the field have been under water flood.

Ultimate recovery by primary methods was determined by preparing production decline curves for each lease. Primary ultimate recovery is expected to average 500 barrels per acre. Secondary ultimate recovery was similarly estimated by studying the production records for the 34 water flood units. The contractor estimated that additional secondary recovery will average 200 barrels per acre. These volumes are considered proved. The secondary recovery reserves for 375,000 acres of future projects are reported under "Indicated Secondary Reserves." The availability of production decline information and the 80 percent extent of depletion of the proved volumes should cause the reserves estimate to be quite firm.

A normal calculation of oil originally in place at Spraberry Trend was not possible. Productive pay thickness or fracture geometry, which would be necessary if the volumetric method were used, cannot be determined. The material balance method of analysis would require knowledge of average pressure in the reservoir and possibly rock compressibility. The consultant firm has calculated an "order of magnitude" value for oil originally in place by assuming that the ultimate recovery proved to date represents only seven percent of the oil originally present.

The FEA report on the Spraberry Trend Area was prepared by Keplinger and Associates, Inc., under Contract No. CO-05-50184-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
TIJERINA-CANALES-BLUCHER FIELD

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas Assoc. (BCF)	Natural Gas Non-Assoc. (BCF)	Natural Gas Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	231.5	0.4	370.4	532.3	
Proved ultimate recovery	133.7	0.3	----[1]	459.0	
Cumulative production	126.6	0.2	----[1]	338.8	
Proved reserves	7.1	0.1	184.2	120.2	
			(Dry Basis)		
Proved reserves			184.2	120.2	NA
Reserves in shut-in reservoirs	0	0	0	49.1	NA
Indicated secondary and tertiary reserves	0		0		
Production					
Year 1973 (total)	6.9	0.1	24.2	41.8	NA
Year 1974 (total)	3.8	---	22.3	22.9	NA
Long-term projection of production (annual total)					
1975	2.0	---	20.2	14.4	
1976	1.4	---	18.9	12.5	
1977	1.0	---	18.1	10.8	
1978	0.6	---	17.6	9.5	
1979	0.5	---	17.3	8.5	
1980	0.3	---	17.1	7.4	
1981	0.3	---	17.0	6.6	
1982	0.2	---	16.8	5.9	
1983	0.2	---	13.7	5.4	
1984	0.1	---	9.1	4.9	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	6.3	---	60	50	NA
Short-term productive capacity (60-day basis)	6.3	---	60	50	

[1]Cumulative production records of associated gas are not reliable.

The Tijerina-Canales-Blucher (T-C-B) oil and gas field is located in Jim Wells and Kleberg Counties of South Texas. The field is in the onshore Oligocene belt of the Texas Gulf Coast 45 miles southwest of Corpus Christi.

The producing formations are loosely consolidated sands of the Frio and Vicksburg series of the Middle and Lower Oligocene age. The depth ranges from 5,500 to 11,000 feet.

T-C-B is an anticlinal structure with a north-south axis. The field is separated from the Seeligson Field to the north by a unit boundary. The productive area is 6,800 acres (11 square miles). The structure is relatively unfaulted. The sands are highly lenticular. There are many shale-outs. Over 72 reservoirs are believed to exist. The report treats 12 different nonassociated gas entities and 6 different oil reservoir groupings in the producing category and 12 shut-in nonassociated gas reservoirs.

Hydrocarbons originally in place were calculated by the volumetric analysis method. The report is well documented with structure and isopach maps, as well as with listings of reservoir rock and fluid characteristics for the important reservoirs.

The oil reservoirs have gas cap and solution gas drives supplemented by water injection. Pressure has been maintained by means of reinjection of produced gas into the associated gas caps. The principal oil reservoirs are now in the final depletion stages and gas cap production has begun. The nonassociated gas reservoirs produce by pressure depletion except for a water drive in one minor reservoir.

Proved reserves of crude oil were estimated by extending production decline trends. The proved reserves of associated gas were estimated by comparing calculated current gas saturation in the reservoir with estimated residual saturations at time of abandonment. This approach appears advisable because cumulative associated gas production minus injection records are not considered reliable. Proved reserves of nonassociated gas were apparently estimated, principally, by production decline curve extension methods. These estimates were tested for reasonableness by observing the recovery efficiency factors.

The FEA report on the Tijerina-Canales-Blucher Field was prepared by James A. Lewis Engineering under Contract No. CO-05-50181-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974

TIMBALIER BAY FIELD

			Natural Gas		
	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Assoc. (BCF)	Non-Assoc. (BCF)	Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	560.2	37.7	801.7	267.9	
Proved ultimate recovery	275.9	14.6	509.9	178.9	
Cumulative production	224.1	10.2	339.3	149.1	
Proved reserves	51.8	4.4	170.6	29.8	
			(Dry Basis)		
Proved reserves			170.6	29.8	NA
Reserves in shut-in reservoirs	5.1	1.5	23.3	19.8	NA
Indicated secondary and tertiary reserves	0		0		
Production					
Year 1973 (total)	9.2	0.8	14.1	10.3	NA
Year 1974 (total)	7.7	0.6	12.8	8.3	NA
Long-term projection of production (annual total)					
1975	6.4	0.5	10.2	6.6	
1976	5.4	0.4	8.6	5.4	
1977	4.4	0.3	7.5	4.3	
1978	3.8	0.2	6.8	3.5	
1979	3.3	0.2	6.3	3.1	
1980	2.8	0.1	5.6	2.5	
1981	2.4	0.1	5.6	2.0	
1982	2.2	---	5.6	1.4	
1983	2.0	---	5.6	0.9	
1984	1.8	---	5.6	---	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	19.0	1.3	32	20	NA
Short-term productive capacity (60-day basis)	19.0	1.3	32	20	

The Timbalier Bay oil field is located in Timbalier Bay along the coastline of Lafourche Parish in southern Louisiana. The location is in the Onshore Miocene Belt, 60 miles south of New Orleans.

The producing sands are in a thick sand-shale sequence of Pleistocene age from 2,300 to 3,400 feet, Pliocene age to 7,700 feet, and Miocene age to 15,900 feet. Some 51 separate sands have been identified, of which 25 have been depleted.

Timbalier Bay is a piercement type salt dome of intermediate depth. Shallowest salt is about 6,400 feet. The salt mass or ridge is related to Caillou Island Field (12 miles west) and Bay Marchand Block 2 Field (8 miles east). There are many radial faults. The Timbalier Bay reservoirs are delineated by salt or shale truncation, stratigraphic pinch-outs, faulting, and bottom water. Some reservoirs are superdomal. There have been 339 separate oil reservoirs and 65 separate nonassociated gas reservoirs at Timbalier Bay. Depleted reservoirs number 208 oil and 43 nonassociated gas. The field has 6,500 productive acres (10 square miles).

Hydrocarbons originally in place were determined, generally, by the volumetric analysis method. The report has listed individual reservoir measurements and rock and fluid parameters for the 153 reservoirs which are not depleted. In the case of the depleted nonassociated gas reservoirs, hydrocarbons originally in place were inferred from ultimate recovery and estimated recovery efficiency factors.

Many of the more important oil reservoirs produce with excellent frontal water drives. Other recovery mechanisms range downward in efficiency to partial water drives, gas cap drives and solution gas drive. The productive nonassociated gas reservoirs are producing with partial water drives or have insufficient pressure data to permit observation of the pressure depletion mechanism. Secondary recovery projects have been carried out in 15 reservoirs (9 gas injection projects and 6 water injection projects). Four of the projects have been abandoned; the field operators have no specific plans pending for additional projects.

The consultant firm has prepared production history plots for the 95 active oil reservoirs. The consultant determined that 33 of these reservoirs were amenable to reserves determination from study of the historical plots. The data from one-third of these 33 production plots appear reasonably indicative. The remaining plots appear to range from only fairly diognostic to indicative of no trend at all. The proved reserves from the other 62 producing oil reservoirs were estimated by assigning recovery efficiency factors, based upon performance history, to the volumetrically determined hydrocarbons originally in place. Recovery efficiency factors were also assigned for the 22 nonassociated gas reservoirs, the 36 shut-in oil reservoirs, and to 13 gas caps overlying oil zones. None of the work or logic employed in these latter 133 instances is documented or discussed in the report.

The FEA report on the Timbalier Bay Field was prepared by Geoscience Consulting Services International, Inc., under Contract No. CO-05-50188-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
TOM O'CONNOR FIELD[1]

	Crude Oil (MMBbls)	Lease Condensate[2] (MMBbls)	Natural Gas: Assoc. (BCF)	Natural Gas: Non-Assoc. (BCF)	Natural Gas: Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	1072.5	NA	778.6	1209.4	
Proved ultimate recovery	699.8	NA	567.4	965.0	
Cumulative production	483.6	NA	358.2	792.2	
Proved reserves	216.2	NA	209.2	172.8	
			(Dry Basis)		
Proved reserves			204.0	168.5	5.8
Reserves in shut-in reservoirs	0	NA	0	0	0
Indicated secondary and tertiary reserves	0		0		
Production					
Year 1973 (total)	27.9	NA	24.1	14.6	0.5
Year 1974 (total)	25.5	NA	21.7	9.6	0.5
Long-term projection of production (annual total)					
1975	23.7	NA	20.1	6.3	
1976	22.0	NA	18.9	8.2	
1977	20.6	NA	17.8	6.8	
1978	19.3	NA	16.8	5.5	
1979	17.5	NA	15.6	5.5	
1980	15.8	NA	14.4	5.5	
1981	13.9	NA	13.1	5.5	
1982	11.9	NA	11.2	5.5	
1983	10.2	NA	9.3	5.5	
1984	8.7	NA	7.8	5.5	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	68.1	NA	58	25	1.3
Short-term productive capacity (60-day basis)	76.8	NA	62	25	

[1]Includes the 5,500; 5,800; and 5,900 feet principal zones as well as 20 other minor zones at 3,900 feet and below. Gas sands above 3,900 feet are assigned to the nearby Greta Field.

[2]Lease condensate volumes are insignificant.

The Tom O'Connor oil field is located in Refugio County, Texas, within the Oligocene belt of the Texas Gulf Coast.

The principal producing zones are the 5,500; 5,800; and 5,900 foot Upper and Middle Frio sandstonesof Oligocene age.

The structure at Tom O'Connor is an elongated anticline with almost 15,000 productive acres (23 square miles).

The oil recovery mechanism is an active water drive. There were small original gas caps in the 5,500 and 5,800 foot reservoirs.

Hydrocarbons originally in place were estimated using the volumetric method. The study team utilized volumetric information which was furnished by the operators and also that from the Texas Railroad Commission files. Based upon their own examination, the study team reduced estimates of net pay thickness and increased estimates of connate water saturation from the amounts which previously had been generally reported. This is most important in the case of the 5,900 foot zone. A material balance analysis of hydrocarbons originally in place was not considered diagnostic because of poor water production records and complications caused by migration of fluids between zones.

Oil production rates have apparently peaked in the 5,500 and 5,800 foot zones, but the period of production decline has not been long enough to establish a predictable trend. The estimate of future reserves in these zones depends, of course, on the average future decline rate which has been estimated at about 15 percent per year. Over half of the reserves at Tom O'Connor are allocated to 5,900 foot sand which has current capacity to produce in excess of its MER of 30,000 barrels daily. The reserves estimate for this zone is based upon an oil recovery efficiency of about 67 percent, which was determined by empirical correlation methods.

The FEA report on the Tom O'Connor Field was prepared by the Region VI Office of the Federal Energy Administration located in Dallas, Texas.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
WASSON FIELD[1]

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas: Assoc. (BCF)	Natural Gas: Non-Assoc. (BCF)	Natural Gas: Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	4806	NA	3510	NA	
Proved ultimate recovery	1401	NA	1914	NA	
Cumulative production	893	NA	1230	NA	
Proved reserves	508	NA	684	NA	
			(Dry Basis)		
Proved reserves			527	NA	98
Reserves in shut-in reservoirs	0	NA	0	NA	0
Indicated secondary and tertiary reserves	86		0		
Production					
Year 1973 (total)	84	NA	55	NA	10
Year 1974 (total)	93	NA	56	NA	10
Long-term projection of production (annual total)					
1975	93	NA	52	NA	
1976	88	NA	49	NA	
1977	61	NA	34	NA	
1978	47	NA	26	NA	
1979	39	NA	22	NA	
1980	30	NA	18	NA	
1981	26	NA	15	NA	
1982	22	NA	12	NA	
1983	18	NA	10	NA	
1984	16	NA	9	NA	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	255	NA	155	NA	29
Short-term productive capacity (60-day basis)	255	NA	155	NA	

[1] Includes the principal San Andres accumulation and minor reserves in the Glorieta, Clearfork, and Wichita Alabny.

The Wasson oil field is located in Gaines and Yoakum Counties, Texas, on the northern plunge of the Central Basin Platform in the North Basin.

The principal producing formation is the San Andres dolomitic limestone of Permian age. Depth to the top of the pay is about 5,000 feet.

The Wasson structure was caused by deposition, regional subsidence, and chemical and reef construction around a pre-Permian high. The accumulation is controlled by structural position and by stratigraphic variations in porosity and permeability. The lower limits are controlled by bottom water. The field has a productive area of 68,500 acres (107 square miles).

Hydrocarbons originally in place were determined both by the volumetric method and by the material balance method. There are difficulties in applying either of these methods at Wasson. The extreme heterogeneity and generally low values of porosity and permeability make average reservoir values and position of gas/oil and oil/water contacts difficult to determine. Also, the very low permeability makes the average reservoir pressure at any time, or the degree to which the overlying gas cap is in communication with the oil zone, difficult to determine. In spite of the foregoing, the analysis at hand appears to be a fair attempt at resolving this most difficult situation.

The crude oil at Wasson was initially saturated and a large gas cap was present. The primary producing mechanism was a dissolved gas drive. The gas cap has not expanded materially. The bottom water has generally been inactive. In 1965, the field was unitized into seven units. Through the process of water injection, the reservoir pressure has been maintained and increased somewhat. The production rate has increased over ten fold since 1965 through the process of water injection, the drilling of 800-900 infilling wells, remedial operations, removal of market demand proration, and increase in MER determination. The individual contributions of each of these simultaneous events can not be isolated.

Application of theoretical water displacement mathematical relationships indicate the ultimate recovery at Wasson will be 30 percent of the original oil in place. This recovery appears supported by extrapolating current production rates.

Operators are continuing to drill infilling wells that intersect porous members which have not been effectively depleted or water flooded. This can be continued, possibly to a significant extent, which should increase oil recovery.

The FEA report on the Wasson Field was prepared by the Region VI Office of the Federal Energy Administration located in Dallas, Texas.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
WEEKS ISLAND FIELD

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas: Assoc. (BCF)	Natural Gas: Non-Assoc. (BCF)	Natural Gas: Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	310.0	40.0	570.0	810.0	
Proved ultimate recovery[1]	217.1	26.5	396.9	569.0	
Cumulative production[1]	200.0	25.0	260.0	558.0	
Proved reserves	17.1	1.5	136.9	11.0	
			(Dry Basis)[2]		
Proved reserves			136.9	11.0	1.6
Reserves in shut-in reservoirs	0	0	0	0	0
Indicated secondary and tertiary reserves	4.7		4.7		
Production					
Year 1973 (total)	8.9	0.1	9.2	6.3	0.4
Year 1974 (total)	6.4	0.1	7.2	4.2	0.4
Long-term projection of production (annual total)					
1975	4.5	0.3	0.9	-----	
1976	3.2	0.1	0.9	-----	
1977	2.1	0.1	0.8	-----	
1978	1.4	----	0.8	-----	
1979	1.1	----	0.3	-----	
1980	0.7	----	0.1	-----	
1981	0.5	----	----	-----	
1982	0.4	----	----	-----	
1983	0.3	----	----	-----	
1984	0.2	----	----	-----	

	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	15.8	0.2	19.0	10.0	1.1
Short-term productive capacity (60-day basis)	15.7	0.1	19.0	10.0	

[1] Estimated by consultant.

[2] The gas volumes have not been corrected for extraction loss which the consultant estimates at about 1 percent.

The Weeks Island oil and gas field is located in Iberia Parish in the coastal marshlands of Weeks Bay of southern Louisiana. The field is 100 miles west southwest of New Orleans in the onshore Miocene Belt.

Production at Weeks Island comes from over 40 sands in a thick Miocene sand-shale sequence. Depths to the sands vary from 9,400 to 16,500 feet.

The structure at Weeks Island is related to a shallow piercement salt dome with salt less than 100 feet from the surface. There is essentially no super cap production. There are many radial and tangential faults and over 90 individual reservoir segments have been mapped in the field. Forty are currently producing. Bottom water is present in most instances. The productive area is about 4,000 acres (6 square miles). Over 90 percent of the reserves are located on the north flank of the dome.

The various reservoirs at Weeks Island produce predominately by water drive with recovery efficiencies indicated to range from 65 to 85 percent. Water injection operations are being conducted in several reservoir segments.

The principal operator in the field is injecting its available associated and nonassociated gas production into the associated gas cap overlying the largest oil reservoir in the field. This is reported as a "tertiary" recovery project to recover additional oil from the naturally watered-out parts of the reservoir. This project has been underway since April 1974. The project details or the circulatory paths of injected and produced fluids are not explained in the report, nor in supplementary material furnished by the consultant.

Hydrocarbons originally in place were estimated by carrying out volumetric analyses in those reservoir segments for which reservoir and fluid data were available. In other cases, hydrocarbons originally in place were inferred by applying estimated recovery efficiency factors to ultimate recoveries, estimated from performance history. In minor instances, it was not possible to estimate hydrocarbons originally in place. From the documentation available in the report, these procedures appear very reasonable in the circumstances.

Ultimate recovery and proved reserves were estimated by methods of extrapolation of past performance, by analogy with comparable wells and reservoirs, and by calculations of recovery factors from reservoir performance. Most of this work is not documented in the report. Production data are reported only for the last two years. However, the field does appear in the final stages of oil depletion.

The FEA report on Weeks Island Field was prepared by Scientifice Software Corporation, under Contract No. CO-05-50182-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
WEST COTE BLANCHE BAY FIELD

	Crude Oil (MMBbls)	Lease[1] Condensate (MMBbls)	Natural Gas Assoc. (BCF)	Natural Gas Non-Assoc. (BCF)	Natural Gas Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	400.3	1.3	292.9	175.5	
Proved ultimate recovery	222.2	0.8	190.4	116.0	
Cumulative production	146.3	0.6	122.1	96.3	
Proved reserves	75.9	0.2	68.3	19.7	
			(Dry Basis)		
Proved reserves			68.3	19.7	NA
Reserves in shut-in reservoirs	21.5	0	19.3	0	NA
Indicated secondary and tertiary reserves	0		0		
Production					
Year 1973 (total)	9.6	---	9.0	2.4	NA
Year 1974 (total)	8.4	---	7.4	2.2	NA
Long-term projection of production (annual total)					
1975	7.5	---	6.8	2.0	
1976	7.1	---	6.4	1.9	
1977	6.8	---	6.1	1.8	
1978	6.4	---	5.8	1.6	
1979	6.0	---	5.4	1.5	
1980	5.3	---	4.8	1.4	
1981	4.6	---	4.2	1.4	
1982	4.1	---	3.7	1.3	
1983	3.6	---	3.2	1.2	
1984	3.1	---	2.8	1.1	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	22.2	---	18.0	9.0	NA
Short-term productive capacity (60-day basis)	22.0	---	18.0	9.0	

[1] Lease condensate production volumes are insignificant.

The West Cote Blanche Bay oil and gas field is located in West Cote Blanche Bay, St. Mary Parish in extreme southern Louisiana. The field is 65 miles south of Baton Rouge in the onshore Miocene Belt.

The producing formations are sands in a thick sand-shale sequence of Pliocene and Miocene age. Depths to the sands range from 1,400 to 10,200 feet.

The structure at West Cote Blanche Bay is related to a shallow piercement type salt dome. The shallowest salt is at about 7,700 feet. There are numerous faults associated with the field and over 200 separate reservoir segments are believed to exist. Some reservoirs are superdomal and are related entirely to the anticlinal structure. Other reservoirs are controlled by truncation of the sands by salt or shale as the salt intruded. Some sands pinch out stratigraphically as deposition approaches the salt mass. Faults and bottom water also delineate the accumulations in most instances. The field has about 2,860 productive areas (4 square miles).

Hydrocarbons originally in place at West Cote Blanche Bay were estimated by means of a "broad" or "coarse" volumetric analysis. A sampling of logs was examined to determine net oil and gas sand thickness and a composite isopach map was prepared. Average reservoir and fluid characteristics were selected.

The predominate recovery mechanism is a water drive. Also there are eleven active water floods, all of which have been in operation long enough to be assessed. The field has been on production decline since 1971. The proved reserves have been estimated by analysis of production history and by analogy with overall performance characteristics of water drive reservoirs. The specific manner in which the shut-in reserves were estimated was not mentioned in the report. Presumably a method similar to that described in the Bay de Chene field summary was followed.

The FEA report on the West Cote Blanche Bay Field was prepared by Keplinger and Associates, Inc., under Contract No. CO-05-50184-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
WEST DELTA BLOCK 30 FIELD

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas: Assoc. (BCF)	Natural Gas: Non-Assoc. (BCF)	Natural Gas: Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place----------------------	723.8	7.6	580.5	325.5	
Proved ultimate recovery-----	410.7	4.6	377.3	226.9	
Cumulative production--------	307.9	3.0	288.4	141.3	
Proved reserves--------------	102.8	1.6	88.9	85.6	
			(Dry Basis)		
Proved reserves--------------			87.4	84.4	2.9
Reserves in shut-in reservoirs----------------	12.3	0	28.6	30.2	0
Indicated secondary and tertiary reserves---------	0		0		
Production					
Year 1973 (total)---------	23.9	0.6	15.9	28.2	0.8
Year 1974 (total)---------	22.0	0.4	14.7	19.2	0.6
Long-term projection of production (annual total)					
1975------------------	18.2	0.4	13.2	19.2	
1976------------------	15.3	0.4	11.9	22.0	
1977------------------	13.0	0.3	11.0	16.7	
1978------------------	11.1	0.2	10.3	11.7	
1979------------------	9.5	0.1	9.4	6.4	
1980------------------	7.5	0.1	7.3	3.0	
1981------------------	5.9	---	5.7	2.3	
1982------------------	4.7	---	4.5	1.8	
1983------------------	3.8	---	3.5	1.3	
1984------------------	3.0	---	2.7	----	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production-----	54.4	0.5	41.0	41.0	1.5
Short-term productive capacity (60-day basis)---	55.0	0.6	41.0	41.0	

The West Delta Block 30 oil and gas field is located 8 miles off the coast of Plaquemines Parish in southern Louisiana. The field is in the offshore Miocene belt in about 50 feet of water.

The producing formations are sands in a thick sand-shale sequence of Pliocene and Miocene age. Depths to the sands range from about 3,000 feet to 15,000 feet.

The structure at West Delta Block 30 Field is related to a large shallow piercement type salt dome. The salt comes to within 3,000 feet of the ocean floor. The field is heavily faulted. Over 200 individual reservoir segments are believed to exist in the field. There is some super cap production, but not of great importance. Other reservoirs are controlled by sand truncation by salt or shale or by sand stratigraphic pinchout near the salt mass. Faulting and bottom water further delineate almost all reservoir segments. The field has about 8,000 productive acres (12 square miles).

The major producing mechanism at West Delta Block 30 is a water drive. There are six waterfloods active in the field, all of which have been in operation long enough to assess their performance. The field has been producing at capacity since 1972. Proved reserves and ultimate recovery have been estimated by analysis of production history, decline curves, and by analogy with performance characteristics of water drive reservoirs.

A detailed study to determine hydrocarbons originally in place was not carried out. Approximate volumes of hydrocarbons originally in place were estimated based upon selection of average recovery efficiency factors, which were 57 percent for oil, 60 percent for lease condensate, 65 percent for associated gas, and 70 percent for nonassociated gas.

About 12 percent of the proved oil reserves and about 34 percent of the proved gas reserves have been placed in the shut-in category. The manner of estimating these volumes is not documented in the report.

The FEA report on the West Delta Block 30 Field has been prepared by Keplinger and Associates, Inc., under Contract No. CO-05-50184-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
WEST RANCH FIELD

	Crude Oil (MMBbls)	Lease Condensate[1] (MMBbls)	Natural Gas: Assoc. (BCF)	Natural Gas: Non-Assoc. (BCF)	Natural Gas: Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	783.7	0.58	744.6	554.4	
Proved ultimate recovery	377.7	0.34	544.7	418.5	
Cumulative production	278.5	0.26	343.5	354.4	
Proved reserves	99.2	0.08	201.2	64.1	
			(Dry Basis)		
Proved reserves			198.5	63.8	1.7
Reserves in shut-in reservoirs	0	0	0	0	0
Indicated secondary and tertiary reserves	0.5		0.2		
Production					
Year 1973 (total)	15.7	NA	19.8	8.9	0.3
Year 1974 (total)	14.9	NA	18.3	13.6	0.3
Long-term projection of production (annual total)					
1975	14.4	NA	19.0	10.8	
1976	13.3	NA	18.5	10.1	
1977	12.2	NA	23.1	6.6	
1978	9.4	NA	26.1	5.3	
1979	8.5	NA	25.2	3.9	
1980	7.0	NA	20.4	3.3	
1981	5.6	NA	13.8	2.8	
1982	4.6	NA	9.0	2.2	
1983	3.7	NA	6.8	1.5	
1984	2.9	NA	5.2	1.3	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	41.0	NA	50.2	37	0.7
Short-term productive capacity (60-day basis)	44.5	NA	50.4	37	

[1]Lease condensate production volumes are insignificant.

The West Ranch field is located in Jackson County on the Texas Gulf Coast. The field is in the onshore Oligocene belt about 100 miles southwest of Houston.

The principal producing sands are in the Frio Series of the Middle Oligocene age. Some 17 percent of the ultimate recovery of nonassociated gas comes from Miocene sands of the Oakville Series and from Upper Oligocene sands of the Anahuac Series. Generally, nonassociated gas and lease condensate are found in the sands occurring from 3,000 to 5,000 feet. The deeper sands from 5,000 to 7,200 feet contain crude oil and associated gas.

West Ranch is an unfaulted anticline with a long northeast, southwest axis containing 10,400 productive acres (16 square miles). The smaller West Ranch South Field is connected to the main field through a saddle area and is included with West Ranch for study purposes. The major reservoirs are continuous over the structure and their lower limits are defined by water levels. The smaller reservoirs are frequently more lenticular and stratigraphically controlled. There are 71 different reservoirs at West Ranch. There are 21 producing oil reservoirs, 13 producing nonassociated gas reservoirs, 13 depleted oil reservoirs, and 24 depleted nonassociated gas reservoirs.

Most of the oil reservoirs had original gas caps and produce with a combination of gas cap drive and water drive. Two of the larger oil reservoirs have water injection projects in operation and secondary water flood reserves are indicated for one of the smaller oil reservoirs. The major nonassociated gas reservoirs produce by means of pressure depletion or by combination of pressure depletion and partial water drive.

Hydrocarbons originally in place in the oil reservoirs were calculated by the volumetric analysis method. The report contains considerable documentation concerning the interpretation of the structure, gas/oil and oil/water contacts, and properties of the reservoir rock and fluids, in all of the important instances. Hydrocarbons originally in place for the nonassociated gas reservoirs were estimated by analysis of pressure data versus cumulative production trends.

Ultimate recovery and proved reserves from the oil reservoirs were generally estimated by extrapolating water cut versus cumulative production trends to an abandonment water cut of 97.5 percent. In most instances, the reasonableness of this estimate could be checked by analysis of oil production decline trends. Proved reserves of associated gas were estimated from analysis of produced gas/oil ratio trends and from the estimates of gas originally in place, combined with reasonable recovery efficiency factors. The nonassociated gas reservoirs are about 85 percent depleted. Proved reserves were estimated from the reservoir pressure versus cumulative production plots, with adjustment for water encroachment.

The FEA report on the West Ranch Field was prepared by James A. Lewis Engineering, under Contract No. CO-05-50186-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
WILMINGTON FIELD

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas: Assoc. (BCF)	Natural Gas: Non-Assoc. (BCF)	Natural Gas: Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	9420	NA	2263	NA	
Proved ultimate recovery	2568	NA	1119	NA	
Cumulative production	1682	NA	971	NA	
Proved reserves	886	NA	148	NA	
			(Dry Basis)		
Proved reserves			133	NA	9
Reserves in shut-in reservoirs	0	NA	0	NA	0
Indicated secondary and tertiary reserves	0		0		
Production					
Year 1973 (total)	66.9	NA	13.3	NA	0.9
Year 1974 (total)	65.3	NA	12.1	NA	0.8
Long-term projection of production (annual total)					
1975	66.3	NA	11	NA	
1976	65.1	NA	11	NA	
1977	62.2	NA	11	NA	
1978	57.4	NA	10	NA	
1979	53.0	NA	9	NA	
1980	47.8	NA	8	NA	
1981	43.3	NA	7	NA	
1982	38.6	NA	7	NA	
1983	34.1	NA	6	NA	
1984	30.3	NA	5	NA	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	178.1	NA	31	NA	2.1
Short-term productive capacity (60-day basis)	183.5	NA	31	NA	

The Wilmington oil field is located in the Long Beach harbor area of southern California, in the Los Angeles Basin.

The producing formations are in the Repetto sands of the Lower Pliocene age and in the Puente sands of the Upper Miocene age. Of the seven producing zones, the more important are the Ranger, the Upper Terminal, and the Lower Terminal found from 3,000 to 4,000 feet. The stratigraphic sequence consists of alternating layers of sand and shale with intermittent layers of siltstone, mudstone and claystone. The sands are friable, unconsolidated and poorly sorted.

The Wilmington structure is an anticline with a NW-SE trending axis. In addition to structure, the accumulations are controlled by several major faults. There are also many minor faults. The overlying Pico--a shale and siltstone formation--serves as the upper seal. Bottom and edge water control the lower limits of the accumulation. The productive area at Wilmington is 14,000 acres (22 square miles).

The hydrocarbons originally in place at Wilmington were estimated by using the volumetric method. The investigators examined available structure and isopach maps of the principal zones in the various fault segments, along with available core and log data, and determined that estimates prepared by the City of Long Beach Department of Oil Properties (who control almost 95 percent of Wilmington) were generally reasonable in this respect.

The crude oil was generally undersaturated in most of the important reservoir segments. Gravity of the oil and its dissolved gas content increase with depth. The ranges are reported as 12° to 30° API and from 90 to 530 SCF/B. The viscosity of the oil decreases with depth, ranging from 4,000 to 70 centipoise at 100° F. The primary recovery mechanism was fluid expansion and dissolved gas drive. There was a limited water drive in some reservoir segments, but generally the edge water has not been an important recovery factor. In the early 1950's, water injection was started to arrest surface subsidence, to dispose of produced waters, and to increase ultimate recovery. Although five spot patterns and alternating line drives are used in some instances, most floods are peripheral. In the mid-1960's, the injection operations became virtually full scale. As a result, oil production has increased; produced gas/oil ratios have been reduced and stabilized; and subsidence of the surface has been arrested and in some instances reversed.

The ultimate recovery from Wilmington has been estimated using empirical displacement of oil by water methods which relate oil recovery, as a fraction of oil in place, with produced water/oil ratios--taking into account reservoir parameters and relative mobility of the fluids. The investigators assumed that the field would be produced until the water cut reaches 96 percent of produced fluids. These same methods were used in determining future production rates.

The estimates of reserves and ultimate recovery are sensitive to the degree to which the empirical analysis method continues to duplicate performance. This is, of course, controlled by the applicability of the method and the proper selection of reservoir and fluid parameters in each of the reservoir segments. The latter is difficult in dirty sand-shale sequences. Relatively firm production decline trends in the important reservoir segments have not yet been established. Also, development in the newer eastern extension of the field is not entirely complete.

The FEA report on the Wilmington Field was prepared by the U.S. Bureau of Mines, Department of Interior, under Interagency Agreement CG-05-50085-00.

SUMMARY REPORT OF
RESERVES AND PRODUCTIVE CAPACITY, DECEMBER 31, 1974
YATES FIELD[1]

	Crude Oil (MMBbls)	Lease Condensate (MMBbls)	Natural Gas Assoc. (BCF)	Natural Gas Non-Assoc. (BCF)	Natural Gas Liquids (MMBbls)
			(Wet Basis)		
Hydrocarbons originally in place	4357.0	NA	693.0	NA	
Proved ultimate recovery	1469.1	NA	451.6	NA	
Cumulative production	637.7	NA	183.0	NA	
Proved reserves	831.4	NA	268.6	NA	
			(Dry Basis)		
Proved reserves			223.0	NA	12.1
Reserves in shut-in reservoirs	0	NA	0	NA	0
Indicated secondary and tertiary reserves	547.0		56.5		
Production					
Year 1973 (total)	18.6	NA	2.8	NA	0.2
Year 1974 (total)	18.7	NA	3.1	NA	0.2
Long-term projection of production (annual total)					
1975	18.9	NA	3.0	NA	
1976	27.9	NA	4.5	NA	
1977	37.0	NA	6.1	NA	
1978	37.0	NA	6.1	NA	
1979	37.0	NA	6.1	NA	
1980	36.9	NA	6.1	NA	
1981	36.9	NA	6.1	NA	
1982	36.9	NA	6.1	NA	
1983	36.8	NA	6.1	NA	
1984	36.8	NA	6.1	NA	
	(MBbls)	(MMbls)	(MMCF)	(MMCF)	(MBbls)
Daily Averages					
December 1974 production	51.4	NA	8.9	NA	0.5
Short-term productive capacity (60-day basis)	200.0	NA	33.2	NA	

[1]Includes the principal Grayburg-San Andres zone and minor reserves in the Yates-Smith and Toborg zones.

The Yates oil field is located in Pecos County in West Texas on the southeastern edge of the Central Basin Platform.

The principal producing formation is the Grayburg-San Andres dolomite of the Guadalupe Series of the Permian age. The depth to the pay ranges from 1,000 to 1,500 feet. There are shallower and minor accumulations in the Toborg Sand of Lower Cretaceous age, and in the Yates-Smith Sand of Upper Permian age.

The controlling trapping feature at Yates is an anticlinal fold. The overlying Queen red bed-evaporite sequence provides the upper seal. When a portion of the lower Queen is sandy and permeable, it is considered a part of the Grayburg-San Andres reservoir. There is a facies change across the field from west to east ranging from shelf to shelf margin to basin types of deposits. The prolific east central part of the field is in the shelf margin area which is a skeletal bank of fossiliferous, coarse grained, reef type deposit. The reservoir is completely underlain by bottom water. The water level is influenced by capillary forces which result in higher occurrences of water in those areas with lower porosity.

Hydrocarbons originally in place in the Grayburg-San Andres reservoir have been estimated at 4.2 billion barrels of oil and 693 billion cubic feet of gas by means of material balance analysis. The consultant firm discounts the advisability of the volumetric analysis method because cores are not available from the highly vugular and prolific east central portion of the field.

The crude oil at Yates was initially saturated with gas and a very small original gas cap may have existed. In the very early years (1926-35) producing gas/oil ratios were several times the solution ratio because some wells had not been drilled deep enough into the section and some completions were either without tubing or with tubing inadequately submerged. After these conditions were corrected, the producing gas/oil ratio returned to a low level and a high degree of gravity segregation of fluids in the reservoir occurred. A large expanding secondary gas cap now exists. Other than gravity drainage, production mechanisms are dissolved gas drive and partial water drive. During the period 1941-51 some 80 million barrels of oil escaped from the reservoir because of casing leaks and poor casing seats. Some 4 million barrels of this oil was recovered from shallow water wells, from shallow drilled wells, from open gravel pits, and from skimming along the river. An unknown amount of this oil may have been produced from the shallow Toborg wells. About two-thirds of the main reservoir wells had to be repaired. Water encroachment into the reservoir has amounted to about 210 million barrels while 598 million barrels of oil have been produced (excluding "escape oil").

The Yates field is in the process of being unitized and completion is expected by the end of 1975. This will minimize the complexities of future reservoir production operations, protect correlative rights, and obtain optimum recovery. Gas handling facilities will be expanded and the production rate will be doubled. Perhaps over half of the wells will be deepened; gas/oil ratios will be controlled; and produced gas will be reinjected into the gas cap in order to make the gravity drainage mechanism fully effective.

The consultant firm estimates that total remaining reserves in the principal reservoir are 1,370 MMBbls. However, 545 MMBbls of these reserves are believed contingent upon the unitized operations outlined above and have thus been placed in the indicated secondary reserves rather than in the proved reserves category. The proved ultimate recovery at Yates Grayburg-San Andres is thus indicated to be 34 percent of oil originally in place. The additional indicated secondary reserves should increase this recovery efficiency factor to 47 percent. These amounts do not include the escape oil which was about 2 percent of the oil originally present.

The Yates Field is one of the three oil fields in the United States which has significant reserve productive capacity. An inability to resolve equity problems concerning mineral rights, in the past, has prevented the utilization of this incremental productive capacity. The allowed producing rate of the field is currently 50,000 barrels daily. Following unitization of the field toward the end of 1975, the production rate probably will be increased to 100,000 barrels daily. The efficiency of the producing mechanism will be closely observed at this increased rate, particularly with regard to water and gas coning, gas/oil ratio control, and the extent of continued gravity segregation. Then, quite possibly, even higher production rates will be considered. There is really no question about the field's ability to produce at a 200,000 barrel daily rate or even more. The problem now is the inability to determine, in the absence of testing, just how high the rate can be raised without significant loss in ultimate recovery.

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