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Engineering for Lawyers, Landmen, and Other Non-Engineers or What is that Guy Talking About?

Robert M. McGowen

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I. INTRODUCTION AND PERSPECTIVE

The purpose of this paper is to give an overview of reservoir engineering principles along with examples so the non-engineer can be aware of engineering practices in connection with their specific oil and gas profession whether it be legal, land or geology.

Perspective is defined as the relationship of aspects of a subject to each other and to a whole. The oil and gas industry has a number of different players performing very unique tasks. For example their are engineers, geologists, landmen, accountants, lawyers, and technicians to name a few. If each discipline is aware of others duties and functions then each person is better rounded and can perform a much better job. Given the current oil and gas environment it is imperative that we all have a general knowledge of the industry as well as a specific expertise.

II. TYPES OF PETROLEUM ENGINEERING

A. Drilling

There are three basic petroleum engineering specialties. The first of these is drilling. This engineer is involved in the drilling of a well from the time drilling cost estimates are obtained to the drilling and completion of a well. Included in his duties are insuring economic and safe operations through the drilling of a well.

B. Production

The production engineer is responsible for designing applicable equipment and monitoring producing wells from the time of completion to abandonment. Included in his duties are tracking and maintaining production, as well as economic and safe operations.

C. Reservoir

The reservoir engineer is responsible for the reservoir management of producing wells and maintaining reserve estimates for all wells. The reservoir engineer also determines the economic
viability of drilling new wells. The main difference between production and reservoir engineers is that the production engineer maintains the well at the surface and well bore while the reservoir engineer maintains the well at the well bore and beyond in the producing formation.

III. RESERVOIR ENGINEERING

A. Petroleum Accumulations

The starting point in reservoir engineering is determining the presence of oil and gas in commercial quantities. The following discussion gives an overview of the how and why of petroleum accumulations.

1. Geologic Time Scale

The geologic time scale relates age to rock formations and plant and animal life. (Figures 1 and 2) This is important in analyzing producing formations in particular oil and gas basins. There are two distinct producing basins in Arkansas. North Arkansas is part of the Arkoma Basin that produces dry gas from formations in the Pennsylvanian, Mississippian, Devonian, Silurian and Ordovician Periods in the Paleozoic Era. The relative age ranges from 275,000,000 years to 500,000,000 years. (Figure 3) South Arkansas is part of the Gulf Coast Basin. Production in South Arkansas is dry and wet gas, sweet, sour, and volatile oil. The producing formations are in the Mesozoic Era in the Cretaceous, Jurassic and Triassic Periods. The relative age ranges from 65,000,000 years to 225,000,000 years. (Figure 4)

2. Origin of Petroleum

There is the organic theory that advocates that sources of organic material being plant and animal life from rivers, plant and animal growth on sea bottom and Plankton minute plant and animal life provided the raw material for petroleum. (Figure 5) Given the age of producing formations the organic material has had sufficient time to evolve into oil and gas accumulations.

3. Reservoir Rocks

In order for formations to contain commercial hydrocarbons and have the ability to allow flow to the surface in economic quantities, the formations must have favorable rock properties. Two of the rock properties necessary for hydrocarbon accumulation are porosity and permeability.

a. Porosity

Porosity of a porous medium is given the symbol of ϕ and is defined as the ratio of void space, or pore volume, to the total bulk volume of the rock. Typical porosity values in Arkansas sands and limestones range from 10-20 percent. The best visual example of porosity would be a jar filled with marbles. The void space between the marbles is porosity. (Figure 6)

b. Permeability

Permeability is given the symbol k and is defined as the fluid capacity to flow in a porous medium. The unit of measure is the darcy. Rock permeability allows hydrocarbon accumulations to migrate to the well bore via a path of flow. Typical permeability values in Arkansas sands and limestones range from 1 millidarcy in tight sandstones to 2,000 millidarcies in porous sandstones and limestones. (Figure 7)

4. Traps

This is a subsurface condition restricting further movement of hydrocarbons such that they may accumulate in commercial quantities. This is the third element necessary for the presence of commercial hydrocarbons. The first two are the origin of petroleum and reservoir quality rock to allow hydrocarbon migration and accumulation.

a. Structural
b. Stratigraphic
c. Combination

Structural traps are those formed by deformation of the earth's crust by either faulting or folding. Stratigraphic traps are those formed by changes in lithology, generally a disappearance of the containing bed or porosity zone. Combination traps are traps having both structural and stratigraphic features. (Figures 8 and 9)

B. Reservoir Fluids and Pressure

1. Type of Fluids

a. Water
b. Oil
c. Gas

Fluids encountered in subsurface formations are fresh water (shallow), brine (salt water), oil, and gas. Petroleum may be defined as a naturally occurring, complex mixture of hydrocarbons which may be either gas, liquid, or solid, depending upon its own unique composition and the pressure and temperature at which it is confined. Hydrocarbons may contain impurities such as carbon dioxide (CO_2), hydrogen sulfide (H_2S), and other compounds of nitrogen, sulphur, and oxygen. The relative salt content of water is referred to as salinity and is a measurement of NaCl in parts per million. The NaCl ppm is proportional to formation depth, pressure, and temperature. Crude oil is measured in API gravity. This is a measurement of oil density and is related to specific gravity. A sweet crude will have an API gravity of around 40°. Gas, like oil, is a unique mixture of hydrocarbons that are predominantly methane. Different types of gases are wet gas (contains appreciable natural gasoline content), sour gas (contains hydrogen sulfide), and sweet gas (contains no hydrogen sulfide). Although there is no rule as to when gas and oil occurs, it can be noted that oil will accumulate only under certain pressures and temperatures and as these two factors increases only gas will be present. The deepest occurrence of oil is approximately 15,000 feet.

2. Fluid Distribution

When more than one fluid exists in a formation they separate with heaviest fluid on the bottom. This can be seen graphically in Figure 10.

3. Reservoir Pressure

Fluid movement from a reservoir rock to a well bore can take place only if a pressure differential can be established between the reservoir and the well. This requires that the fluids in the rock be confined under an elevated pressure. The measurement of subsurface pressures are important phases of petroleum engineering. Reservoir pressures are measured by a bottom hole pressure gauge or estimated by reading shut-in surface gauges and estimated the fluid gradient to the open formation.

a. Normal
b. Abnormal

Normal pressures encountered in producing formations have a pressure gradient of about .465 psi/ft. Abnormal pressured formations which are due to overburden pressures are most common in soft rock areas such as the Gulf Coast. The pressure gradient in these formations can be as high as .9 psi/ft. The importance of abnormal pressure formations is as a source of drilling and production hazards. (Figure 11)

C. Reservoir Drive Mechanisms

There are different forces of nature present in different reservoirs that provide the drive mechanism that causes the hydrocarbon accumulations to migrate and flow in the reservoir and ultimately be produced to the surface. The importance of identifying the drive mechanism is necessary to determine the optimum production rates, methods, and recoveries.

1. Depletion Drive
   a. Solution-Gas Drive
   b. Gas-Cap Drive
   c. Gas Expansion Drive

These drive mechanisms are based on pressure depletion due to hydrocarbon production and resultant reservoir voidage. Solution-gas drive is applicable in oil reservoirs and is based on gas breaking out of the oil as pressure is reduced by production . The expanding gas pushes the oil to the producing wells. This type drive can recover between 5-25 percent of oil-in-place. Gas-cap drive is applicable in oil reservoirs and is based on the presence of a significant cap of gas that overlays an oil deposit that are in communication in the same reservoir. The oil portion of the formation is produced and as reservoir pressure is reduced the gas cap expands and pushes oil ahead of it. (Figure 12) This type drive can recover between 20-40 percent of oil-in-place. Gas expansion drive reservoirs are applicable to gas producing formations. Production causes a reduction in pressure and the expansion of gas which causes migration and movement to the well bore. This type drive can recover between 75-85 percent of gas-in-place.

2. Water Drive
   a. Bottom-Water Drive

b. Edge Water Drive

Water drive reservoirs occur when the hydrocarbon occurrence is in communication with a large water aquifer (ten to one-hundred times the volume of the hydrocarbon volume) that expands to replace the produced hydrocarbons and pushes the hydrocarbons to the well bore. This drive mechanism maintains reservoir pressure depending on the size of the aquifer. The bottom-water drive occurs when the hydrocarbons are completely underlain by water and the water expansion is uniform. This drive can recover between 35-60 percent of oil-in-place and 60-70 percent of gas-in-place. This drive can be identified by pressure and production observance and good geologic control. (Figure 13) Edge-water drive occurs when the hydrocarbons are not completely underlain by water and the water expansion occurs in certain areas of the reservoir or from the edges. This drive is not as efficient as the bottom- water drive.

3. Combination Drive

There are a number of times when the there are a combination of drive mechanisms that are present in producing reservoirs. This can improve recoveries but prudent engineering must be utilized to insure proper production rates and methods.

4. Gravity Drainage

This drive mechanism occurs where there is extreme structural relief in the producing reservoir. The flow and migration of oil is due to gravity segregation. These type drives can have very high recoveries of oil-in-place.

IV. RESERVOIR ENGINEERING EXAMPLES

A. Estimation of Oil and Gas Reserves for Drilling Prospect, Lawsuit Damages, Field Rules Hearing

Utilizing the information discussed in this paper oil and gas reserves can be estimated. Oil and gas reserves can be used to examine drilling prospects, determine if damages have occurred in oil and gas litigation, demonstrate the necessity of a particular field rule application, economic planning, and monitoring well performance. Some general definitions used in reserve estimation are as follows.

<u>Oil-in-Place</u> - Volume of oil <u>originally</u> in place in reservoir rock of oil reservoirs (N).

<u>Gas-in-Place</u> - Volume of gas <u>originally</u> in place in reservoir rock of gas reservoirs (G).

<u>Recovery Factor</u> - Fraction of oil-in-place or gas-in-place that will be ultimately recoverable (RF).

<u>Ultimate Recovery</u> - Volume of oil or gas that will be recovered from an oil or gas reservoir

during the producing life of that reservoir.

$$Np = RF * N$$
$$Gp = RF * G$$

Cumulative Recovery - Volume of oil or gas produced to a specific date.

Reserves - Volume of oil or gas expected to be produced after a specific date.

Ultimate Recovery = Cumulative to date + Reserves after date

There are different classifications and categories related to reserves that relate to current conditions and degrees of uncertainty in ultimate oil and gas recovery. The Society of Petroleum Engineers *Definitions For Oil and Gas Reserves* as Figure 14 as an aid to present various reserve classifications and categories. Care should be taken when reviewing reserve estimations as to the reserve classification.

1. Method
   a. Performance
   b. Volumetric Analysis
   c. Analogy

There are three distinct methods used in making reserve estimates. The performance method is the most reliable and will yield the best results in terms of accuracy. This method is used when the well examined has some production and pressure history. Decline analysis is performed by plotting monthly production versus time. This is generally done on semi-log paper with the production plotted on the logarithmic y axis. If the production data exhibits a straight line relationship then future production can be estimated by extrapolation. (Figure 15) Material balance is performed by examining production data and corresponding reservoir bottom-hole pressure data. When there is sufficient data this method is the most accurate. Figure 16 shows pressure and production data for a gas reservoir and the resultant P/Z plot. The premise of the material balance method is that in a closed system pressure drops are proportionate to hydrocarbon withdrawal. This method will determine total gas-in-place and allows the estimation of recoverable reserves.

The volumetric method is used when performance is not available (new well) and as a check to the performance method. A summary of this method for both oil and gas is shown below.

How to calculate oil-in-place

$$N = (7{,}758(\phi)(1-S_w))/B_o$$

Definition of Terms

N - Oil-in-Place, stb/AF

ϕ - Average Porosity, fraction

S_w - Connate Water Saturation, fraction

B_o - Formation Volume Factor, res bbl/stb

Where to get data

	Source		
Data	Best	Next Best	Better than Nothing
Porosity	Core Analysis Porosity Log		Guess
Connate Water Saturation	Log Calculations	Capillary Pressure Data	Guess
Formation Volume Factor	PVT Analysis	Correlation Chart	

Example

Porosity (ϕ) = 18%
Connate Water Saturation (S_w) = 30%
Solution Gas-Oil Ratio, cf/stb = 200
Gas Gravity = .9
Reservoir Temperature = 180°F
Oil Gravity = 30°API
B_o = 1.15

$N = (7{,}758(\phi)(1-S_w))/B_o = (7{,}757(.18)(1-.30))/1.15 = 850$ STB/AF

How to calculate gas-in-place

$$G = 43.56(\phi)(1-S_w)((P+15)/15)(520/(T+460))(1/Z)$$

Definition of Terms

G - Gas-in-Place, MCF/AF
ϕ - Average Porosity, fraction
S_w - Connate Water Saturation, fraction
P - Average Reservoir Pressure, psig
T - Reservoir Temperature, °F
Z - Compressibility Factor

Where to get data

	Source		
Data	Best	Next Best	Better than Nothing
Porosity	Core Analysis Porosity Log		Guess
Connate Water Saturation	Log Calculations	Capillary Pressure Data	Guess

	Source		
Data	Best	Next Best	Better than Nothing
Reservoir Pressure	BHP Measurement DST	Surface Shut-In Correlation	
Reservoir Temperature	Measurement	Log Heading	70°F + (Depth * .015)
Compressibility	PVT Analysis	Correlation Chart	

Example

Porosity (ϕ) = 18%
Connate Water Saturation (S_w) = 30%
Reservoir Pressure = 5,000 psig
Reservoir Temperature = 180°F
Compressibility Factor = 1.005

$G = 43.56(\phi)(1-S_w)((P+15)/15)(520/(T+460))(1/Z)$
$= 43.56\ (.18)(1-.3)(5015/15)(520/(460+180))(1/1.005) = 1{,}485$ MCF/AF

The volumetric method utilizes assumptions concerning the drainage area when converting STB/MCF or MCF/AF to STB or MCF. The drainage area should be estimated based on existing well control. If geologic control is minimal than never assume an area greater than the unit size for the producing formation in the area. Drainage may also be determined from analogous production in the area.

The third reserve determination method is by analogy. This method is also a check for the performance and volumetric methods. Basically, this involves examination of offset production from similar formations to determine typical reserves. This provides a quick way to check drilling prospect reserves. If offset production for one zone averages 50,000 barrels of oil per well and a new well is estimated to produce 1,000,000 barrels of oil then the new well reserves may be suspect. This method is the least reliable in terms of accuracy but provides a good check for the volumetric method.

B. Valuation of Oil and Gas Reserves for Drilling Prospect, Lawsuit Damages, Field Rules Hearing

1. Revenue Projections
    a. Scheduling Annual Production
    b. Escalation Assumptions
    c. Fair Market Value

Once reserves are determined and scheduled on an annual basis, a value of the reserves is then derived. This is done by the preparation of a cash flow revenue projection. See example on this page.

PROJECTION OF FUTURE REVENUE

EVALUATION OF THE INTEREST OF ABC OIL COMPANY IN PECAN LAKE FIELD

EFFECTIVE DATE: JANUARY 1,1994

ABC-CUTLER NO.1
CUTLER SAND
PECAN LAKE FIELD
CAMERON PARISH, LOUISIANA

PROVED
DEVELOPED - PRODUCING

COUTRET & ASSOCIATES, INC.
PETROLEUM RESERVOIR ENGINEERS
810 LOUISIANA TOWER
401 EDWARDS STREET
SHREVEPORT, LOUISIANA

YEAR 12 MONS. ENDING 12 / 31	--TOTAL PRODUCTION-- OIL/COND. BBL.	GAS MCF	---EVALUATED INTEREST SHARE--- OIL/COND. BBL	GAS MCF	REV. AFTER PRODUCTION TAX--$	OPERATING EXPENSES $	CAPITAL COSTS $	NET CASH FLOW $	PRESENT WORTH @ 10 % YEAR $	CUMULATIVE $
1994	2,600	207,000	142	11,302	23,743	0	0	23,743	22,638	22,638
1995	2,000	153,000	109	8,353	17,609	0	0	17,609	15,263	37,901
1996	1,500	114,000	82	6,224	13,128	0	0	13,128	10,344	48,245
1997	1,100	84,000	60	4,586	9,669	0	0	9,669	6,926	55,172
1998	1,000	69,000	55	3,767	8,016	0	0	8,016	5,220	60,392
TOTAL	8,200	627,000	448	34,232	72,165	0	0	72,165	60,392	
CUMULATIVE	16,700	1,577,000								
ULTIMATE	24,900	2,204,000								

INITIAL LEASE DATA

EXPENSE INTEREST 0.000000
REVENUE INTEREST 0.054597
GROSS OIL PRICE, $/BBL 16.00 NET OIL PRICE, $/BBL 14.00
GROSS GAS PRICE, $/MCF 2.00 NET GAS PRICE, $/MCF 1.92
OPERATING EXPENSE, $/YEAR: 0
CAPITAL EXPENSE, $ 0
YEARS LIFE IN LAST LINE 1

PRESENT WORTH PROFILE

PRESENT WORTH @ 5%	$65,744
PRESENT WORTH @ 10%	$60,392
PRESENT WORTH @ 15%	$55,878
PRESENT WORTH @ 20%	$52,029
PRESENT WORTH @ 25%	$48,715
PRESENT WORTH @ 30%	$45,838
PRESENT WORTH @ 35%	$43,320

COMMENTS: Qi=20,000 MCFPM, DECLINE = 26%/YR

Once oil and gas reserves are scheduled then prices are applied to determine future cash flow. Prices should reflect current average prices in effect at the effective date of the evaluation. Escalation assumptions may vary depending on the purpose of the study. Cash flow projections for investment determination purposes should not be escalated. Current conventional wisdom dictates escalation of 5% per year for ten years for both prices and costs for cash flow projections when escalation is requested. One use of revenue projections is to determine Fair Market Value. This is the price a willing buyer would pay a willing seller in a free and open market with both parties having equal access to all pertinent data. The Fair Market Value of the above example would be $48,700. This would represent a rate of return of 25%. This is a reasonable rate of return to expect accounting for production risks. A quick look Fair Market Value would be to determine net reserves and multiply them by 1/3 of the wellhead price. This is no alternative to a complete analysis but a quick way to determine if asking prices are reasonable.

C. Pressure Analysis Methods and Examples

Pressure analysis methods are used by Petroleum Engineers to determine reservoir pressure, reservoir permeability, well bore damage, flow efficiency, well bore interference, and reservoir limits. These methods can be designed to determine specific information about a well or reservoir. One type of analysis is a pressure build up analysis. A well is produced for a period of time at stable rates then shut-in and the bottom-hole pressure is measured as the pressure builds up. At the end of the test, build up time and corresponding pressure is compiled. A Horner plot analysis is made to determine reservoir pressure, insitu-permeability in the test area and well bore damage or enhancement. (Figure 17) Tests can be designed to determine if two wells are in communication in the same reservoir. Both wells can be shut-in and then one well produced while the other remains shut-in with a bottom-hole pressure gauge in the shut-in well. An examination of the shut-in well's time and pressure readings can determine whether or not the two wells interfere with each other. An examination of reservoir pressure can determine well drainage and depletion in a multi well field. Again, any test can be designed to attempt to determine specific reservoir information.

V. WORLDWIDE PRODUCTION AND RESERVES

Figure 18 shows worldwide reserves and production as of January 1, 1993. OPEC has seventy seven percent of the oil reserves and produces forty percent of the daily oil production. The United States has two percent of world oil reserves and produces twelve percent of the daily oil rate. This graphically demonstrates how oil price is controlled by the OPEC producing countries. Figure 19 is a recent United States Industry Scorecard that shows oil supply and demand. This illustrates that one-half of the U.S. demand is imported. This demonstrates the importance of the domestic oil industry.

APPENDIX

Relative time scale				Radiometric dates
Phanerozoic Eon	Cenozoic Era		Pleistocene Epoch	2,000,000 years B.P.
		Tertiary Period	Pliocene Epoch	12,000,000 years B.P.
			Miocene Epoch	25,000,000 years B.P.
			Oligocene Epoch	38,000,000 years B.P.
			Eocene Epoch	55,000,000 years B.P.
			Paleocene Epoch	65,000,000 years B.P.
	Mesozoic	Cretaceous Period		135,000,000 years B.P.
		Jurassic Period		180,000,000 years B.P.
		Triassic Period		225,000,000 years B.P.
	Paleozoic Era	Permian Period		275,000,000 years B.P.
		Carboniferous Period		350,000,000 years B.P.
		Devonian Period		413,000,000 years B.P.
		Silurian Period		430,000,000 years B.P.
		Ordovican Period		500,000,000 years B.P.
		Cambrian Period		600,000,000 years B.P.

Figure 1-8 The geologic column of the Phanerozoic Eon. The time scale is shown on the left page and the corresponding range of the chief vertebrate and plant groups on the right page.

Figure 1

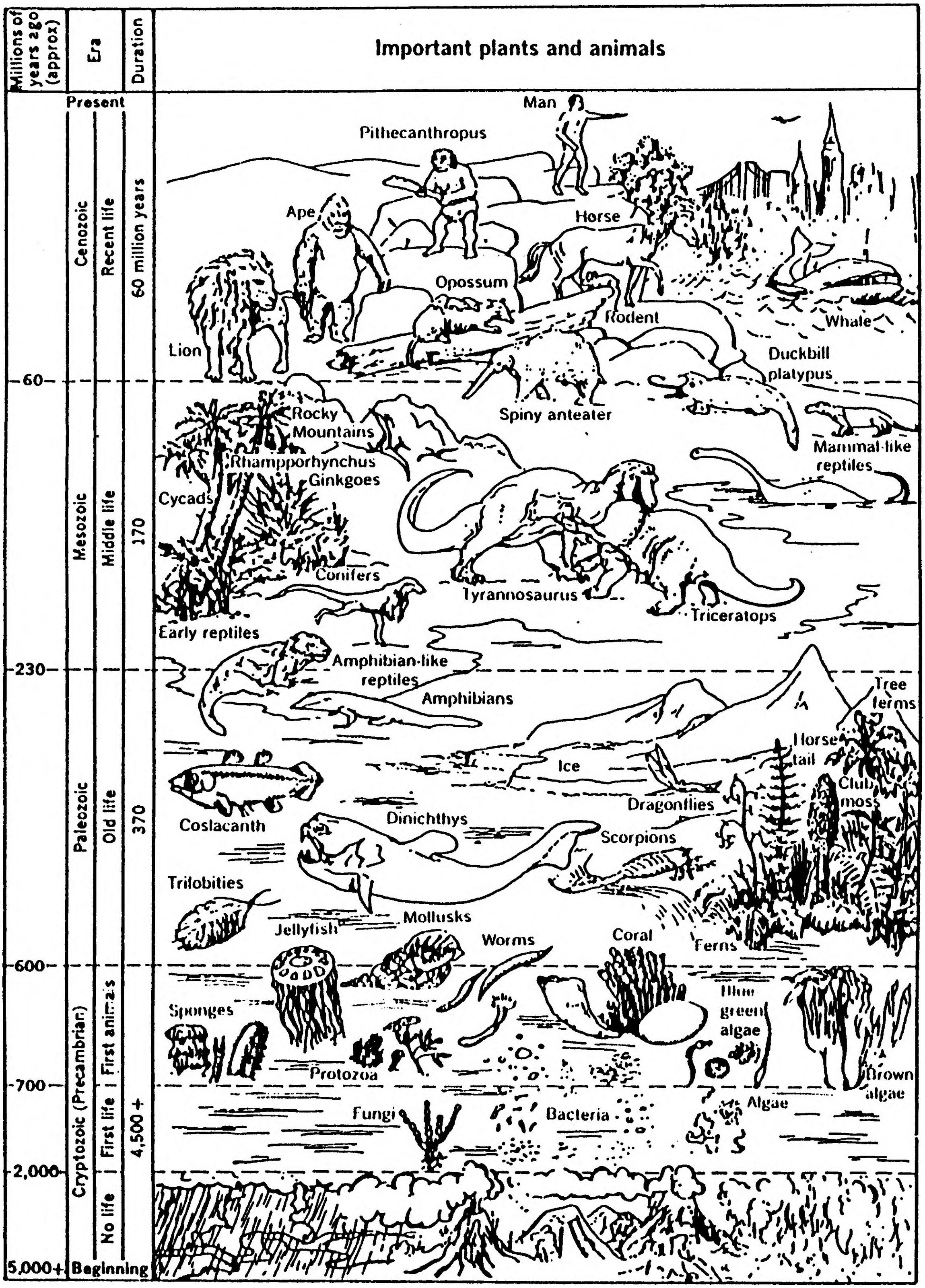


FIG. 2–1 How life has developed on earth during the various eras.

Figure 2

ARKOMA BASIN (ARKANSAS)

STRATIGRAPHIC SECTION

C	SYS.	SERIES		ABR.	FORMATION
	PENNSYLVANIAN	UPPER ATOKA		CA	CARPENTER "A"
				uA	UPPER ALMA
				lA	LOWER ALMA
				CB	CARPENTER "B"
				M	MORRIS – (SELF – TACKETT)
		MIDDLE ATOKA		A	ARECI – (MOYER)
				By	BYNUM – (HOOD)
				F	FREIBURG – (HENSON – PEARSON)
				C	CASEY – (VERNON – HUDSON No. 1)
		LOWER ATOKA	CECIL SERIES	DA	DUNN "A" – (SELLS – McGUIRE – HUDSON No. 2)
				RB	RALPH BARTON – (JENKINS – UPPER ALLEN)
				DB	DUNN "B"
				DC	DUNN "C" – (DAWSON "A" – LOWER ALLEN)
				PB	PAUL BARTON – (DAWSON "B" – RUSSELL)
				CS	CECIL SPIRO – (HAMM)
				Pa	PATTERSON
				O	ORR – (SPIRO – KELLY – BARTON)
		MORROWAN	BLOYD SHALE	K	KESSLER LS. – (WAPANUCKA)
				BW	BRENTWOOD LS.
			HALE SANDS	uH	UPPER HALE
				mH	MIDDLE HALE
				l H	LOWER HALE
	MISS.	CHEST-ERIAN		P	PITKIN LS.
				Fy	FAYETTEVILLE <WEDINGTON MEMBER
				Bv	BATESVILLE
		MERA		Mo	MOOREFIELD
		OSAG.		Bo	BOONE
	DEVON.	CHAT.		Ch	CHATTANOOGA SHALE
				Sy	SYLAMORE SAND
		+	HUNTON	Pn	PENTERS
	SIL.	+ +		Hn	HUNTON
	ORDOVICIAN	CINCIN-NATIAN		Ca	CASON SHALE
			VIOLA	Fe	FERNVALE LS.
				Ki	KIMMSWICK LS.
		CHAMP.	SIMPSON	Pl	PLATTIN DENSE – (JOACHIM DOLO.)
				SP	ST. PETER SAND
				Ev	EVERTON
		CANADIAN	ARBUCKLE	BR	BLACK ROCK
				Sm	SMITHVILLE
				Po	POWELL DOLO.
				Co	COTTER DOLO.
				DH	DRY HOLE

\+ ULESTERIAN

\+ + NIAGARAN & ALLEXANDRIAN

NOTE: "C" = COLOR CODE AS TO WELL PRODUCING ZONES.

Figure 3

SOUTH ARKANSAS & NORTH LOUISIANA GEOLOGIC COLUMN

ERA	SYSTEM (AGE)	SERIES (EPOCH)	GROUP			FORMATION
CENOZOIC	TERTIARY	EOCENE	WILCOX			WILCOX
		PALEOCENE	MIDWAY			MIDWAY CLAYTON
MESOZOIC	UPPER CRETACEOUS	GULFIAN SERIES	NAVARRO			ARKADELPHIA NACATOCH
			TAYLOR GROUP			SARATOGA
						ANNONA
						OZAN
			AUSTIN GROUP			TOKIO
						AUSTIN
			EAGLEFORD			EAGLEFORD
			WOODBINE			TUSCALOOSA
	LOWER CRETACEOUS	COMANCHEAN SERIES	WASHITA GROUP			WASHITA-FREDERICKSBURG
			FREDERICKSBURG			
			TRINITY GROUP			PALUXY
				GLEN ROSE		MOORINGSPORT
						FERRY LAKE ANHYDRITE
					RODESSA	HILL
						GLOYD
						DEES
						YOUNG
						JAMES
						PINE ISLAND
		COAHUILAN SERIES				SLIGO
						HOSSTON
	JURASSIC		COTTON VALLEY GROUP			SCHULER
						BOSSIER
						HAYNESVILLE / BUCKNER
						SMACKOVER
						NORPHLET
						LOUANN
						WERNER
	TRIASSIC					EAGLE MILLS
PALEOZOIC	PENN					MOREHOUSE

Figure 4

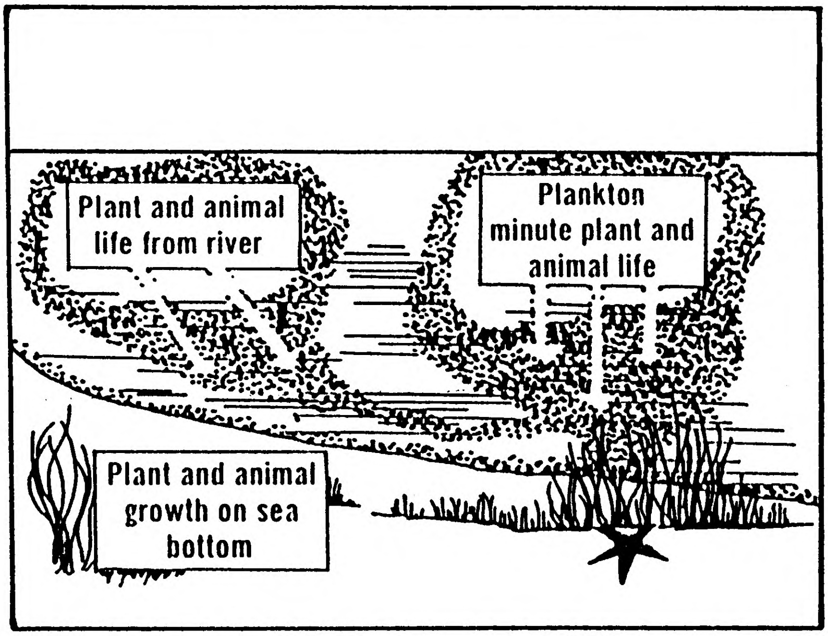


FIG. 2–3 Some sources of organic material that, according to the organic theory, provided the raw material for petroleum.

Figure 5

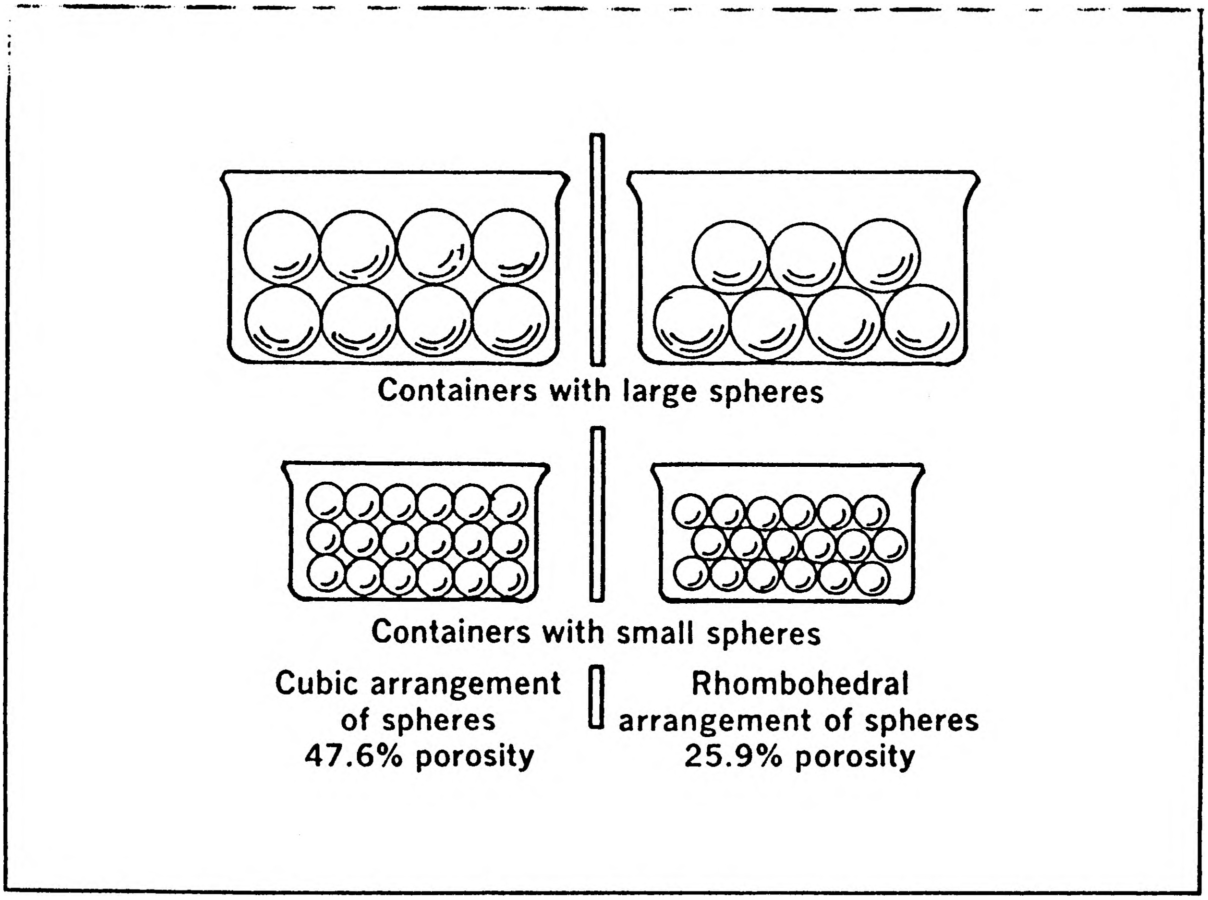


FIG. 2–8 The arrangement and size of the spheres affects the porosity. Cubic arrangement can have a maximum porosity of 47.6%. A rhombohedral arrangement can yield a porosity of 25.9% (courtesy SPE-AIME).

Figure 6

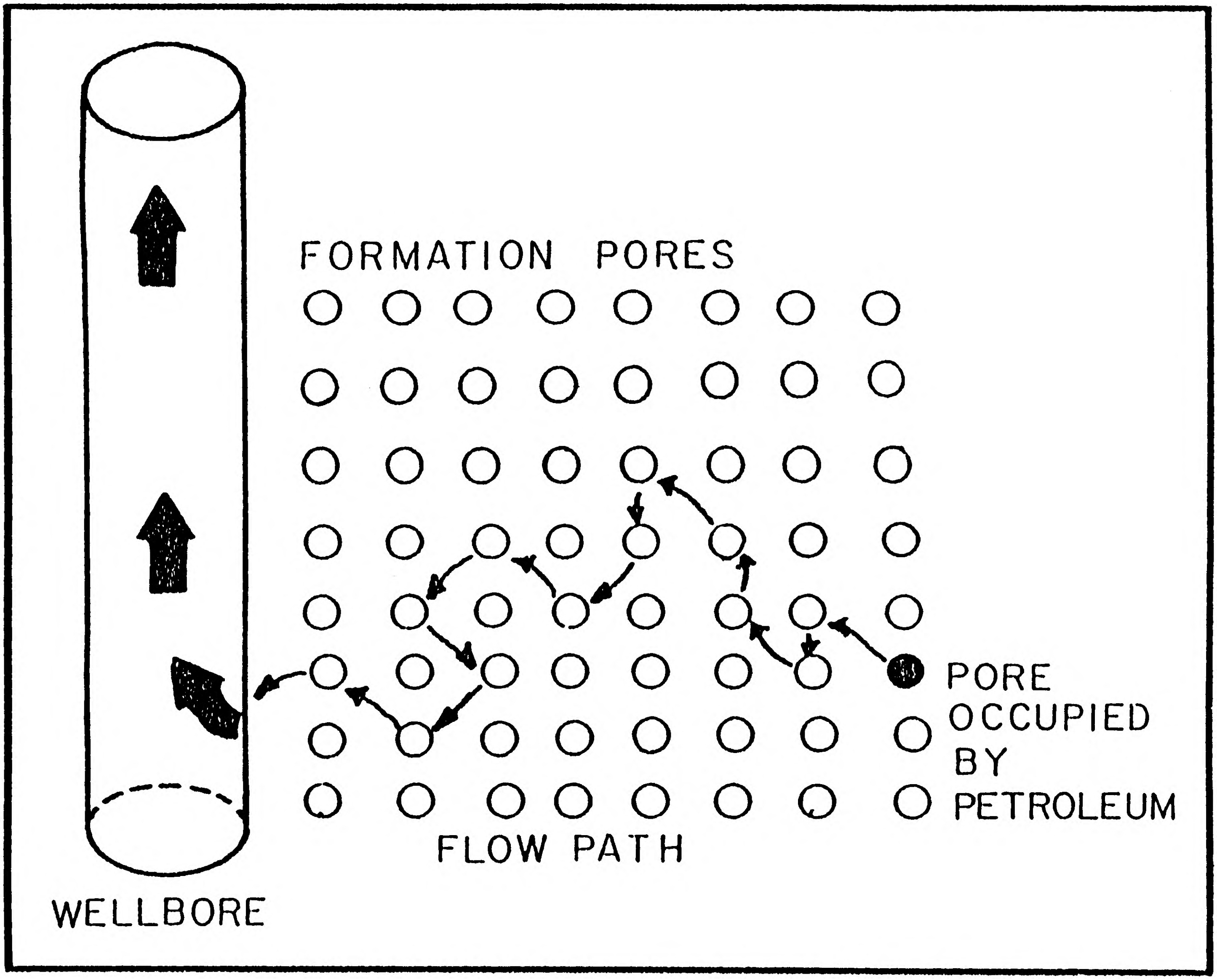
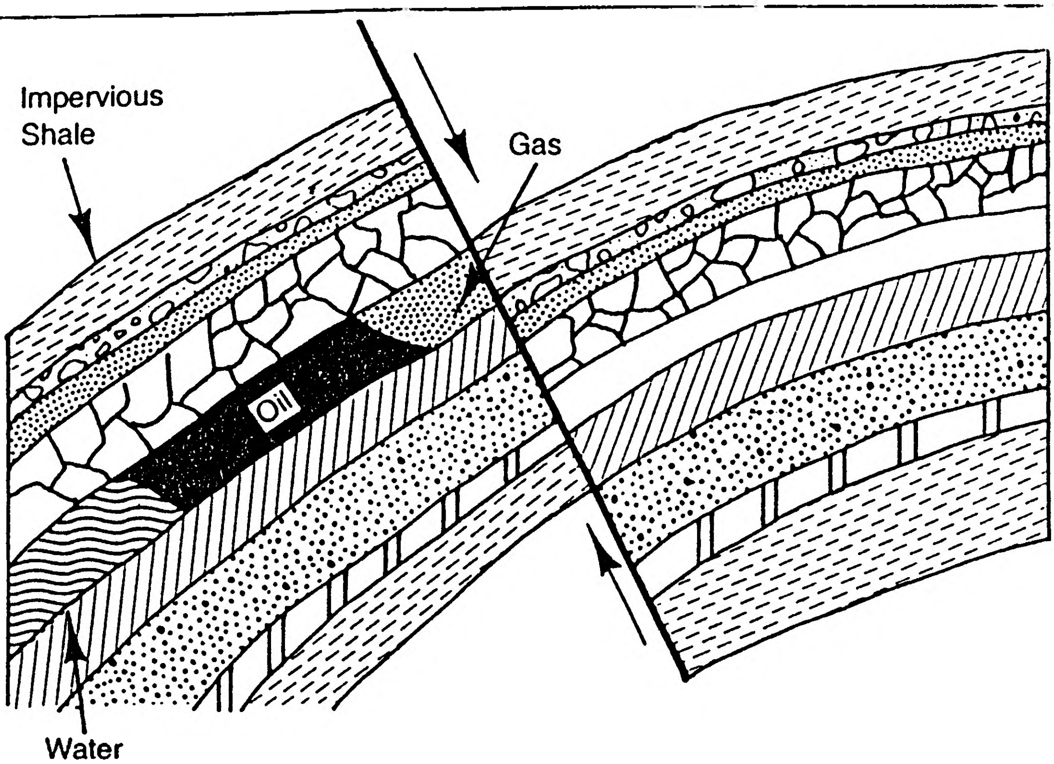

FORMATION PORES
PORE OCCUPIED BY PETROLEUM
FLOW PATH
WELLBORE

Figure 7



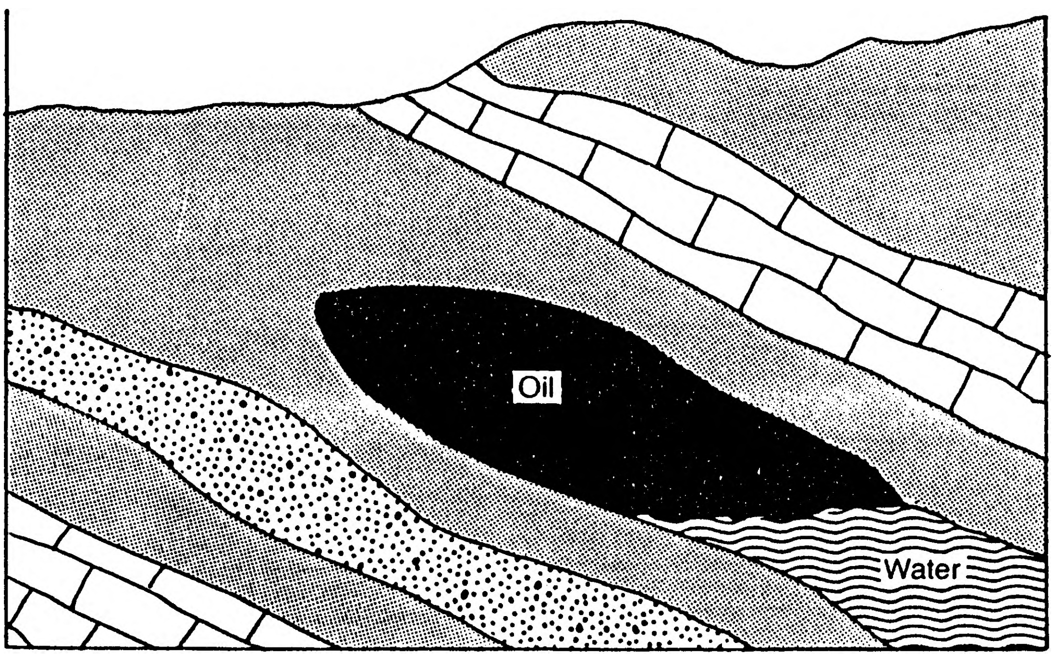


FIG. 2–7 Structural and stratigraphic traps.

Figure 8

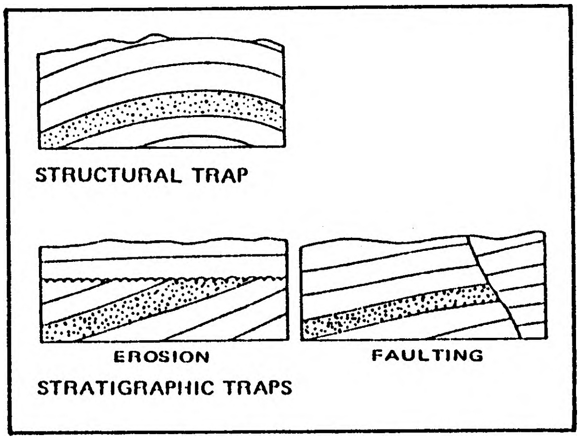


Figure 1.13. Basic hydrocarbon reservoirs are structural and/or stratigraphic traps.

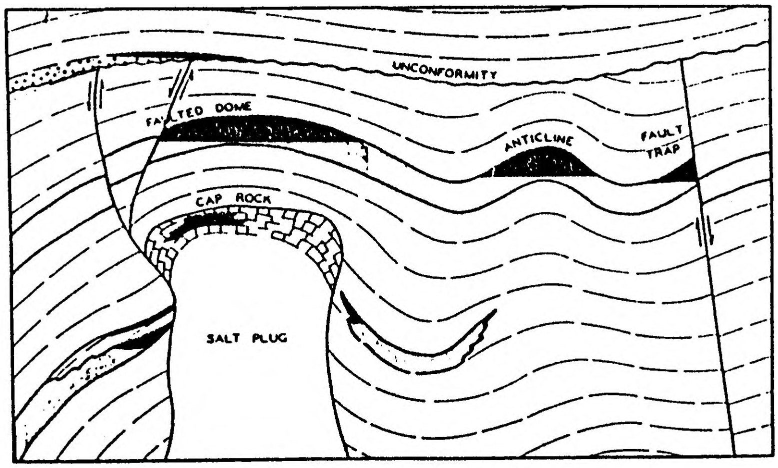


Figure 1.14. Common types of structural traps

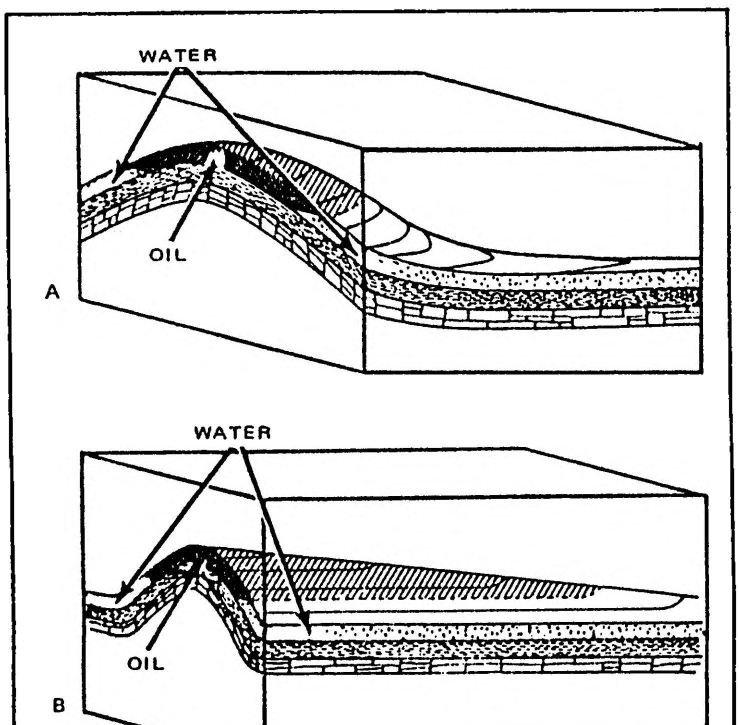


Figure 1.15. Oil accumulates in a dome-shaped structure (*A*) and an anticlinal type of fold structure (*B*). An anticline is generally long and narrow while the dome is circular in outline. *(Courtesy of American Petroleum Institute)*

Figure 9

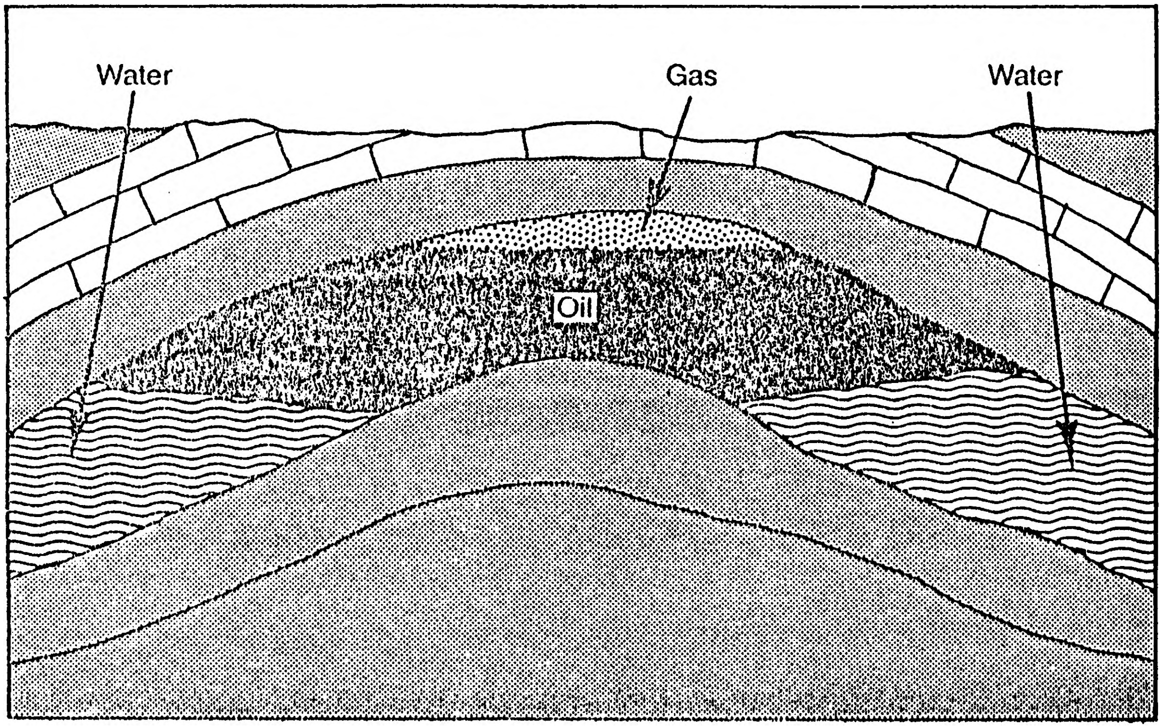


FIG. 2–6 Oil, gas, and water tend to separate into three layers.

Figure 10

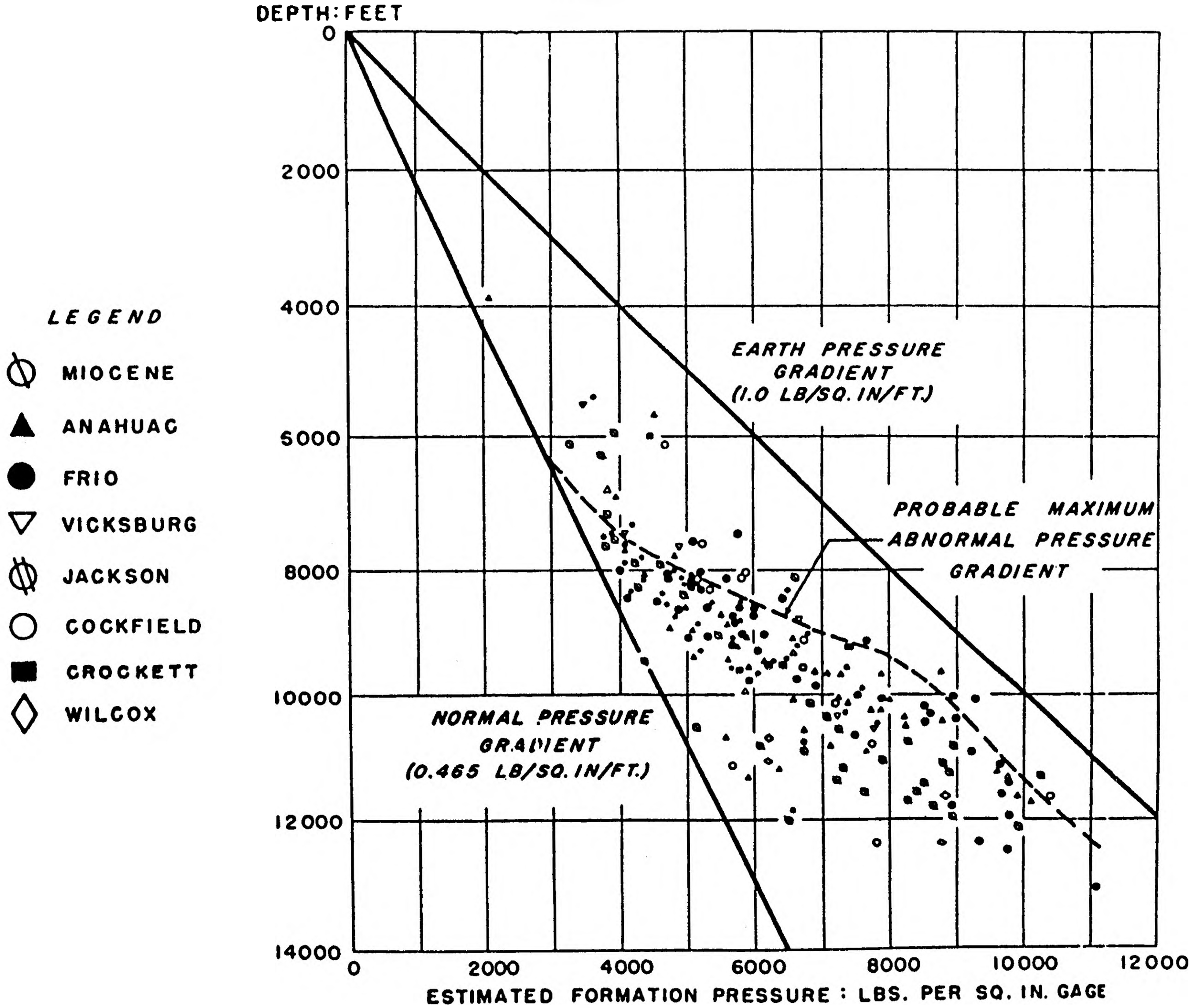


Fig. 2.11. Magnitude of some abnormal pressures encountered in the Gulf Coast area. After Cannon and Sullins,[13] courtesy API.

Figure 11

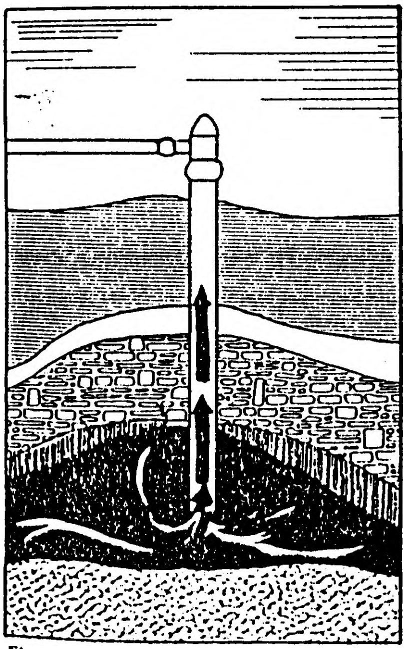


Figure 1.26. Solution-gas drive reservoir. Before a well is drilled, the hydrocarbon accumulation is totally comprised of oil at or above the pressure that would allow gas bubbles to form. When pressure is reduced by drilling a well into the reservoir, vapor comes out of solution in the hydrocarbon accumulation, and the expanding bubbles push the oil to the producing wells.

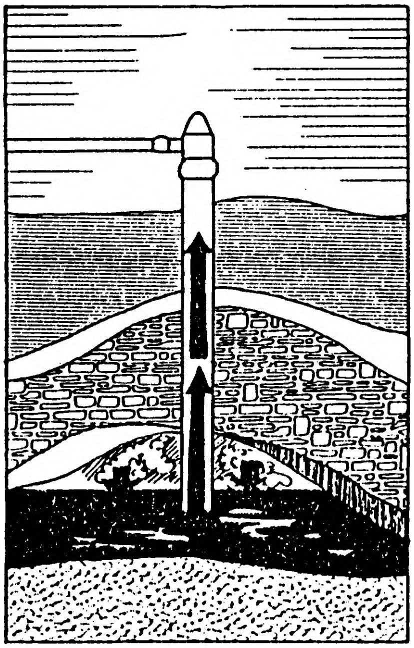


Figure 1.27. Gas-cap drive. Arrows depict the idea that as pressure is reduced in the oil zone by withdrawal, the gas cap expands and pushes oil out ahead of it.

Figure 12

Figure 1.28. Water drive reservoir. The oil is associated with the water-bearing formation. Arrows indicate the encroachment of water, which drives oil toward and out of the producing well.

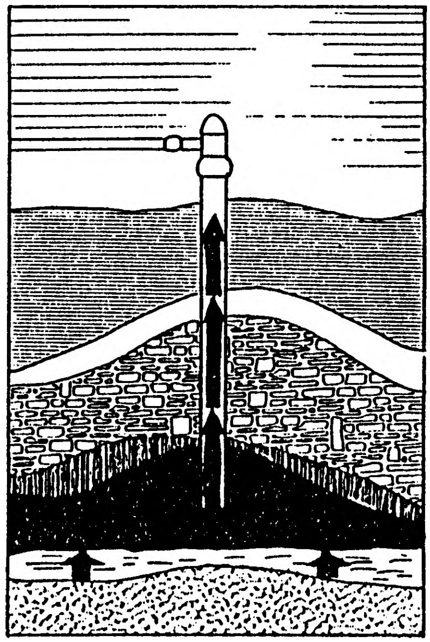


Figure 13

RESERVE CLASSIFICATION

Reserves estimates have been classified in accordance with the approved definitions by the Board of Directors of the Society of Petroleum Engineers (SPE), Inc. on February 27, 1987. These definitions have been developed in cooperation with other technical organizations and are widely accepted in the oil and gas industry. While they are not identical, these definitions basically conform to the definitions used by the United States Securities and Exchange Commission.

The definitions, which are provided in their entirety on the following pages, basically require that reserve estimates be classified as proved or unproved. These are defined as follows:

Proved Reserves which can be estimated with reasonable certainty to be recoverable under current economic conditions. Current economic conditions include prices and costs prevailing at the time of the estimate.

Unproved Reserves which are based on geologic and/or engineering data similar to that used in estimates of proved reserves; but technical, contractual, economic, or regulatory uncertainties preclude such reserves being classified as proved. They may be estimated assuming future economic conditions different from those prevailing at the time of the estimate.

There are two subcategories of unproved reserves:

a. **Probable** - Probable reserves are less ceratin than proved reserves and can be estimated with a degree of certainty sufficient to indicate they are more likely to be recovered than not.

b. **Possible** - Possible reserves are less certain than probable reserves and can be estimated with a low degree of certainty, insufficient to indicate whether they are more likely to be recovered than not.

Reserves are further classified by producing status. The status categories that have been used in this report, if applicable, are as follows:

Developed - Producing
Developed - Nonproducing - Shut-in
Developed - Nonproducing - Behind Pipe
Developed - Improved Recovery
Undeveloped - Undrilled

Figure 14

Definitions For Oil and Gas Reserves

Approved by the Board of Directors, Society of Petroleum Engineers (SPE), Inc.

Society of Petroleum Engineers

Reserves

Reserves are estimated volumes of crude oil, condensate, natural gas, natural gas liquids, and associated substances anticipated to be commercially recoverable from know accumulations from a given date forward, under existing economic conditions, by established operating practices, and under current government regulations. Reserve estimates are based on interpretation of geologic and/or engineering data available at the time of the estimate.

Reserve estimates generally will be revised as reservoirs are produced, as additional geologic, and/or engineering data become available, or as economic conditions change.

Reserves do not include volumes of crude oil, condensate, natural gas, or natural gas liquids being held in inventory. If required for financial reporting or other special purposes, reserves may be reduced for on-site usage and/or processing losses.

The ownership status of reserves may change due to the expiration of a production license or contract; when relevant to reserve assignment such changes should be identified for each reserve classification.

Reserves may be attributed to either natural reservoir energy, or improved recovery methods. Improved recovery includes all methods for supplementing natural reservoir energy to increase ultimate recovery from a reservoir. Such methods include (1) pressure maintenance, (2) cycling, (3) waterflooding, (4) thermal methods, (5) chemical flooding, and (6) the use of miscible and immiscible displacement fluids.

All reserve estimates involve some degree of uncertainty, depending chiefly on the amount and reliability of geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves in one of two classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be subclassified as probable or possible to denote progressively increasing uncertainty.

Proved Reserves

Proved reserves can be estimated with reasonable certainty to be recoverable under current economic conditions. Current economic conditions include prices and costs prevailing at the time of the estimate. Proved reserves may be developed or undeveloped.

In general, reserves are considered proved if commercial producibility of the reservoir is supported by actual production or formation tests. The term proved refers to the estimated volume of reserves and not just to the productivity of the well or reservoir. In certain instances, proved reserves may be assigned on the basis of electrical and other type logs and/or core analysis that indicate subject reservoir is hydrocarbon bearing and is analogous to reservoirs in the same area that are producing, or have demonstrated the ability to produce on a formation test.

The area of a reservoir considered proved includes (1) the area delineated by drilling and defined by fluid contracts, if any, and (2) the undrilled area that can be reasonably judged as commercially productive on the basis of available geological and engineering data. In the absence of data on fluid contracts, the lowest known structural occurrence of hydrocarbons controls the proved limit unless otherwise indicated by definitive engineering or performance data.

Proved reserves must have facilities to process and transport those reserves to market that are operational at the time of the estimate, or there is a commitment or reasonable expectation to install such facilities in the future.

In general, proved undeveloped reserves are assigned to undrilled locations that satisfy the following conditions: (1) the locations are direct offsets to wells that have indicated commercial production in the objective formation, (2) it is reasonably certain that the locations are within the known proved productive limits of the objective formation, (3) the locations conform to existing well spacing regulations, if any, and (4) it is reasonably certain that the locations will be developed. Reserves for other undrilled locations are classified as proved undeveloped only in those cases where interpretations of data from wells indicate that the objective formation is laterally continuous and contains commercially recoverable hydrocarbons at locations beyond direct offsets.

Reserves that can be produced through the application of established improved recovery methods are included in the proved classification when (1) successful testing by a pilot project or favorable production or pressure response of an installed program in that reservoir, or one in the immediate area with similar rock and fluid properties, provides support for the engineering analysis on which the project or program is based and (2) it is reasonably certain the project will proceed.

Reserves to be recovered by improved recovery methods that have yet to be established though repeated commercially successful applications are included in the proved classification only (1) after a favorable production response from subject reservoir either (a) a representative pilot or (b) an installed program, where the response provides support for the engineering analysis on which the project is based, and (2) it is reasonably certain the project will proceed.

Unproved Reserves

Unproved reserves are based on geologic and/or engineering data similar to that used in estimates of proved reserves; but technical, contractual, economic, or regulatory uncertainties preclude such reserves being classified as proved. They may be estimated assuming future economic conditions different from those prevailing at the time of estimate.

Estimates of unproved reserves may be made for internal planning or special evaluations, but are not routinely compiled.

Unproved reserves are not to be added to proved reserves because of different levels of uncertainty.

Unproved reserves may be divided into two subclassifications: probable and possible.

Probable Reserves Probable reserves are less certain than proved reserves and can be estimated with a degree of certainty sufficient to indicate they are more likely to be recovered than not.

In general, probable reserves may include (1) reserves anticipated to be proved by normal stepout drilling where subsurface control is inadequate to classify these reserves as proved, (2) reserves in formations that appear to be productive based on log characteristics but that lack core data or definitive tests and which are not analogous to producing or proved reservoirs in the area, (3) incremental reserves attributable to infill drilling that otherwise could be classified as proved but closer statutory spacing had not been approved at the time of the estimate, (4) reserves attributable to an improved recovery method which has been established by repeated commercially successful applications when a project or pilot is planned but not in operation and rock, fluid, and reservoir characteristics appear favorable for commercial applications, (5) reserves in an area of a formation that has been proved productive in other areas of the field but subject area appears to be separated from the proved area by faulting and the geologic interpretation indicates subject area is structurally higher than the proved area, (6) reserves attributable to a successful workover, treatment, retreatment, change of equipment, or other mechanical procedure, where such procedure has not been proved successful in wells exhibiting similar behavior in analogous reservoir, (7) incremental reserves in a proved producing reservoir where an alternate interpretation of performance or volumetric data indicates significantly more reserves than can be classified as proved.

Possible Reserves Possible reserves are less certain than probable reserves and can be estimated with a low degree of certainty, insufficient to indicate whether they are more likely to be recovered than not.

In general, possible reserves may include (1) reserves suggested by structural and/or stratigraphic extrapolation beyond areas classified as probable, based on geologic and/or geophysical interpretation, (2) reserves in formations that appear to be hydrocarbon bearing based on logs or cores but that may not be productive at commercial rates, (3) incremental reserves attributable to infill drilling that are subject to technical uncertainties, (4) reserves attributable to an improved recovery method when a project or pilot is planned but not in operation and rock, fluid, and reservoir characteristics are such that a reasonable doubt exists that the project will be commercial, and (5) reserves in an area of a formation that has been proved productive in other areas of the field but subject area appears to be separated from the proved area by faulting and geological interpretation indicates subject area is structurally lower than the proved area.

Reserves Status Categories

Reserves status categories define the development and producing status of wells and/or reservoirs.

Developed. Developed reserves are expected to be recovered from existing wells (including reserves behind pipe). Improved recovery reserves are considered developed only after the necessary equipment has been installed, or when costs to do so are relatively minor. Developed reserves may be subcategorized as producing or nonproducing.

Producing. Producing reserves are expected to be recovered from completion intervals open at the time of the estimate and producing. Improved recovery reserves are considered to be producing only after an improved recovery project is in operation.

Nonproducing. Nonproducing reserves include shutin and behind-pipe reserves. Shut-in reserves are expected to be recovered from completion intervals open at the time of estimate, but which had not started producing, or were shut in for market conditions or pipeline connection, or were not capable of production for mechanical reasons, and the time when sales will start is uncertain.

Behind-pipe reserves are expected to be recovered from zones behind casing in existing wells, which will require additional completion work or a future recompletion prior to the start of production.

Undeveloped. Undeveloped reserves are expected to be recovered: (1) from new wells on undrilled acreage, (2) from deepening existing wells to a different reservoir, or (3) where a relatively large expenditure is required to (a) recomplete an existing well, (b) install production or transportation facilities for primary or improved recovery projects.

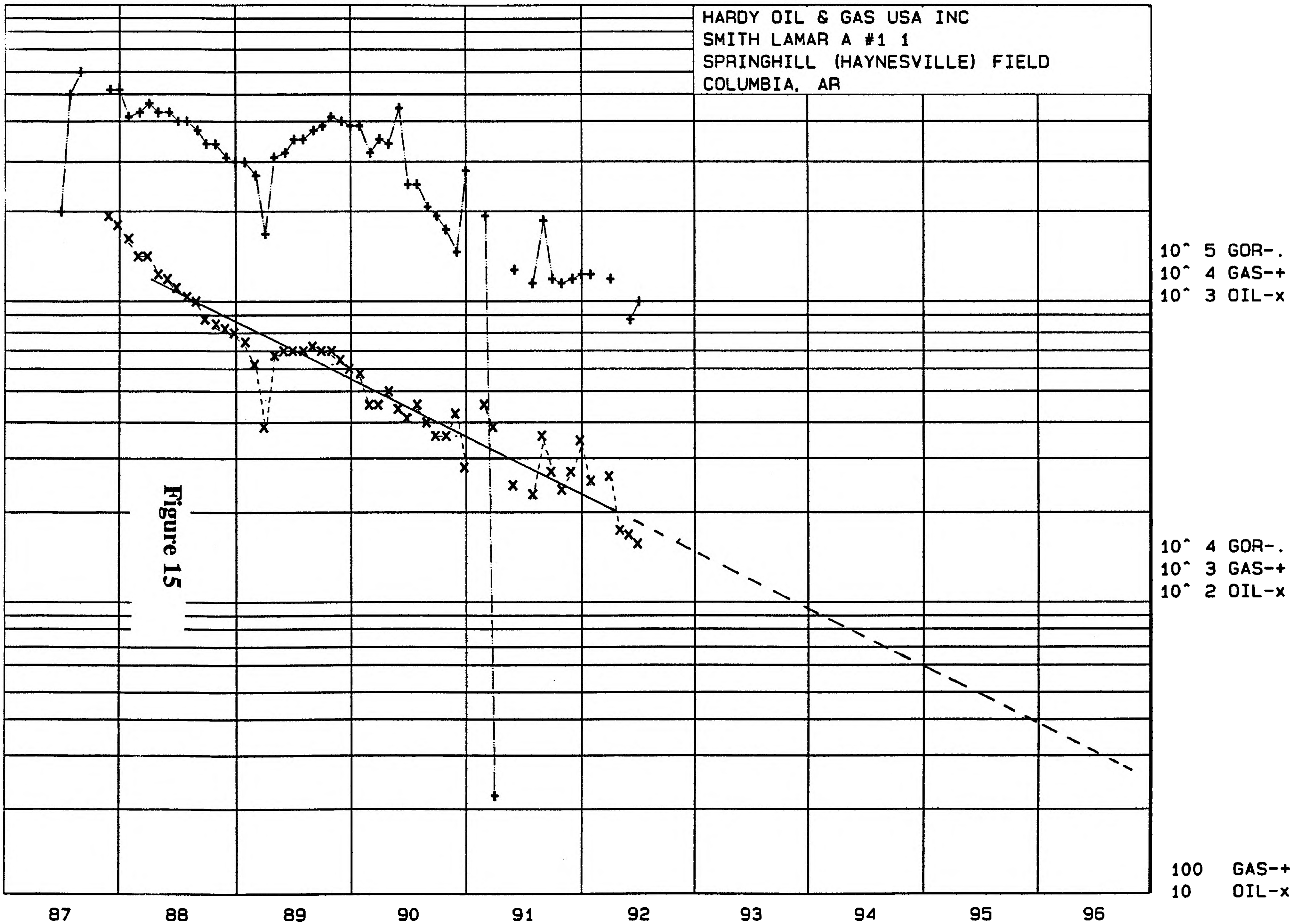
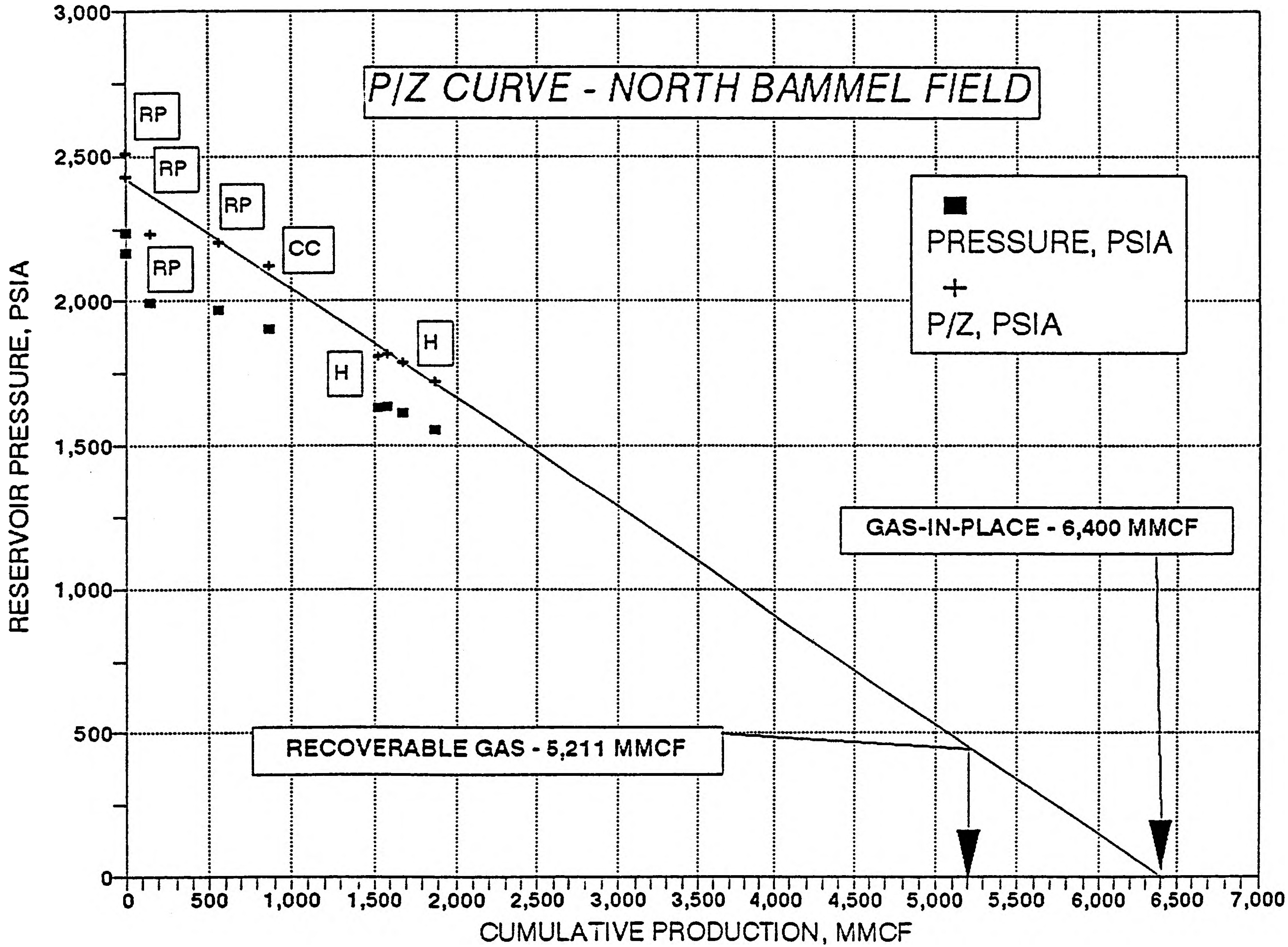

HARDY OIL & GAS USA INC
SMITH LAMAR A #1 1
SPRINGHILL (HAYNESVILLE) FIELD
COLUMBIA, AR
10^ 5 GOR-.
10^ 4 GAS-+
10^ 3 OIL-x
10^ 4 GOR-.
10^ 3 GAS-+
10^ 2 OIL-x
100 GAS-+
10 OIL-x
87
88
89
90
91
92
93
94
95
96

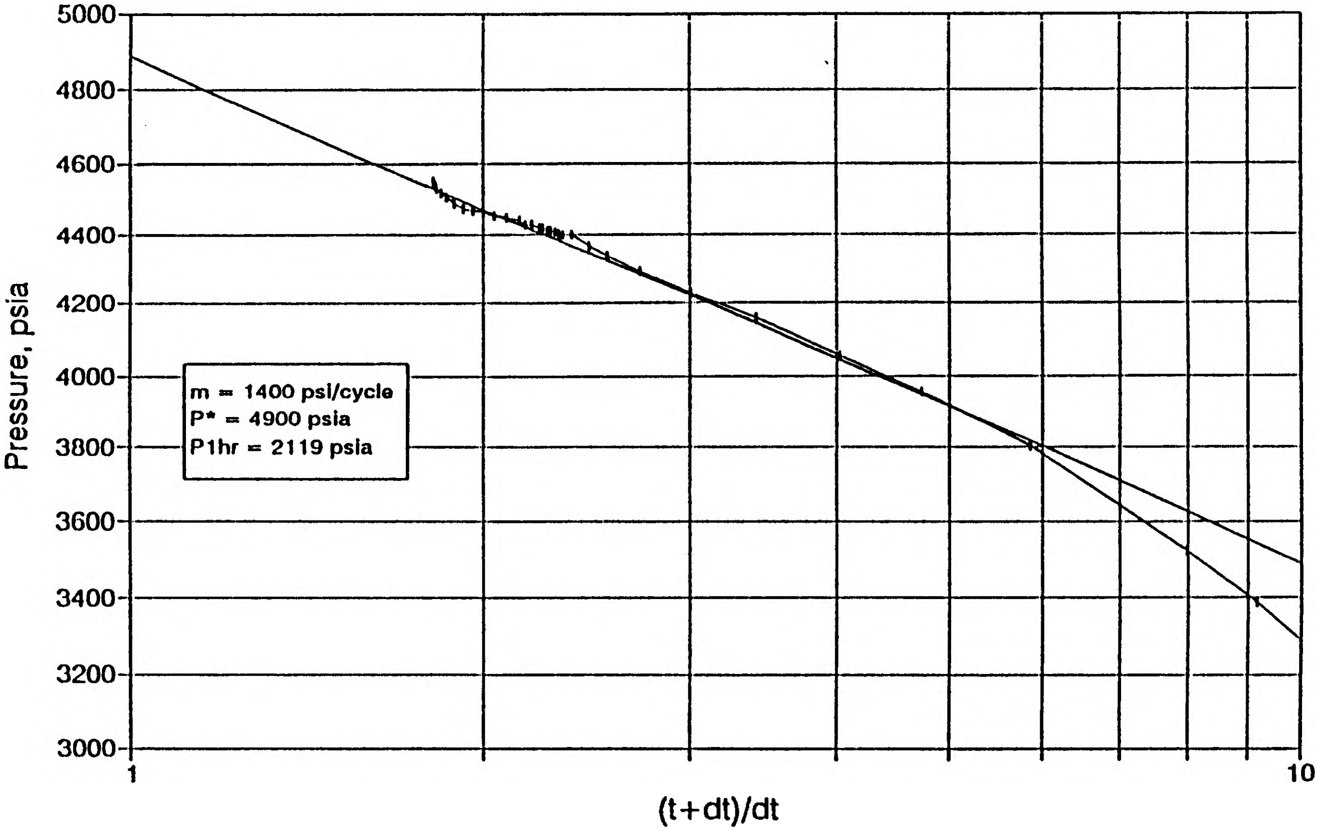
Figure 15

Figure 16

DATE	SOURCE WELL - TEST	PRESSURE PSIA	P/Z PSIA	CUMULATIVE PRODUCTION MCF
06-Aug-87	RP - G-1	2,238	2,512	0
01-May-88	RP - FLD RULES	2,164	2,428	0
05-Oct-88	RP - FLD RULES	1,994	2,233	145
28-Jul-89	RP - FLD RULES	1,967	2,202	569
02-Feb-90	CC - FLD RULES	1,900	2,124	876
17-Jan-91	H - BHP	1,630	1,809	1,529
15-Feb-91	H - BHP	1,636	1,816	1,584
18-Apr-91	H - BHP	1,614	1,790	1,681
26-Aug-91	H - BHP	1,554	1,720	1,881



P/Z CURVE - NORTH BAMMEL FIELD
RESERVOIR PRESSURE, PSIA
CUMULATIVE PRODUCTION, MMCF
3,000
2,500
2,000
1,500
1,000
500
0
0
500
1,000
1,500
2,000
2,500
3,000
3,500
4,000
4,500
5,000
5,500
6,000
6,500
7,000
RP
RP
RP
RP
CC
H
H
PRESSURE, PSIA
P/Z, PSIA
GAS-IN-PLACE - 6,400 MMCF
RECOVERABLE GAS - 5,211 MMCF



5000
4800
4600
4400
4200
4000
3800
3600
3400
3200
3000
Pressure, psia
m = 1400 psi/cycle
P* = 4900 psia
P1hr = 2119 psia
1
10
(t+dt)/dt

Figure 17

PRESSURE BUILDUP ANALYSIS

$$B_g = \frac{zTP_{sc}}{T_{sc}\left(\frac{P* + P_{wf}}{2}\right)}$$

T =	690	° R			
T_{sc} =	520	° R	P_{sc} =	15.025	PSIA
P^* =	4900	PSIA	P_{avg} =	2731	PSIA
P_{wf}	2710	PSIA	z =	0.9981	
B_g	0.007286	RB/STB			

$$C_t = S_g C_g + S_w C_w + C_f$$

S_g =	0.58		C_g =	3.318×10^{-4}	1/PSI
S_w =	0.42		C_w =	13×10^{-6}	1/PSI
			C_f =	5.5×10^{-6}	1/PSI
C_t =	2.034×10^{-4}	1/PSI			

$$kh = \frac{162.6 q\mu B}{m}$$

q =	59821	bbls/d	μ =	0.01664	cp
B_g =	0.0073	RB/STB	m =	1400	psi/cycle
kh =	0.8	md*feet			
h =	68	feet			
k =	0.0124	md			

$$s = 1.151\left(\frac{P_{1hr} - P_{wf}}{m} - \log\left(\frac{k}{\phi\mu C_t R_w^2}\right) + 3.23\right)$$

P_{1hr}	2119	PSIA	ϕ =	0.08	
R_w	0.365	FEET			
s =	-1.37				
ΔP_{skin}:	-1673	PSI			
J_{actual}:	13.8	bbl/psi	J_{ideal}:	10.0	bbl/psi
Flow eff.:	1.39				

WORLDWIDE LOOK AT RESERVES AND PRODUCTION

COUNTRY	ESTIMATED PROVED RESERVES Jan 1, 1993 Oil (1,000 bbl)	Jan 1, 1993 Gas (bcf)	Jan 1, 1992 Oil (1,000 bbl)	Jan 1, 1992 Gas (bcf)	OIL PRODUCTION Producing oil wells* Dec 31, 1991	Estimated 1992 (1,000 b/d)	Change from 1991 (%)	Actual 1991 (1,000 b/d)
ASIA-PACIFIC								
Afghanistan	...	3,500	...	3,530	...	...	...	
Australia	1,767,900	18,254	1,523,700	15,057	1,097	539.3	−0.9	544.0
Bangladesh	1,500	25,400	500	25,600	10	0.5	0.0	0.5
Brunei	1,350,000	14,000	1,350,000	11,200	638	158.7	9.7	144.7
China	24,000,000	49,400	24,000,000	35,400	49,700	2,833.6	1.2	2,800.0
China, Taiwan	4,000	2,400	4,000	670	88	1.2	−36.8	1.9
India	6,049,068	25,954	6,126,740	25,772	2,756	573.8	−8.2	625.0
Indonesia	5,779,000	64,388	6,581,293	64,837	7,614	1,370.0	−2.9	1,410.7
Japan	59,850	968	59,753	968	311	17.2	13.9	15.1
Malaysia	3,700,000	67,800	3,045,000	59,055	502	661.0	1.4	652.0
Myanmar (Burma)	50,000	9,800	50,000	9,350	450	15.0	25.0	12.0
New Zealand	169,570	3,386	170,230	3,449	53	35.0	−12.5	40.0
Pakistan	412,000	31,000	162,000	22,600	108	75.0	4.2	72.0
Papua New Guinea	340,000	14,200	200,000	8,000	1	40.4	20,100.0	0.2
Philippines	147,540	1,600	38,000	100	14	11.9	296.7	3.0
Thailand	241,900	8,463	262,000	13,600	304	49.0	12.9	43.4
Viet Nam	500,000	500	500,000	100	NA	102.7	28.4	80.0
Total Asia-Pacific	44,572,328	341,013	44,073,216	299,288	63,646	6,484.3	0.6	6,444.5
WESTERN EUROPE								
Austria	93,200	569	84,984	388	1,167	24.4	0.4	24.3
Denmark	729,618	3,985	755,000	4,059	111	157.0	10.3	142.3
France	177,434	1,240	170,836	1,296	635	58.5	−2.0	59.7
Germany	449,314	12,113	449,000	8,760	2,108	65.3	−5.1	68.8
Greece	41,000	300	41,000	44	13	13.3	−5.0	14.0
Ireland	...	700	...	1,700	...	...	...	...
Italy	746,977	12,996	692,153	11,370	224	89.2	1.8	87.6
Netherlands	144,650	68,860	144,650	69,570	204	54.5	−16.2	65.0
Norway	8,805,734	70,629	7,609,400	60,670	336	2,096.1	11.7	1,876.1
Spain	22,518	700	21,389	740	39	21.1	3.9	20.3
Turkey	474,761	608	540,450	705	666	84.6	−0.7	85.2
United Kingdom	4,143,630	19,070	3,994,310	19,247	735	1,821.9	−0.1	1,823.2
Total Western Europe	15,828,836	191,770	14,503,172	178,549	6,238	4,485.9	5.1	4,266.5
EASTERN EUROPE & C.I.S.								
Albania	165,000	700	165,000	670	NA	30.0	0.0	30.0
Bulgaria	15,000	250	15,000	250	100	4.0	0.0	4.0
C.I.S.	57,000,000	1,942,300	57,000,000	1,750,000	148,990	8,898.8	−13.6	10,296.0
Croatia	162,462	1,316	...	...	1,006	43.0	−3.4	44.5
Czechoslovakia	15,000	470	15,000	490	400	3.0	0.0	3.0
Hungary	146,956	3,758	158,500	3,758	1,766	36.9	−4.4	38.6
Poland	42,208	5,597	30,000	4,590	2,324	3.3	0.0	3.3
Romania	1,568,754	7,335	1,150,000	3,700	250	140.0	0.0	140.0
Yugoslavia	77,500	1,580	240,000	2,900	646	22.0	−0.9	22.2
Total Eastern Europe & C.I.S.	59,192,880	1,963,306	58,773,500	1,766,358	155,482	9,181.0	−13.2	10,581.6
MIDDLE EAST								
Abu Dhabi	92,200,000	188,400	92,200,000	182,800	993	1,891.4	−2.9	1,947.0
Bahrain	69,584	5,810	83,490	6,010	352	36.6	−3.9	38.1
Dubai	4,000,000	4,500	4,000,000	4,600	150	402.0	−7.4	434.0
Iran	92,860,000	699,200	92,860,000	600,350	688	3,415.3	1.7	3,358.0
Iraq	100,000,000	109,500	100,000,000	95,000	58	417.3	47.5	283.0
Israel	3,418	15	1,289	10	11	0.2	0.0	0.2
Jordan	4,000	215	5,000	100	4	0.1	0.0	0.1
Kuwait	94,000,000	52,400	94,000,000	48,000	295	845.3	521.5	136.0
Neutral Zone	5,000,000	1,000	5,000,000	1,000	158	311.3	141.3	129.0
Oman	4,483,000	16,900	4,250,000	9,900	1,235	729.0	4.0	700.7
Qatar	3,729,000	227,000	3,729,000	162,000	238	416.3	7.6	386.0
Ras al Khaimah	400,000	1,200	400,000	1,200	7	0.8	0.0	0.8
Saudi Arabia	257,842,000	182,600	257,842,000	184,048	1,400	8,206.7	0.6	8,158.0
Sharjah	1,500,000	10,500	1,500,000	10,700	30	43.0	24.3	34.6
Syria	1,700,000	7,000	1,700,000	6,400	963	530.3	10.9	478.0
Yemen	4,000,000	13,900	4,000,000	7,000	119	176.0	−11.0	197.8
Total Middle East	661,791,002	1,520,140	661,570,779	1,319,118	6,701	17,420.6	7.0	16,281.3

Figure 18

	ESTIMATED PROVED RESERVES				OIL PRODUCTION			
	Jan 1, 1993		Jan 1, 1992					
COUNTRY	Oil (1,000 bbl)	Gas (bcf)	Oil (1,000 bbl)	Gas (bcf)	Producing oil wells* Dec 31, 1991	Estimated 1992 (1,000 b/d)	Change from 1991 (%)	Actual 1991 (1,000 b/d)
AFRICA								
Algeria	9,200,000	128,000	9,200,000	116,500	969	771.3	−3.9	803.0
Angola	1,500,000	1,800	1,818,173	1,800	464	553.2	11.3	497.0
Benin	19,900	...	19,900	...	8	3.9	0.0	3.9
Cameroon	400,000	3,900	400,000	3,880	175	139.0	−8.6	152.0
Congo	830,000	2,700	830,000	2,600	342	182.7	14.8	159.2
Egypt	6,200,000	15,400	4,500,000	12,400	976	870.7	−0.8	878.0
Equatorial Guinea	3,600	1,300	...	840	NA	1.0	...	...
Ethiopia	...	800	...	880	...	...	...	...
Gabon	730,000	400	730,000	450	325	302.7	3.0	294.0
Ghana	500	...	500	...	...	...	...	...
Ivory Coast	100,000	3,500	100,000	3,500	12	1.5	15.4	1.3
Libya	22,800,000	46,200	22,800,000	43,000	1,078	1,468.7	−2.7	1,509.0
Madagascar	...	70	...	70	...	...	...	...
Morocco	1,604	37	2,139	43	12	0.3	0.0	0.3
Mozambique	...	2,300	...	2,290	...	...	...	...
Namibia	...	5,200	...	2,100	...	...	...	...
Nigeria	17,899,820	120,000	17,899,820	104,720	1,595	1,887.0	1.1	1,867.0
Rwanda	...	2,000	...	2,000	...	...	...	...
Somalia	...	200	...	210	...	...	...	...
South Africa	...	1,900	...	1,800	...	...	...	...
Sudan	300,000	3,000	300,000	3,000	...	...	...	...
Tanzania	...	4,100	...	4,100	...	...	...	...
Tunisia	1,700,000	3,000	1,700,000	3,000	159	110.3	2.5	107.6
Zaire	187,000	1,058	187,000	1,058	119	27.0	−7.2	29.1
Total Africa	61,872,424	346,865	60,487,532	310,241	6,234	6,319.3	0.3	6,301.4
WESTERN HEMISPHERE								
Argentina	1,569,987	22,700	1,569,987	20,449	8,362	544.3	11.3	489.2
Barbados	5,892	7	3,337	6	102	1.3	8.3	1.2
Bolivia	112,136	4,108	119,000	4,500	323	21.2	−4.5	22.2
Brazil	3,030,000	4,400	2,800,349	4,046	5,976	640.7	2.7	623.8
Canada	5,291,630	95,734	5,587,798	96,734	39,284	1,618.1	4.5	1,548.4
Chile	300,000	3,900	300,000	4,100	331	14.9	−16.3	17.8
Colombia	1,935,200	7,200	1,935,200	3,889	3,067	454.4	5.9	429.0
Cuba	100,000	100	100,000	100	200	15.0	0.0	15.0
Ecuador	1,599,793	3,899	1,550,000	3,885	999	322.4	7.4	300.2
Guatemala	207,000	10	34,797	10	11	6.1	48.8	4.1
Mexico	51,298,000	70,900	51,298,000	71,508	4,740	2,775.7	0.1	2,774.0
Peru	380,866	7,054	382,181	7,075	3,312	115.7	0.7	114.9
Suriname	49,200	...	37,600	...	191	4.1	−2.4	4.2
Trinidad & Tobago	572,600	8,702	535,000	8,900	3,215	139.1	−3.4	144.0
United States	24,682,000	167,062	26,250,000	169,300	600,786	7,136.6	−3.8	7,416.5
Venezuela	62,650,000	126,492	59,100,000	110,000	12,140	2,328.7	−0.9	2,349.6
Total Western Hemisphere	153,784,304	522,268	151,603,249	504,502	683,039	16,138.3	−0.7	16,253.9
TOTAL WORLD	997,041,774	4,885,362	991,011,448	4,378,056	921,340	60,029.4	−0.2	60,129.2
Total OPEC	772,189,613	1,965,679	769,392,113	1,733,090	28,737	24,399.2	4.3	23,399.9

EDITOR'S NOTE: All reserves figures except those for the C.I.S. (and gas for Canada) are reported as proved reserves recoverable with present technology and prices. C.I.S. figures are "explored reserves" which include proved, probable, and some possible. Canadian gas figure, under criteria adopted by Canadian Petroleum Association in 1980, includes proved and some probable. *Does not include shut in, injection, or service wells.

U.S. INDUSTRY SCOREBOARD 12/20

Latest week 12/10	4 wk. average	4 wk. avg. year ago*	% change	Year-to-date average*	YTD avg. year ago*	% change
Demand (1,000 b/d)						
Motor gasoline	7,421	7,207	3.0	7,429	7,261	2.3
Distillate	3,247	3,068	5.8	3,129	2,958	5.8
Jet fuel	1,409	1,537	−8.3	1,455	1,448	0.5
Residual	1,076	1,138	−5.5	1,021	1,080	−5.5
Other products	4,108	4,441	−7.5	4,222	4,232	−0.2
TOTAL DEMAND	**17,261**	**17,391**	**−0.7**	**17,256**	**16,979**	**1.6**
Supply (1,000 b/d)						
Crude production	6,904	7,052	−2.1	6,902	7,175	−3.8
NGL production	1,910	1,750	9.1	1,820	1,699	7.1
Crude imports	7,138	6,056	17.9	6,680	6,099	9.5
Product imports	1,773	1,805	−1.8	1,752	1,804	−2.9
Other supply†	1,121	1,207	−7.2	1,290	1,167	10.5
TOTAL SUPPLY	**18,846**	**17,870**	**5.5**	**18,444**	**17,944**	**2.8**
Refining (1,000 b/d)						
Crude runs to stills	13,709	13,421	2.1	13,641	13,464	1.3
Input to crude stills	13,967	13,654	2.3	13,892	13,615	2.0
% utilization	92.2	89.2	—	90.5	88.1	—

Latest week 12/10	Latest week	Previous week*	Change	Same week year ago*	Change	% change
Stocks (1,000 bbl)						
Crude oil	345,395	339,336	6,059	329,422	15,973	4.8
Motor gasoline	223,354	222,564	790	212,569	10,785	5.1
Distillate	144,808	145,666	−858	140,447	4,361	3.1
Jet fuel	41,505	41,493	12	46,874	−5,369	−11.5
Residual	46,139	45,434	705	46,706	−567	−1.2
Drilling						
Baker Hughes rotary rig count	868	876	−8	930	−62	−6.7
Futures prices§						
Light sweet crude ($/bbl)	14.71	15.23	−0.52	19.05	−4.34	−22.8
Natural gas ($/MMBTU)	1.99	2.20	−0.22	2.03	−0.05	−2.4

* Based on revised figures. † Includes other hydrocarbons and alcohol, refinery processing gain and unaccounted for crude oil. § Weekly average of daily closing futures prices.

Figure 19