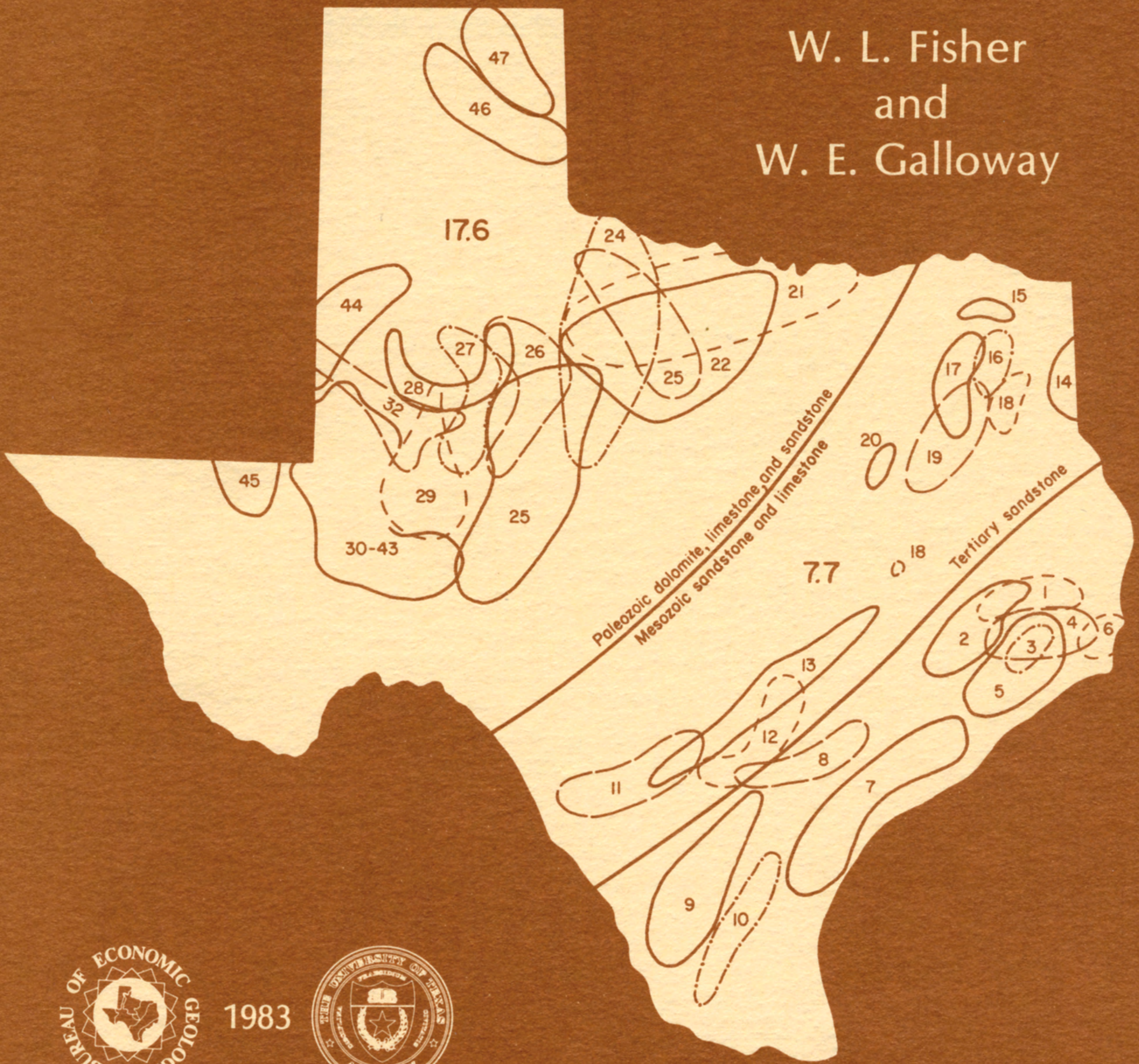
Geological Circular 83-2

Potential for Additional Oil Recovery in Texas

W. L. Fisher
and
W. E. Galloway



1983

Bureau of Economic Geology • W. L. Fisher, Director
The University of Texas at Austin • Austin, Texas 78712

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POTENTIAL FOR ADDITIONAL OIL RECOVERY IN TEXAS

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Texas has long been a major oil province, accounting for nearly 40 percent of the historic production of crude oil in the United States. Texas now holds less than 30 percent of the Nation's proven reserves and less than 15 percent of its estimated as-yet-undiscovered oil. Discovery and conventional production of oil in Texas have peaked, but more than 100 billion barrels of oil now classed largely as unrecoverable still exist in Texas. This oil, even with the geologic, technical, and economic constraints on its recovery, constitutes a major target for future production.

INTRODUCTION: BACKGROUND AND TRENDS

To date, some 156 billion barrels of oil have been discovered in Texas. About 46 billion barrels have been produced, and 8 billion barrels exist as proven reserves; thus, current estimated ultimate recovery is 54 billion barrels, or a little less than 35 percent recovery of the in-place discovered oil. Estimates of how much oil is left for future discovery vary, although nearly 20 billion barrels in place is a reasonable mean of the estimates. Consequently, Texas oil is thought to total about 176 billion barrels, of which an estimated ultimate conventional recovery is on the order of 60 billion barrels. Approximately 116 billion barrels of the 176 billion barrel total is now classed, at least by most conventional means, as unrecoverable. A portion of this large volume is a target for different or combined forms of unconventional recovery.

No one knows how much of the now unrecoverable oil in Texas will ultimately be recovered. Recent estimates range from as little as 5 percent to as much as 40 percent. Undoubtedly, however, the long-term future of Texas oil production, including moderation of the decline of conventional production, hinges on our ability to recover oil now classed as unrecoverable. Future progress will depend increasingly on our technical expertise in enhancing recovery of already known oil and less on new field wildcatting. Such is the direction in which we are already headed: Of total Texas oil completions over the past decade, less than 3 percent have been new field wildcats.

Discovery of Texas oil reached its peak in the 1930's, a decade in which nearly 40 percent of all discoveries to date were made. By the end of the 1940's, 84 percent had been found, and by the end of the 1950's, 96 percent of total discoveries to date had been posted. Current production of crude oil in Texas is supported chiefly by old, large fields (Fisher, 1982). More than half of current production comes from fields discovered more than 40 years ago; nearly three-fourths is from fields more than 30 years old. Fields discovered in the past 20 years contribute less than 11 percent to total current production, and those found during the upsurge

Keywords: petroleum geology, oil recovery, reservoir characterization, Texas

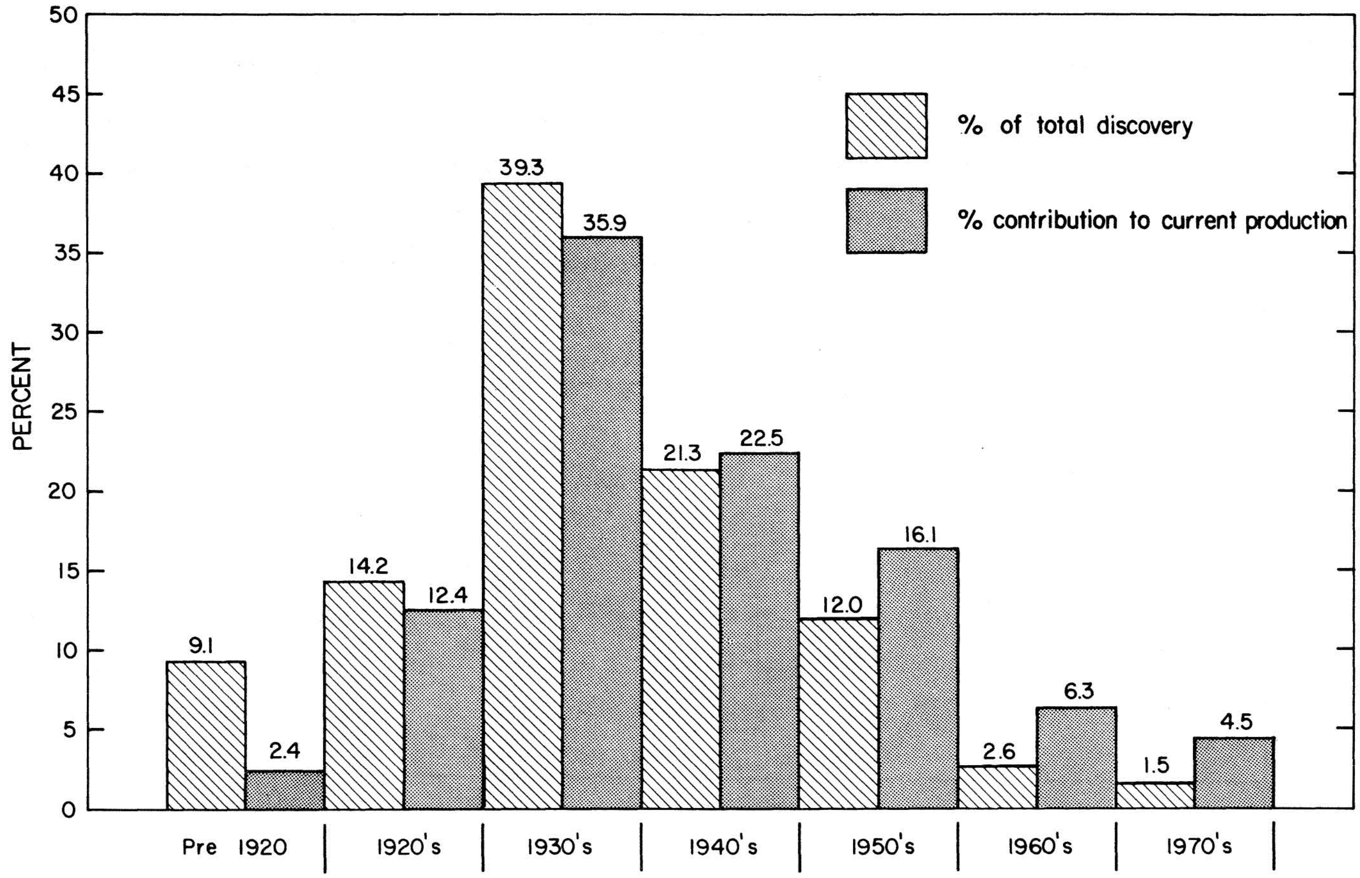

Figure 1. Time distribution of reservoir discovery and contribution to current oil production in Texas.

of drilling in the past decade, less than 5 percent (fig. 1). If estimates of undiscovered resources are correct, only 12 percent of the total universe of Texas oil is yet to be discovered, and that will most likely be in increasingly smaller fields.

Although the significant decline in drilling between the late 1950's and early 1970's contributed to the lower discovery level during the past three decades, the paramount cause has been a steady and serious deterioration in finding rate (or volume of oil discovered per increment of drilling) since the mid-1950's. Even with the upsurge in drilling during the past 8 years, total reserve additions exclusive of revisions have amounted to less than 12 percent of declining production. However, including revisions, total additions have averaged nearly 40 percent of production, indicating that revisions including reserve growth, based in part on further development of older fields, are the primary factor in total reserve additions. In contrast to discovery rate, improved recovery is a more positive aspect of Texas additions. Historically, estimated ultimate recoveries in existing reservoirs have increased an average of about 0.3 percent annually. In the 1970's, Texas' average annual reserve growth, including all fields, was 0.8 percent, nearly triple the historic rate. During the increased drilling of 1980, 1981, and 1982, the estimated annual reserve growth rate exceeded 1.5 percent.

Ultimate conventional recovery from Texas oil fields discovered in the past decade will amount to about 400 million barrels, or about 0.7 percent of the total discovery to date. By contrast, reserve growth or oil moving to the recoverable reserve column over the past decade, largely through improved recovery, has amounted to some 3.5 billion barrels of oil, nearly an order of magnitude greater than new discoveries. Nehring (1981), calculating future reserve growth from existing fields and the volume of future new field discoveries, estimated reserve growth to be about 9 to 12 times greater than future new field discovery. Nehring's calculation is comparable to the difference actually recorded in Texas during the past decade.

It is reserve growth, particularly during the accelerated rate of development drilling of the period 1974-82, that has been the chief contributor to moderating the Texas production decline rate from 6 percent annually to less than 3 percent. Future levels of production will likely depend greatly on the volume of oil completion as well as how strategically and effectively development completions are deployed.

At present, tertiary recovery in Texas totals about 30 million barrels annually, about 3 percent of annual production. The bulk of tertiary production (97 percent) is by injection of miscible carbon dioxide in West Texas carbonate reservoirs. Enhanced oil recovery (EOR), although apparently a contributor to reserve growth, thus far appears to be much less significant than intensive development and infill drilling programs.

CHARACTER OF THE NONCONVENTIONAL TARGET

The increasing emphasis on development drilling, an apparently increasing rate of reserve growth from existing fields, and the increasing ratio of reserve growth to new field discovery all indicate that the switch from wildcatting to recovery improvement is already taking place in Texas. Increased development drilling also appears to be having a positive result: the crude reserve decline is being modified. From 1974 through 1979, Texas reserves dropped at an average annual rate of 7.9 percent; in the past 2 years that decline rate has slowed to 1.2 percent. Production decline, which hit a low of 6.0 percent in 1979, last year (1982) stood at 2.9 percent, a decrease of 50 percent. The reserve-to-production ratio, which dropped well below 8.0 in 1977 and which had been slipping at an average annual rate of 3.7 percent from 1973 through 1979, has increased in the past 2 years at an average annual rate of 3.2 percent.

The volume of so-called nonconventional oil in Texas is huge, and the trend toward recovering it, although not yet commonplace, has been established. The larger question is how much additional oil can be recovered, and what are the technical and economic problems attendant on its recovery?

Nonconventional oil exists in a variety of conditions. In some cases, the fluid state must be modified to achieve additional recovery; in others, the rock state must be modified; and in still others, better depletion can be achieved by strategic infill drilling designed around the widespread heterogeneities that exist within reservoirs. The historical assumption has been that the reservoirs and the distribution of fluids in them are essentially uniform and homogeneous or that the variation is generally uniform. Accordingly, conventional field development has been based on a specified number of uniformly spaced wells (acre-spacing). Considerable evidence indicates that many reservoirs show significant geologic variations and compartmentalization and that uniform spacing, unless very dense, does not efficiently tap and drain a sizeable volume of the reservoir. Such untapped oil is the potential target of strategic infill drilling, provided that controlling heterogeneities can be delineated. In contrast, oil remaining in parts of reservoirs that have been tapped and drained in the course of conventional primary and secondary production, that is, oil in parts of the reservoir effectively swept, is the target of enhanced or tertiary recovery. These targets, and techniques requisite to their recovery, may overlap.

CHARACTERIZING MAJOR OIL RESERVOIRS IN TEXAS

Adequate geologic and engineering characterization of reservoirs is essential to the development of optimum depletion plans, whether such plans entail primary development, secondary recovery, or additional recovery through enhanced recovery programs or strategic infill drilling. Because reservoirs differ widely in physical framework and fluid behavior, different recovery strategies are required to obtain maximum depletion.

As part of a long-term research program using geologic synthesis to increase petroleum recovery, the Bureau of Economic Geology has completed a regional characterization of the major oil reservoirs in the State (Galloway and others, in press). Since the number of Texas oil-producing reservoirs is immense, several screening criteria were applied to reduce the data collection effort to manageable proportions. First, the study focused on the primary element of hydrocarbon production--the individual reservoir. Second, only pools that had produced at least 10 million barrels of oil at the end of 1981 were included in the data base. Where production is commingled or statistics are not maintained for individual producing horizons within a field, production was partitioned among the largest reservoirs. In all, about 500 individual reservoirs met these criteria. Publications, field reports, and hearings files of the Oil and Gas Division of the Railroad Commission of Texas, along with information supplied directly by operators, provided adequate data for a basic geologic and engineering characterization of more than 430 of these reservoirs.

Data collected for each reservoir included (1) general information about the reservoir, (2) matrix and fluid properties, (3) engineering attributes and technology deployed to date, and (4) oil volumetrics. An example of the resultant tabulation is shown in figure 2.

The second, and equally important, product of this Texas oil reservoir characterization project was the grouping of geologically similar reservoirs into "plays." The concept of play

PLAY NAME: HORSESHOE ATOLL (28)

RRC DIST	FIELD AND RESERVOIR	DISC. DATE	LITH- OLOGY	TRAP	DRIVE	DEPTH (FT)	OIL COL. (FT)	POR. (%)	PERMEABILITY AVG. (MD)	PERMEABILITY LOG RANGE	H2O SAT. (%)	API GRAV.	INIT. GOR	INIT. PRES.	TEMP. (F)	PRODUCTION TECHNOLOGY	UNIT. DATE	WELL SPACING (ACRES)	ROS (%)	OIP (MMBBL)	CUM. PROD. (MMBBL)	ULT. RECOV. (MMBBL)	RECOVERY EFFICIENCY (%)
8A	ADAIR WOLFCAMP	50	LS	DTR	SG	8500	215	12	28		24	43	430	3513	133	WF	56	40	35	110	47.4	53.0	48
8A	COGDELL	49	LS	DTR	SG	6800	770	10	18		35	42	664	3125	136	PM	55	40	30	524	240.0	250.1	48
8A	DIAMOND M	48	LS	DTR	SG+PWD	6600	440	9	72	-1 4	28	44	850	3135	130	PM,WF	51-55	40	26	616	221.6	239.5	39
8A	GOOD	49	LS	DTR	WD	8000	489	8	52	-1 3	36	44	1158	3650	140	PM		40	9	124	40.5	50.2	40
8A	HOBO	51	LS	DTR	WD	7100	100	10	32		30	46	1290	2990	150	PM		40		28	11.1	11.7	42
8A	KELLY-SNYDER	48	LS	DTR	SG	6700	700	8	19		22	42	1010	3122	130	WF,CO2,M	53	40	26	2161	1075.6	1229.6	57
8	OCEANIC	53	LS	DTR	WD	8100	215	12	84		18	42	978	3410	160			40-80		59	21.0	21.9	37
8A	REINECKE	50	LS	DTR	SG+PWD	6800	304	10	22	-1 4	21	46	1100	3164	139	PM,WF	71	40	57	166	68.4	90.9	55
8A	SALT CREEK	50	LS	DTR	SG	6300	726	12	10	-1 1	29	40	338	2940	129	PM,M,LPG	52	80		471	194.1	248.0	53
8	VEALMOOR EAST	50	LS	DTR	WD	7400	610	10	38	-1 3	16	48	1290	3362	155	WF,M	74	40	16	125	50.5	67.7	54
8	VEALMOOR	48	LS	DTR	WD	7800	200	10	32	0 2	31	46	1145	3500	164	FM		40		81	34.7	37.9	47
8A	VON ROEDER AND N.V.R	54-59	LS	DTR	SG	6800	155	10	13		20	43	1200	3020	134	PM,WF	54	40	60	62	26.1	27.3	44
8A	WELLMAN	50	DOLO	DTR	SG+PWD	9300	800	8	100	-1 3	23	43	400	4105	151	PM,WF	78	40	35	164	51.4	83.9	51
						6850	632	9	28		25	42	881	3165	133		69 %		28	4691	2082.4	2411.7	51

Figure 2. Format for data tabulation and summary used to characterize geologic and engineering attributes of major Texas oil plays and component larger reservoirs (Galloway and others, in press). The example, the Horseshoe Atoll, includes geographically associated limestone reservoirs deposited as a series of reef pinnacles and knolls that were later buried by basinal marine shale.

analysis has been used commonly in petroleum exploration strategies and in estimating or assessing potential oil and gas resources (White, 1980). A play, in this application, is defined on the basis of depositional origin of the reservoir, structural or trap style, and nature of available source rocks and seals. In characterizing Texas oil reservoirs, we found that the play concept can be usefully applied to producing or producible reservoirs for two reasons. First, the larger reservoirs themselves constitute a major proportion of the target for improved recovery. Second, the larger reservoirs of each play typify the geologic and engineering parameters characteristic of the many smaller reservoirs that can be readily included in the plays.

During reservoir development and production, a substantial volume of geologic and engineering data is collected. Several of these data, or combinations thereof, can be used to order and constitute plays, as long as plays having meaningful common attributes can be established. Features such as depth, thickness, lithology, recovery efficiency, gravity, trap mechanism, and drive mechanisms can be used for play definition. However, our experience, based on analysis of all the major oil reservoirs in Texas, shows that the most unifying, first-order character in play definition is the genetic origin of the reservoir. When grouped by common depositional or diagenetic systems, reservoirs show great similarity in a variety of attributes. This is true because the physical, chemical, and biologic processes particular to specific depositional environments and resulting depositional facies determine many attributes that are of direct and indirect consequence to hydrocarbon generation, migration, entrapment, and subsequent producibility. These include

1. External geometry and configuration of the reservoir facies;

2. Internal geometry and vertical and lateral variations in both pay and nonpay zones;

3. Reservoir facies relationship to other facies components of the depositional system critical to the source and sealing of hydrocarbons;

4. Direct trapping mechanism, if stratigraphic;

5. Aquifer extent and behavior critical to collecting hydrocarbons and to determining the extent of natural water drive;

6. Control or modification of subsequent diagenetic history, which may determine reservoir properties;

7. Kinds, abundance, and relationships of porosity and permeability.

In some cases, however, first-order definition of plays must be based on factors other than genetic depositional origin. Examples include naturally fractured reservoirs having very low matrix permeability or extensively faulted reservoirs associated with piercement salt domes. In other cases, reservoir plays were defined by relationships to unconformities where weathering diagenesis was an overriding factor in reservoir genesis. However, in most geologic situations, depositional and structural style have at least some genetic coincidence (for example, growth faulting); diagenetic style is commonly influenced strongly by fluid flow paths determined by facies variation attributed to original deposition, and intensity of natural fracture systems is commonly related to attributes resulting from facies variation. Although structural configuration and style may be critical to scale and mechanics of trapping as well as to hydrocarbon migration, factors that are the consequences of genetic depositional origin are generally predominant in defining engineering and geologic attributes of reservoirs.

Because both the reservoir and its contained petroleum have a common genesis within plays, fluid attributes tend to be similar. Thus, reservoir engineering problems and applicable technologies are common to most or all of the reservoirs of a defined play.

Data on the reservoirs contained in each play were combined to provide a generalized characterization of each play (fig. 2), which summarizes its importance to total State production and provides basic data for determining potential applicability of various additional recovery strategies or technologies. The relatively homogeneous population of reservoirs in each play is also a logical starting point for evaluation and comparison of additional recovery targets and controls on production efficiency. A basic goal of reservoir play analysis is to establish predictive models for reservoirs of varying degrees and kind of internal heterogeneity, facilitating more strategic deployment of improved recovery programs.

LARGER OIL PLAYS OF TEXAS

The selected Texas reservoirs were grouped into 47 major plays. A summary tabulation and the generalized areal distribution of the plays are shown in figure 3. All but 16 of the 430

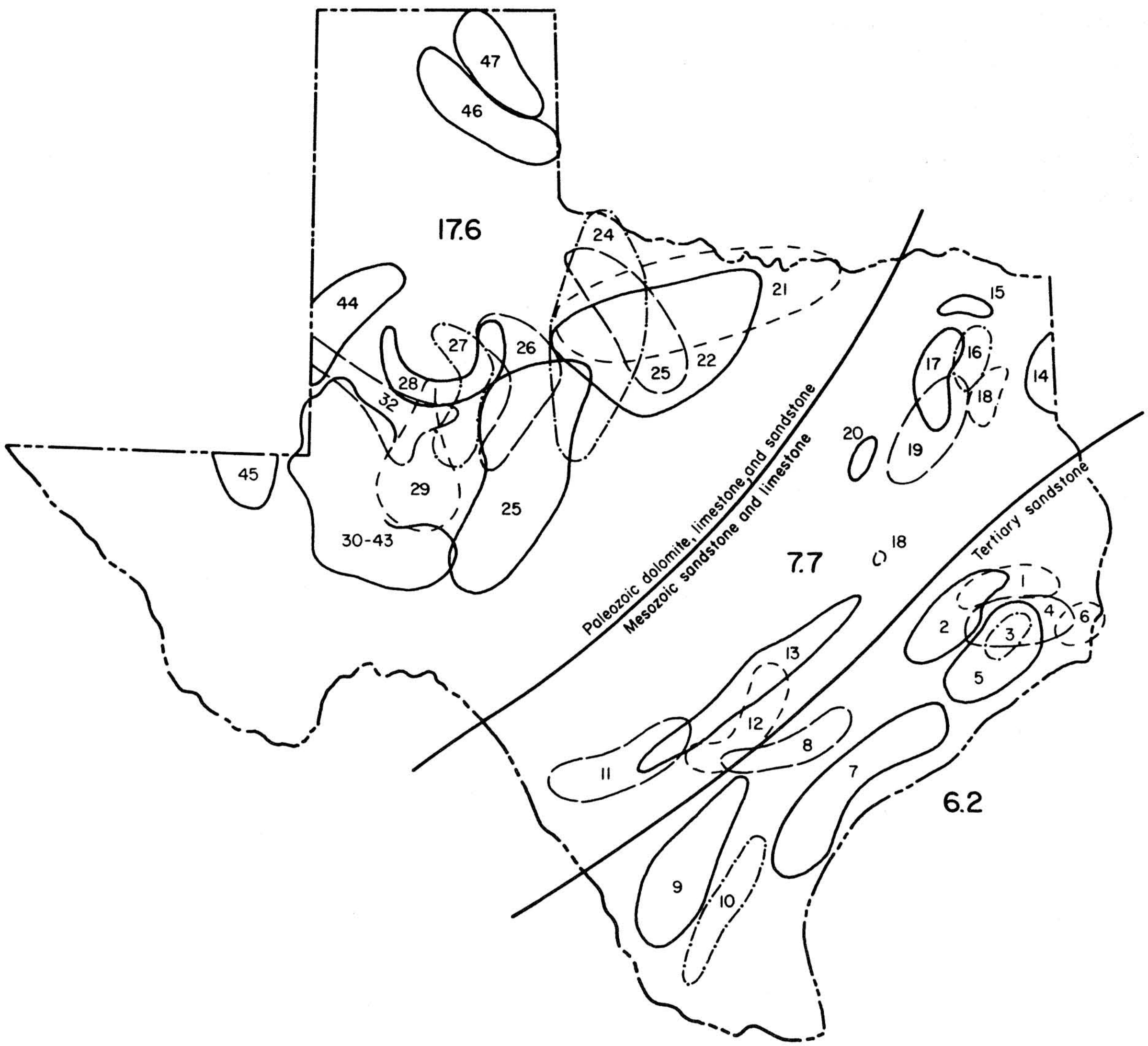

Figure 3. Geographic distribution of the 47 major Texas oil plays. Modified from Galloway and others (in press).

characterized reservoirs were incorporated into the identified plays. Each of the 16 represents modest production from geographically or geologically isolated smaller plays that might be of interest in more detailed, regional studies.

Oil production occurs in two broad belts cutting diagonally across the State (fig. 3). Approximately 6.2 billion barrels of oil have been produced from the geologically young, Tertiary sandstone reservoirs constituting plays 1 through 10 along the Coastal Plain. About 7.7 billion barrels have been produced from large sandstone, limestone, and chalk reservoirs of Mesozoic age that extend as a belt from northeast Texas along the inner Coastal Plain. By far the greatest volume of oil (approximately 17.6 billion barrels) has been derived from Paleozoic dolomite, limestone, sandstone, and conglomerate of North-Central and West Texas. The greatest concentration of vertically stacked plays (numbers 30 through 43) is along the Central

Basin Platform in Andrews, Ector, Winkler, Ward, Crane, Upton, Pecos, and Crockett Counties. Significantly, these same Paleozoic reservoirs exhibit the lowest recovery efficiencies and thus offer the largest aggregate target for additional infill and tertiary recovery. Brief reviews of each play and tabulated data on the constituent reservoirs are contained in a Bureau of Economic Geology Open-File Report by Galloway and others (1982).

RECOVERY EFFICIENCY OF TEXAS RESERVOIRS

The overall efficiency of primary oil recovery is largely determined by three groups of variables: (1) drive mechanisms (energy source), (2) basic rock properties (lithology), and (3) fluid properties. If large groups of fields are being considered, the average productivity may be approximated by cross plots of drive mechanism, lithology, and oil gravity. Significant deviations from such average curves indicate important modification of the producibility of oil by other parameters, such as abnormally low permeability or poor reservoir continuity.

More detailed mathematical analysis of oil production (American Petroleum Institute, 1969) shows that, for solution gas and water drive reservoirs, recovery efficiency is controlled by reservoir porosity, permeability, water saturation, formation volume factor, oil viscosity, and the ratio of initial or bubble point pressure and pressure at abandonment. However, even these extensive statistical treatments of reservoir performance are unaccountably variable. Recently, production engineers and geologists have recognized a fourth family of variables relating to the depositional and diagenetic facies makeup of the reservoir (Harris and Hewitt, 1977).

As pointed out by Alpay (1972), variations in ultimate hydrocarbon recovery from a reservoir result from three levels of heterogeneity. (1) Microscopic heterogeneities occur at the dimensions of pores within the rocks. Microscopic variables include pore-size distribution, pore geometry, and amounts of isolated or dead-end pore space. These elements primarily affect the irreducible water saturation (S_w) and the residual oil left in swept portions of the reservoir. Consequently, analysis of microscopic heterogeneity is particularly important in design of tertiary recovery programs.

(2) Macroscopic heterogeneity determines well-to-well recovery variability and is a product of primary stratification and internal permeability trends within reservoir units. Complexities include

1. Stratification (bedding) contrasts in grain size, texture, degree of cementation, and so on;
2. Non-uniform distribution of stratification types;
3. Lateral discontinuity of individual strata;
4. Reservoir compartmentalization due to low-permeability zones;
5. Permeability heterogeneity;

6. Vertical or lateral permeability trends;

7. Permeability anisotropy.

All these features are inherent attributes of the reservoir that are products of its depositional history and subsequent diagenetic overprint. It is at the scale of such macroscopic variability that large volumes of reservoir are partially or wholly isolated from the effective swept area. These features usually extend only a few acres areally or a few feet vertically. Consequently, compartments or layers that are not drained by conventional well spacing or completion practices may, if recognized, be tapped by selective infill drilling or by modification of well completion practices.

(3) Megascopic variations, such as lateral facies changes, porosity pinch-outs, and separation of reservoirs by widespread sealing beds, reflect fieldwide or regional variations in reservoirs and are caused by either original depositional setting or subsequent structural deformation and modification. Such large-scale variations are conventionally evaluated during modern reservoir development and management by techniques such as structure and porosity mapping, net-pay isopach preparation, and detailed well-log cross section correlation. Macro-scale heterogeneity, that is, interwell variation or boundaries, is the least studied, the least known, and the most difficult of the three types of variations to define with precision. It is in this area that merging of geologic and engineering perspectives is most needed. Macroscopic heterogeneity, and methods of predicting such offer the greatest potential for increasing ultimate oil recovery.

FACTORS AFFECTING RECOVERY EFFICIENCY

Analysis of characterization of the major Texas oil-producing plays delineates the factors that determine ultimate recovery of hydrocarbons from these reservoirs. The median recovery efficiency of the plays is 38 percent, better than the average efficiency of all reservoirs. Recovery efficiency data constitute three classes of reservoirs. (1) Poor reservoirs yield less than 32 percent of the in-place hydrocarbons. (2) The better reservoirs yield more than 46 percent of their oil. (3) Average reservoirs are projected to recover between 32 and 46 percent of the oil in place. However, even within a single play, the range of recovery from reservoir to reservoir may vary greatly. Comparison of play averages, as well as evaluation of intraplay variability, suggests several trends affecting and generalizations about ultimate field recovery.

1. The most obvious factor determining recovery efficiency is the reservoir drive mechanism. Either a strong natural water drive or a combination of drive mechanisms working in concert characterizes nearly all plays that are projected to produce more than 40 percent of their oil in place. In contrast, nearly all low-recovery plays are characterized by solution gas (depletion) drives. However, well-engineered and carefully managed solution gas reservoirs may approach the recovery efficiency of water drive reservoirs. Because most large plays are

composites of many reservoirs, the extent of applied production technology ranges widely, and for the play as a whole, the calculated recovery efficiency tends to reflect the well-known relative efficiency of the natural drive mechanism.

2. Lithology also influences recovery efficiency, but there is great overlap among the various lithic categories. In general, comparison of average play recovery efficiency shows that sandstone reservoirs perform better than limestone reservoirs, which, in turn, outperform dolomite reservoirs. Conglomerates appear to be highly variable. Sand and sandstone reservoirs show great variation in average recovery, which is strongly influenced by the drive mechanism operating within the reservoir. Dolomite reservoirs exhibit, at best, moderate recovery efficiencies. Like sandstones, they are least efficient in solution gas drive reservoirs.

3. Porosity shows little direct correlation with recovery efficiency. However, a weak inverse correlation between porosity and residual oil saturation is apparent. Published reservoir-specific data (Murphy and others, 1977) suggest a decrease in residual oil as porosity increases within the same lithologic type.

4. Permeability varies widely among the reservoirs of the various plays, but shows little obvious correlation with recovery efficiency. Permeability appears to be an overriding limitation on ultimate production only in a few Texas reservoirs where average values are very low (less than a few millidarcys).

5. Specific gravity of the oil, expressed as API gravity, limits recovery in a few reservoirs. Within most plays, oil gravity varies within a narrow range and thus does not account for production variability within the play. Oil viscosity would likely be a more effective predictor of recovery efficiency, but viscosity is highly dependent on measurement techniques and conditions, which are rarely specified in hearings files of the Railroad Commission of Texas.

6. The impact of well spacing on recovery is difficult to isolate. Within individual plays, spacing typically is reasonably uniform; differences that do exist commonly reflect major changes in overall recovery strategy or technology. To further confuse possible trends that might emerge from comparison of various plays, many shallow, low-recovery reservoirs usually have dense well spacing. Even with unusually close well spacing, they are still poor to average reservoirs. However, the argument that closer well spacing leads to improved ultimate recovery, other factors being equal, is strongly supported by numerous individual field case histories, which document measurably increased projections of ultimate recovery following programs of infill drilling. Many such programs date from the early 1970's and thus require substantial followup to document results.

7. Field development practice emerges as one of the most obvious controls on ultimate recovery efficiency. Table 1 compares the average production efficiency of the large, and consequently more thoroughly engineered, reservoirs included in this survey with the State

Table 1. Comparative recovery rates.

	OOIP* (BBO)	Conventional ultimate recovery (BBO)	Percent recovery
Gulf basins			
Giant fields	17	12	70.6
Non-giant fields	32	13	40.6
Subtotal	49	25	51.0
West Texas basins			
Giant fields	43	14	32.6
Non-giant fields	64	15	23.4
Subtotal	107	29	27.1
Total	156	54	34.6
Statewide giant fields	60	26	43.3
Statewide non-giant fields	96	28	29.2
Surveyed reservoirs			
Gulf basins	28	17	60.7
West Texas basins	73	22	30.1
Total	101	39	39.0

*OOIP = original oil in place BBO = billion barrels of oil

average and average for non-giant field recovery. Average projected recovery of the larger reservoirs notably exceeds the average of all reservoirs included in the tabulation.

8. Reservoir genesis--the geologic origin and nature of the producing zone--is an important determinant (and predictor) of recovery efficiency, for two reasons. First, parameters discussed in points 1 through 7 are interrelated variables that are determined by the geologic history of the reservoir. Second, although the relation between interpreted reservoir genesis and productivity is modified by extremes in permeability or fluid parameters, it otherwise follows predictable trends based on the known scale and internal complexity of depositional or diagenetic "compartments" and heterogeneity within the geologic system.

UTILITY OF GENETIC RESERVOIR MODELS IN IMPROVING RECOVERY EFFICIENCY

Application of genetic reservoir analysis to oil field development is relatively new. A survey of the literature shows that the use of genetic models is most advanced in interpretation of sandstone reservoirs. However, the potential utility of facies or of combined facies/diagenetic analysis in limestone and dolomite reservoirs is presaged by studies such as that of the Zelten field (Bebout and Pendexter, 1975) and the Means San Andres Unit (Barbe, 1971) and in the review by Jardine and others (1977). Genetic facies interpretation and models of sandstones were primarily developed for, and directed toward, improving prediction of reservoir distribution within areas of exploration. Genetic models of sandstone bodies were defined to allow early recognition of reservoir origin so that the direction and probable extent of specific oil-bearing sandstones could be predicted. Facies analysis applied to stratigraphic-trap exploration and discovery-well offset drilling led directly to the development of models that predict external geometry of a sandstone body--its trend, lateral extent, thickness, and potential for recurrence. More than 20 years of effort have been devoted to the generation and application of such exploration-oriented models.

A much smaller body of literature illustrates the potential use of genetic stratigraphic analysis in field development and enhanced recovery programs. In many large fields, external dimensions of the permeable facies rather than trap size determine the productive limits of the reservoirs. In a classic study of the Frio Sandstone in Seeligson field (play 10, South Texas), Nanz (1954) described and interpreted the complex distributary-channel geometry typical of several stacked reservoir sand bodies. In Seeligson field, reservoir dimensions are areally delimited by the sand-body geometries, which, in turn, reflect deposition by upper delta-plain fluvial and distributary channels within a delta system.

Single reservoirs, as defined from apparent correlation and apparent uniform fluid content, may in fact consist of a mosaic of individual genetic units. Pennsylvanian sandstones in the Elk City field of the southern Anadarko Basin exemplify the genetic complexity inherent in a large reservoir analogous to reservoirs of plays 22 and 46. Elk City is a large, asymmetrical anticline covering about 25 mi^2. Detailed stratigraphic analysis (Sneider and others, 1977) of one reservoir, the L_3 zone, revealed highly variable thickness and distribution patterns that reflect an equally complex facies composition. Core, log pattern, and isolith data were combined to differentiate and map river-channel-fill, distributary-channel-fill, delta-margin, and barrier-bar sandstone facies. Distribution of these facies influences the comparative efficiency of various well completion and recovery practices. Similarly, Hartman and Paynter (1979) described several examples of Gulf Coast reservoir drainage anomalies, some of which are clearly related to facies boundaries within single reservoir sand bodies. For example, wells penetrating distributary-channel fills were found to have poorly drained adjacent delta-margin facies. Closely spaced infill wells tapped essentially virgin reservoir pressures and oil-water contacts. Porosity and permeability of these geologically young Gulf Coast reservoirs are high, reflecting the unconsolidated condition of the sands. Similar delta-system reservoirs dominate Coastal Plain plays 1, 2, 3, 5, and 10. Drainage anomalies were noted during infill drilling of Devonian carbonate reservoirs in play 34, where wells as close as 200 ft to abandoned wells have produced water-free oil at near virgin pressures.

Within a single genetic facies, macroscopic heterogeneities are introduced by bedding and by spatial variability of textural parameters. Bedding produces a stratified permeability distribution that restricts cross-flow and channel fluids within the more permeable beds (Polasek and Hutchinson, 1967; Alpay, 1972). Preliminary studies (Zeito, 1965, for example) indicated the potential for continuity of internal permeability stratification and showed that the geometry and continuity of bedding correlated with interpreted depositional environment of the sand body. Weber (1982) presented a quantitative summary of the relation between environment and continuity of shale beds. The impact of horizontal stratification is well recognized in reservoir simulation studies; however, more complex bedding styles associated with lateral accretion or progradation are less commonly recognized. Shannon and Dahl (1971) demonstrated compartmentalization of a distributary-mouth-bar reservoir by progradational bedding geometry in a Strawn delta system of play 21. Recognition of the individual reservoir lenses, which reflect the deposition of frontal splays, suggested modifications to well completion practices and improved oil recovery.

Within relatively uniform sand bodies or their component beds, permeability may vary systematically either laterally or vertically and thus influences drainage patterns. For example, distinctive vertical permeability trends that reflect sediment textural trends characterize channel-fill, delta-front, and barrier-shore-face sequences in the Elk City reservoirs (Sneider and others, 1977). Sneider and others (1978) suggested generalized trends of various reservoir properties for framework bar- and channel-type facies of delta systems. The trends are qualitative but can be calibrated with engineering data and used to more accurately simulate reservoir conditions (see Weber and others, 1978, for example) and to improve oil recovery in deltaic reservoirs.

Grain orientation and textural lamination introduce microscopic heterogeneity, which, if systematic, produces permeability anisotropy within the sand bed. Study of modern sand bodies (Pryor, 1973) showed maximum permeability in alluvial sands to be oriented along the channel axis. Thus, flow is greatest along the axis of the resultant genetic unit. In contrast, upper shoreface and beach sands have maximum permeability axes that are oriented parallel to wave swash, producing an axis of maximum permeability perpendicular to the trend of the sand body.

Taken together, studies of both modern sand bodies and their reservoir counterparts suggest that genetic interpretation allows prediction of a hierarchy of parameters, ranging from external dimensions and morphology to internal compartmentalization and permeability stratification, heterogeneity, and anisotropy, that affect reservoir performance. Integrating and calibrating these predictions with reservoir engineering data has been shown to considerably improve recovery efficiency.

Example: Use of Meanderbelt Model for Infill Drilling

As would be expected from their highly variable depositional styles, fluvial (river) systems constitute diverse reservoirs for oil and gas. At one extreme, sand-rich fluvial systems contain abundant reservoir rock but are source- and seal-poor; conversely, mud-rich systems contain only moderate quantities of reservoir lithologies encased in abundant mudstone. However, all fluvial systems share several common reservoir attributes: (1) principal reservoirs are the channel-fill and bar sands; (2) reservoir continuity is excellent to good, at least along channel trend; and (3) internally, fluvial reservoirs are extremely heterogeneous and anisotropic.

Meanderbelt sand bodies are a particularly common reservoir in many productive formations, such as the Wilcox, Yegua, and Frio (plays 2, 3, 5, and 10), Woodbine (play 19), and Strawn (play 21) sandstones. Interbedded floodplain and levee shale results in partial isolation of the commonly stacked meanderbelt sand bodies. Individual meanderbelt sand bodies are, in turn, characterized by well-developed, complex anisotropy and heterogeneity, particularly in their upper section, where hydrocarbons preferentially accumulate. The systematic upward-fining textural trend is reflected by upward-decreasing permeability. Lateral-accretion bedding introduces permeability stratification that cuts across the sand body. The resultant permeability units are arcuate in plan view. The reservoir may be partially compartmentalized by mud plugs. In addition, the top of the permeable reservoir lithology commonly displays buried topography reflecting preservation of muddy ridge-and-swale and channel plugs.

Neches field (Woodbine, play 19) provides an example of the application of this comparatively well-known genetic facies model in targeting an infill well location. Neches field is a simple anticlinal trap producing from a stacked series of laterally discontinuous sandstones deposited as point-bar complexes in a meandering river system. Continuous floodplain shale units separate sandstone bodies vertically, imparting local but strongly expressed vertical heterogeneity to the reservoir (fig. 4). Truncation of the mudstones and local superposition of sandstone units result in vertically interconnected reservoirs, which originally had a common oil-water contact.

Of great importance to management of the reservoir was the recognition of clay plugs within the point-bar sandstone units (fig. 4). As the reservoir drains, these impermeable abandoned channel fills are barriers to oil flow. The field operator recognized that areas downdip of the plugs potentially trapped oil that would not be drained at the conventional 40-acre well spacing. Detailed structural maps of the top of individual sandstone units, combined with interpretive facies information, were used to outline locations of proposed infill wells (fig. 5). Because these wells had to be drilled off regular spacing, locations were submitted to

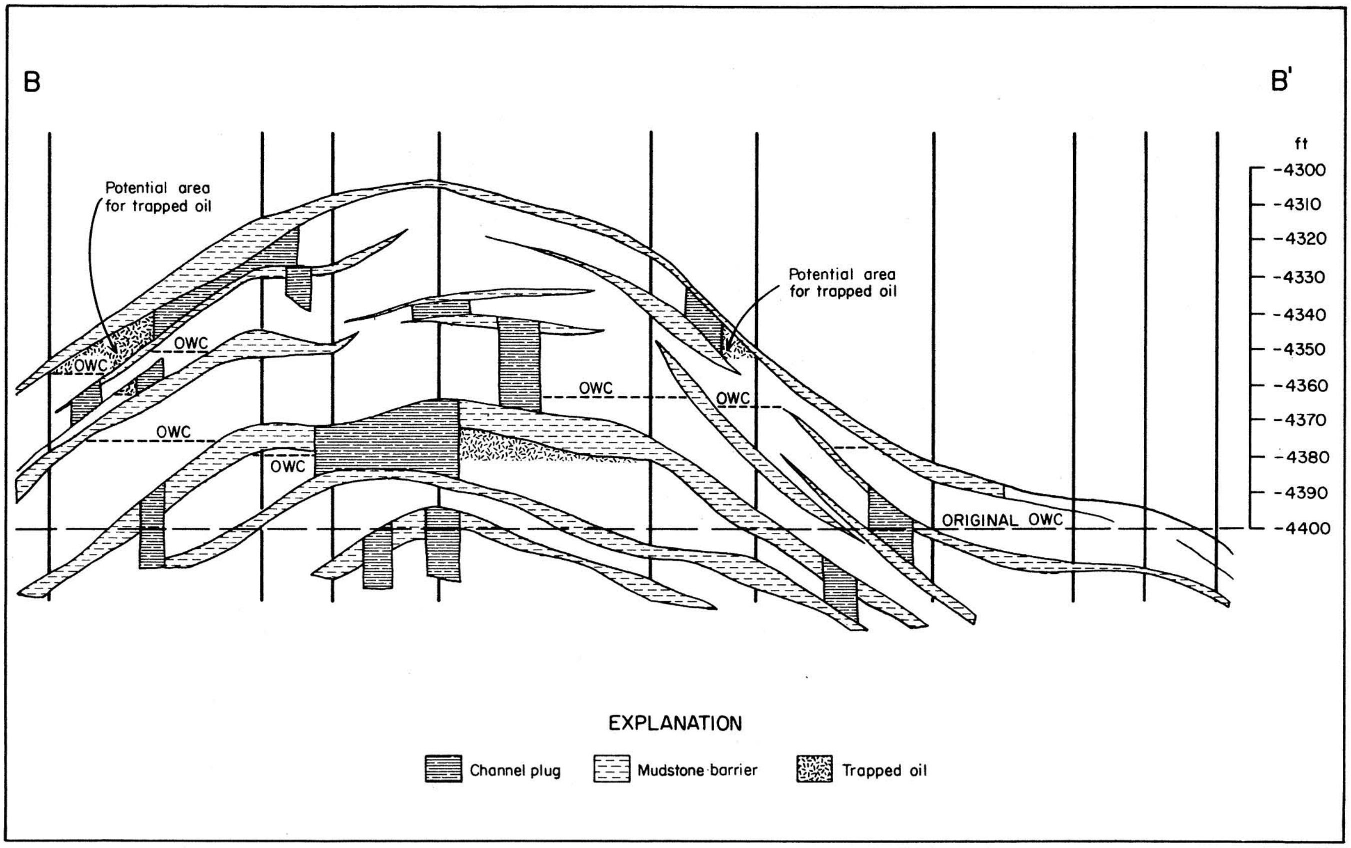

Figure 4. Cross section showing stacked river meanderbelt sandstone bodies forming the Woodbine reservoir in Neches field. Mud plugs form impermeable barriers that result in divergent oil-water contacts (OWC) and locally trap oil within the reservoir. Modified from information in hearings files of the Railroad Commission of Texas.

and approved by the Railroad Commission of Texas. Specific results of the infield exploration program are not reported, but an indication of the operators' success is the estimated recovery of 63 percent of the 210 million barrels of oil in place indicated for this reservoir.

Example: Infill Drilling in a Limestone Reef Reservoir

Analogous predictive genetic models of carbonate reservoirs that must reflect both the depositional facies and the pervasive post-depositional diagenetic modification are only now being developed. The Kelly-Snyder limestone reservoir (SACROC unit, play 28) displays the pronounced permeability layering typical of carbonate reef deposits (Jardine and others, 1977). Lateral discontinuity of the lenses, combined with irregular topography on the top of the reservoir, creates isolated lenses of trapped and bypassed oil (fig. 6A). According to the field operator, such lenses can be due to several factors, including (1) pinch-out of permeable beds between wells, (2) isolation of lenses within local reservoir topographic closures, and (3) less than optimal sweep efficiencies produced by existing injector-well locations and completion intervals. As shown by figure 6B, typical infill wells located substantial new intrareservoir

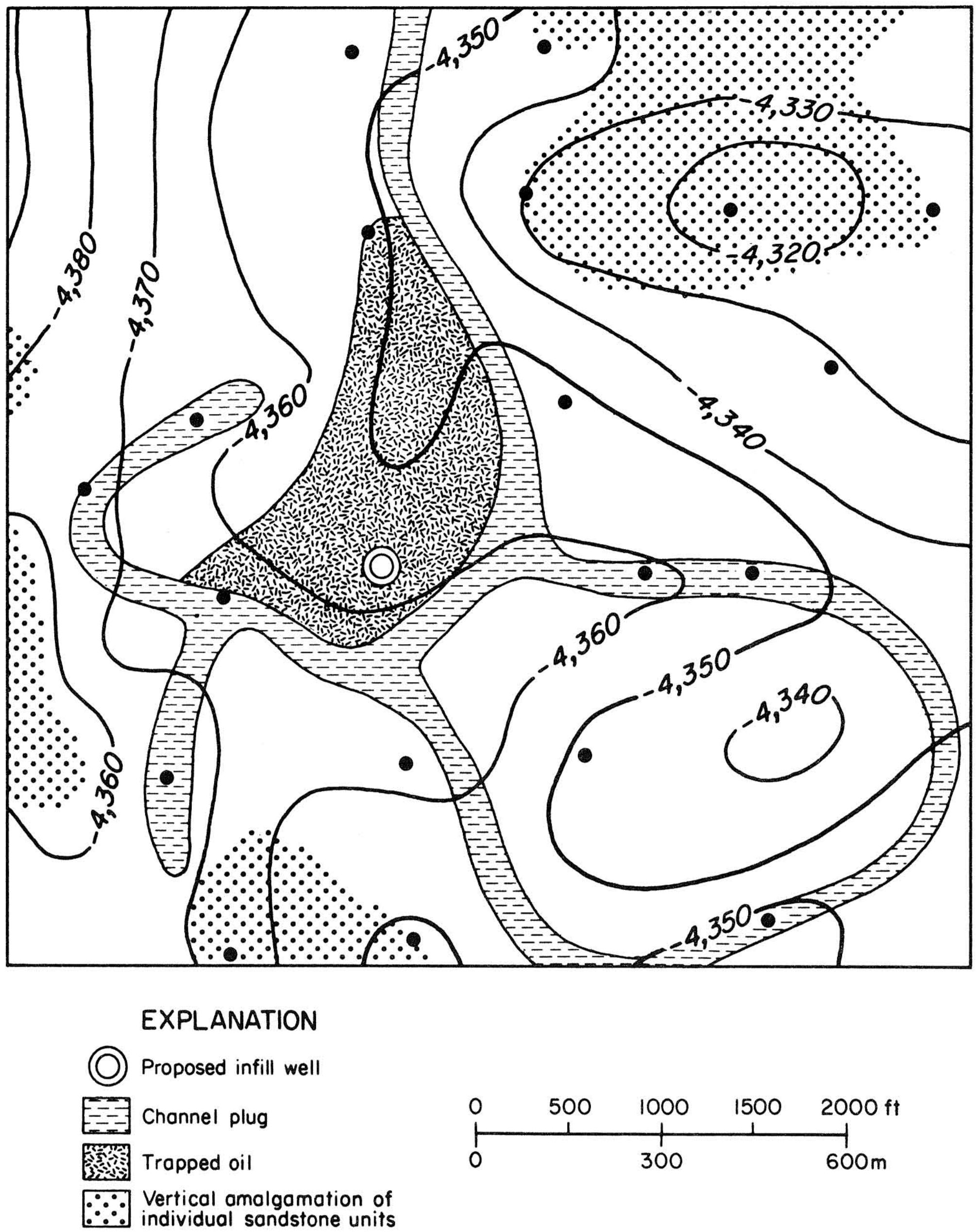

Figure 5. Map of one infill drilling target in Neches field. The contours show the structure on top of an undrained sandstone compartment isolated from the surrounding sandstone by the muddy channel plug. Modified from information in hearings files of the Railroad Commission of Texas.

zones of oil production. Over a 5-year production history following the infill drilling program, additional production of 30 million barrels was attributed by the operator to the infill wells. This amounts to an increase of more than 1 percent in recovery efficiency for this giant field, which is also undergoing miscible flood. Together, the combined infill and tertiary development programs were projected to result in a production efficiency of 57 percent, the best of any of the 13 reservoirs in the Horseshoe Atoll limestone play.

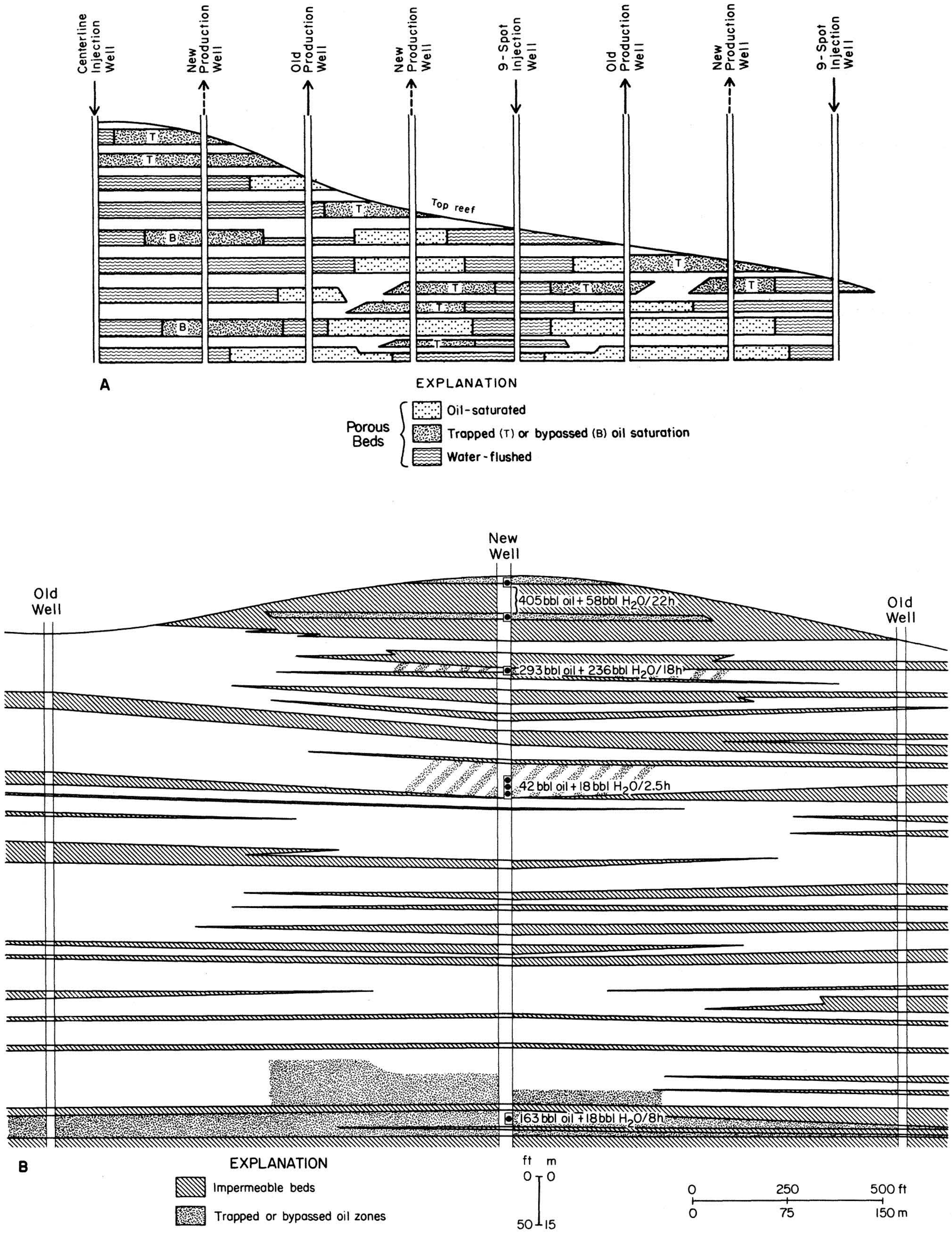

Figure 6. A. Schematic illustration of anticipated trapped oil lenses in the highly layered reef reservoir at Kelly-Snyder field. B. Test results of an infill well drilled to recover lenses of trapped oil. Modified from information in hearings files of the Railroad Commission of Texas.

CONCLUSIONS

The volume of in-place, discovered oil in Texas to date is huge, nearly 156 billion barrels. Approximately 54 billion barrels will be recovered through the deployment of current conventional techniques and practices. The balance--more than 100 billion barrels--is a potential target for a variety of additional non-conventional recovery techniques.

Currently estimated ultimate recovery from major Texas oil reservoirs varies considerably, from as little as 5 percent to as much as 85 percent. This wide range of recovery efficiency is attributable to a variety of complex factors, some well understood, others much less understood, at least to the extent of providing guidance for economically feasible improved recovery.

On the basis of a recent survey and analysis, an estimated target of about 30 billion barrels exists for application of strategic infill drilling programs, consistent with and guided by detailed geologic characterization of reservoirs. The balance of now unrecoverable oil is a potential target for tertiary recovery. Some of these targets are now being realized. How much of the total target will be converted into actual production depends in part on future economic conditions and in part on more detailed geologic and engineering comprehension of the complex entities called oil reservoirs.

The age of the sophisticated productionist--who combines geologic and engineering expertise--is here. The productionist will be as much a part of the future of Texas as the wildcatter was a part of the past. We are now, and indeed during the last decade have been, moving rapidly from the discovery phase to the improved recovery phase for Texas oil.

The supply of now unrecoverable oil is huge--more than 100 billion barrels. Recovering the maximum amount of this resource is in the paramount interest of this State and its future economy.

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