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RESERVOIR CHARACTERISTICS, PRODUCTION CHARACTERISTICS, AND RESEARCH NEEDS FOR FLUVIAL/ALLUVIAL RESERVOIRS IN THE UNITED STATES

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Michael L. Fowler, Viola Rawn-Schatzinger, S. Phillip Salamy, Mark A. Young,
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BDM-Oklahoma, Inc.
P.O. Box 2565
Bartlesville, Oklahoma 74005

ABSTRACT

The Department of Energy's (DOE's) Oil Recovery Field Demonstration Program was begun in 1992 to maximize the economically and environmentally sound recovery of oil from known domestic reservoirs and to preserve access to this resource. Cost-shared field demonstration projects have been initiated for geologically defined reservoir classes. The reservoir classes have been ranked by their potential for incremental recovery and their risk of abandonment. This document defines the characteristics of the fifth geological reservoir class in the series, fluvial/alluvial reservoirs.

The reservoirs of Class 5 include deposits of alluvial fans, braided streams, and meandering streams. Deposit morphologies vary as a complex function of climate and tectonics and have a high degree of fluid-flow heterogeneity due to extreme variations in water energy when the deposits formed.

The 84 Class 5 reservoirs analyzed from the DOE's Tertiary Oil Recovery Information System (TORIS) database contain a total of 39 billion barrels of original oil in place (OOIP) or about 11% of the 360 billion barrels of OOIP in U.S. reservoirs listed in TORIS. Using the TORIS database and its predictive and economic models, the recovery potential which could result from future application of improved oil recovery technologies was estimated to be between 228 million and 4.4 billion barrels, depending on oil price and the level of technology advancement. As much as 43% of this potentially recoverable oil may be abandoned by the year 2000 if prompt action is not taken. TORIS analysis and review of past industry experience with improved recovery applications in Class 5 reservoirs indicated that the following processes, in order of decreasing importance, have the greatest potential for improving production: (1) infill drilling, especially when used with profile modification and/or polymer flooding; (2) steam processes; (3) in situ combustion; (4) CO_2 miscible processes; (5) alkaline floods; and (6) surfactant floods.

Efficient reservoir management through selecting the most suitable improved recovery process and applying it optimally for the properties of the reservoir can also contribute to increased recovery. Class 5 reservoirs will benefit from research on general reservoir characterization technologies and methodologies, but Class 5 reservoirs also need very specific reservoir characterization models for individual reservoirs, plays, and basins. Such models addressing the depositional, diagenetic, tectonic, and fluid aspects of Class 5 reservoirs will increase the predictability of results from improved oil recovery processes. Other areas of research and development that may enhance Class 5 recoveries include reservoir simulation, wellbore and facilities, and environmental considerations. Environmental research needs include more cost-effective waste management practices and integrated design practices in which petroleum engineering and environmental requirements are considered simultaneously.

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EXECUTIVE SUMMARY

The Department of Energy's primary mission in the national oil reserch program is to maximize the economically and environmentally sound recovery of crude oil from known domestic reservoirs and to preserve access to this resource. The Department of Energy has grouped domestic reservoirs into geologically defined reservoir classes which have been ranked by their potential for incremental recovery and their risk of abandoment. Cost-shared field projects demonstrating improved oil recovery processes and reservoir characterization methods have been initiated in the three highest priority geologic reservoir classes. This document defines the characteristics of the fifth geological class of reservoirs (fluvial/alluvial), reviews the oil recovery activities and technological challenges of these reservoirs, and summarizes technological and methodological research, development, and demonstration that are most likely to improve oil recovery.

The reservoirs of Class 5 are the deposits of fluvial/alluvial systems, which include deposits of alluvial fans, braided streams, and meandering streams. Each of these end member deposit types results from water flowing over and through uplifted land areas toward an ocean, sea, or lake. Deposit morphologies vary as a complex function of climate and tectonics, but all fluvial/alluvial reservoirs have a high degree of fluid-flow heterogeneity due to extreme variations in water energy as the deposits formed.

The 84 Class 5 reservoirs in the DOE Tertiary Oil Recovery Information System (TORIS) database that have sufficient information for analysis using the TORIS predictive models contain a total of 39 billion barrels of original oil in place (OOIP) or about 11% of the 360 billion barrels of OOIP in U.S. reservoirs listed in TORIS. Cumulative production from Class 5 reservoirs as of 1994 was 13.7 billion barrels, or approximately 35% of Class 5 OOIP. The projection of Class 5 ultimate recovery under current operations is about 3.9 billion additional barrels. This leaves over 21 billion barrels as the target for future improved oil recovery projects in Class 5 reservoirs.

Even with contributions from large reservoirs developed by major oil companies over the last few decades in Alaska and California, production from Class 5 reservoirs is severely declining. Production profitability in both Alaska and California is under pressure from environmental and oil price concerns. In other parts of the United States the situation is more serious. Most of the Class 5 resources in states other than Alaska and California were developed in the early part of the twentieth century, and some fields were already producing for many years at the turn of the century. It is not surprising that most of these Class 5 reservoirs, many of which are operated by independent oil companies, are in the mature stage of their developmental history. Production decline is steep, proved reserves are small, and current production is approaching economic limits. A number of Class 5 reservoirs listed in the TORIS database have already been abandoned. There is a marked trend for smaller operators, with lower overhead but less access to

new technologies, to acquire Class 5 production being divested by major oil companies as production continues to decline. Cost-effective techniques are needed to select and apply new and existing technologies to extend the productive life of these fields.

Depositional characteristics of Class 5 reservoirs often lead to poor reservoir drive mechanisms (e.g., solution gas, gas cap expansion) that lead in turn to low recovery efficiencies. Pressure maintenance has been required in many Class 5 reservoirs soon after production began. The reservoir-drive challenge is more pronounced in the deposits of meandering streams and deposits contained in incised valleys. In these situations reservoir units tend to be effectively isolated both from each other and from extensive aquifers that might lend drive support.

Internal depositional heterogeneities on several scales lead to inefficient recoveries from Class 5 reservoirs at all stages of development. Overbank fine deposits, abandoned channel plugs, and shale drapes result in nonuniform drainage and flooding patterns, leaving behind large quantities of mobile oil not accessible with existing wells and recovery mechanisms. Also, wide variations in grain size corresponding to variations in depositional energy within permeable units lead to nonuniform flow patterns. Channeling problems during waterflood operations are a common consequence.

Efficient reservoir management may be the single most important contributor to increasing production from most Class 5 reservoirs. Selecting the most suitable improved recovery process and applying it correctly, optimally, and in a way consistent with the properties of the reservoir can make the difference between technical and economic success or failure. Better methods for designing, implementing, and revising reservoir management plans and strategies are the critical research needs, for Class 5 reservoirs.

Class 5 reservoirs will benefit from research associated with general reservoir characterization methodologies, but Class 5 reservoirs also have a need for very specific models for characterizing individual reservoirs, plays, and basins. These models should address the deposition, diagenesis, tectonics, and fluid contents of Class 5 reservoirs. Development of such models will increase the predictability of the results from improved oil recovery process applications in Class 5 reservoirs.

The future application of both existing and technologically advanced improved oil recovery processes could increase reserves in Class 5 reservoirs. Based on the TORIS database and its predictive and economic models, the recovery potential which could result from future application of improved oil recovery technologies was estimated to be between 228 million and 4.4 billion barrels, depending on oil price and the level of technology advancement. A significant portion of this potentially recoverable oil, up to 43% under certain conditions of oil price and technology advancement, may be abandoned by the year 2000 if immediate action is not taken. The TORIS analysis and review of past industry experience with improved recovery applications in Class 5 reservoirs indicated that the following processes, in order of decreasing importance, have the greatest potential for improving recovery from Class 5 resevoirs: (1) infill drilling

(including targeted drilling and directional or horizontal wells), especially when used with profile modification and/or polymer flooding; (2) steam flooding; (3) in situ combustion; (4) CO_2 miscible flooding; (5) alkaline flooding; and (6) surfactant flooding.

Other areas for research, development, and demonstration that may increase Class 5 recoveries include reservoir simulation, wellbore and facilities, and environmental considerations. Simulation needs involve improving the availability, accuracy, and cost-effectiveness of simulators for Class 5 reservoirs. Improved technologies and methodologies for reducing the costs of drilling, completing, recompleting, and stimulating wells, and operating production and injection facilities are also important. Environmental research needs impact all of the Class 5 resource, with these most important to pursue: (1) cost-effective waste management (minimization) practices, especially in drilling-related operations, and (2) integrated engineering design concepts in which petroleum engineering and environmental factors are considered simultaneously in design of improved oil recovery projects.

An overview of the chapters in this report follows:

Chapter 1 briefly sets the context for fluvial/alluvial reservoirs of Class 5 by covering (1) the objectives of DOE's Oil Recovery Field Demonstration Program, (2) the overall significance of the Class 5 resource in comparison with reservoir classes defined in previous field demonstration program solicitations, and (3) the overall potential for future oil recovery from Class 5 reservoirs.

Chapter 2 geologically defines Class 5 and discusses the nature of fluvial/alluvial systems, as well as the factors that control the formation of the end member types of fluvial/alluvial systems (i.e., alluvial fans, braided streams, and meandering streams). This chapter also reviews recognition criteria, key sources of depositional heterogeneity, and the special considerations that accompany deposits in incised valleys.

Chapter 3 reviews the geologic and geographic distribution of the Class 5 resource and discusses the depositional, diagenetic, structural, and fluid content aspects of major reservoirs as well as past improved oil recovery applications. This chapter treats reservoirs in Alaska, California, and the other states as three separate groups to focus on those reservoirs most in need of immediate attention in the form of improved recovery technologies.

Chapter 4 summarizes the results of analysis of Class 5 reservoirs using the TORIS improved oil recovery predictive models.

Chapter 5 considers the descriptive and predictive work addressed in Chapters 3 and 4 in order to summarize the research, development, and demonstration activities that will improve oil recovery in Class 5 reservoirs and postpone their abandonment.

Seven appendixes are also attached. These provide background information that will enable operators of Class 5 reservoirs to better understand the characteristics and research needs of the Class. Appendixes address the following topics: (A) terminology associated with deposition and description of Class 5 deposits, (B) a listing of Class 5 reservoirs contained in the TORIS

database, (C) a review of the TORIS predictive methodology used to analyze the future recovery potential from Class 5 reservoirs, (D) a review of recent research activities on improved oil recovery processes, (E) a summary of recent progress in simulator development that may have application to Class 5 reservoirs, (F) a summary of environmental compliance issues that will have relevance to improved recovery projects in Class 5 reservoirs, and (G) a bibliography of literature relevant to understanding the deposition of Class 5 reservoirs and the properties and development history of Class 5 reservoirs by geographic location.

CHAPTER 1
BACKGROUND AND OVERVIEW

Chapter 1 briefly sets the context for fluvial/alluvial Class 5 reservoirs by covering (1) the objectives of the Department of Energy's (DOE's) Oil Recovery Field Demonstration Program (Section 1.1), (2) the overall significance of the Class 5 resource in comparison with reservoir classes defined in previous field demonstration program solicitations (Section 1.2), and (3) the potential for future oil recovery from Class 5 reservoirs (Section 1.3).

1.1 Objectives

DOE's Oil Recovery Field Demonstration Program was begun in 1992 to support DOE's primary mission in the national oil research program of maximizing the economically and environmentally sound recovery of crude oil from known domestic reservoirs and preserving access to this resource. The goals and objectives of this program support the broader strategic goals of the federal government's Comprehensive National Energy Policy Act (1992) and Domestic Natural Gas and Oil Initiative (1993). The ongoing field demonstration program supports this mission by demonstrating improved oil recovery processes and reservoir characterization methods. DOE has grouped domestic reservoirs into geologically defined reservoir classes which have been ranked by their potential for incremental recovery and their risk of abandonment. Cost-shared field projects demonstrating improved oil recovery processes and reservoir characterization methods have been initiated in the three highest priority geologic reservoir classes.

The purpose of this report is (1) to define the geological, reservoir, and production characteristics of the fifth geological reservoir class (fluvial/alluvial), (2) to review oil recovery activity, technological challenges, and environmental issues related to reservoirs of this class, and (3) to identify technological and methodological research, development, and demonstration (RD&D) needs that are most likely to improve oil recovery from Class 5 reservoirs.

1.2 General Characteristics and Significance of the Class 5 Resource

The geologically defined reservoir classes are based on depositional environment and were originally defined by the Geoscience Institute for Oil and Gas Recovery Research (1990) in conjunction with the Interstate Oil and Gas Compact Commission. These geologic classifications were applied to the reservoirs that are included in the DOE Tertiary Oil Recovery Information System (TORIS) (BPO TORIS 1995). TORIS contains information on more than 2,500 domestic oil

reservoirs representing two-thirds of the known domestic oil resource, or about 360 billion barrels of original oil in place (OOIP). The TORIS reservoirs were classified into 22 geologically defined groups. The 16 clastic reservoir groups are shown in Figure 1–1, and the six carbonate reservoir groups are shown in Figure 1–2. These groups were then ranked in terms of OOIP, remaining oil in place (ROIP), future recovery potential, and abandonment risk to define the highest priority groups for research emphasis. Some groups were combined into formally defined classes for the cost-shared field demonstration projects.

The TORIS database contains information on 117 Class 5 reservoirs in the United States containing a total of 42 billion barrels of OOIP. Of these 117, 84 contain sufficient information to allow accurate and meaningful analysis using the TORIS predictive models. These 84 reservoirs contain 39 billion barrels, or 93%, of the OOIP in TORIS Class 5 reservoirs and will be used as representatives of the class in later analyses.

Figure 1–3 allows comparison of ROIP associated with each of the first five defined reservoir classes with other depositionally defined groups of reservoirs in the TORIS database. The first four classes target about 60% of the 240 billion barrels of ROIP for reservoirs listed in TORIS, as shown in Figure 1–4. Class 5, which represents a combination of geologically defined groups (i.e., alluvial fan, braided stream, meandering stream, and fluvial undifferentiated groups in Fig. 1–1), targets an additional 9%, or approximately 21 billion barrels, of the remaining oil in place.

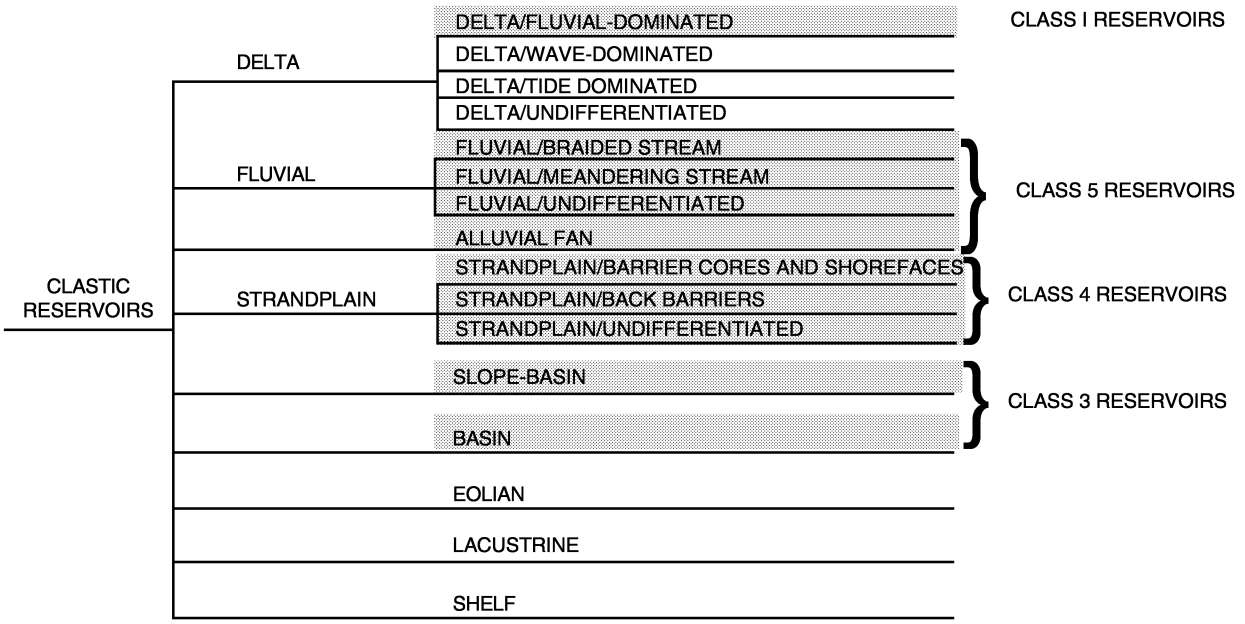


Figure 1–1 Classification of Clastic Reservoirs

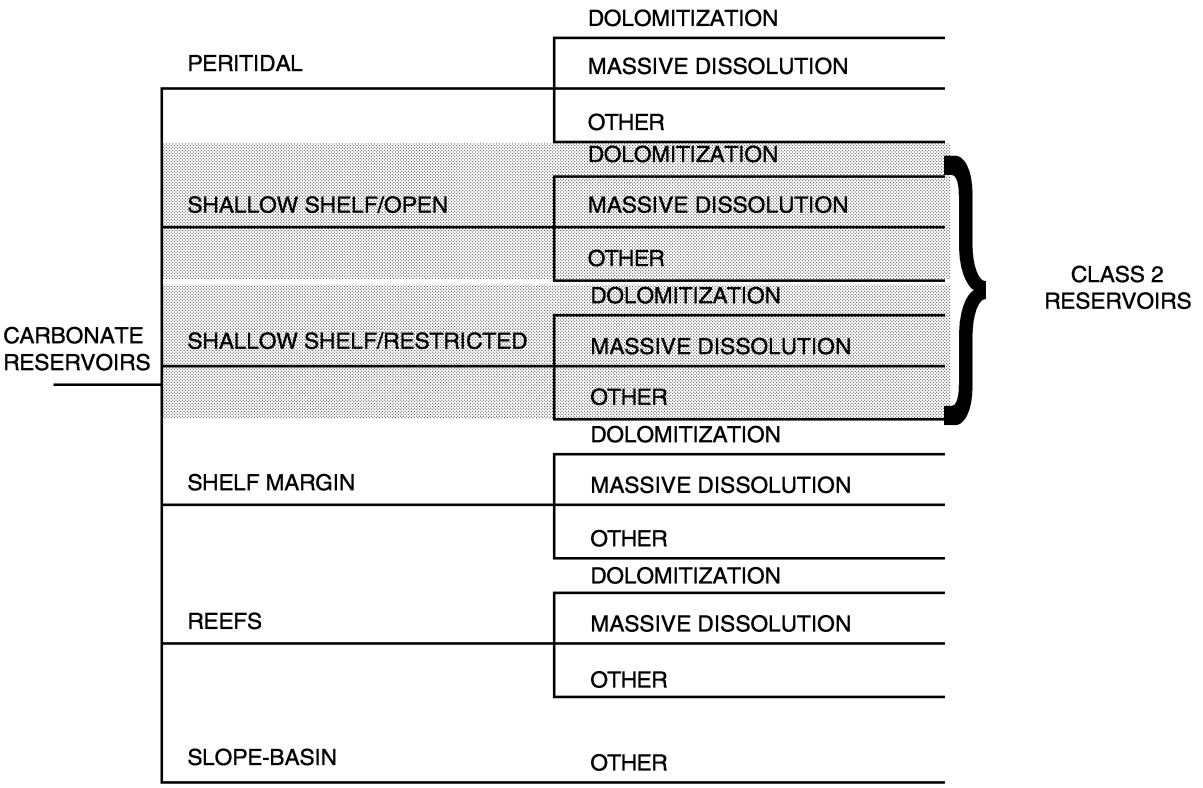


Figure 1–2 Classification of Carbonate Reservoirs

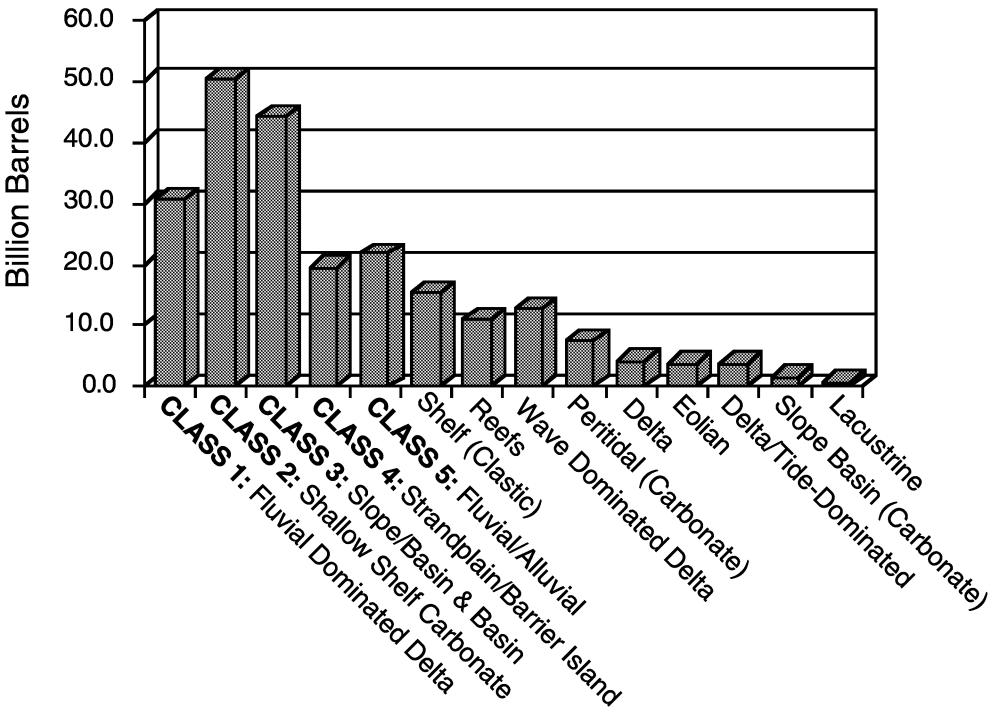


Figure 1–3 Remaining Oil in Place (ROIP) by Geologic Class (Source: BPO TORIS 1995)

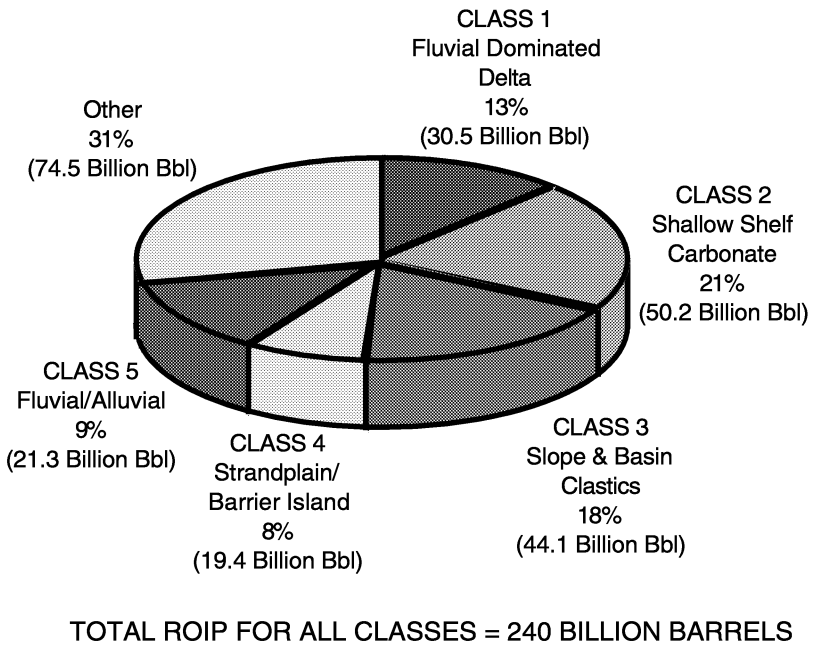
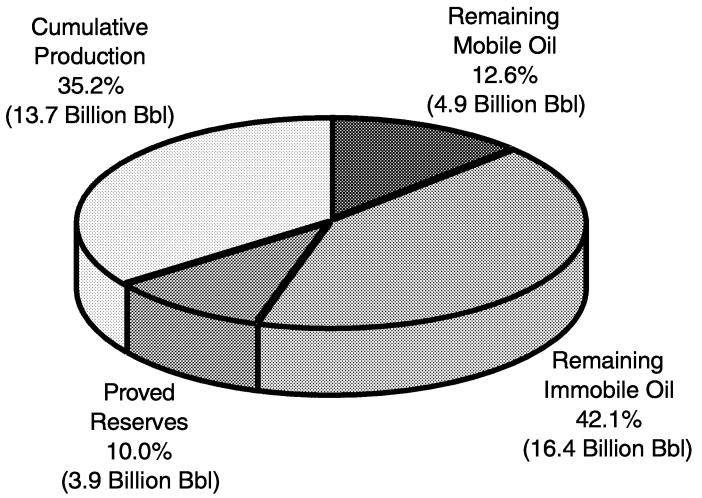


Figure 1–4 Distribution of Remaining Oil in Place (ROIP) for TORIS Reservoirs (Source: BPO TORIS 1995)

1.3 Potential Recovery from Class 5 Reservoirs

The total original oil in place (OOIP) for Class 5 reservoirs in DOE's TORIS database is 39 billion barrels, which represents about 11% of the nearly 360 billion barrels of OOIP in reservoirs listed in TORIS. As of 1994, the cumulative production from TORIS Class 5 reservoirs totaled 13.7 billion barrels, or about 35% of OOIP (see Fig. 1–5). Using the TORIS decline curve models, the projected remaining reserves under current production operations are 3.9 billion barrels (an additional 10% of OOIP). Ultimate recovery from Class 5 reservoirs will be 17.6 billion barrels, or 45%, of OOIP. Projected remaining oil in place (ROIP) at the end of current operations totals 21.3 billion barrels, consisting of 4.9 billion barrels of mobile oil and 16.4 billion barrels of immobile oil. The mobile portion of the ROIP is the target for future application of advanced secondary recovery (ASR) technologies. The immobile portion of the ROIP is the target for application of enhanced oil recovery (EOR) technologies. A significant volume of oil will be left behind unless improved recovery technologies can be implemented economically.

Future improved recovery potential in Class 5 reservoirs was analyzed using the TORIS predictive models. This potential ranges from about 228 million to 4.4 billion barrels, depending on oil price and the level of technology advancement (see Fig. 1–6). About one-fourth of the future potential is at risk of abandonment by the year 2000, which emphasizes the urgent need for developing and implementing economical improved oil recovery processes in Class 5 reservoirs.



ORIGINAL OIL-IN-PLACE FOR 84 RESERVOIRS = 38.9 BILLION BARRELS

Figure 1–5 Oil in Place Volumes for Class 5 (Source: BPO TORIS 1995)

1.4 References

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Geoscience Institute for Oil and Gas Recovery Research, 1990, Reservoir heterogeneity classification system for characterization and analysis of oil resource base in known reservoirs: prepared by the University of Texas, Austin, TX, for the U.S. Department of Energy, Office of Fossil Energy, Bartlesville Project Office.

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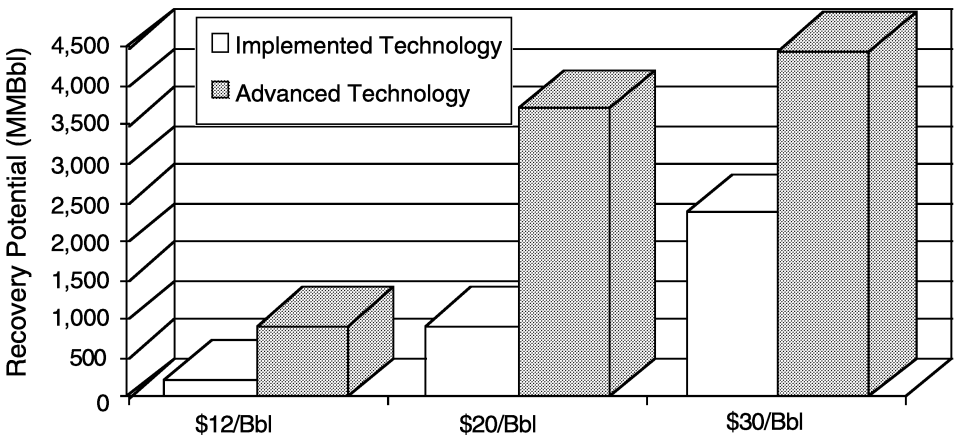

Figure 1–6 Total Recovery Potential for Class 5 Reservoirs (Source: BPO TORIS 1995)

Comprehensive National Energy Policy Act (EPACT), 1992, Summary of HR 776 on EPACT by S. Daniels and L. Harvey: NTIS No. PB92-960104/XAB, March, United States Federal Government, Washington, D.C.

CHAPTER 2
DEPOSITIONAL CHARACTERISTICS OF FLUVIAL/ALLUVIAL SYSTEMS

An adequate knowledge of the range of reservoir-unit geometries and their attendant internal variations in fluid retention and flow properties is necessary to efficiently develop and exploit any petroleum reservoir. This knowledge becomes critical for recovering remaining oil in place as reservoirs approach their economic limits under current operations.

Reservoir-unit geometries and their internal patterns of heterogeneities affecting fluid flow are related in predictable, though imperfectly understood, ways to the geological factors and processes controlling deposition and preservation of Class 5 fluvial/alluvial deposits. A better understanding of these fundamental geological factors, processes, and their interactions will make exploitation of Class 5 reservoirs more efficient.

Section 2.1 defines the general nature of fluvial/alluvial systems, delimits the portion of fluvial/alluvial systems that constitutes Class 5, and introduces the end member fluvial/alluvial system types. Section 2.2, 2.3, and 2.4 discuss the specific formation conditions and depositional characteristics for alluvial fans, braided streams/rivers, and meandering streams/rivers, respectively. Section 2.5 briefly reviews the formation and significance of fluvial valley-fill deposits. Section 2.6 summarizes the gradational nature of the end member fluvial/alluvial system types. Section 2.7 discusses the significance of their associated heterogeneities and the criteria that may be used to recognize fluvial/alluvial deposits.

2.1 Introduction to Fluvial/Alluvial Systems

Consideration of fluvial/alluvial systems will be limited to alluvial fan systems and stream or river systems. These are the fluvial/alluvial systems that constitute Class 5. The other major type of fluvial/alluvial system, deltas, is included within other depositionally defined classes and will not be addressed here. In this document deltas are considered to include any deposits whose facies or architecture are substantially influenced by marine or lacustrine processes.

Fluvial/alluvial systems are the conduits through which precipitation falling on uplifted land areas flows downward toward an ocean, sea, or lake. Water flowing through a fluvial/alluvial system invariably erodes and transports sediment and, given sufficient time, will produce a net decrease in elevation of the entire land area if no additional uplift occurs. The original uplift and subsequent lowering of the land is called the erosion cycle. Fluvial/alluvial systems are generally erosive systems over the long term. However, over shorter periods of time, and particularly early in the cycle of erosion, aggradation may occur in parts of the system or

Table 2–1
Factors Controlling Deposition in Fluvial/Alluvial Systems

	Tectonic Factors		Climate Factors			Provenance Factors
Alluvial Fans	Active Uplift	High Gradients	Less Humid to Arid Climate	Sparse Vegetation	Physical Weathering Dominates	Very Strong Influence on Sediment Composition
Braided Streams	Commonly with Uplift	Intermediate to Low	Typically Less Humid	Typically Sparse	Typically Physical	Typically Strong Influence
Meandering Streams	Stable or Subsiding	Low Gradients	More Humid Climate	Dense Vegetation	Chemical Weathering Dominates	Much Weaker Influence on Sediment Composition

throughout the system as a whole. Fluvial/alluvial systems may be long-lived in terms of the stability of geologic and climatic factors. The natural progress of the erosion cycle may be shortened, extended, or complicated along the course of the fluvial/alluvial system by external influences such as tectonic movements, changes in climate, or changes in base level.

There are three common types of morphological end member fluvial/alluvial systems: alluvial fan systems, braided stream/river systems, and meandering stream/river systems. Each of these system types results from specific tectonic, climatic, and provenance or source area factors (see Table 2–1). These factors combine to control the nature of sediment transport mechanisms or processes and their typical magnitudes within each system type (see Table 2–2). Sediment

Table 2–2
Sediment Transport Phenomena in Fluvial/Alluvial Systems

	Gravity Transport	Water Transport					
Alluvial Fans	Common	Low Average Discharge	Very High Discharge Variability	Very High to High Flow Velocity	High Bed Load	Low Average Competence with Respect to Particle Size	Low Average Sediment Volume Throughput
Braided Streams	Rare (Bank Slumps)	Typically Low	High Variability	Inter-mediate	High Bed Load	Typically Low (Variable)	Intermediate
Meandering Streams	Rare to Nonexistent	High Average Discharge	Low Discharge Variability	Low Flow Velocity	High Suspended Load	High Average Competence with Respect to Particle Size	High Average Sediment Volume Throughput

Table 2–3 Sedimentary Deposit Characteristics in Fluvial/Alluvial Systems				
Alluvial Fans	Large Average Particle Size	High Particle Size Variability	Low Volume of Associated Fines	Texturally and Compositionally Immature
Braided Streams	Variable	Variable (in Channel)	Typically Low	Intermediate (in Channel)
Meandering Streams	Small Average Particle Size	Low Particle Size Variability (in Channel)	High Volume of Associated Fines	Texturally and Compositionally Mature (in Channel)

transport mechanisms in turn control deposit characteristics (see Table 2–3). Tables 2–1 through 2–3, which purposely describe fluvial/alluvial phenomena only in descriptive or semiquantitative terms, will form the primary basis for comparing and contrasting fluvial/alluvial end member system types. Descriptive terminology in Tables 2–1 through 2–3 is meant to apply to typical or more common occurrences of the various system types, but may not apply to all occurrences of a given type.

2.2 Depositional Characteristics of Alluvial Fans

Alluvial fans are sedimentary deposits that typically form at the base of a mountain-front fault scarp or other steep slope. Fans are generally triangular to semicircular in plan view and radiate downslope from the apex. The apex marks the point of emergence of a mountain stream from the highlands. Surface slopes average about 5° and range from 1° to 25°, seldom exceeding 10°–12° (Nilsen 1982; Blair and McPherson 1994). Alluvial fan deposits are typically wedge shaped, with the thickest accumulation of sediment at the apex (Nilsen 1982; Blair and McPherson 1994).

2.2.1 Alluvial Fan Depositional Processes and Facies

Primary depositional processes on alluvial fans fall into three categories: (1) processes associated directly with flowing water (i.e., streamflow and sheetfloods); (2) gravity-associated processes including rockfalls, slides, and avalanches; and (3) processes associated with density flows (i.e., debris flows and mud flows) (Friedman and Sanders 1978; Reineck and Singh 1980; Blair and McPherson 1994). Primary processes are directly associated with the transport of materials from the highland drainage basin to the site of fan deposition by feeder streams. Secondary processes are processes that act locally at the fan site to remobilize and modify previously deposited sediments. Secondary processes include reworking by wind and surface runoff, physical and chemical weathering, burrowing by organisms, and stabilization and alteration by vegetation.

During floods, deeply incised, narrow channels and high gradients on the upper part of the fan give feeder streams sufficient water depth and velocity to transport large quantities of sediment including clasts ranging up to a meter or more in diameter. Flow depth and gradient conditions that enable transport of particles of a given diameter are summarized in Figure 2–1.

When the rate of downward erosion of the feeder stream through the bedrock exceeds the rate of relative uplift between the highland and the fan depositional site, the stream may become incised into previously deposited fan sediments. During floods, violent discharge also prevail in this extension of the feeder valley. Boulder-size particles are commonly transported through these channels, and older fan deposits are usually completely reworked. The point downfan where the incised channel(s) intersect the fan surface is called the intersection point (Nilsen 1982). The position of incised channels on the fan may change periodically due to avulsion and secondary or surface erosional processes.

Characteristic deposits in fan channels are coarse boulder lag deposits, but they may be interbedded with other fan facies (Blair and McPherson 1994). Fan channels also serve to confine flows associated with other primary processes such as density flows or avalanches. Abandoned channels may be filled by any type of primary or secondary fan facies.

When catastrophic flows reach the end of an incised valley or channel, either at the fan apex or downfan at the intersection point, the walls of the valley or channel are no longer present to contain the flow. As a result the flow spreads laterally, becomes shallower, and rapidly loses its

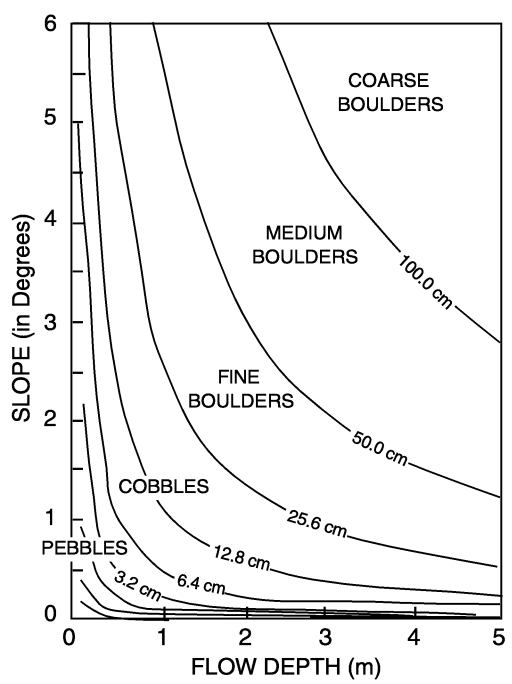

Figure 2–1 Flow Depth versus Slope Conditions Necessary to Transport Gravel Clasts of Varying Diameter (Modified from Blair and McPherson 1994)

ability to transport larger particles as it moves down the fan surface. This depositional process, known as sheetflooding, is the most common and important depositional process associated with flowing water in the construction of alluvial fans (Blair and McPherson 1994).

Sheetflood deposits are characterized by high rates of flow attenuation and deposition, but these deposits are formed in very high-energy environments from water flowing turbulently and rapidly down the appreciable slope of a fan surface. They are typical of the upper flow regime and consist predominantly of laterally extensive parallel planar beds. The most common sheetflood deposits are beds of gravel containing cobbles and boulders interbedded with very coarse, pebbly and moderately sorted sand (Nilsen 1982; Blair and McPherson 1994).

Gravity-associated processes are often responsible for the presence of certain characteristic types of fan sediments, particularly in the upper reaches of the fan near the apex or emergent point of the feeder stream. Rockfalls involve the release of individual fragments that may fall or roll onto the fan surface forming talus or scree deposits. Rock slides or colluvial slides involve masses of rock and/or sediment, respectively, that move downslope as an intact mass to the fan site either slowly or as episodic events (Blair and McPherson 1994). Rock avalanches involve catastrophic falls of large masses of material resulting in intense brecciation and granularization followed by downslope gliding through a granular-flow mechanism (Blair and McPherson 1994).

Density flows are substantial contributors to the sediment volume of many alluvial fans. They arise from rapid admixture of fluids (water and/or air) to mixtures of loose sediment containing considerable amounts of clay, typically 25% or more (Friedman and Sanders 1978; Blair and McPherson 1994). The resulting mass flows plastically downslope in a laminar, nonerosive manner but may be capable of transporting even large boulders in suspension. Density flows containing a large size range of sediment up to cobble and boulder size are termed debris flows (see Fig. 2–2), while those with mostly sand-size or finer entrained particles are called mud flows (Friedman and Sanders 1978). Most commonly they are formed by transforming a water-saturated episodic colluvial slide as it is jostled during downslope movement (Blair and McPherson 1994). A second mechanism involves encroachment of rapidly moving water onto a drainage basin slope mantled by abundant sediment (Blair and McPherson 1994).

2.2.2 Factors Controlling Alluvial Fan Deposition

Alluvial fans are almost always associated with tectonically active areas (see Table 2–1). They often occur adjacent to normal faults where the rate of relative uplift exceeds the rate of downward erosion by streams on the upthrown side. Stream gradients in the fan's drainage basin and on the surface of the fan itself are often quite high. Fan slopes nearly always exceed 1.5°.

Alluvial fans can form under widely varying climatic conditions ranging from humid to desert-like in nature. Humid fans are neither as well understood nor as extensively studied as their more arid counterparts. Part of the problem may be due to a simple lack of recognition. Their

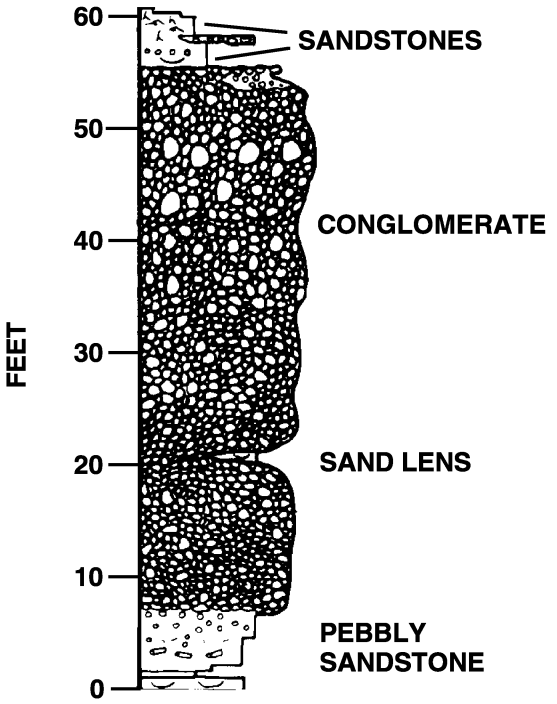

Figure 2–2 Vertical Sequence within Debris Flow Conglomerates (Modified from Nilsen 1982)

characteristically lower slopes, large size, and presence of perennial streams have led many of them to be considered as braided stream deposits (Blair and McPherson 1994). Most well-studied fans are associated with semiarid conditions or conditions characterized by sporadic rainfall and/or seasonal snowmelt typical of uplifted areas. Low annual rainfall supports less vegetation to bind and stabilize sediments both in the drainage basin and on the fan itself. Low rainfall also leads to the predominance of physical or mechanical (as opposed to chemical) weathering processes.

Exposed rocks and sediments in the drainage basin have a very strong influence on mineralogic composition (and perhaps to some extent the size) of sedimentary particles found in alluvial fan deposits. Typically the drainage basin is small and nearby, and deposits closely reflect the composition of their source areas.

Sediment transport by gravity is important on many alluvial fans primarily because of the high gradients associated with the drainage basin and the fans themselves (see Table 2–2). In arid areas, where mechanical weathering processes greatly predominate, rockfalls, rockslides, and avalanches commonly contribute to fan deposits, particularly in the upper reaches of the fan near the apex. In more humid situations where chemical weathering of appropriate rocks in the source area affords some clays, fans may contain or even be dominated by debris flow and mud flow deposits.

Stream discharge associated with alluvial fans is relatively low and constant (or even nonexistent) most of the time (see Table 2–2). Because fans are associated with areas of uplift, however, moisture-laden air masses forced to rise and cool can occasionally result in torrential rains over the entire extent of a fan's drainage basin. The tremendous surface runoff associated with such events is collected by the drainage network and arrives more or less simultaneously at the fan's primary feeder channel. The narrow, usually incised, valley combined with large water volume and high gradient give rise to some of the highest energies known to be associated with transport of sediment by water. Deep water moving at high velocities in these valleys and their extensions onto the fan are capable of moving sediment of virtually any size by traction along the stream bed. Such flood events are very short lived, however, and within a few minutes or hours water levels drop drastically along with the ability to transport large sediment particles.

Except under those infrequent conditions of maximum flooding, larger particle sizes are not moved (i.e., by normal or daily stream flow). Despite an impressive capability to transport coarse sediment in times of flood, the actual transported volume of sediment in alluvial fan settings is relatively small, being more or less limited to the volume of the fan deposits themselves less the volume of fines transported away by streams and surface runoff.

As a result of the processes and mechanisms previously discussed, alluvial fan deposits have distinctive characteristics (see Table 2–3). Typical arid alluvial fans contain substantial amounts of coarse material. Fans in more humid environments are typically larger in size and have lower surface gradients. Fans in areas with higher relative rates of uplift have larger average particle size and steeper surface gradients. Highly variable energy associated with variable stream discharge and possible admixture of debris flow and/or mud flow deposits leads to the characteristically poor sorting generally associated with alluvial fan deposits. The volume of associated clay size material is usually small and sediments are mineralogically immature. Somewhat greater amounts of associated clays may be present in fans forming under humid conditions where chemical weathering is dominant.

2.2.3 Fan Evolution, Architecture, and Associated Heterogeneities

Deposition on alluvial fans strongly reflects prevailing tectonic and climatic conditions. When an initial period of rapid uplift is followed by more or less stable conditions, a typical fan architecture can be expected to develop. Initially gravity processes may dominate fan deposition. High fan slopes and coarse, very poorly sorted sediments prevail and the fan radius is relatively short. As time goes on, the drainage basin develops, and the feeder stream may become deeply incised, even to the point of extending its channel out onto the fan. At the same time water-laid deposits become dominant, fan slopes decrease, sediment becomes finer grained and better sorted, and the fan radius increases.

However, during its depositional lifetime an alluvial fan may be influenced by changes in climate and/or the relative rate of uplift. Both the internal and external architecture of the fan can be affected. For this reason, major constructional facies of fans observed in modern

environments may not be representative of processes seen operating at the surface today. Changes in the interaction between tectonics and climate during fan deposition can result in either progradational architecture (i.e., grain size and bed thickness increasing upward) or retrogradational architecture (i.e., grainsize and bed thickness decreasing upward).

Heterogeneities associated with alluvial fan deposits occur on a wide range of scales from those associated with individual fans enclosed within large laterally coalesced complexes of fans—called piedmonts, bajadas, or clastic wedges (Friedman and Sanders 1978; Nilsen 1982)—to those associated with directional heterogeneities within single sedimentary structures (Neton et al. 1994). Piedmont deposits may extend for hundreds of miles and may be many thousands of feet thick. Their internal geology may be extremely complex. Coalesced fans derived from compositionally dissimilar source areas can have significantly different depositional facies makeup. Such dissimilar deposits will undergo significantly different diagenetic alteration leading to fluid flow heterogeneities on a very large scale.

Individual fan deposits may be from a few feet to thousands of feet in thickness and may range from a few hundred feet to many tens of miles in radius. Internal facies architecture is usually a complex function of tectonic and climatic controls resulting in significant large-scale heterogeneities and anisotropies in both vertical and horizontal directions due to juxtaposition of permeable and impermeable deposits. Other common sources of heterogeneity include within-fan faulting, mud drapes, development of soil horizons, and numerous small-scale features such as laminations and clast and grain imbrication (Neton et al. 1994). Other factors contributing to heterogeneity under certain circumstances include volcanic dikes and sills and the sediment-rock contact across the border or bounding fault (Neton et al. 1994).

2.3 Depositional Characteristics of Braided Streams

Braided streams are named for their distinctive channel form. Braided streams consist of a wide and shallow main channel consisting of numerous smaller channels which meet and redivide around islands and/or bars in a complex fashion resembling the strands of a braid in plan view (see Fig. 2–3) (Reineck and Singh 1980; Gary et al. 1974). Individual channels as well as the whole channel system tend to migrate laterally over considerable distances. Lateral migration distances may be measured in tens to hundreds of feet for individual channels but in hundreds of feet to hundreds of miles for channel systems.

In the realm of clastic sedimentation, braided streams often physically occupy a position between higher gradient alluvial fan environments upstream and lower gradient meandering stream environments downstream (LeBlanc 1972). Typical gradients for braided streams are invariably less than 0.5°. In comparison, typical alluvial fans have gradients of 5° or more (Blair and McPherson 1994).

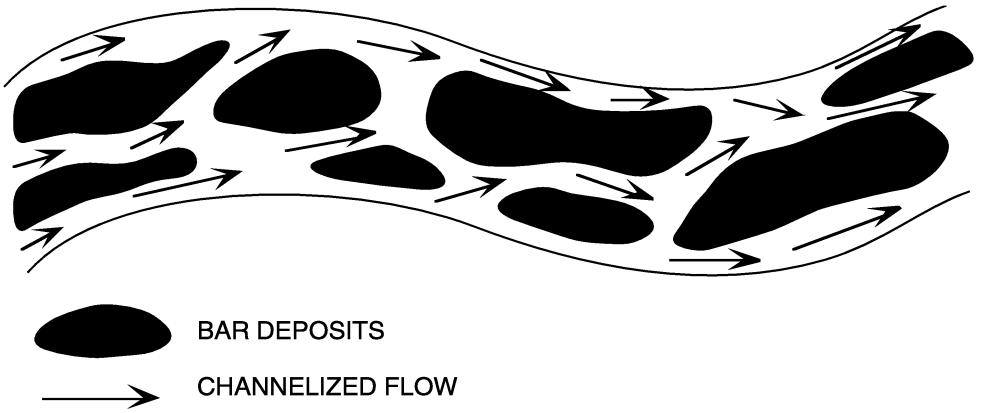

Figure 2–3 Channel Form for Braided Systems. This schematic depiction shows a low-water stage.

2.3.1 Braided System Depositional Processes and Facies

Deposition from flowing water is the primary process responsible for braided stream deposits. A wide range of flow conditions apply in forming braided stream deposits, but consideration of two conditions, maximum flooding and normal or daily flow, will suffice to describe the more significant aspects of deposition.

Under maximum flood conditions, a braided stream will rise to cover its entire channel complex, including any associated banks. This stream will be capable of transporting all sediment sizes (sand to cobble sizes are typical) associated with its bed deposits. The flow may become quite laterally extensive and may be similar in many respects to sheetflood flow on alluvial fans. However, although upper flow regime conditions still prevail, lower gradients in braided streams result in much lower energies than in alluvial fan sheetflood events. Flood attenuation in braided stream environments is relatively rapid. Flow attenuation results in very significant depositional events involving coarser sediment fractions in former channel courses and accumulation of overbank fines outside the main channel complex.

Under normal flow conditions, the stream lacks the competence to transport the coarser sediment fractions making up its bed deposits. This lack of competence is the primary condition required for braiding (LeBlanc 1972). At all nonflood stages, flow is confined to channels between bars anchored by lag deposits dropped in the waning stages of major flood events. All but the coarser sediment fractions of these bars may continue to be eroded and redeposited, causing channels to migrate laterally. A wide variety of bar types may form, depending on local flow conditions and channel geometries. Deposition of fines during periods of moderate flooding may lead to bar stabilization by vegetation and the formation of semipermanent islands (Reineck and Singh 1980). Finer sediment fractions may continue to be transported through the system under nonflood conditions.

Under most circumstances, bedforms and deposits formed under maximum flood conditions are modified as flooding wanes and are not preserved. Facies normally observed in braided stream or river deposits are those associated with normal flow conditions and minor flood events. The facies observed are as variable and complex as the conditions of sediment supply and water flow that give rise to them, but primarily they are associated with various types of bar development.

In some instances, preserved vertical sequences consist of stacked beds of imbricated, clast-supported, horizontally bedded gravels with little representation of finer sediment fractions (see Fig. 2–4*A*) (Cant 1982; Miall 1977). In other situations characterized by an abundance of sand as well as gravel, vertical sequences consist of numerous fining-upward cycles (see Fig. 2–4*B*) (Miall 1977; Reineck and Singh 1980; Cant 1982). Cycles typically begin with massive to horizontally or low-angle crossbedded and imbricated gravel units with scoured bases. Gravel units grade upward through tabular, planar, and sometimes trough crossbedded sands to ripple-bedded sand and silt deposits. Sequences are generally capped by laminated silts and clays.

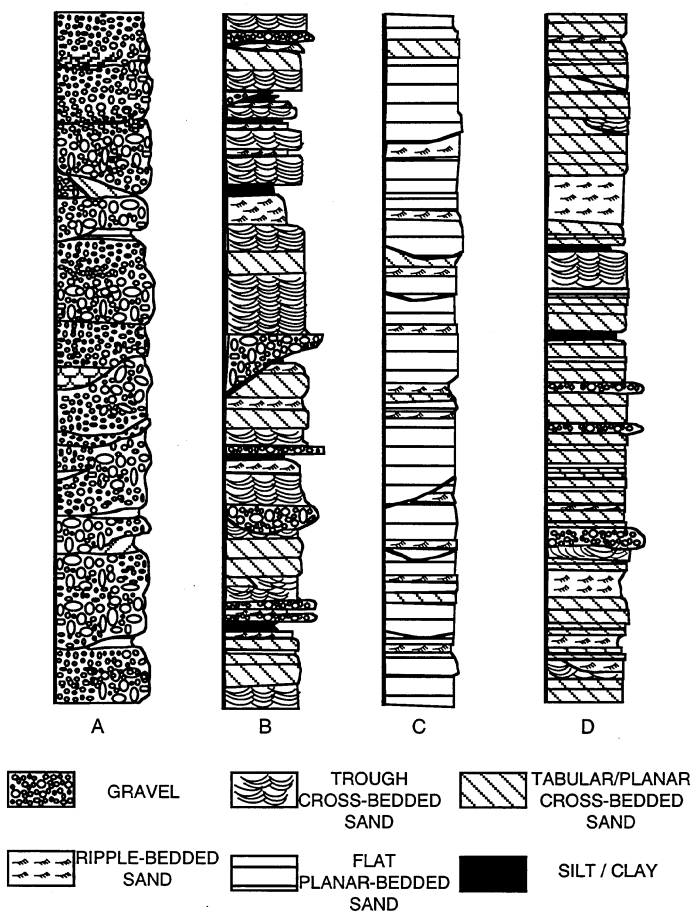

Figure 2–4 Models of Vertical Sequences in Deposits of Braided Systems. (*A*) Stacked gravel sequences. (*B*) Stacked fining-upward sequences. (*C*) Deposits typical of upper flow regime in sand-dominated systems. (*D*) Deposits typical of lower flow regime in sand-dominated systems (Modified from Miall 1977).

In some deposits associated with ephemeral streams and dominated by sand size sediments, good preservation of horizontal to low angle parallel-laminated beds of upper flow regime flood conditions has occurred (see Fig. 2–4*C*). There is very little vertical segregation of grain size in these deposits (Cant 1982; Miall 1977). Other sand-dominated sequences contain abundant tabular and planar crossbeds associated with bar topography (see Fig. 2–4*D*).

2.3.2 Factors Controlling Braided System Deposition

Braided streams are commonly associated with mountainous terrains in valleys with steep gradients or with alluvial fans (see Table 2–1) (Friedman and Sanders 1978; Reineck and Singh 1980). Gradients are typically higher than those found in meandering systems, but braided system gradients are typically less than those associated with most alluvial fans. Because of their influence on stream gradients and local climate, areas of active uplift favor braided stream deposition. Braided streams, however, can occur in a wide variety of tectonic settings and are by no means limited to the upper reaches of drainage systems. Many flow directly into oceans or lakes.

Braided streams, like alluvial fans with which their deposits are often confused, form under a variety of climatic conditions. Most are found in semiarid to arid areas, in areas associated with highly seasonal precipitation, or in areas associated with runoff from seasonal snowmelt such as glacial outwash plains (LeBlanc 1972). Braided streams are typically found where the variation in precipitation and runoff is great. They are often found where vegetation is not abundant and where physical weathering processes dominate over chemical weathering processes, but these conditions are not required for them to form.

Braided streams typically have larger drainage areas than alluvial fans. Larger drainage areas mean that braided systems generally will have a wider variety of mineralogies in their source areas and sediments than alluvial fans. Because transport distances are usually greater, braided system deposits will usually contain lesser amounts of physically weak and mineralogically unstable sediment grains.

Sediment transport in braided streams is primarily by flowing water (see Table 2–2). It is likely that some sediments deposited by gravity mechanisms and identified as braided stream in origin may in reality be of alluvial fan origin (Blair and McPherson 1994). Gradients associated with braided stream deposition are generally not great enough to allow operation of gravity mechanisms.

Braided streams, like alluvial fans, are most commonly found in areas of low average rainfall. Also like alluvial fans, braided streams are strongly associated with highly variable discharge volumes on a seasonal or sporadic basis. But because of the generally larger size of their drainage basins, braided systems usually are associated with higher average discharge volumes. Gradients are appreciably less than on alluvial fans and flow velocities are lower. Still, fine-grained sediments are efficiently moved through most braided systems under normal flow

conditions, through a large percentage of the coarse sediment fractions moves only under flood conditions. Sediment sizes associated with the bed load may move more often and in greater overall volume in braided streams, than in typical alluvial fans.

Textural maturity in braided stream deposits is slightly greater than in fan deposits. Average particle size is smaller. Larger particles in braided deposits are typically rounded as opposed to the more angular clasts generally associated with fan deposits, and overall sorting is improved somewhat also. Particle size variability is high, but not as high as in typical alluvial fan deposits. Sorting within individual sediment packages may be moderate to good, leading to high initial permeabilities. The overall volume of associated fines is typically low in comparison to the volume of coarser material present. Clay size fractions are generally either (1) not available in abundance in the system or (2) have been efficiently transported through the system. As mentioned previously, mineralogical maturity of braided stream deposits may also be somewhat greater than typical alluvial fan deposits.

Braided systems can occur in almost any range of sediment grain size (see Table 2–3). Modern and ancient systems frequently contain very little material coarser than sand size and only minor vertical variation in grain size (Le Blanc 1972; Cant 1982). Grain size in some braided systems is predominantly finer than sand size (Coleman 1969).

2.3.3 Braided System Evolution, Architecture, and Associated Heterogeneities

Braided rivers owe their existence to a very complex interaction of tectonic and climatic factors (Miall 1994). The conditions under which braiding occurs represent a geologically temporary aggradation made possible by highly variable water discharge volume. This phenomenon occurs on various scales ranging from small rivulets associated with local surface runoff to major river systems hundreds of miles long. Sediments deposited by waning flood waters of a braided system are frequently incompletely removed before the next major flood. Incomplete removal of sediment results in net aggradation accompanied by a tendency for switching of major channels by avulsion. By this mechanism deposits may aggrade for long periods of time. If tectonic activity ceases and allows topography to be reduced over time by erosion, the variability of stream discharge will decrease and aggradation will stop. Under these circumstances a braided system may evolve into a meandering system. In cold climates where variability in stream discharge is controlled primarily by seasonal temperature variation, such evolution of morphology will not occur.

Long-term preservation of braided deposits probably requires local subsidence or else the deposits would be removed by later erosion. Under conditions of very low local subsidence, channel avulsion would be frequent. Fining-upward sequences associated with individual depositional events would be incompletely preserved, and the resulting deposit architecture might be aggradational or progradational. Under conditions of more rapid subsidence, channel avulsion would be less frequent. Preserved sequences would be more complete (the thickness of each fining-upward cycle roughly equivalent to the depth of water during the depositional

event), and overall deposit architecture might be aggradational or even retrogradational. Thickness of braided deposits is a function of both the scale of the depositional system responsible and the prevailing local conditions of subsidence. Deposits associated with typical braided systems may range from a few tens to a few hundreds of feet thick, but if major river systems combine with proper conditions of subsidence, deposits thousands of feet thick may result.

Because frequent and extensive lateral channel migration is a prevalent feature of braided systems, the resulting deposits often have lateral extents measured in tens of miles to 100 miles or more. Lateral migration of channels also generally results in thorough reworking of previous deposits and removal of most associated fine-grained material. Shales associated with overbank deposits, abandoned channel fills, or clay drapes are occasionally preserved, however. These shales can cause significant heterogeneity to fluid flow on several scales in petroleum reservoirs.

The natural vertical (fining-upward) sequence of grain sizes often associated with individual sediment packages within braided deposits is another common source of heterogeneity. When coarser portions of the sequences exhibit very high permeability and are continuous between wells, they can form thief zones, preventing the reservoir from being uniformly drained or flooded unless corrective action is taken. Boundary surfaces separating sediment packages are themselves potentially significant sources of heterogeneity, often acting as barriers to fluid flow (Senger et al. 1993; Chang et al. 1994; Miall 1994).

2.4 Depositional Characteristics of Meandering Streams

Meandering streams are characterized by flow in a single distinct channel which typically is not straight, but wanders from side to side in more or less regularly spaced curving loops of similar average amplitude (Gary et al. 1974; Friedman and Sanders 1978; Cant 1982). Meander length and amplitude are related to channel width (Reineck and Singh 1980).

Sinuosity is defined by Leopold and Wolman (1957) as the length measured along the stream or river course divided by the corresponding valley length of fluvial systems. By this definition a perfectly straight stream has a sinuosity of 1.0. Sinuosity is a characteristic commonly used to distinguish meandering (sinuosity typically greater than 1.5) from braided (sinuosity typically less than 1.5) systems. The transition between these systems, however, is purely gradational in this and many other respects (Miall 1987). Individual meander loops have a tendency to migrate laterally with time. The entire channel with its accompanying meanders may also move laterally within a meander belt which occupies about twice the total amplitude of the meanders (Cant 1982).

Meandering streams often occur in low-relief coastal-plain areas depositionally updip from deltas and downdip from braided streams (LeBlanc 1972) and have been traditionally thought of as representing the mature stage of river or landscape development. High sinuosity reaches that behave as meandering systems can occur, however, in almost any setting (Miall 1987).

2.4.1 Meandering System Depositional Processes and Facies

Like braided system deposits, meandering stream deposits are primarily the result of deposition from flowing water. Again, two conditions require attention, normal flow, and maximum flooding.

During normal or daily flow conditions the stream is confined to its sinuous channel. Although it may transport a considerable amount of sediment in suspension, it may or may not be actively migrating laterally. Compared to channels of braided systems, those of meandering systems are narrow and deep, consisting of a series of pools, riffles, and bars (see Fig. 2–5) (Friedman and Sanders 1978; Reineck and Singh 1980; Cant 1982). Pools are areas of relative scour and bank erosion associated with higher velocity flow. They occur on the outside (cutbank side) of meander loops. Bars, referred to specifically as point bars, are depositional features on the inside (low velocity side) of meander loops receiving sediment derived from bank erosion upstream. Riffles are shallow areas characterized by neither erosion nor deposition that occur between meander loops.

During the waning stages of maximum floods and during intermediate flood stages when the flow follows the stream's meandering course, lateral migration of meander loops is most active. As banks on the outside of meander loops erode, point bar deposits on the inside of the loops, where flow velocity is lower, accrete laterally. In ideal form the point bar deposit consists of a single fining-upward sequence whose height is more or less comparable to the flood depth (see Fig. 2–6) (Friedman and Sanders 1978, Reineck and Singh 1980; Galloway and Hobday 1983).

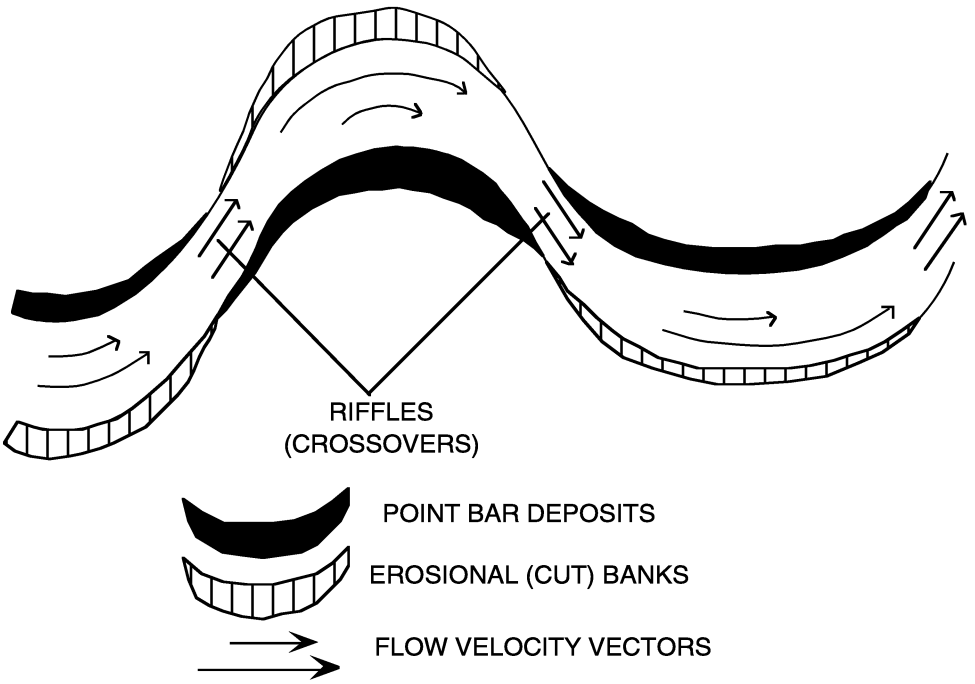

Figure 2–5 Channel Form and Major Features of Meandering Systems

Point bar sequences are frequently incomplete, especially in the upper part, due to erosion preceding the next depositional event (Friedman and Sanders 1978). Grain sizes will always be a function of the range of sizes available to and transportable by the system.

During severe floods in coarse-grained meandering systems with high discharge variability, flow tends to move in a straighter path down the valley. As a result, erosion often occurs in the form of one or more chutes or channels scoured into the upstream ends of point bar deposits (see Fig. 2–7) (Galloway and Hobday 1983). As flow in these chutes spreads across the point bar surface, sediments are redeposited as large, wedge-shaped tabular or crossbedded sand units

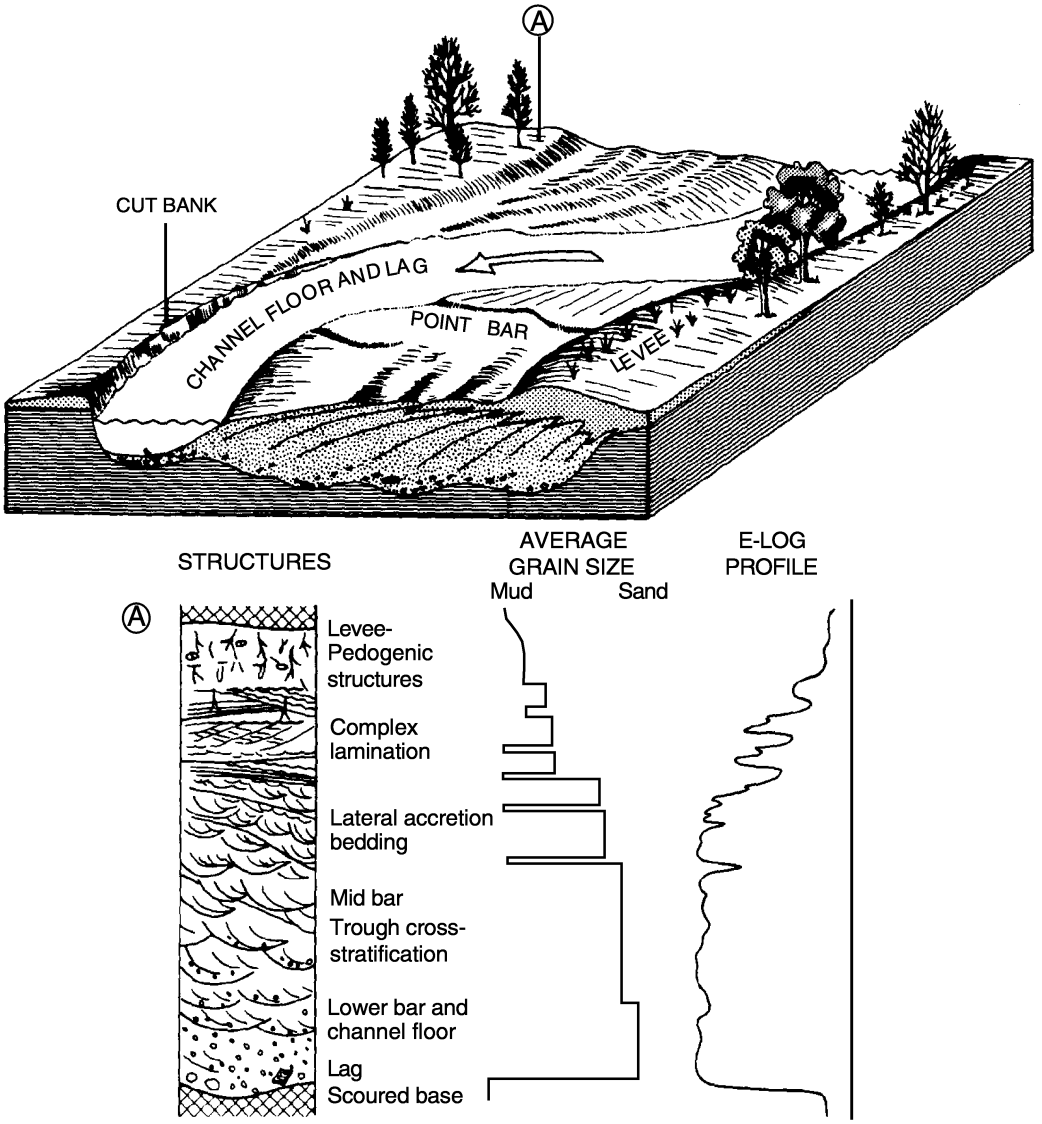

Figure 2–6 **Generalized Depositional Model, Vertical Sequence, and Electric Log (S.P.) Profiles of a Sand Body Produced by a High-Sinuosity Meandering Channel (Modified from Galloway and Hobday 1983)**

that may extend into the riffle or crossover areas between meanders. The presence of these chute bars may give rise to vertical sequences that show little or no upward fining (see Fig. 2–7) (Cant 1982; Galloway and Hobday 1983).

During periods of overbank flooding, fines carried in suspension may be transported great distances from the river channel before settling out. Clay size fines may be transported lateral distances often measured in tens of miles, well beyond the limits of the meander belt. Abandoned channels (i.e., cutoff meander loops) typically fill with overbank fines. Coarser materials (usually silts or fine sands) may drop out quickly upon leaving the rapid and turbulent flow environment of the main channel. Deposits formed by these sediments are elongate low relief mounds (natural levees) immediately adjacent to the main channel that tend to contain its flow. These natural levee deposits are sometimes breached by surface erosion or by floodwater overflow from the channel. When this occurs, large volumes of water are funneled quickly from the main channel, resulting in thin overbank deposits resembling small-scale deltas (called *crevasse splays*) of variable areal extent.

2.4.2 Factors Controlling Meandering System Deposition

Meandering systems are most commonly associated with low relief (tectonically inactive) areas located in continental interiors or on coastal plains (see Table 2–1) (Friedman and Sanders 1978). Gradients are characteristically lower than those associated with braided systems.

Meandering streams, like their braided counterparts, are found under a variety of climatic conditions, but most are associated with a continuous flow. Average discharge or base flow in meandering systems is considerably higher than in braided systems of comparable size. Discharge volume may still be considerably variable (e.g., seasonal), but discharge is less than overbank flood in magnitude for a large percentage of the time. Flow velocities may be high during flood, extending well into the upper flow regime (Friedman and Sanders 1978), but they are generally lower than in braided systems, which usually have higher gradients.

Meandering systems are commonly, but not always, associated with more humid climates, which in turn implies an abundance of vegetation (in Devonian and later examples) and a general predominance of chemical over mechanical weathering processes. Meandering systems typically drain larger areas than braided systems. As a result, they are often located farther from their source areas and have access to a wider variety of source materials. In comparison to braided systems, chemical weathering and attrition during transport in meandering streams reduce the amount and diversity of mineralogically unstable materials and increase the amount of clay.

Meandering systems, except at their very lowest discharge stages, tend to transport considerable quantities of fines (clays and/or silt) in suspension (see Table 2–2). In general, sediment is transported mostly as suspension load rather than as bed load in meandering systems (Reineck and Singh 1980). The total sediment volume throughput in such systems is considerably greater

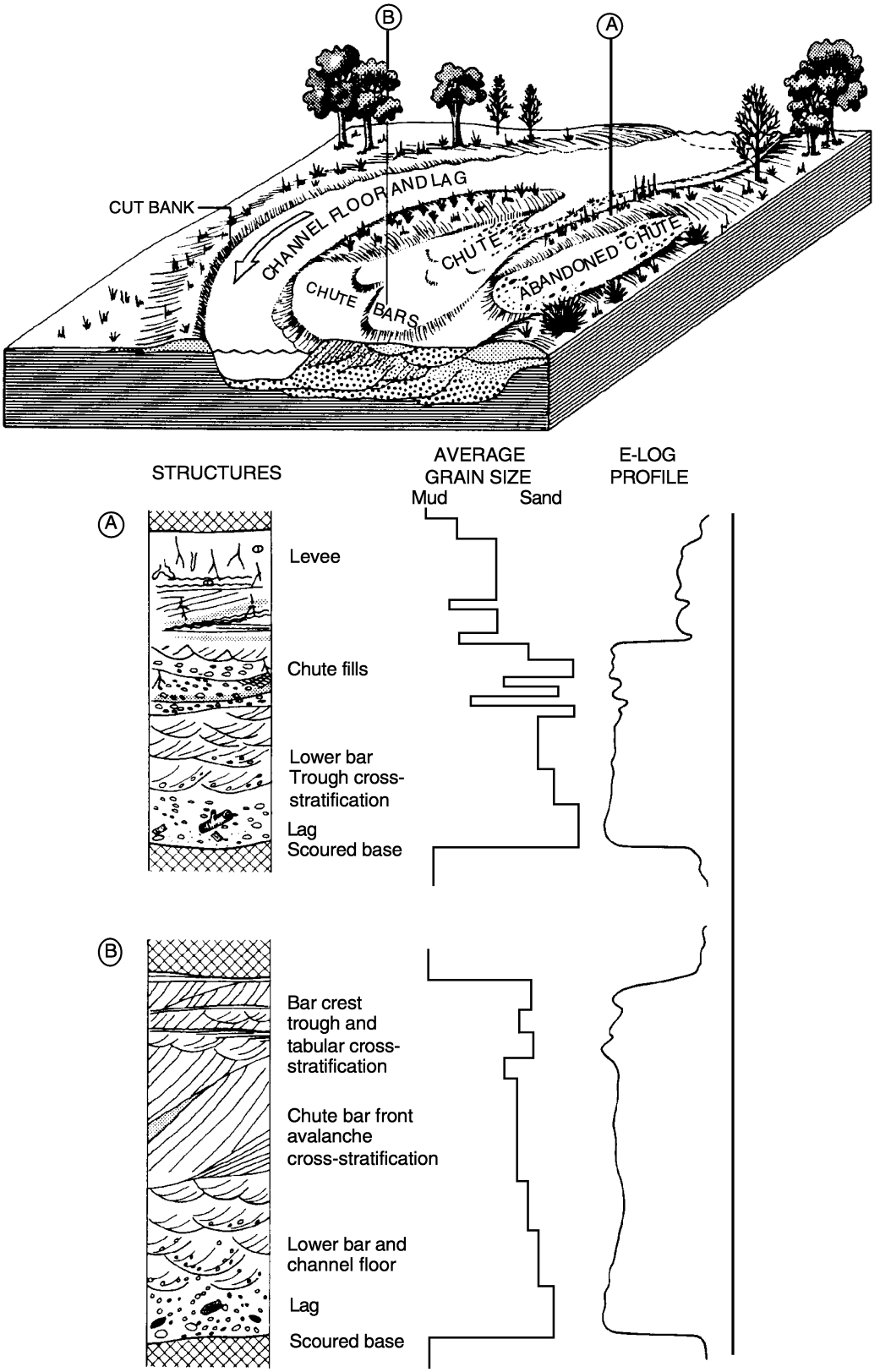

Figure 2–7 **Generalized Depositional Model, Vertical Sequences, and Electric Log (S.P.) Profiles of a Chute-Modified Point Bar (Source: Galloway and Hobday 1983)**

than in braided systems which move large volumes of sediment only under flood conditions. During maximum flood conditions, most meandering systems can move sediment particles much larger than those associated with their bed load.

The average particle size in deposits of meandering systems is smaller than the average particle size in braided systems (see Table 2–3). Braided system deposits such as those of the silt-dominated Brahmaputra system described by Coleman (1969) can be deceptively fine-grained, however, and coarse-grained meandering systems are not uncommon (Cant 1982). Grain size is a poor criterion to distinguish braided from meandering stream deposits.

Channel or bar deposits within meandering systems are generally moderately to well sorted, displaying at least a moderate degree of textural maturity. If overbank deposits are included, however, overall particle size variability of the system may be quite large. Despite the fact that meander belts may migrate laterally with time, meandering systems do not do as thorough a job of reworking their floodplain deposits as do braided systems. Large volumes of overbank silts and clays are available to surround and encase channel deposits of the meander belt.

2.4.3 Meandering System Evolution, Architecture, and Associated Heterogeneities

Meandering systems are typically found depositionally down dip from braided systems. Bank stabilization by vegetation has been an often-cited cause for development of the meandering channel pattern, but the underlying causes are now recognized as being numerous and complex. Meandering reaches can occur in almost any fluvial setting in response to local conditions (Miall 1987), and reaches of alternating braided and meandering style are possible. Reineck and Singh (1980) pointed out that a wide spectrum of meandering systems exists. The most familiar type is the traditional fine-grained, high-sinuosity system. At the other end of the spectrum are coarser grained, low-sinuosity (1.4–1.7) high-gradient systems characterized by more variable discharge, higher bed loads, and more frequent and better developed chutes and chute bars. Meandering systems are usually associated with mature landscapes, where streams are at grade. In an erosive or at-grade situation, a stream is capable, on average over a long period time, of transporting through the channel system all sediment supplied to it. Although meandering systems may be aggradational for long periods of time through deposition of overbank fines, ultimately surface erosion will remove the overbank deposits.

Climate and tectonics are major controlling factors relative to stream morphology and attendant depositional architecture. Because these controlling factors can change with time, systems can change from braided to meandering or vice versa. Examples of such changes include major river systems such as the Mississippi, which was primarily a braided system during the post-Pleistocene rise in sea level (Cant 1982), and the braided Brahmaputra in Bangladesh, which was a meandering system as little as 100 years ago (Coleman 1969).

Preservation of the deposits of meandering systems, especially those next to marine settings, often occurs through relative subsidence of the depositional site by tectonic movement or a rise in absolute sea level. Both mechanisms give rise to inundation by marine conditions with good opportunity for preservation, deposition of seals, and lateral connection with hydrocarbon source beds. Preservation potential in meandering systems is more likely than in braided systems and alluvial fan systems. The braided river and alluvail fan systems are typically located farther from ocean basins, are less likely to be inundated by marine conditions, and require special circumstances for preservation.

Deposits of interest as reservoirs in meandering fluvial systems are associated with the meander belt, where considerable reworking of sediment occurs primarily through channels laterally migrating by bank erosion and point bar deposition (Cant 1982). This primarily sandy belt may itself follow a curving path and is generally encased in dominantly muddy and mostly impermeable overbank sediments. Individual bar sequences within meander belt deposits may be somewhat thicker than their counterparts in braided stream deposits. The total preserved thickness of the meander belt deposit is mainly a function of local relative subsidence and sediment supply. When subsidence occurs slowly and sediment supply is sufficient, avulsions may take place. The resulting lateral relocations of the meander belt create wide expanses of loosely interconnected meander belt deposits. Allen (1978) suggests that if the total section in such instances consists of 50% or more of sand in vertical sequence, individual sandstone bodies are likely interconnected. The probability of interconnection is correspondingly greater if the overall grain size is coarser. When subsidence is rapid and/or sediment supply is insufficient, isolated sandstone bodies result.

Because of the abundance of overbank fine material available within meandering systems, heterogeneity within individual meander belt deposits is usually greater than within deposits of braided systems. Energy within channels may be high, but although bar deposits themselves may be very clean and well sorted, they are commonly separated from one another by fine-grained materials with low permeability such as clay plugs, clay drapes, etc. Because of the wide variation in energies in association with bar deposition, fluid-flow heterogeneity within bar deposits can be great due to high variation in grain size associated with sedimentary structures (crossbeds, laminae, etc.).

2.5 Incised Valleys and Valley-Fill Deposits

An incised valley is created by the downward erosion of a stream into older sediments or rocks caused by steepening its course in response to tectonic movements or a change in sea level (Cant 1982). Relative tectonic uplift can have an effect practically anywhere along the course of a stream. The influence of sea level or base level changes, however, is generally greatest in the lower reaches of a stream's course. Incised valleys may be deep, narrow, and steep sided or broad and shallow in cross section (Brown 1973). They may range from less than one to many tens of miles wide with depths ranging from tens to several hundreds of feet (VanWagoner et al.

1990). Most are relatively straight or gently curving in plan view as a result of lateral or bank erosion by streams during downcutting (Cant 1982). If the rate of relative uplift or sea level drop is rapid, however, incised streams may preserve any meandering morphology originally present. Many of the characteristics of incised valleys, such as their size and distribution, can be related to the dimensions, sediment supply, and other properties of the streams present at the onset of incision (VanWagoner et al. 1990).

If the period of relative uplift or sea level fall that led to incision is followed by periods of stability, uplift, and/or sea level rise, the formerly erosional valleys will experience aggradation and sedimentary fill. The type of fill depends strongly upon location along the course of the incised stream. In the stream's upper reaches, valley fill sediments will probably be fluvial, although almost any morphological stream type could be involved in filling the valley (Cant 1982). In the lower reaches of a stream it is common to find that during its erosive period (usually related to a fall in sea level), it extends itself partly or wholly across a marine shelf exposed to subaerial erosion (VanWagoner et al. 1990). Subsequently, when sea level rises, valley fill sediments may be almost any type. A slow rise in sea level may allow part or all of the valley to be filled by marine shales. Intermediate rates of sea level rise may result in fills with nearshore marine influence such as beach, tidal flat, deltaic or estuarine deposits (VanWagoner et al. 1990). Rapid rise can result in fully fluvial fills, generally with the sedimentological characteristics of braided streams.

Aggradational fluvial deposits in incised valleys are strongly influenced by the confinement provided by the consolidated sediment or bedrock of the valley walls (Cant 1982; Galloway and Hobday 1983). Bank and bed erosion are limited, although meandering may take place freely within the confines of the valley, and channel avulsion is reduced (Galloway and Hobday 1983).

Stream deposits of any morphological type may be present in alluvial valley fills (Cant 1982). The large-scale geometry of resulting deposits is primarily determined by the form of the valley. There is a strong tendency for sand-rich channel deposits to predominate over overbank fines in alluvial fills regardless of the morphological type of the stream occupying the valley (Galloway and Hobday 1983). This occurs because flood waters throughout all but the later stages of aggradation are confined to the incised valley. In narrow, deep valleys coarser channel facies may fill the entire valley. The finer sediment fractions in such instances may be represented only by isolated floodplain remnants and abandoned channel plugs. The typical vertical sequence in a valley fill is a composite, thick, fining-upward unit composed primarily of sand and gravel (Brown 1973; Galloway and Hobday 1983). The nature of the sediment fill may change appreciably (e.g., more fines may be present and the scale of sedimentary structures may decrease) when the level of sedimentary fill reaches a point where floodwaters are no longer confined to the incised valley (Brown 1973).

Identifying ancient fluvial deposits in valley fills requires recognizing the erosional episode that led to valley incision. Recognition of erosional episodes may be difficult in any reaches of a fluvial/alluvial system where incision occurred into previously deposited fluvial/alluvial sediments. In the lower reaches of a system, however, careful regional and/or local stratigraphic

analysis can provide significant clues (Galloway and Hobday 1983; VanWagoner et al. 1990). Large and abrupt basinward shifts of sedimentary facies characterize the erosional events accompanying incision. Fluvial deposits can rest directly on middle to outer marine shelf deposits with no indication of sediments deposited in intermediate environments (VanWagoner et al. 1990). Such sudden vertical changes in facies accompanied by stratigraphic and or sedimentologic evidence of erosion at the base of fluvial deposits are excellent indicators of valley fills.

2.6 Gradational Nature of Fluvial/Alluvial Systems and Their Deposits

After examining the spatial distribution of a wide variety of fluvial/alluvial systems and often observing that the basic nature of these systems can change with time, prominent fluvial/alluvial researchers have concluded that end member fluvial/alluvial system types are more or less completely gradational (Cant 1982; Miall 1987). In essence, the characteristics, processes, and deposits of alluvial fan systems, braided systems, and meandering systems are gradational both in space and time. Because fluvial/alluvial systems potentially can be extensive in space (length) and time (duration), it is important to consider the repercussions of such a conclusion.

Both alluvial fan and braided systems represent aggradational, although temporary, episodes in transport of loose rock and soil material away from areas of relative uplift. The expression of each morphological type reflects complex tectonic and climatic controls on discharge variability and volume, gradient, and sediment availability. Because the controls are continuously variable spatially, alluvial fan systems or deposits may pass laterally into braided systems or deposits. Similarly, controls can vary with time causing a vertical transition from one system type to another. For example, it is common to find the surface of many modern alluvial fans covered by networks of braided streams that, although they are in equilibrium with present controls, may not be responsible for deposition of the bulk of the underlying fan (Blair and McPherson 1994). In arid environments, alluvial fan and braided systems are characteristically distinct. In humid climates, however, the two end member types take on similar characteristics and may be indistinguishable unless a criterion such as presence of mud flow or debris flow deposits is used to differentiate them.

The same stream or river may exhibit braided or meandering channel morphology in different parts of its course in response to changes in tectonic and climatic controls. Changes in controls through time may cause changes in the local morphology of a stream (Burnett and Schumm 1983; Peterson 1984; Carson 1984; Miall 1987). In fact, modern streams reflect current controls and are often found to be at odds with their associated deposits. The channel morphology of streams at various flow stages may be different also; some streams that exhibit meandering form at bank full flow are braided at stages of low flow (Reineck and Singh 1980). Disequilibrium between modern rivers and their earlier deposits is especially prevalent in North America. Here, erratic and voluminous discharge and high sediment availability associated with Late

Pleistocene deglaciation produced an abundance of aggradational situations favoring braided channel morphology. Many of these aggradational situations have since been replaced by postglacial rivers with lower and more constant discharge, often displaying a meandering channel morphology.

These discussions indicate that we should anticipate that the character of fluvial/alluvial systems and their associated deposits will change with time, because their morphology is controlled by ever-changing tectonics and climate. It would therefore be unwise to assume that fluvial style will remain constant throughout any given stratigraphic unit (Miall 1987).

Distinguishing the morphological type (e.g., alluvial fan, braided, or meandering system) of fluvial/alluvial deposits by using subsurface data may be difficult. With the exception of some alluvial fans constructed mostly by mud flows and/or debris flows, nearly all fluvial/alluvial deposits are formed by flowing water characterized by a wide range in flow energies. A small number of observations may not be sufficient to make the distinction (Miall 1987). Fining-upward vertical sequences corresponding to the ebb and flow of flood events can be found in all fluvial/alluvial systems. Proportions of coarse bar sands or presence of lateral accretion bar deposits likewise cannot be used alone to differentiate fluvial system types (Miall 1987; Miall 1988). Only multiple observations from an aggregate of deposits may give a clue to fluvial/alluvial system morphology (Cant 1982; Miall 1987).

2.7 Significant Differences and Similarities in Deposits of Fluvial/Alluvial Systems

Several characteristic heterogeneities within deposits of fluvial/alluvial system morphologic end member types are potentially consequential to oil recovery operations. Deposits of alluvial fan systems are usually not as well sorted as those of other fluvial/alluvial system types. Heterogeneities related to mineralogical variations are also of concern in producing from alluvial fan deposits. Braided system deposits characteristically are more areally extensive than alluvial fan deposits. They also have somewhat better sorting (due to fines removal) and usually have a somewhat more uniform and mature mineralogic composition than alluvial fan deposits. Meandering systems have slightly thicker, slightly better sorted and more mineralogically mature channel deposits than braided systems. Sandstones in deposits of meandering systems are generally less laterally extensive and their lateral continuity is characteristically interrupted by impermeable deposits of overbank fines. The relatively complete spectrum of possible gradations between the braided and meandering system types, however, implies that a similarly complete gradation in their typical heterogeneities also exists. Because deposit characteristics are gradational between all three end member fluvial/alluvial system types, the most useful approach is to focus on the common properties of all fluvial/alluvial deposits that distinguish them from deposits of other depositional environments.

The stratigraphic context of a deposit is a powerful indicator of its likelihood of fluvial/alluvial association. Consideration may be on a local scale, such as in establishing the presence of coal or peat deposits of meandering river floodplains, or on a regional scale, such as would be required in tracing contemporaneous deposits updip from shallow marine through deltaic and shoreline-associated deposits into the fluvial/alluvial realm.

Other powerful indicators of fluvial/alluvial origin are sand body orientation, geometry, size, and thickness. Elongation of sandbodies perpendicular to established paleoshorelines is good supporting evidence for nonmarine deposition, particularly if deposits are located between basins and uplifted areas. Sand bodies with thickness, size, and shape in ranges characteristic of any of the fluvial/alluvial systems constitute further evidence.

Presence of facies and vertical sequences of facies typical of any of the end member systems is also a strong indicator of fluvial/alluvial origin. Perhaps the most characteristic sedimentologic feature of fluvial/alluvial systems, however, is their extreme heterogeneity. Deposits of fluvial/alluvial systems are probably the most heterogeneous of all common depositional systems. They are characterized by frequent and drastic lateral and vertical changes in sediment and fluid-flow properties. This variability, which commonly is expressed as sediment packages of small areal extent with fining-upward grain size trends, reflects the variations in depositional energy that are characteristic of fluvial/alluvial systems. Because of partial erosion of sediment packages during subsequent events and multiple vertical stacking of sediment packages, not all vertical sequences associated with fluvial/alluvial systems display fining-upward grain size trends. However, other sedimentological criteria, such as erosional basal contacts on sediment packages, and an average conformance of paleocurrent indicators, such as crossbeds, in a depositionally down dip direction are also indicators of fluvial/alluvial deposition.

A lack of marine indicators is also a criterion for distinguishing fluvial/alluvial deposits (Friedman and Sanders 1978; Cant 1982). No flora, fauna, or particles indicative of marine conditions should be present, but presence of grains such as fossils or glauconite reworked from older deposits can make this criterion difficult to apply correctly.

Presence of terrestrial plant fragments, including leaves, roots, stems, pollen, etc., can also be a fluvial/alluvial indicator. However, because these materials may be carried by streams and rivers into marine environments, their presence should be used with caution in confirming fluvial/alluvial deposition. Similarly, remains of terrestrial fauna (e.g., bones, teeth, etc.) can indicate fluvial/alluvial deposition, but this criterion should also be used with caution because of the potential for transporting such fragments into marine deposits. Careful attention should be paid to document the quantity and distribution of such materials, and other criteria should be used to corroborate the interpretation.

Because of the likelihood of exposure to oxygenated water during early diagenesis, deposits of fluvial/alluvial systems in general may develop characteristics that are distinct from those of other deposystems (Cant 1982). Oxygen-bearing fluids may react with the varied mineralogy of detrital grains to produce early pore-filling clays. The same fluids may react with iron minerals

present to form hematite which provides the deposits with a distinctive red coloration. Of course, there are exceptions; oxygen-rich diagenetic alteration can produce similar results in deposits not of fluvial/alluvial origin; and not all environments associated with fluvial/alluvial systems are oxygen-rich (e.g., reduced overbank floodplain marsh deposits of meandering rivers).

In practice, none of these criteria for recognition of fluvial/alluvial systems should be used alone to identify deposits as fluvial/alluvial in origin. The support of several of the above criteria will generally be necessary.

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CHAPTER 3
GEOLOGICAL AND PRODUCTION CHARACTERISTICS OF FLUVIAL/ALLUVIAL RESERVOIRS

Chapter 3 summarizes the characteristics of Class 5 reservoirs based on analysis of relevant geologic and engineering literature and information from DOE's TORIS database. As an introduction, Section 3.1 provides an overview of Class 5 fluvial/alluvial reservoirs as a whole. This overview focuses on the geographic and geologic distribution of the Class 5 resource and presents a summary of the reservoir and production characteristics of Class 5.

Individual geographic regions with Class 5 production are treated separately in Sections 3.2 through 3.4. This geographic breakout was performed (1) to emphasize differences in resource and reservoir size, reservoir depositional type, reservoir maturity, and operator profile among the major Class 5 areas and (2) to allow the resource to be considered in an organized fashion to ascertain research, development, and demonstration needs. Depositional history and geologic, reservoir, and production characteristics are addressed for major plays and subplays within each of these major regions. In addition, summaries are provided for any notable improved oil recovery (IOR) process applications. Section 3.2 presents information on the large Class 5 reservoirs and resource of Alaska, predominantly braided stream reservoirs of only moderate maturity developed by major oil companies in the last half of the twentieth century. Section 3.3 deals with the moderate-to-large, dominantly heavy oil resource of California, contained largely in mature reservoirs mostly of alluvial fan origin and operated mainly by major oil companies. Section 3.4 summarizes smaller, very mature Class 5 reservoirs found in various basins around the country in states other than Alaska and California. These reservoirs represent a wide variety of fluvial/alluvial depositional environments and a spectrum of operators from major oil companies to small independents.

As a step toward defining Class 5 research, development, and demonstration needs, two additional sections are included in this chapter. Section 3.5 compares and contrasts salient geological and production characteristics among Class 5 reservoirs in the major geographic regions defined previously. Similarly Section 3.6 presents a summary of significant past and current IOR process applications in Class 5 reservoirs.

3.1 Overview of Class 5 Reservoirs

This section provides a cursory summary of the Class 5 resource in terms of geographic distribution by state (see Section 3.1.1), geologic distribution by basin and end member depositional system type (see Section 3.1.2), and reservoir and production characteristics (see Section 3.1.3).

3.1.1 Geographic Distribution of the Resource

The geographic distribution of both original oil in place (OOIP) and remaining oil in place (ROIP) in Class 5 reservoirs in the TORIS database is decidedly uneven (see Fig. 3–1)). Over 80% of OOIP and ROIP in Class 5 reservoirs is in Alaska and California. A more detailed division of the Class 5 resource into produced and remaining categories is presented by state in order of descending ROIP in Table 3–1, which was compiled from the TORIS database using only those Class 5 reservoirs with appropriate reserves and recovery information available. Table 3–1 also shows the strong contrast in proved reserves in Alaskan and Californian reservoirs versus reserves in other states.

Although Alaska and California dominate Class 5 with respect to both proved reserves and ROIP, over 70% of Class 5 reservoirs occur in other states (see Table 3–1). Calculated from the data in Table 3–1, Class 5 reservoirs in other states average about 65 million barrels of ROIP versus 650 million barrels for Alaskan and Californian reservoirs.

3.1.2 Geologic Distribution of the Resource

Class 5 production comes from a wide variety of basins of different age and markedly different development histories (see Fig. 3–2). Discussion of individual plays and reservoirs in the context of development of many of the basins depicted in this figure will be found in Sections 3.2 through 3.4.

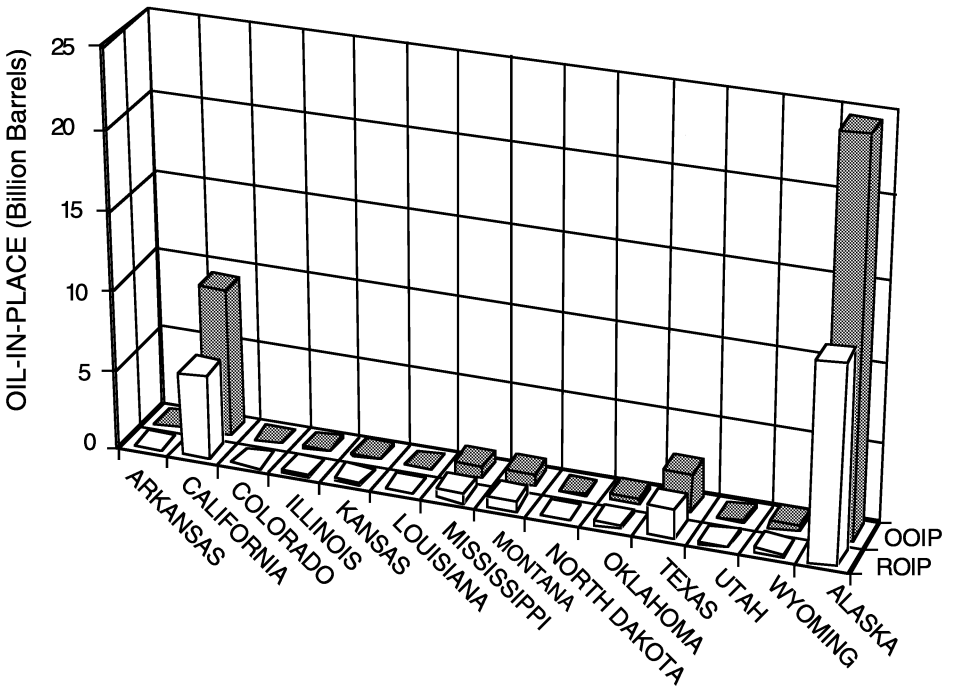


Figure 3–1 Distribution of Original Oil in Place (OOIP) and Remaining Oil in Place (ROIP) in Class 5 Reservoirs by State (Source: BPO TORIS 1995)

Table 3–1
Geographic Distribution of Class 5 Resources by State (Source: BPO TORIS 1995)

State	Original Oil in place MBO	Cumulative Recovery MMBO	Proved Reserves MMBO	Remaining Oil in place MMBO	Number of Reservoirs
Alaska	24,510	9,363	2,809	12,338	7
California	9,340	2,939	1,082	5,319	20
Texas	2,519	690	10	1,819	19
Montana	833	187	<1	646	6
Mississippi	782	246	1	535	4
Oklahoma	424	88	1	330	2
Wyoming	376	151	1	224	13
Kansas	78	26	1	54	1
Other*	168	56	2	110	10
Total	39,030	13,746	3,907	21,377	84

* Sum of states with less than 100 MMBO ROIP each.

A division of original oil in place (OOIP) among the various end member fluvial/alluvial system types in the TORIS database is presented in Figure 3–3. The dominance of the braided stream category is notable. TORIS data predict that ultimate recovery efficiency will also be highest in the braided stream category, where approximately 48% of OOIP will be recovered under current operations. In alluvial fan reservoirs ultimate recovery efficiency will be only 42% and in meandering stream reservoirs only 38% of OOIP. These recoveries are consistent with the depositional nature of the end member deposit types as discussed in Section 2.7. Alluvial fan systems typically have poor sorting which suggests poor recovery, but their reservoirs are not usually severely compartmentalized by overbank fines to the extent observed in meandering stream deposits. Deposits of braided systems, despite heterogeneities due to grain size variation, are the most uniform of the three end member types.

By sheer number in the TORIS database, meandering streams are the most abundant depositional end member reservoir type (see Fig. 3–4). Therefore, considering the data presented in Figures 3–3 and 3–4, reservoirs of the meandering stream type are considerably smaller on average than reservoirs of the alluvial fan or braided stream types.

3.1.3 Reservoir and Production Characteristics

The average reservoir parameters for Class 5 in Table 3–2 reservoirs were calculated state by state from TORIS data. Average values for depth, net pay, porosity, permeability, initial oil saturation, oil gravity, initial pressure, and ultimate recovery factor are summarized.

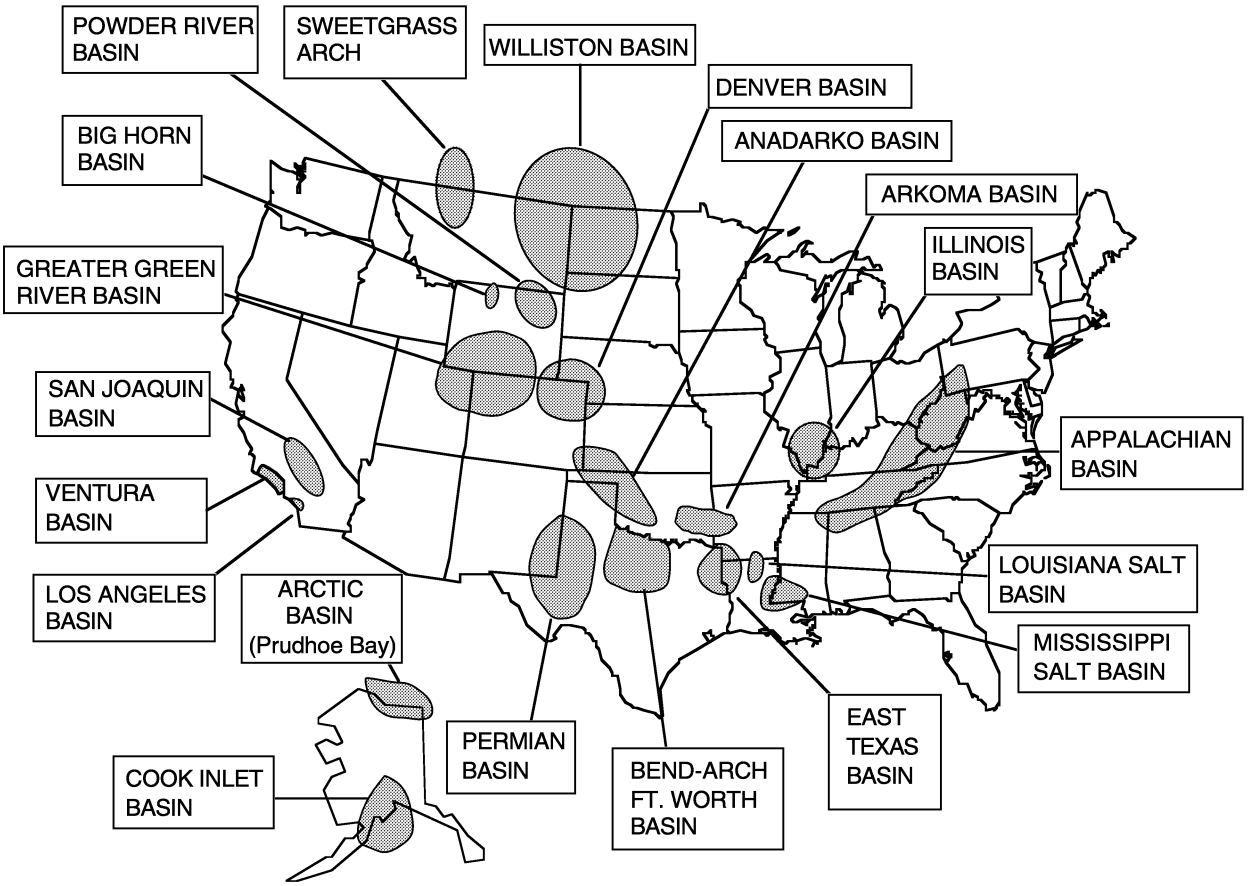


Figure 3–2 Basins Containing TORIS Class 5 Reservoirs (Modified from Galloway et al. 1983; Rasco and Adler 1983; Merschat 1985; Peterson 1985; Lyday 1985; California Oil and Gas Fields 1985 and 1991; Frezon and Finn 1988; Zuppann 1988; Roehler 1992)

Average Class 5 reservoir depth ranges from less than 1,500 feet in the eastern United States to a maximum of over 9,000 feet in Alaska. Average net pay thickness is notably greater in Alaska and California (207 and 153 feet, respectively) than in reservoirs in the rest of the United States (23 feet). California reservoirs appear to have the best reservoir quality in terms of porosity (29%) and permeability (1,119 mD), but oil gravity averages only 19° API in California reservoirs versus typical gravities in the 30° to 40° API range in all other areas. In the light oil category, reservoirs in Alaska have the poorest overall permeabilities (124 mD) and low average porosities (17%), while reservoirs of the eastern Gulf Coast have the highest permeabilities (562 mD) and porosities (24%).

The distribution of reservoir mean porosities for TORIS Class 5 is distinctly bimodal (see Fig. 3–5). Diagenetic alteration, discussed in Section 3.2.1.3, is the most probable explanation for this distribution. Oil gravity in Class 5 reservoirs also shows a distinct bimodal distribution (see Fig. 3–6) with a definite separation at about 30° API. In this instance, the observed bimodality is largely a function of geographic location.

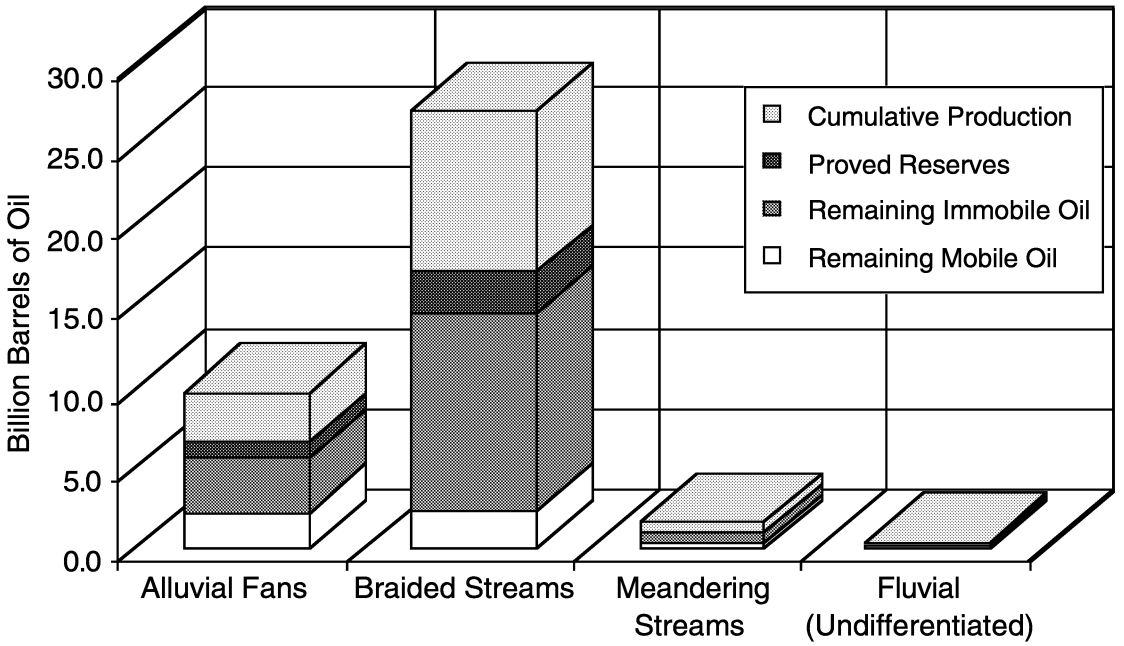


Figure 3–3 Distribution of Class 5 Original Oil in Place by Fluvial/Alluvial Depositional System Type (Source: BPO TORIS 1995)

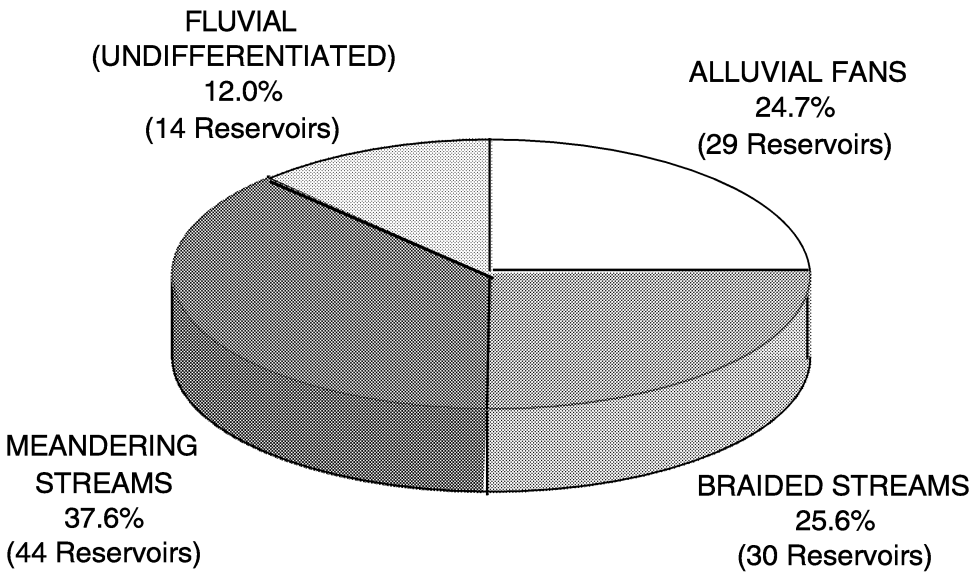


Figure 3–4 Distribution of Class 5 Reservoirs by Fluvial/Alluvial Depositional System Type (Source: BPO TORIS 1995)

Table 3–2
Summary of Average Reservoir Properties in Major Class 5 Producing Areas (Source: BPO Toris 1995)

Region	Depth, ft	Net Pay, ft	Porosity, %	Permeability, mD	Initial Oil Sat., %	Oil Gravity, ° API	Initial Pressure, psi	Ultimate Recovery, %
Alaska	9,076	207	17	124	62	35	4,390	46
California	3,474	153	29	1,119	66	19	1,487	27
Other Areas								
N. Rocky Mountains	4,265	22	17	177	70	37	1,921	44
S. Rocky Mountains	6,033	32	17	196	66	41	2,721	31
W. Texas	5,201	23	17	238	70	37	2,191	36
E. Gulf Coast	5,182	25	24	562	67	33	2,308	48
E. United States	1,413	12	17	273	73	34	617	30
Avg. All Other Areas	4,419	23	19	294	69	36	1,952	40
Avg. All Regions	5,656	128	21	512	66	30	2,610	38

Figure 3–7 shows the TORIS production history from 1970 thorough 1993 for Class 5 reservoirs. The sharp increase in production beginning in 1976 corresponds with the onset of light oil production from the Prudhoe Bay Field on Alaska's North Slope. Removing all Alaskan production from the production history of Figure 3–7 results in a plot dominated by heavy oil strongly reflecting Californian production (see Fig. 3–8). Taking the process of elimination one step further by also eliminating all Californian production yields the decline curve plot for Class 5 reservoirs in all other states (see Fig. 3–9). The low current rate of production and the relatively rapid rate of production decline shown on Figure 3–9, coupled with the scarcity of proved reserves (see Table 3–1), emphasize the extreme maturity of these reservoirs and the need for prompt action to maintain access to the resource.

Figure 3–10 shows the frequency distribution of temperature and salinity for the 66 Class 5 reservoirs in DOE's TORIS database that have such data. Figure 3–11 shows the temperature-salinity distribution of ROIP for the same reservoirs. Applicability of most enhanced oil recovery (EOR) processes depends upon reservoir temperature and salinity (see Appendix C, Section C.2). Most Class 5 reservoirs (and the majority of the Class 5 ROIP) occur within acceptable temperature and salinity limits for EOR process application (see Appendix C, Tables C–1, and C–2).

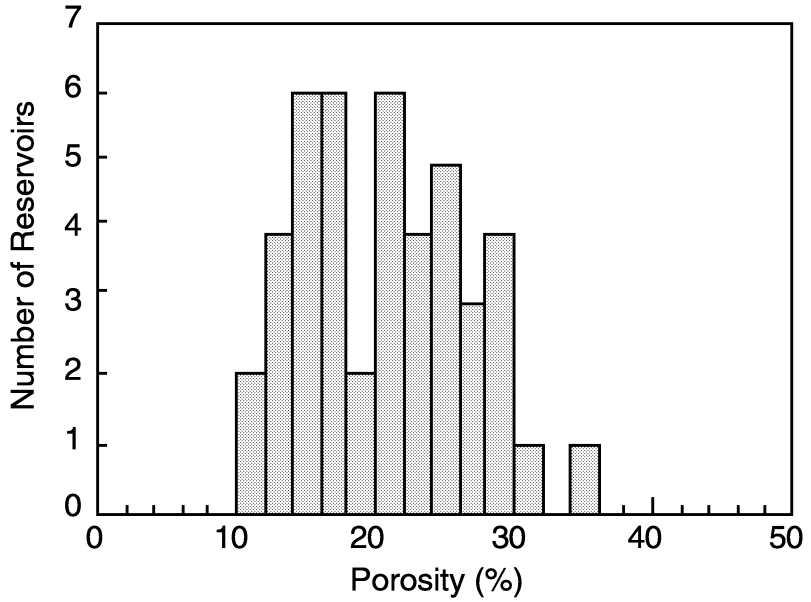


Figure 3–5 Distribution of Mean Porosity in Class 5 Reservoirs (Source: BPO TORIS 1995)

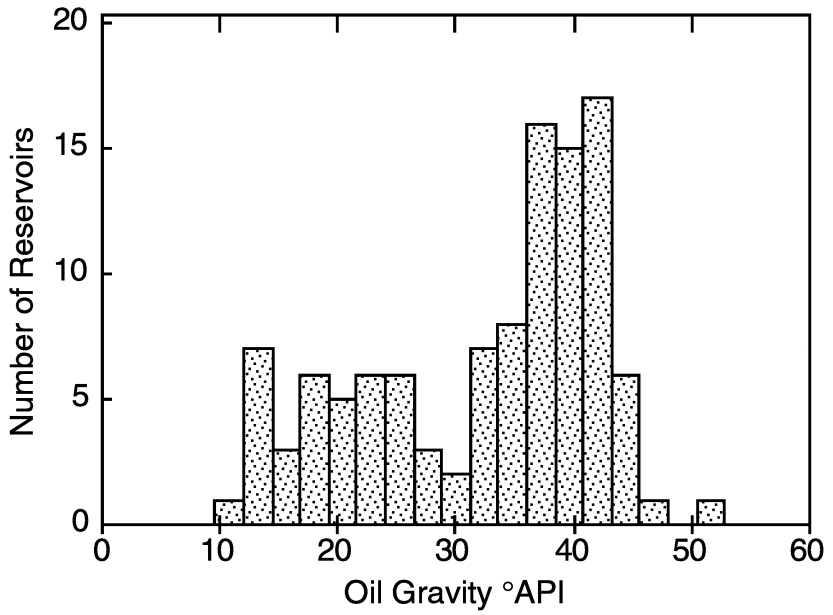


Figure 3–6 Distribution of Oil Gravity in Class 5 Reservoirs (Source: BPO TORIS 1995)

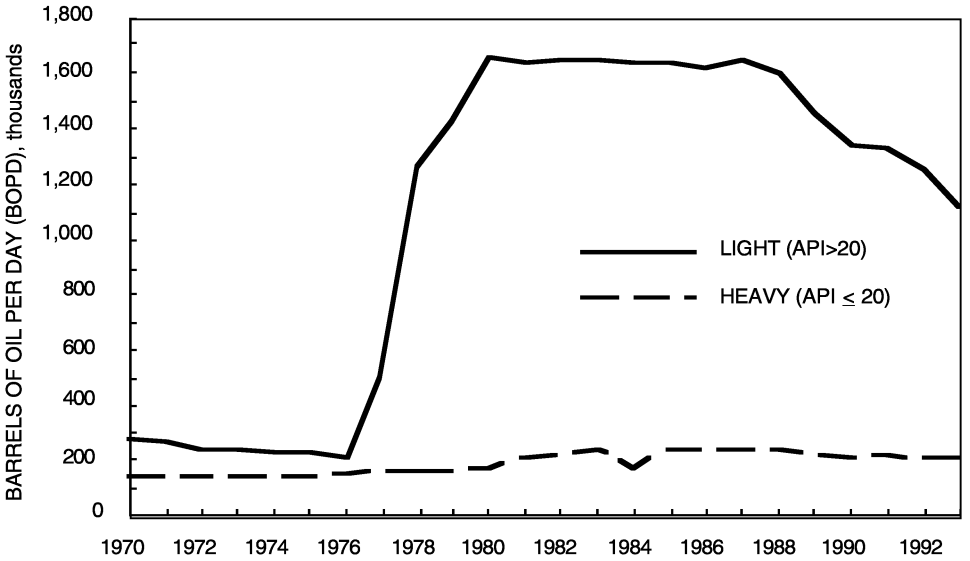


Figure 3–7 Production History for Class 5 Reservoirs (Source: BPO TORIS 1995)

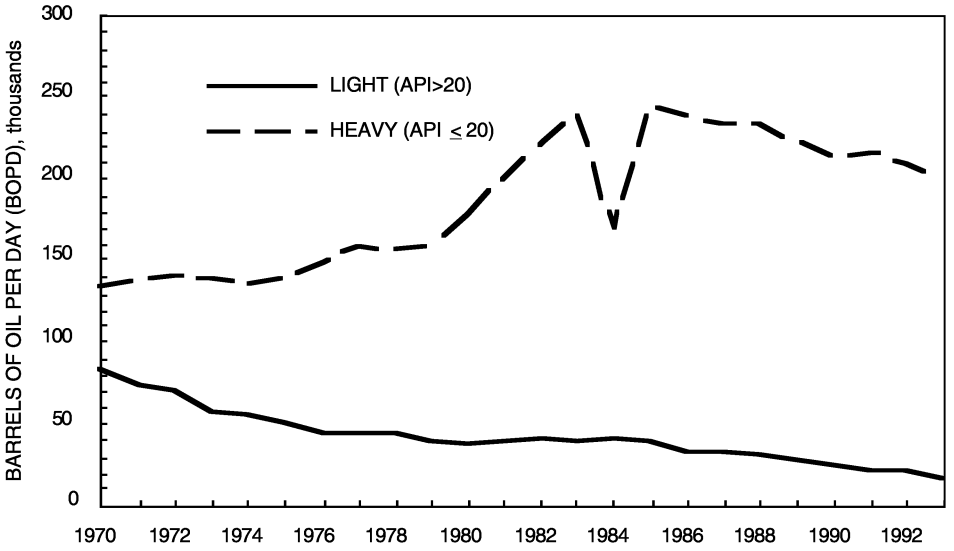


Figure 3–8 Production History for Class 5 Reservoirs—Excluding Reservoirs in Alaska (Source: BPO TORIS 1995)

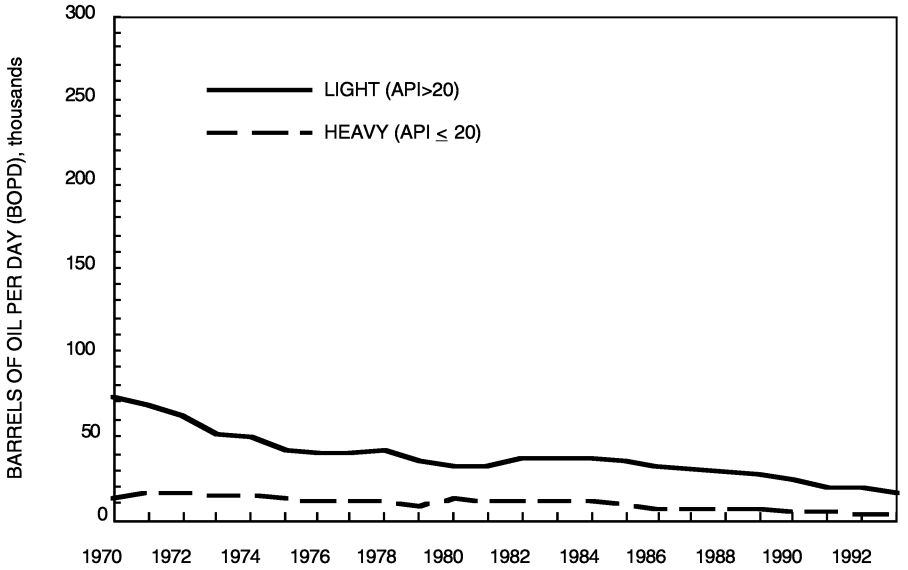


Figure 3–9 Production History for Class 5 Reservoirs—Excluding Reservoirs in Alaska and California (Source: BPO TORIS 1995)

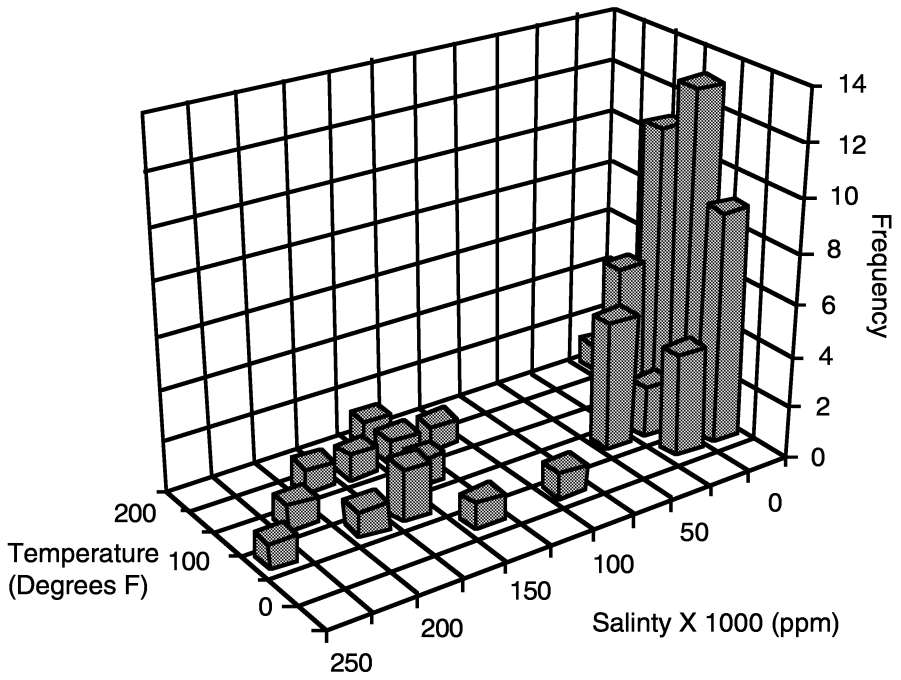


Figure 3–10 Frequency Distribution of Temperature and Salinity for Class 5 Reservoirs (Source: BPO TORIS 1995)

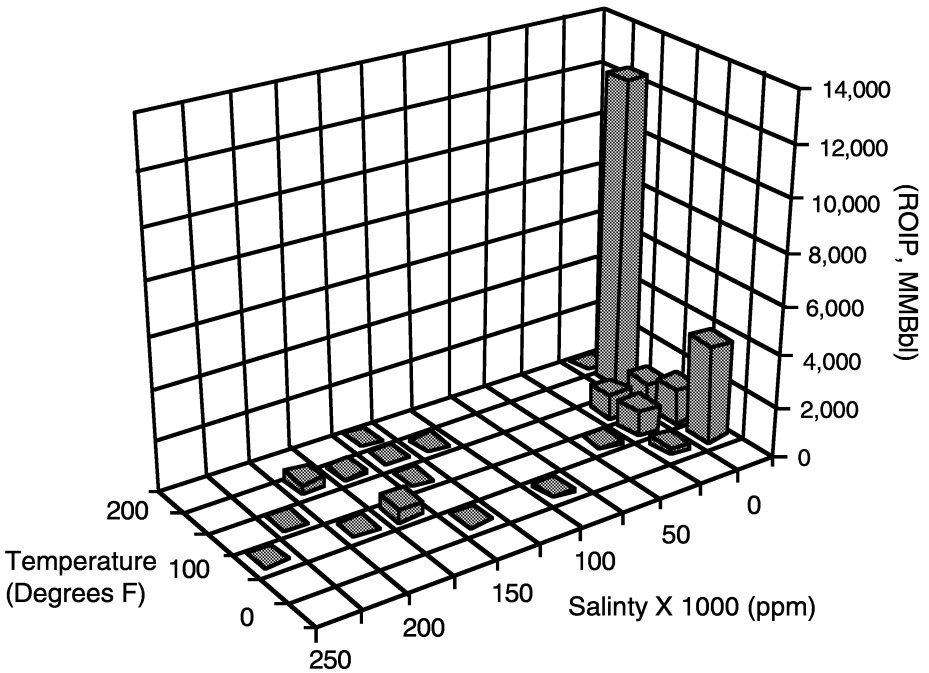


Figure 3–11 Distribution of Remaining Oil in place (ROIP) by Temperature and Salinity for Class 5 Reservoirs (Source: BPO TORIS 1995)

Based on TORIS production volumes, major oil companies operate over 98% of the TORIS Class 5 production (see Table 3–3). Class 5 reservoirs in Alaska are exclusively operated by major oil companies, and nearly 97% of Class 5 production in California is also operated by majors. Only in states other than Alaska and California do independents play a significant role in Class 5 production. Even in the other states, however, major oil companies operate nearly 60% of production.

3.2 Major Plays in Alaska

In Alaska, the most prolific producing region for Class 5, two plays account for essentially all Class 5 production. One play is associated with the Prudhoe Bay Field on Alaska's North Slope; the other is associated with production from numerous Class 5 reservoirs in the Cook Inlet Basin southwest of Anchorage. The following sections (3.2.1 and 3.2.2) discuss geological, reservoir, and production characteristics of the two major Alaskan Class 5 plays and also review the important improved oil recovery activities in each. The majority of Alaska Class 5 reservoirs produce from braided stream deposits (see Fig. 3–12).

Table 3–3 Class 5 Operator Profile Summary (Source: PI Data 1991; Beck and Biggs 1992; BPO TORIS 1995)				
Operator Size (Total Co. Reserves)	**Alaska %**	**California %**	**OtherStates %**	**Total %**
Majors (>250 MMBO)	100.0	96.8	59.5	98.3
Large Independents (100 to 250 MMBO)	0.0	2.9	1.6	0.2
Midsize Independents (10 to 100 MMBO)	0.0	0.0	2.2	0.1
Small Independents (<10 MMBO)	0.0	0.3	36.7	1.4

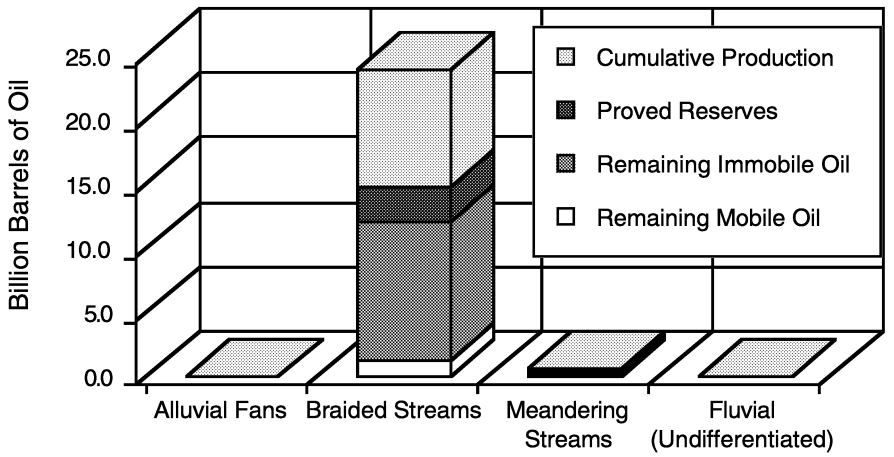


Figure 3–12 Distribution by Depositional System Type of Original Oil in Place in TORIS Class 5 Reservoirs in Alaska (Source: BPO TORIS 1995)

3.2.1 The Sadlerochit/Ivishak Play at Prudhoe Bay

The dominantly fluvial/alluvial deposits of the Ivishak Sandstone of the Permian-Triassic Sadlerochit Group comprise the most prolific producing horizon in the giant Prudhoe Bay Field on Alaska's North Slope (see Fig. 3–13A). Prudhoe Bay, discovered in 1968, is the northernmost oil field in the world and is the largest oil and gas field in North America (Wadman et al. 1979).

3.2.1.1 Depositional History and Facies Characteristics

Permian to Triassic Age sediments in the Prudhoe Bay area were derived from no-longer-existent highlands, the Beaufort Uplift, to the north (Melvin and Knight 1984; Wood 1985). Sediments eroded from this uplift were transported southward toward a marine basin in the direction of the present day Colville Trough. In the Prudhoe Bay area these sediments formed progradational deposits 200–500 feet in thickness (Geehan et al. 1986). On the basis of a complete lack of indigenous macrofauna and microfauna, presence of an abundant and varied assemblage of terrestrial pollens (Jones and Speers 1976), and abundant sedimentological and stratigraphic evidence, Ivishak deposits have been interpreted as of fluvial or alluvial fan origin by most authors. Most commonly they have been interpreted as braided streams prograding seaward over shallow marine and shoreline-associated clastics.

The initial progradation over deltaic and marine deposits resulted in a complex of mixed sandy and pebbly sediments up to about 300 feet thick (Jamison et al. 1980). This series of deposits contains individual fining-upward sequences up to 25–30 feet thick as well as thinner 2–10 foot thick sequences showing no distinct change in grain size vertically. This series has been interpreted as braided stream or mixed braided and meandering stream in origin (see Fig. 3–14) (Eckelmann et al. 1976; Geehan et al. 1986; Lawton et al. 1988). Although dominated by sand,

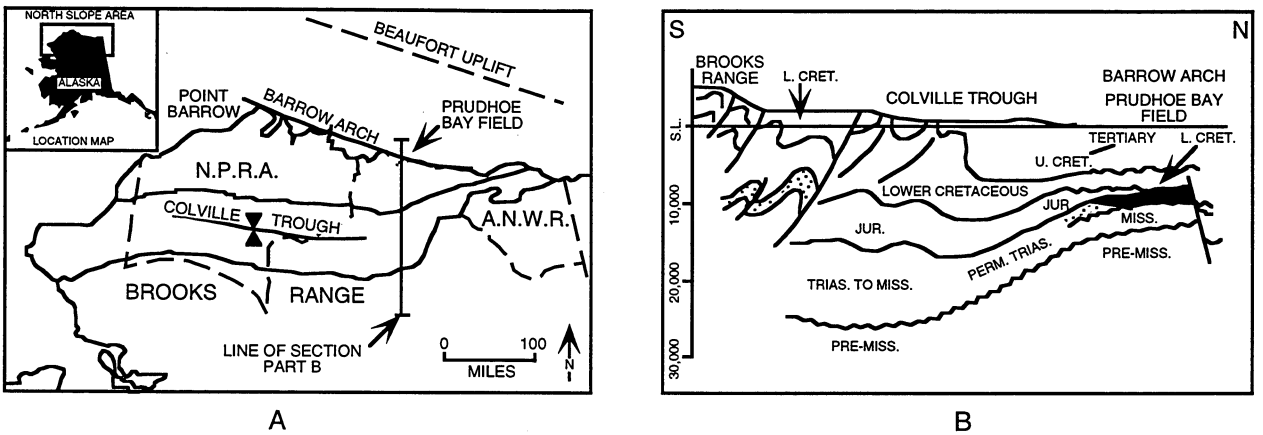


Figure 3–13 Prudhoe Bay Field on Alaska's North Slope. (*A*) North Slope Structural Features (*B*) Structural Cross Section Through the Prudhoe Bay Field (Modified from Atkinson et al. 1990)

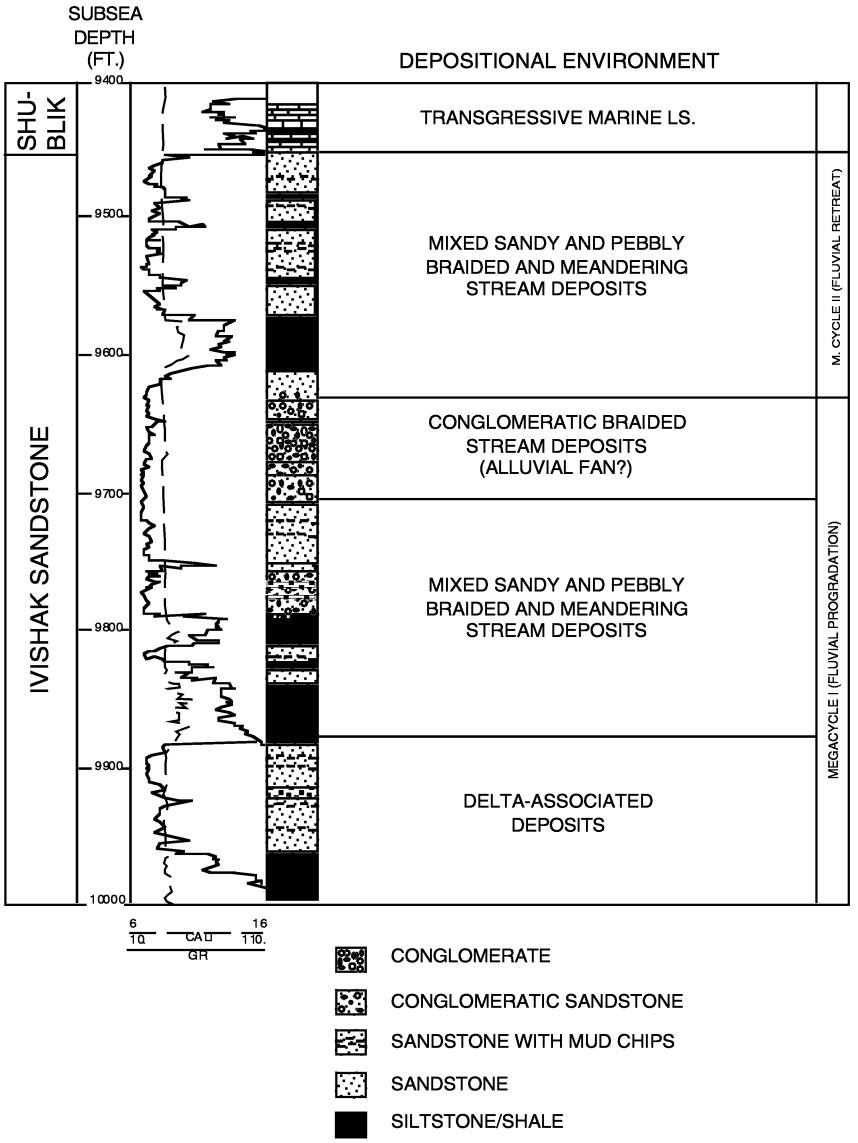


Figure 3–14 Ivishak Formation Vertical Lithologic Sequence and Type Log (Modified from Atkinson et al. 1990)

these deposits contain abundant examples of continuous (i.e., extending over one or more well spacings) low-permeability, 6-inch-to-4-foot-thick siltstones or shales and other less areally extensive or discontinuous siltstones or shales interpreted as floodplain and abandoned channel deposits, respectively (Lawton et al. 1988; Atkinson et al. 1990). Thinner more localized discontinuous shales represent drapes and other slack water deposits formed in the last waning

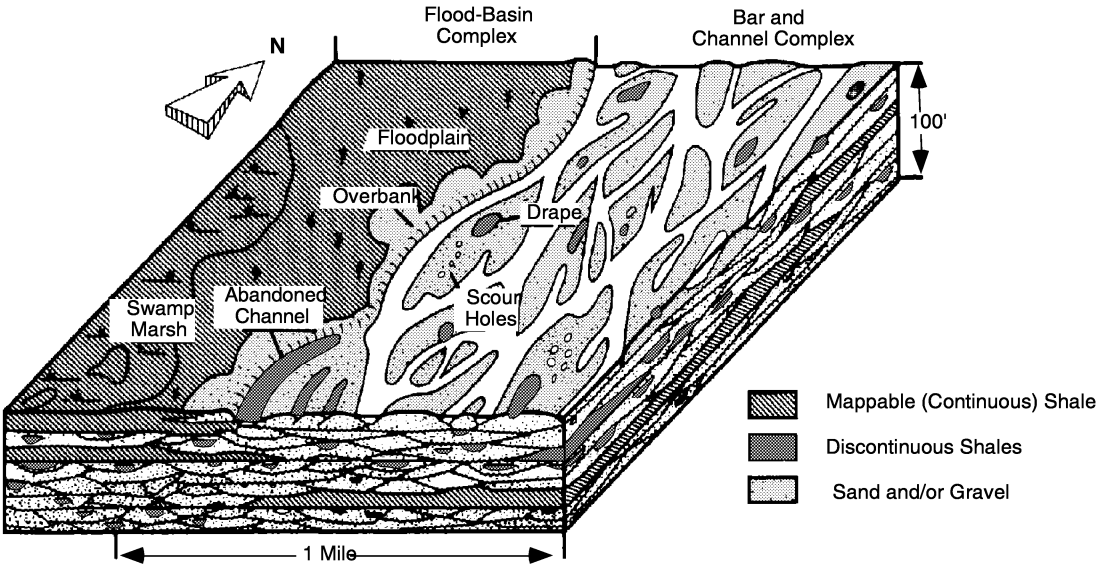
stages of floods or in the lee of bedforms or fluvial bars. These low-permeability layers are more abundant in the lower part of the section. Figure 3–15A is a reconstruction of depositional environments representing the bulk of the nonmarine portion of this initial progradational unit.

Continuing the progradation, the immediately overlying 40–140 foot thick section is predominantly a clast-supported conglomerate with clasts up to cobble size and a poorly sorted coarse sand matrix (Jamison et al. 1980; Lawton et al. 1988). Grain size coarsens upward through this unit as does the thickness of individual depositional sequences (4–10 feet), but coarsening upward trends within individual sequences are not always evident (Geehan et al. 1986; Lawton et al. 1988). Most commonly this unit is interpreted as braided stream deposits, but in some instances an alluvial fan interpretation has been offered based on recognized debris flow criteria (see Fig. 3–14) (Melvin and Knight 1984). Despite its overall coarse grain size, this unit is interspersed with sandy sequences and with low-permeability siltstone or shale beds, the latter interpreted as abandoned channel fills (Lawton et al. 1988). Figure 3–15B is a reconstruction, assuming a braided stream interpretation, of depositional environments representative of the conglomeratic unit.

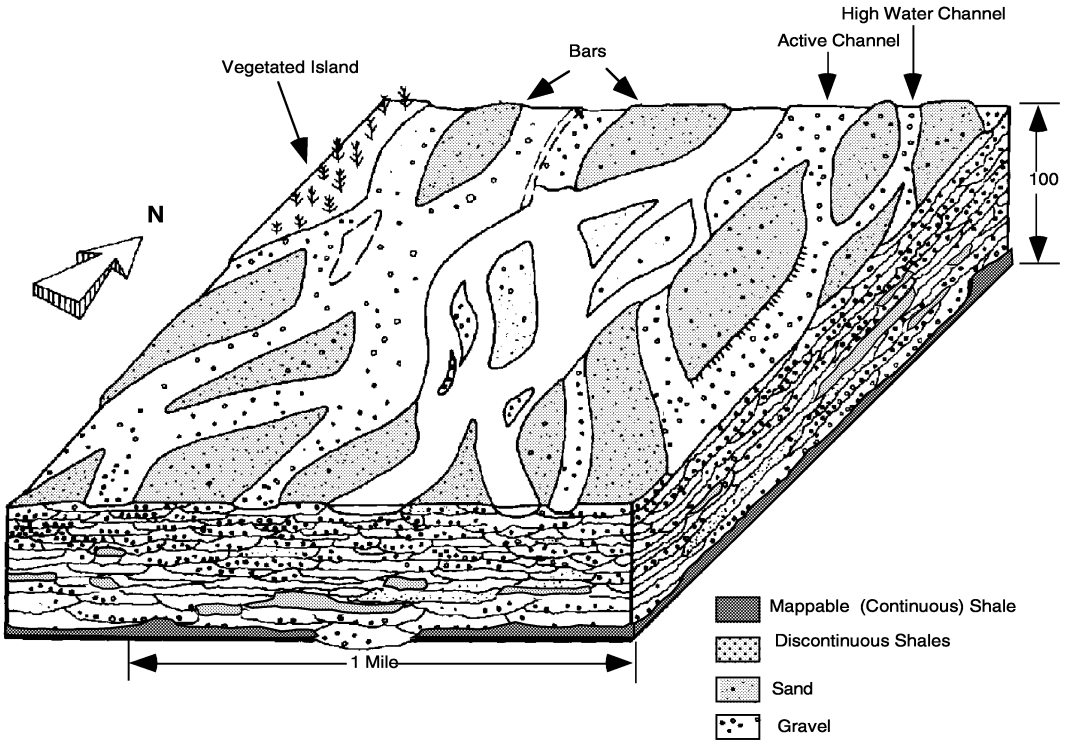
Immediately overlying the conglomeratic unit is a roughly 200 foot thick unit dominated again by sand size sediment (Jamison et al. 1980). There is a gradual upward decrease in average grain size throughout this unit ranging from medium sand near the base to fine sand near the top (Melvin and Knight 1984). Grain size change is also accompanied by an upward increase in shale ripup clasts or mud chips derived from erosion of floodplain and abandoned channel deposits (Lawton et al. 1988). Thickness of individual fining-upward sequences throughout this unit averages about 8 feet, and the deposits have been interpreted as being of braided stream and/or mixed braided and meandering stream origin (see Fig. 3–14) (Geehan et al. 1986; Lawton et al. 1988; Atkinson et al. 1990). The abrupt onset of the fluvial retreat or relative transgression represented by the deposits of this unit with respect to the underlying conglomerates most probably is due to erosional reduction of the source area accompanied by some reworking or erosion of the upper portion of the underlying conglomeratic unit (Eckelmann et al. 1976). The source area may have eroded as a result of decreased tectonic activity and/or climatic change that increase the effectiveness of erosional processes. Figure 3–15A represents the dominant depositional environments of this transgressive unit.

3.2.1.2 Trapping Mechanism

Continued subsidence and marine transgression in the Prudhoe Bay area and southward were responsible for preservation of the aggraded fluvial/alluvial deposits of the Ivishak. Subsidence was followed by arching along the present northern shoreline of Alaska (Barrow Arch) which led to erosion of overlying units and eventual truncation of the Ivishak over the arch in the Early Cretaceous. Further marine transgression covered the exposed Ivishak with a Lower Cretaceous marine shale (see Fig. 3–13). More basinward portions of this shale were the source rock for the oil subsequently trapped at Prudhoe Bay (Atkinson et al. 1990). Closure on the trap at Prudhoe Bay is provided by a combination of (1) the gentle 1°–2° dip of the Ivishak to the southwest on



A



B

Figure 3–15 Ivishak Fluvial Depositional Environments at Prudhoe Bay. (*A*) Meandering Stream Environments (*B*) Braided Stream Environments (Modified from Lawton et al. 1988)

the flank of the Barrow Arch, (2) the Lower Cretaceous sealing shale immediately overlying the Early Cretaceous unconformity, and (3) down-to-the-north normal faults of Early Cretaceous Age on the north edge of the field with throws of up to 1,000 feet (Jones and Speers 1976; Atkinson et al. 1990).

3.2.1.3 Diagenetic Alteration

Sediments that make up the bulk of the Ivishak deposits at Prudhoe Bay are compositionally quite mature, consisting primarily of monocrystalline quartz and chert rock fragments (Atkinson et al. 1990). Sediments with the textural immaturity of braided stream deposits and with such high compositional maturity indicate that the source area was probably predominantly composed of quartz-rich sedimentary rocks from a previous erosional cycle. Detrital clay is very minor except in finer grained rocks and all Ivishak deposits are very low in feldspar content (Melvin and Knight 1984).

Diagenesis of the Ivishak section consists of effects of (1) compaction, (2) cementation (primarily by quartz overgrowths, siderite, and kaolinite), and (3) secondary porosity formation by dissolution of grains (probably chert) and cements (Melvin and Knight 1984; Payne 1987; Atkinson et al. 1990). Sand-dominated units had better sorting and higher initial porosities and permeabilities than more poorly sorted conglomeratic units, which made them preferential pathways for the movement of early diagenetic fluids. Early emplacement of quartz overgrowths provided a rigid framework to resist compaction and maintain porosity and permeability in these sandy units (Payne 1987). Subsequent dissolution of grains, most likely chert grains because of their extensive microporosity and surface area, greatly enhanced these permeability pathways. Despite later partial cementation by carbonates, kaolinite, and other minerals, the sandy units remained much more permeable than associated conglomerates in which only primary porosity reduced by compaction was available for fluid transmission. Late stage partial dissolution of carbonate cements further enhanced porosity and permeability of sandy units prior to oil migration.

3.2.1.4 Geological Heterogeneities

Permeability contrasts between conglomeratic and sandy lithologies are quite significant, being roughly an order of magnitude in difference (i.e., hundreds versus thousands of millidarcies). This permeability contrast is commonly observed within the middle conglomeratic unit of the Ivishak when thin sand intervals are encountered.

Other significant heterogeneities within the Ivishak relate to the distribution of shale or siltstone lithologies previously discussed. These include what may be called continuous shales or shales of floodplain or marsh origin that extend continuously over several well spacings, and discontinuous shales that cannot be traced from well to well. Discontinuous shales include abandoned channel fills as well as more localized slack water deposits of lesser areal extent.

3.2.1.5 Reservoir and Production Characteristics

The Sadlerochit/Ivishak reservoir at the Prudhoe Bay Field contains an estimated 20 billion barrels of OOIP and 23 trillion cubic feet of free gas (Wadman et al. 1979). The Prudhoe Bay Field is approximately 30 miles by 20 miles in maximum extent and has a surface area of approximately 225 square miles (Atkinson et al. 1990). Average depth of the reservoir is approximately 8,500 feet subsea, and it contains over 900 wells at an average spacing of from 1,867 to 2,640 feet. Porosities range from 16% to 25%, and permeability varies from 100 to 1,000 mD (Wadman et al. 1979). Net to gross pay ratio is very high at .87 (Atkinson et al. 1990). Initial production at Prudhoe Bay was facilitated by gravity drainage combined with gas-cap expansion (Atkinson et al. 1990). The field has a total hydrocarbon column of approximately 1,200 feet from the top of the gas accumulation to the oil-water contact, while the Ivishak reservoir has a light oil column thickness of approximately 425 feet (Atkinson et al. 1990).

Ivishak oil has a formation volume factor of 1.36 reservoir barrels per stock tank barrel (STB), an average viscosity of 0.8 cP and a gas/oil ratio of 750 standard cubic feet per STB (Wadman et al. 1979). Oil gravity varies from greater than 32° API to about 15° API (Jones and Speers 1976; Atkinson et al. 1990). Oil gravity tends to decrease with depth in the reservoir ranging from about 28° API near the gas-oil contact to less than 15° API near the base of the oil column (Jones and Speers 1976). The heavy-oil interval reaches a maximum thickness of about 70 feet in that part of the field where the base of the oil column is represented by the oil-water contact (Jones and Speers 1976).

3.2.1.6 Development History and Improved Oil Recovery (IOR) Activities

The ARCO-Humble (Exxon) Prudhoe Bay discovery well was drilled in 1968, but production from the field did not begin until 1977. Initial reservoir pressure was reported at 4,480 psi. By 1983 production from the field had reached 1.5 million barrels of oil per day (Leonard 1983).

Prudhoe Bay oil field is divided into the Western and Eastern Operating Areas (WOA and EOA), as shown in Figure 3–16. The areas are operated jointly on behalf of co-owners by BP Exploration (Alaska) Inc. (previously operated by Sohio) and ARCO Alaska, Inc., respectively (Schuldt et al. 1993).

Waterflood Feasibility Studies

In 1983 the field operators conducted field tests and reservoir simulation studies to identify potential waterflood areas. The three potential areas considered for the study, as indicated in Figure 3–16, were Flow Station Two (FS2) operated by ARCO, Northwest Fault Block (NWFB) operated then by Sohio and currently by BP Exploration, and the Peripheral Wedge Zone (PWZ) operated by both ARCO and BP (Leonard 1983).

The FS2 area had extensive shale stringers and rapidly declining reservoir pressures compared to the rest of the field. Simulation studies favored an inverted nine-spot injection pattern for a waterflood project (Leonard 1983).

At NWFB the pressure decline was greater than the field average, because downthrown fault blocks present were remote from the gas cap and had restricted aquifer influx. Reservoir performance and analysis of injection tests coupled with simulation studies favored a peripheral injection pattern for the NWFB area (Leonard 1983).

A similar study was conducted for the PWZ area which had poor aquifer support, lack of overlying gas cap and a relatively thin oil column. Simulation studies indicated that an inverted nine-spot pattern would be most efficient and would contribute to additional oil recovery (Leonard 1983).

Implemented Injection Projects

In August 1984, BP Exploration initiated a waterflood project in the NWFB in response to a large areal pressure sink resulting from poor communication with the gas cap (Nitzberg and Broman 1992). The project area contained about 1.1 billion barrels of OOIP. Production was 100,000

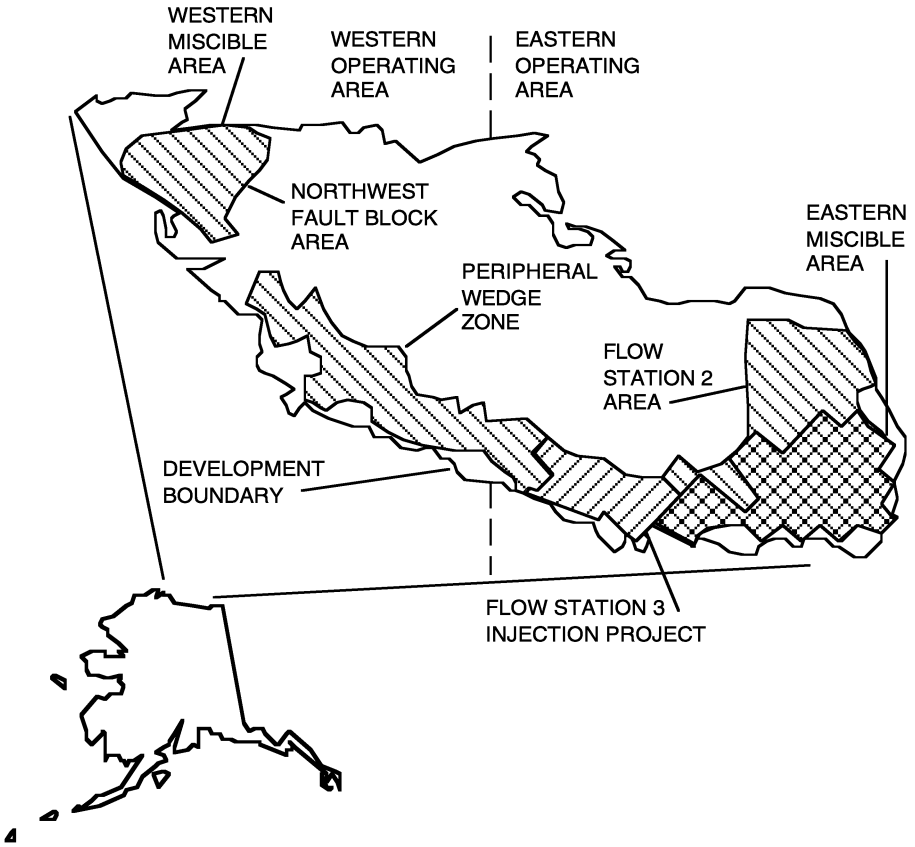


Figure 3–16 Improved Oil Recovery Project Areas at Prudhoe Bay (Modified from Williamson et al. 1985)

barrels of oil per day with a 48% watercut at a 1,300 standard cubic feet per barrel gas-oil ratio. The area had 53 production wells in 18 inverted nine-spot patterns developed on 80-acre spacing with four line drive injectors. In 1986, tracer testing in addition to production logging and well performance analyses were conducted on one of the injection patterns to evaluate the injected-water movement in the reservoir. Results indicated that 90% of the injected water was entering a high permeability or thief zone. The study found that some injected water also moved horizontally along faults. Reservoir performance studies and modeling predictions led to a reduced estimate of the vertical to horizontal permeability ratio, and hence to a refined waterflood management strategy (Nitzberg and Broman 1992).

Injection of sea water from Prudhoe Bay caused a slow but significant reduction in permeability around the wellbores. In 1988, BP Research and Exploration conducted a study on the quality of waterflood injected water and remedial treatment options (Hsi et al. 1990). The study concluded that acid stimulation and xylene wash could restore much of the damaged water injectivity. No surfactant solutions tested were effective in preventing damage when injected continuously in the Prudhoe Bay water stream. To improve water quality, BP installed gas flotation units as part of water treatment facilities (Hsi et al. 1990). Currently, no published information is available on the success of these units. Under Class 1 Field Demonstration Projects, a field study is being conducted by the University of Kansas on the use of air flotation units to improve water quality and curtail permeability reduction. Early results indicate both economic and technical improvements to the waterflood project as a result of installing the air flotation unit in the Savonburg Field (University of Kansas 1995).

As part of the waterflood project at NWFB, and in conjunction with improving incremental oil recovery, BP Exploration conducted two additional studies. The first analyzed the post-fracture production performance of over 360 wells (Schuldt et al. 1993). The second study evaluated the potential of infill drilling (Shirzadi and Lawal 1993). Results of the first study indicated that fractured wells average a three-fold improvement in productivity. Oil recovery rate accelerated in the first year, and total incremental recovery was as high as 500 thousand STB per well. These benefits/improvements will last for a period of 3 to 5 years. Based on reasonable economic limits and constraints, the average additional recovery from these fractured wells will be on the order of 250 thousand STB per well (Schuldt et al. 1993). The second study concluded that if infill wells are drilled on the existing 80-acre spacing in one of the older developed areas, the estimated overall incremental oil recovery will be 2.1 million STB (Shirzadi and Lawal 1993).

In 1982 ARCO initiated a pilot project for a water-alternating-gas (WAG) flood in the PWZ area. Prior to initiating the WAG flood pilot project, several improved oil recovery processes were considered for evaluation such as thermal, chemical, and enhanced waterflooding. Williamson et al. (1985) identified the various economical and operational reasons/considerations for selecting the WAG process for this part of the field. Indicated on Figure 3–16, the project (called the Flow Station Three Injection Project or FS3IP) covered an area of 3,650 acres and involved 442 million barrels of OOIP. The area has 60 wells developed on 80-acre spacing in 11 inverted nine-spot

patterns (Rupp et al. 1984). Total gas injection was designed to be more than 10% of the total pore volume (TPV), injected at a rate of approximately 1% of TPV per year. Estimated incremental-to-waterflood recovery was 5.5% of the OOIP or 24 million barrels of oil (Rupp et al. 1984).

Encouraged by the results of the miscible gas pilot test, ARCO initiated a major planning project to design a large-scale miscible flood at Prudhoe Bay (Williamson et al. 1985). The selected project areas, shown in Figure 3–16, were named the Western Miscible Region (WMR), coincident with the NWFB area, and the Eastern Miscible Region (EMR), which is contained entirely within the FS2 area. These areas were defined as having approximately 4.9 billion reservoir barrels of pore volume and an OOIP of 2.2 billion STB. Compositional reservoir simulations were conducted to select the best of the three areas previously identified for waterflooding projects. As a result the WMR and the EMR were selected for miscible flood using the same inverted nine-spot pattern which was previously selected for waterflooding. Miscible gas injection rate was optimized at 1% of TPV per year up to 10% of TPV as designed for the FS31P pilot project. Early project performance forecasts indicated that 950 million STB of oil will be recovered by primary and waterflooding mechanisms, and miscible flooding will contribute an additional 115 million STB of oil over a 10-year period (Williamson et al. 1985).

3.2.1.7 Influence of Heterogeneities on Performance

Relative to most other sand-body types, the deposits that make up the Ivishak reservoir at Prudhoe Bay can be considered largely homogeneous; however, significant heterogeneities are present that will undoubtedly affect secondary and tertiary recovery operations (Atkinson et al. 1990). The distribution of lower permeability shale and siltstone units that serve as barriers to fluid flow is an important heterogeneity consideration at Prudhoe Bay. Continuous and discontinuous shales or siltstones act as effective vertical permeability barriers (Geehan et al. 1986). As such they may help prevent gas coning and water influx in production wells. If shales are of sufficient lateral extent to intersect the gas cap, however, gas underrunning may result. Heterogeneities of smaller scale such as shale drapes associated with bedforms can give rise to problems of nonuniform drainage and sweep on a smaller scale.

High contrasts in permeability between interbedded thin, sand-dominated units (permeabilities in thousands of millidarcies), and conglomerate-dominated units (permeabilities in hundreds of millidarcies) result from both depositional and diagenetic factors (Melvin and Knight 1984). In other instances better sorted clast-supported conglomerate units with exceptionally high permeabilities can promote similar permeability contrasts (Atkinson et al. 1990). Consideration of such thief zones becomes important when the reservoir is evaluated for water injection.

3.2.2 The West Foreland, Hemlock, Tyonek Play in the Cook Inlet Basin

Tertiary oil reservoirs of the Cook Inlet Basin in southern Alaska have also been interpreted as fluvial/alluvial in origin. Well over a billion barrels of oil remain to be recovered in the Cook Inlet's West Foreland/Hemlock/Tyonek fluvial sandstone play (BPO TORIS 1995). Location of some of the major fields associated with this play is shown in Figure 3–17.

3.2.2.1 Depositional History and Facies Characteristics

The 70-by-200 mile Cook Inlet Basin owes its origin to plate convergence and subduction and is commonly referred to as a basin of the arc-trench gap type as defined by Dickinson (1970) or as a forearc basin (Calderwood and Fackler 1972; Boss et al. 1976; Magoon and Egbert 1986). It is a sedimentary fill sequence deposited between the magmatic arc (i.e., the Alaska Peninsula or Alaska Range) to the north and the Aleutian Trench to the south. Cook Inlet deposits were laid down on continental crust which protected them from severe deformation characteristic of sediments deposited closer to the subduction zone.

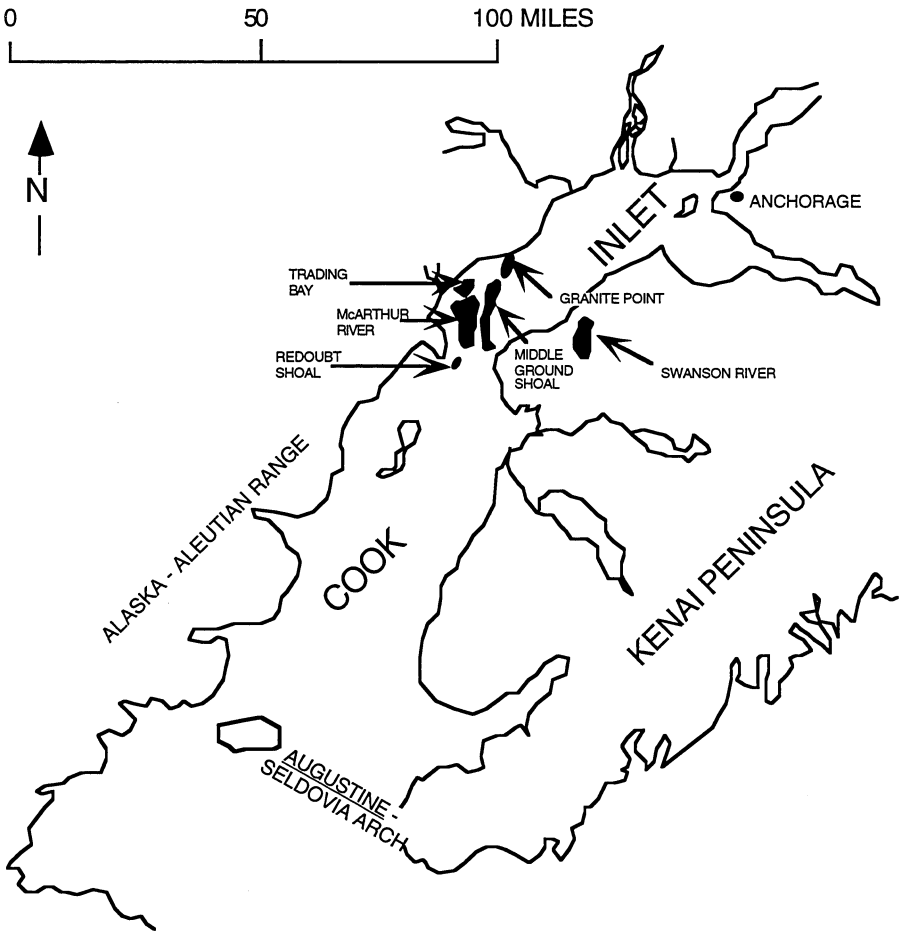


Figure 3–17 Major Class 5 Reservoirs in the Cook Inlet Basin (Modified from Calderwood and Fackler 1972; Boss et al. 1976; Fisher and Magoon 1978; Magoon and Egbert 1986)

At least five episodes of active uplift and erosion associated with plate convergence took place in the Cook Inlet area since the Early Mesozoic. Each episode involved a geographic shift of the depocenter and an increase in the relative area of emergent land (Kirschner and Lyon 1973). The three Mesozoic episodes deposited marine sediments that were subsequently deformed into a synclinal configuration (Fisher and Magoon 1978; Fisher et al. 1987). The limbs of this syncline were erosionally truncated before the basinwide deposition of nonmarine Tertiary fluvial/alluvial sediments associated with later tectonic episodes (Boss et al. 1976; Fisher and Magoon 1978).

Tertiary deposits reach a thickness greater than 25,000 feet at the basin center, but thin rapidly to the northwest and southeast by onlap onto the ancestral Alaska and Chugach Ranges, respectively (Boss et al. 1976; Fisher et al. 1987). Less than 10,000 feet of Tertiary sediments remain in the northeastern part of the basin. A similar or thinner section remains to the south in the area of the Augustine-Seldovia Arch, where sediments were eroded in the Late Pliocene to Pleistocene by renewed orogenic uplift (Calderwood and Fackler 1972; Boss et al. 1976; Fisher et al. 1987).

Tertiary formations containing reservoirs of fluvial/alluvial origin include the Late Paleocene to Early Eocene West Foreland Formation and the Oligocene to Miocene Hemlock and Tyonek formations of the Kenai Group (see Fig. 3–18) (Magoon and Claypool 1980; Magoon and Egbert 1986). Ages of these formations have been determined primarily by identification of associated nonmarine flora (i.e., leaf fossils and palynomorphs). Source areas lay primarily to the northwest and north, with some mineralogic associations indicating possible sources as remote as east-central Alaska or western Canada (Kirschner and Lyon 1973).

The West Foreland Formation occurs throughout the majority of the Cook Inlet Basin and lies unconformably on truncated Mesozoic rocks. On the northwest flank of the basin it overlies progressively younger rocks from north to south (Fisher and Magoon 1978). It averages from a few hundred to nearly 1,000 feet thick in the basin proper and reaches a thickness of 3,000 feet in outcrop at the northwest basin edge (Kirschner and Lyon 1973; Boss et al. 1976). West Foreland sediments consist mainly of siltstones and claystones or shales (sometimes red and green variegated), but volcaniclastic and often conglomeratic sandstones may also be present as well as subaerial basalts, volcanic tuffs, and thin coal beds (Calderwood and Fackler 1972; Boss et al. 1976). Conglomerates become more prominent toward the northwest (Kirschner and Lyon 1973). Average composition of the West Foreland Formation reflects a higher content of mineralogic components that are relatively unstable in sedimentary environments than the overlying formations of the Kenai Group (see Table 3–4). Composition of rock fragment grains shows strong influence of a volcanic source area, but some of the sediments of the West Foreland may have been derived from previously deposited Mesozoic sedimentary rocks (Magoon and Egbert 1986). Depositional environments are dominantly fluvial, but conglomeratic deposits on the northwest flank of the basin have been interpreted by some authors as coalescing alluvial fans. West Foreland sediments are generally poorly sorted, but may contain porosities greater than 20% and permeabilities exceeding 100 mD as observed at shallow depth (1,350–2,600 feet) in the

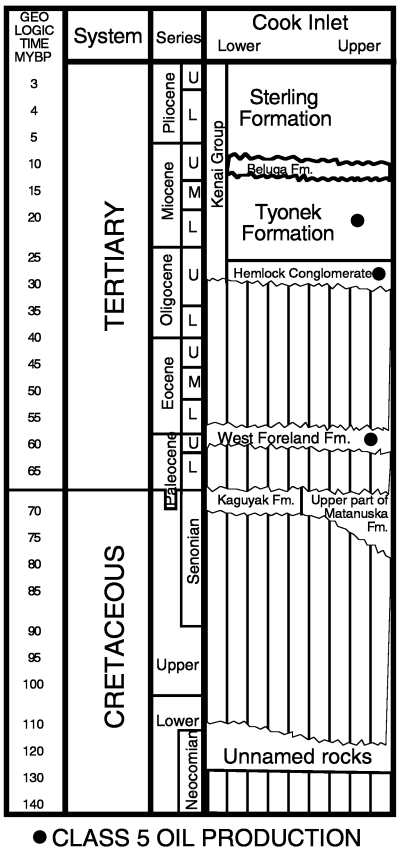


Figure 3–18 Mesozoic and Tertiary Columnar Section for the Cook Inlet Basin (Modified from Magoon and Claypool 1981)

TABLE 3–4
COMPOSITION OF COOK INLET TERTIARY FORMATIONS
(SOURCE: MAGOON AND EGBERT 1986)

	Bulk Composition %			Mineralogic Stability Indicators		
Formation	**Quartz**	**Feldspar**	**Rock Fragments**	**Plagioclase/ Total Feldspar**	**Volcanic/ Total Rock Fragments**	**Chert/ Total Quartz**
Tyonek	61	19	20	.46	.2	.17
Hemlock	66	15	19	.5	.21	.14
West Foreland	23-29	22-30	47-51	.62-.95	.79-1.0	0-.33

Atlantic Richfield Lower Cook Inlet COST No. 1 well (Magoon and Claypool 1981; Magoon and Egbert 1986). The West Foreland Formation produces only in the McArthur River and North Trading Bay fields.

A minor unconformity separates the base of the Hemlock Formation, more accurately considered a member of the overlying Tyonek Formation, from the underlying West Foreland Formation (Boss et al. 1976). The Hemlock, the basal formation of the Kenai Group, covers most of the Cook Inlet Basin reaching a thickness of 600-800 feet near the basin center (Boss et al. 1976; Magoon and Egbert 1986). Although often referred to as a conglomerate, the Hemlock most commonly is composed of about 50%–75% sandstone which is moderately conglomeratic, with 1/4–2 inch pebbles representing the maximum grain size (Calderwood and Fackler 1972; Boss et al. 1976). Sands of the Hemlock are much more mineralogically stable or compositionally mature than those of the underlying West Foreland Formation and contain appreciably lesser proportions of rock fragments (particularly volcanic rock fragments) as well as fewer feldspars (particularly plagioclases) (see Table 3–4). The remainder of the formation consists primarily of siltstones, shales, and thin coals. The Hemlock is generally considered to represent deposition by braided streams with siltstones, shales, and coals representing overbank and floodplain deposits. The Hemlock is the major producing formation in the Cook Inlet Basin (it produces in all of the Cook Inlet oil fields), and it is responsible for over 90% of the oil produced (Fisher et al. 1987; Stewart and Logan 1993).

The Tyonek Formation immediately overlies and is in depositional continuity with the Hemlock. It is also similarly widespread in distribution. It reaches a thickness of approximately 8,000 feet near the basin center and thins toward the basin margins (Boss et al. 1976). The formation consists of about 25% sandstones that are frequently massive, commonly conglomeratic, and are compositionally similar to the underlying Hemlock Formation (see Table 3–4), implying a common source (Boss et al. 1976; Magoon and Egbert 1986). Accompanying these sands, which are generally interpreted as fluvial in origin, are overbank and floodplain deposits of silts, shales, and coals. Thickness of sand units and coal beds decreases upward as the supply of sediment decreased from the north and the primary sediment source shifted southward (Kirschner and Lyon 1973; Magoon and Egbert 1986). The Tyonek is oil bearing in all fields on the northwest side of the basin.

3.2.2.2 Trapping Mechanism

The latest episode of uplift, deformation, and erosion associated with plate convergence began in Late Pliocene and continued through the Pleistocene. Two significant events were concurrent with this tectonic episode: (1) marine source rocks, deeply buried by Tertiary clastics in the Cook Inlet Basin, reached maturation and began to expel oil (Magoon and Claypool 1981), and (2) compression led to formation of an extensive series of basin-axis-parallel anticlinal folds of varied amplitude in the Tertiary section which exclusively formed the traps for the majority of Cook Inlet oil fields (Kirschner and Lyon 1973).

3.2.2.3 Diagenetic Alteration

Diagenesis of the Tertiary producing formations has not been extensively documented in the literature. General experience dictates that compositionally immature, quartz-poor sandstones such as those in the Tertiary of the Cook Inlet Basin commonly have inadequate reservoir properties due to diagenetic effects (Hayes et al. 1976). Tertiary formations of the Cook Inlet, however, have appreciable amounts of porosity (see Fig. 3–19). Sandstones of the Kenai Group underwent less severe diagenetic alteration than those of the underlying West Foreland Formation because (1) they contained lesser amounts of mineralogically unstable components such as volcanic rock fragments and plagioclase feldspars (see Table 3–4), and (2) they were not buried as deeply. An average porosity versus depth relationship for Cook Inlet reservoirs is presented in Figure 3–19.

The Tyonek Formation, as observed in outcrop on the north side of the Cook Inlet Basin, is mostly composed of poorly consolidated sands containing only a few pebbly carbonate-cemented intervals (Odum et al. 1988). In the Atlantic Richfield COST No. 1 well at the southwest end of the basin, the West Foreland Formation, the youngest Tertiary formation

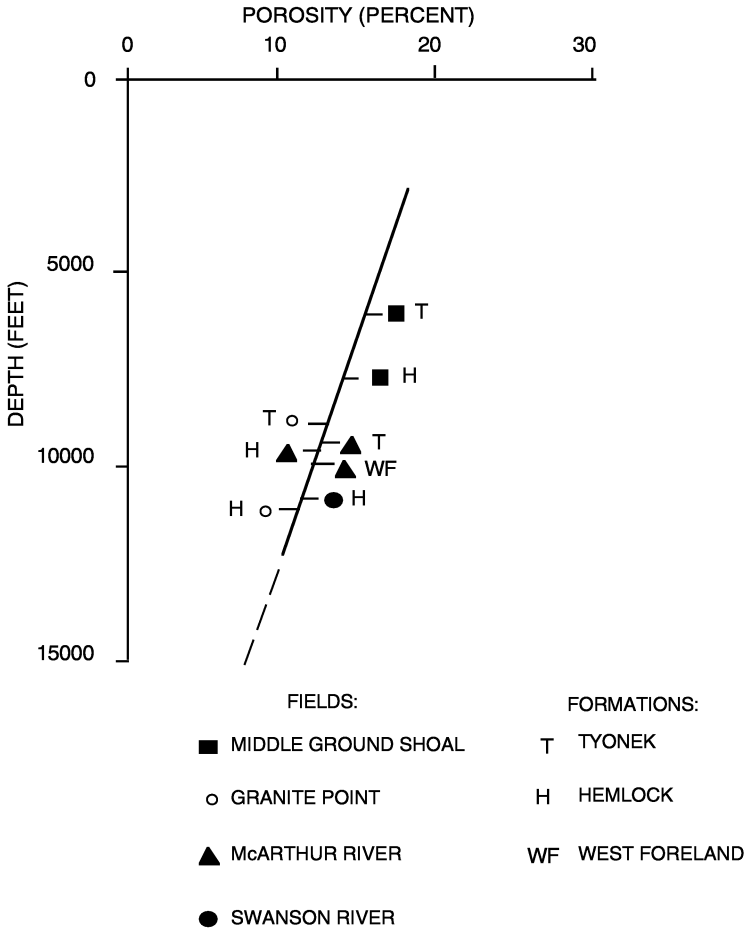


Figure 3–19 Porosity versus Depth Relationship for Class 5 Reservoirs in the Cook Inlet Basin (Modified from Magoon and Claypool 1981)

examined in detail, occurs at a depth of only 1,350 feet and has high porosity and permeability indicating relatively little diagenetic alteration. With increasing depth in the COST well, diagenetic changes most affected volcanic rock fragments and plagioclase feldspars in Mesozoic rocks, resulting in formation of authigenic clay cements and alteration of grains to a clay pseudomatrix (Magoon and Egbert 1986). Some cementation by calcite was also encountered in the COST well sediments, but compaction was definitely not observed to be a major component in their diagenetic history.

Subsurface and outcrop diagenetic studies of the Sterling Formation, a younger fluvial-sandstone-dominated member of the Kenai Group, by Hayes et al. (1976) found that dissolution of volcanic rock fragments, biotite, hornblende, and hypersthene during burial produced significant secondary porosities up to about 35%. Similar but less extensive development of secondary porosity may contribute to the productive capacity of reservoirs in older Tertiary formations as well. Such secondary porosity development almost certainly is responsible for the high (28%) porosity observed in the Beaver Creek Field at a depth greater than 15,000 feet (Magoon and Claypool 1981).

3.2.2.4 Development History and Improved Oil Recovery (IOR) Activities

Swanson River Field

The Swanson River Field, located in the northwest part of Alaska's Kenai River Peninsula, about 50 miles southwest of Anchorage, was discovered by Richfield Oil Corporation in 1957. The first well was completed in the Hemlock Formation between 11,150 and 11,215 feet. Initial production was reported at a rate of 900 barrels of oil per day (Parkinson 1962).

In 1962 the field's oil production averaged 27,250 barrels of oil per day from a total of 48 wells producing from the Hemlock Formation. By 1970 the field contained 70 wells drilled to the Hemlock with 59 of these wells completed as producers.

The original reservoir pressure was recorded at 5,500 psi, but because the reservoir is highly undersaturated and lacks sufficient water encroachment, the reservoir pressure declined from 5,500 psi to 1,100 psi by 1961 (Armstrong 1966). In 1966 Standard Oil of California compared the effects of gas repressuring to those of waterflooding for a possible pressure maintenance program (Armstrong 1966). Results of the study indicated that the wells had enough producing capacity that, with the help of gas repressuring, the field would produce an estimated 30,000 barrels of oil per day for about five years. The study also indicated that waterflooding would leave a high residual oil content in the reservoir. By mid-1966 Standard Oil initiated the gas injection project, and by 1970 the reservoir pressure was back to original at 5,500 psi after a total gas injection of 350 billion cubic feet. Total injection was designed to continue at a rate of 200 million cubic feet per day. By 1976 the gas injection process recovered about 38% of OOIP compared to a forecasted 31% of OOIP (Young et al. 1976).

In the mid 1960s several Tertiary reservoirs were discovered offshore in the Cook Inlet. These reservoirs exhibited production characteristics similar to those of the Swanson River Field.

McArthur River Field

The McArthur River Field, discovered by Union-Marathon in 1965, lies about 70 miles southwest of Anchorage. Union Oil Company is the unit operator with Union, Marathon, and ARCO as sub operators for three drilling and production platforms (Diver et al. 1975).

OOIP in the Hemlock reservoir was estimated at 1.3 billion barrels. Early production rates were high, attaining rates of 70,000 barrels per day of 35° API gravity oil compared to nearby fields producing from the same formation at a rate of 30,000 barrels per day (Diver et al. 1975).

An initial reservoir pressure of 4,300 psi and a bubblepoint pressure of 1,790 psi reflect an undersaturated reservoir. The undersaturated crude combined with lack of substantial waterdrive led to a rapid decline in reservoir pressure and a rapid decline in production. In early 1969, after a detailed study of possible pressure maintenance programs, a full-scale water injection program was initiated. In late 1969, before balance between injection and production was achieved, the field's average pressure was calculated at 2,850 psi. Cumulative oil production at this time was 53.5 million barrels. Water injection continued and by mid-1970 the total injection rate was 120,000 barrels of water per day, about the volume required to replace the void created by oil production. In 1971 water injection facilities were expanded, leading to a total water injection rate of 170,000 barrels per day which was maintained thereafter (Diver et al. 1975).

In 1973 infill wells were drilled on 80-acre spacing (the field was originally developed on 160-acre spacing) resulting in a substantial increase in the field's production from 40,000 barrels per day to over 100,000 barrels per day. At that point the field contained 56 producing wells and 22 water injection wells (Cordiner et al. 1979). By June 1975 the cumulative recovery from the field was 250 million barrels of oil, of which 65 million barrels were attributed to the infill drilling program. The cumulative water injection at that time was 208 million barrels, approximately 20% of the pore volume (Diver et al. 1975).

In 1978 an analysis of production and injection profiles using production logging tools and reservoir simulation led to the redrilling of 10 wells and the drilling of three new wells. Incremental oil recovery resulting from these actions was 24 million barrels (Cordiner et al. 1979).

In 1990 the McArthur River Field was shut in completely for four months from March until June due to nearby volcanic activity. Water injection was continued during the shutin, resulting in an increase in reservoir pressure of about 230 psi. This increase in reservoir pressure contributed to a rise in oil production rate after production resumed (Wolodkiewicz et al. 1993).

Due to increase in water cut and a drop in production to approximately 15,000 barrels per day in 1991 (Starzer et al. 1991), the three field operators developed a more direct and concise reservoir management method by subdividing the Hemlock reservoir into seven performance areas. Subdividing the reservoir aided the operators in assembling reservoir management strategies and promptly examining those strategies as conditions changed (Starzer et al. 1991).

Granite Point Field

The Granite Point Field was discovered in 1965 by Amoco and UNOCAL Corporation. Granite Point produces 41° API gravity oil chiefly from the Tyoneck, but production has recently been established from the underlying Hemlock as well (Stewart and Logan 1993). Amoco operates the northern two-thirds of the field, while UNOCAL operates the southern third of the field.

Due to rapid pressure depletion and low recoveries of oil in place, a waterflood project was initiated in 1971 for pressure maintenance and enhanced recovery. In 1989, the average daily oil production from the Tyoneck was reported at 7,500 barrels of oil per day for an average water injection of 7,930 barrels per day. Cumulative oil production at that time was 108 million barrels of oil, which equals 60% of the recoverable reserves (Tucker et al. 1989).

Amoco conducted a study on the efficiency of the waterflood project and concluded that the waterflood was influenced by heterogeneities due to reservoir sand distribution and faulting. In the northern area of the field the vertical sweep efficiency of the waterflood was very low at 0.36 compared to a 0.85 vertical sweep in the southern portion of the field. Better waterflood performance in the southern part of the field was attributed to a smaller number of thicker pay sands, resulting in a low permeability variation (Tucker et al. 1989).

In 1993 the *Oil and Gas Journal* (OGJ 1993) reported that UNOCAL, in a 1992 redevelopment program, drilled four wells that boosted production at Granite Point from 2,300 barrels per day to 5,200 barrels per day. Two of these wells were completed in the Hemlock Formation, as noted earlier. Computer modeling and measurement-while-drilling techniques were employed to accurately place slant-hole wells within the Tyonek Formation on the steeply dipping flank of the Granite Point structure (Stewart and Logan 1993). These slant-hole wells tapped the Tyonek for rates four to five times greater than conventional wells in the formation.

3.3 Major Class 5 Plays and Reservoirs in California

Fluvial/alluvial reservoirs produce primarily heavy oil in the San Joaquin, Ventura, and Los Angeles Basins in California from Tertiary and Pleistocene Age reservoirs. Class 5 reservoirs were discovered and developed mostly in the first half of the twentieth century and have reached a mature stage of production in which substantial numbers of wells are being abandoned (see Table 3–5). High porosities and permeabilities, coupled with low oil gravities are

Table 3–5
Activity in Typical Class 5 Reservoirs in California
(Source: Conservation Committee of California Oil and Gas Producers 1994)

			Wells at Year End 1993		
Field	**Area/Pool**	**Discovery Date**	**Shut-In**	**Producing**	**Abandoned**
Belridge South	Tulare	1911	2,772	2,758	4,004
Edison	Main Area	1952	219	249	150
Edison	West Area/Chanac	1935	77	54	153
Fruitvale	Main Area/Chanac	1928	205	223	282
Kern Front	Main	1912	687	713	439
Kern River	Pliocene	1899	1,765	7,136	3,476
McKittrick	Main Area/Upper	1887	648	316	479
Montalvo West	Offshore Area/Colonia	1953	4	6	1
Oxnard	McInnes	1953	3	3	79
Playa Del Ray	Venice Area	1929	2	1	206
Playa Del Rey	Del Rey Hills Area	1931	44	7	30
Pleito	Ranch Area/Chanac	1957	2	10	4
Poso Creek	Premier Area/Main	1919	547	137	167
Poso Creek	Enas Area	1929	37	2	16
Raisin City	Zilch (Miocene)	1941	114	37	52
Rosedale Ranch	Chanac	1945	18	9	2
Santa Susana	Sespe-Second & Third	1963	6	7	
Shiells Canyon	Main Area/Sespe Others	1911	30	22	76
Shiells Canyon	Main Area/Sespe	1912	6	6	121
South mountain	Main Area/Sespe	1916	94	312	72
Tapo Canyon South	Sespe	1954	3	16	2
White Wolf	Miocene	1959	11	7	8
Yorba Linda	Shallow	1954	204	246	77
TOTALS			7,498	12,277	9,896

the dominant characteristics of Class 5 reservoirs in the state (see Table 3–6). By far the majority of Class 5 oil in California reservoirs listed in DOE's TORIS database is produced from deposits identified as of alluvial fan origin (see Fig. 3–20).

Class 5 oil is found primarily in three basins in southern California: in the middle to southern part of the San Joaquin Basin (Section 3.3.1), in the Ventura Basin (Section 3.3.2), and in the Los Angeles Basin (Section 3.3.3).

Table 3–6
Reservoir Characteristics for Class 5 Fields in California's San Joaquin Basin (Source: California Gas Fields 1985; Conservation Committee of California Oil and Gas Producers 1994)

Field	Formation (Reservoir)	Additional Reference	Trap Type	Depth, Feet	Zone Thickness, Feet	Porosity, %	Permeability, mD
Belridge South	Tulare	Miller et al. 1990	Combination	400	400	35	3,070
Edison	Chanac (Main)	Lohmar 1984	Structural	750–4,200	450	30	1,500–2,000
Edison	Chanac (West)	Sullwood 1954	Combination	3,200	200	15–40	200–10,000
Fruitvale	Etchegoin-Chanac	Hluza 1961	Structural	4,050–4,150	30	24–28	1,390–7,900
Kern Front	Chanac-Etchegoin	Nicholson & Hurst 1980 Park 1965	Combination	2,290	100–700	32	1,280–1,700
Kern River	Kern River	Nicholson & Hurst 1980 Readdy & Skyll-ingstad 1982	Stratigraphic	400–1,300	100 –500	30–40	1,000–5,000
McKittrick	Tulare		Stratigraphic	500–1,000	300 –500	23–35	10 - 2,500
Midway-Sunset	Tulare	Lennon 1990	Combination	200–1,400	50 –200	33	400–8,200
Pleito	Chanac	Callaway & Rheem 1961a	Structural	8,900–13,000	300–750	13–24	20–800
Poso Creek	Chanac (Enas)	CA Oil & Gas 1973 Connan & Coustau 1987	Combination	1,900	150	30	1,700
Poso Creek	Chanac-Etche-goin (Premier)	Welge 1973	Combination	2,500	250	28	125–7,600
Raisin City	Zilch (Zilch Sand)	Sloat 1947 Hunter 1954	Stratigraphic	5,080	35	30	579
Raisin City	Zilch (Zilch Tar)	Sloat 1947 Hunter 1954	Stratigraphic	4,680	20	29	1,210
Rosedale Ranch	Chanac	Nahama & Ster-ling 1991	Combination	4,675–4,900	100	29	16–1,100
White Wolf	Sespe	Callaway & Rheem 1961b	Structural	815	350	30	339

3.3.1 San Joaquin Basin

The San Joaquin Basin (see Fig. 3–21), the southern extension of the Great Valley of Califo filled with over 25,000 feet of post-Jurassic sediments. It is bordered by the Sierra N plutonic complex to the east and the California Coast Ranges to the west. The San Andrea lies just a few miles to the west of its western margin. Structurally, it is an asymmetri

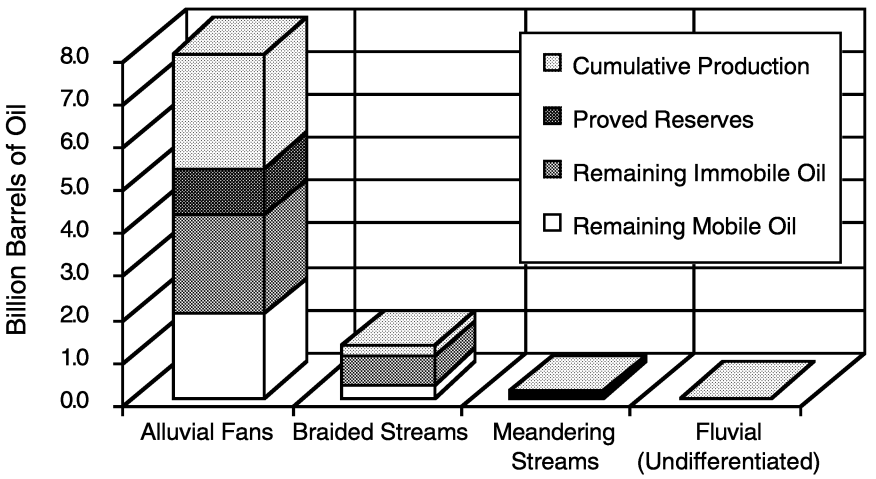


Figure 3–20 Distribution by Depositional System Type of Original Oil in Place in TORIS Class 5 Reservoirs in California (Source: BPO TORIS 1995)

whose eastern flank is a broad, gently dipping, and relatively undeformed homocline. The western flank is narrow and consists of a tightly folded and complexly faulted composite anticlinal structure paralleling the San Andreas Fault. The basin began formation in the Late Cretaceous or Paleocene as a convergent margin basin, but by Miocene time the tectonic regime had become dominated by transform margin tectonics associated with rapid subsidence (Davis and Lagoe 1988).

Early Tertiary sediments were derived mainly from the Sierra Nevada batholith. Later in the Tertiary, active transform margin tectonics led to arc volcanism and delivery of an abundance of quartzo-feldspathic volcaniclastic sediments, particularly to the northern part of the basin (Bent 1988). Rapid subsidence throughout most of the Tertiary led to deposition of a thick sequence of deep marine mudstones and turbidite sandstones. In the northern part of the basin and along the basin margins, shallow marine and nonmarine clastic deposition dominated. In Late Miocene and later times shallow marine and nonmarine clastic deposition spread throughout the basin.

In the San Joaquin Basin, Class 5 reservoirs are found in the Lower Miocene Zilch Formation, the Upper Miocene Chanac Formation, the Upper Pliocene Kern River Formation, and the Pleistocene Tulare Formation (see Fig. 3–22). The relative position of a reservoir within a foldbelt can determine associated trapping conditions (Harding 1976). Pools nearest the San Andreas Fault typically are segmented by complex internal faulting and are strongly compartmentalized. Away from the fault anticlinal closures are not accompanied by significant faulting, and intact drainage areas are greater. Middle Miocene and older reservoirs account for most of the oil and gas produced, much of it from stratigraphic traps resulting from early syndepositional growth of underlying structures. Toward the south, major production is from later Miocene and younger beds that are time-equivalent with folding episodes.

3.3.1.1 Zilch Formation Reservoirs

The Zilch Sandstone, productive at the Raisin City Field in the northern San Joaquin Basin southwest of Fresno, is a continental facies of the Oligocene-Miocene Temblor Formation (Hunter 1954). The Zilch is 1,400 feet thick at Raisin City Field and consists primarily of alluvial fan deposits dumped on the Sierran Coastal Plain from mountainous source areas to the south and east (Bent 1985). The Zilch Formation is made up of thin beds of clays, silts, and lenticular sandstones (Hunter 1954).

The field, discovered in 1941, contained two producing zones, an upper Tar Zone producing 16°–17° API oil from a depth of 4,600– 4,900 feet, and a lower zone producing 24° API oil at 5,200–6,100 feet (Sloat 1947; Hunter 1954). Both producing zones showed discontinuities due to the lenticular nature of the sands, and because of difficulties in producing heavy oil and tar, the field was shut in in 1952 (Hunter 1954). Improved techniques for heavy oil and tar production allowed the field to be reopened in the 1980s. By the end of 1993 Raisin City Field contained 37 producing wells (Conservation Committee of California Oil and Gas Producers 1994).

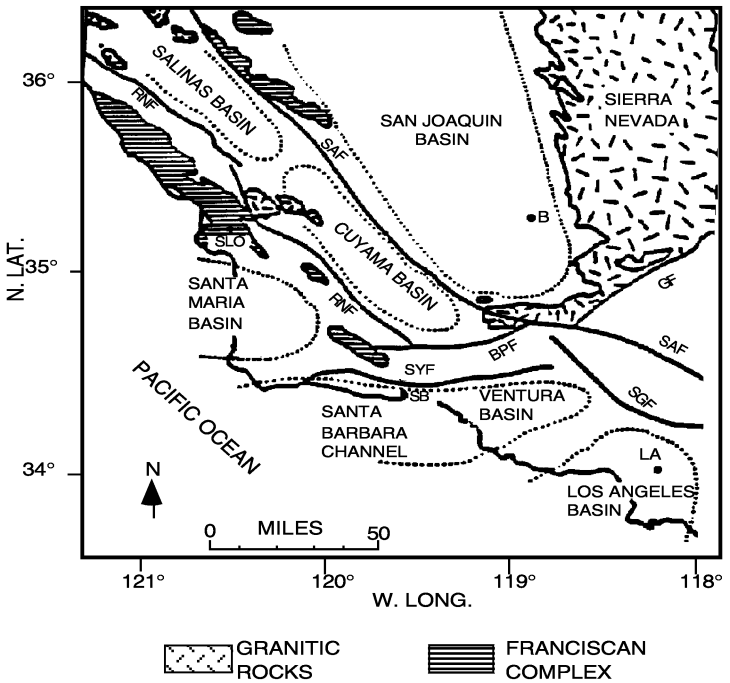


Figure 3–21 **Major Basins in West Central California. Faults: Rinconada-Nacimiento Fault (R-NF), San Andreas Fault (SAF), Big Pine Fault (BPF), Santa Ynez Fault (SYF), San Gabriel Fault (SGF), Garlock Fault (GF). Cities: Bakersfield (B), San Luis Obispo (SLO), Santa Barbara (SB), Los Angeles (LA) (Modified from Lagoe 1984)**

AGE	SAN JOAQUIN VALLEY FORMATIONS		
	NORTHERN	WEST SIDE & CENTRAL	EASTSIDE
PLEISTOCENE	Undifferentiated Nonmarine Strata	Tulare ●	Tulare ●
UPPER PLIOCENE		San Joaquin Clay	Kern River ●
LOWER PLIOCENE		Etchegoin Jacalitos	Etchegoin
UPPER MIOCENE	Santa Margarita	Reef Ridge Stevens McClure McDonald	Chanac ● Santa Margarita Fruitvale
MIDDLE MIOCENE	Zilch ●	Devilwater Gould Button Bed	Up. Round Mountain Mid Round Mountain McVan
LOWER MIOCENE		Media Carneros Santos Phacoides Vaqueros	Low Round Mountain Olcese Jewett Vedder Walker
OLIGOCENE	Kreyenhagen	Tumey Leda Oceanic	? Kreyenhagen

● CLASS 5 OIL PRODUCTION

Figure 3–22 San Joaquin Basin Tertiary Stratigraphic Column for Class 5 Reservoirs (Modified from Conservation Committee of California Oil and Gas Producers 1994)

3.3.1.2 Chanac Formation Reservoirs

The Chanac Formation was deposited during the Late Miocene, when the rising Sierra Nevada Mountains shed sediments westward into the San Joaquin Basin and alluvial fans formed at the base of the mountain fronts (Link et al. 1990). These fans graded westward into braided stream deposits and high-sediment-load meandering stream deposits characteristic of deposition on a low-relief mud-dominated plain with abundant marshes and ponds. The Chanac reaches 600 feet in thickness and consists primarily of discontinuous lenticular units consisting of sandstone, conglomerate, and mudstone. Individual sand packages extend laterally from 100 to 600 feet, reach thicknesses up to 30 feet, and are highly sinuous (Link et al. 1990). Channels trend east-west and are elongate, narrow, and discontinuous. Areally extensive mudstone deposits form low-permeability barriers within sands.

Kern Front Field

The Kern Front Field, discovered in 1912, is approximately five miles long and about two and one-half miles wide at its broadest point (California Oil and Gas Fields 1985) (see Fig. 3–23 and Table 3–6). It lies on the northwesterly striking regional homocline along the east side of the San

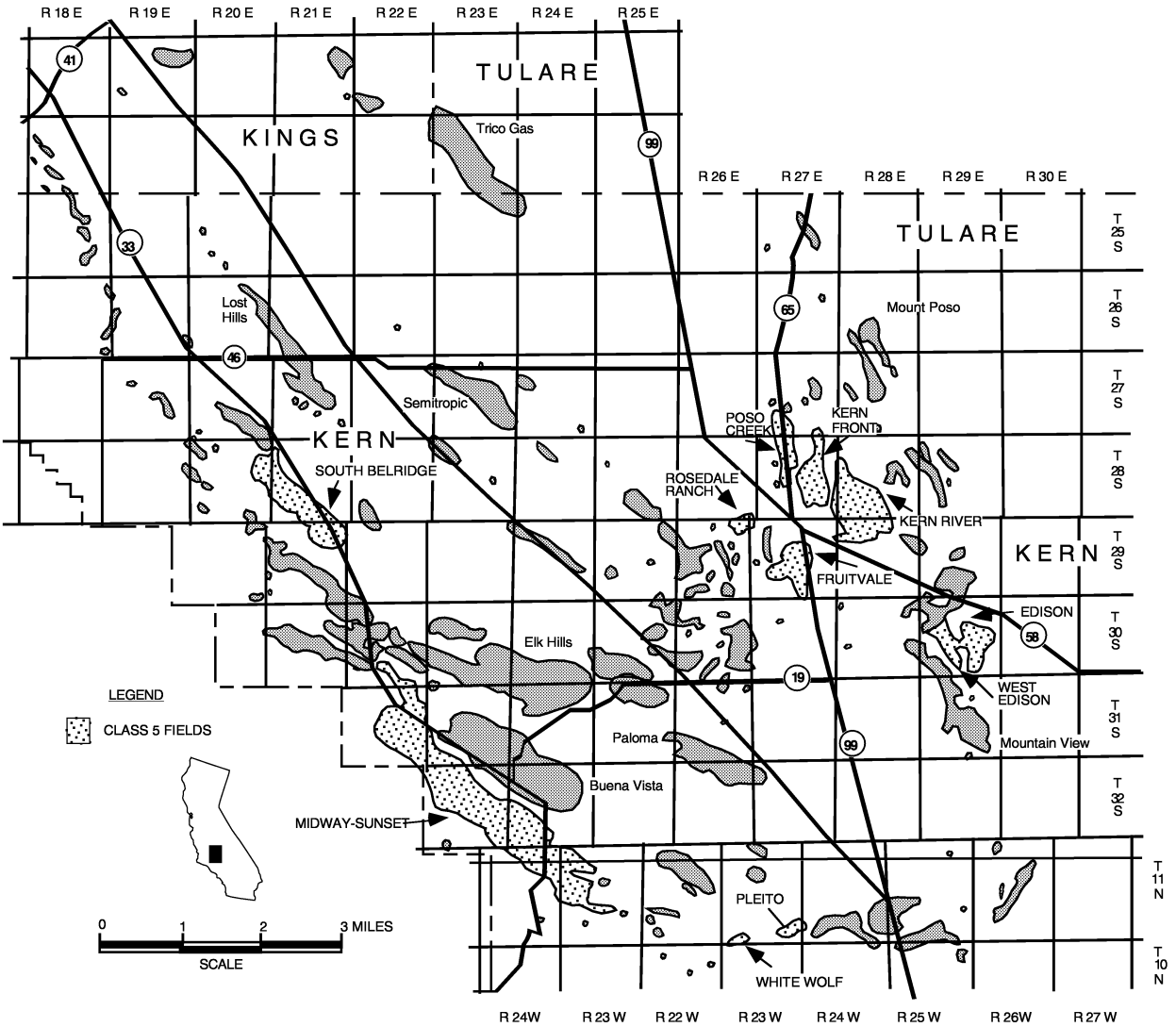


Figure 3–23 Class 5 Oil Fields in the Southern San Joaquin Basin (Modified from California Oil and Gas Fields 1985)

Joaquin valley. The main productive sand is the Chanac, but Pliocene age Etchegoin sands also produce (Eson et at. 1981). Trapping mechanisms in the field are faulting and sand pinchout updip.

The following facies were recognized in the Kern Front Field by Link et al. (1990): (1) coarse channel sands with porosities greater than 35% and permeabilities over 5,000 mD occurring in discontinuous and lenticular packages up to 10 feet thick with composite thicknesses up to 40 feet, (2) low-permeability marsh, pond, and floodplain deposits in sheet-like packages up to 100 feet thick, and (3) wedge-shaped crevasse splay deposits up to 50 feet thick with moderate to good reservoir quality.

Operators in the field have been troubled since its earliest history by normal faults in the Chanac and intermediate zones of sands containing fresh water within the producing interval. Oil gravity at Kern Front varies from 11.6° to 15.5° API (Park 1965). Steam processes were applied as early as the mid-1960s. In 1978 the Petro-Lewis Corporation began a steamflood by converting producing wells to steam injection creating six, 10-acre inverted nine-spot patterns in the North Kern Front area (Eson et al. 1981). High steam injection rates of 850 barrels per day combined with extreme variations in vertical permeability, adverse structural dip, and edge waterdrive caused steam channeling and premature breakthrough. In 1980 Petro-Lewis initiated steamfoam injection field tests to address the channeling problem. Results indicated that steamfoam injection can enhance the economic profitability of a steam project by improving the sweep efficiency. In addition, this approach resulted in lower steam usage. Incremental oil recovery attributed to the steamfoam process was between 75 and 100 barrels of oil per day per pattern (Eson et al. 1981). Other chemical agents such as Thin Film Spreading Agent (TFSA) were tested in cyclic steam injection in the Chanac reservoir to enhance oil production (Blair et al. 1983). Early results indicated an enhancement that carried over to following cycles.

Fruitvale Field

Fruitvale Field, on the west side of Bakersfield (see Figs. 3–21 and 3–23 and Table 3–6), was discovered in 1928. The first wells produced from the Chanac Formation in the Main area at an average depth of 3,250 feet (California Oil and Gas Fields 1985). The Calloway area, discovered in 1938, includes the western part of the field and produces from both the Chanac and Etchegoin formations (Hluza 1961). Oil gravity at Fruitvale Field ranges from 15°–22° API (California Oil and Gas Fields 1985). The surface structure is a gently dipping homocline (Hluza 1961). At the end of 1993, Fruitvale Field had 223 producing wells (Conservation Committee of California Oil and Gas Producers 1994).

In the main area the Chanac Formation has an average thickness of 190 feet (California Oil and Gas Fields 1985). The Chanac Formation at Fruitvale Field is described as a nonmarine fine- to coarse-grained, friable sand interbedded with siltstones (Hluza 1961). Oil is trapped by an updip northwest-southeast trending normal fault which has a maximum displacement of 65 feet in the Calloway area (Hluza 1961).

Recent activity at Fruitvale Field has involved in situ combustion or fireflooding which began in 1980 (Rintoul 1980a, b). Direct heat was applied to the oil sands to increase production of heavy crudes (Rintoul 1980a). Fireflood tests began in a 15 foot interval of the middle Kernco Sand Member of the Chanac Formation at a depth of 3,500 feet (Rintoul 1980a). The middle Kernco has an average oil gravity of 14° API (Rintoul 1980a).

The fireflood was accomplished by controlled injection of air using 10% of the oil in place for combustion (Rintoul 1980a). Recovery was expected to quadruple in 10 years and extend the life of the field for 50 years (Rintoul 1980b). The fireflood design was expected to solve two

problems: (1) reduce the cost of fueling the air compressors by 50% by using flue gas and (2) eliminate intermediate hydrocarbons (butane and propane) by using the flue gas and thus reducing air pollution (Rintoul 1980b).

West Edison Field

West Edison oil field is located on the east side of southern San Joaquin Valley about 9 miles southeast of Bakersfield (California Oil and Gas Fields 1985) (see Fig. 3–23 and Table 3–6). The field produces from the Chanac Formation (Pliocene-Miocene), the marine Santa Margarita Sand (Upper Miocene), the marine Nozu Sand (Middle Miocene), and the Olcese Sand (Lower Miocene).

The field is composed of a series of fault traps on a southwest dipping homocline characteristic of the east side of the San Joaquin Valley. Dip averages 800 feet per mile. Trapping mechanisms include normal faults, where oil is on the down-thrown sides, and sand pinchouts (Sullwood 1953).

West Edison produces from the lower 700 feet of the Chanac. Sandstone permeabilities range from 200–10,000 mD, and porosities range from 15% to 40%. Oil gravity ranges from 16° to 24° API, and oil-water ratios vary from 0.10 to about 0.8 (Sullwood 1953).

Rosedale Ranch Field

Rosedale Ranch Field (see Fig. 3–23 and Table 3–6) was discovered in 1945 (Betts 1955). The main producing reservoirs are two zones in the Chanac sands at depths of 4,675 and 4,900 feet and a shallower Lerdo Zone in the basal Etchegoin Formation at 4,200 feet (Betts 1955; California Oil and Gas Fields 1985). The Chanac zones are classified as fluvial/alluvial (BPO TORIS 1995).

The Chanac Formation at Rosedale Ranch Field is a 650 foot thick interval of continental sands (Betts 1955). The structure is a faulted anticline (Nahama and Sterling 1991). Oil entrapment is by minor faults and permeability variations within the producing sand layers (Betts 1955). The Chanac reservoirs are discontinuous due to numerous minor faults (California Oil and Gas Fields 1985). The overlying Lerdo Sand of the Etchegoin Formation is more continuous and has higher production (California Oil and Gas Fields 1985).

Peak oil production at Rosedale Ranch Field was in 1955 (California Oil and Gas Fields 1985). A decline in production and difficulties with sand clogging led to abandonment of the lower Chanac Zone in the early 1950s (Betts 1955). Chevron began extensive drilling in the Lerdo Zone in 1959 and began improved recompletion techniques in 1985 to increase production of the 13° API oil (Nahama and Sterling 1991). At the end of 1993, nine wells were producing from the Chanac sands (Conservation Committee of California Oil and Gas Producers 1994).

Pleito Field

Pleito Field (see Fig. 3–23 and Table 3–6) was originally discovered as Pleito Creek Field in 1951 and Pleito Ranch Field in 1957 (California Division of Oil and Gas 1973). Pleito Ranch area is the smaller of the two areas, covering 170 acres; Pleito Creek is 220 acres (California Division of Oil and Gas 1973). The Chanac Formation at the Ranch area of Pleito Field is identified as Class 5 production (BPO TORIS 1995). The rugged terrain at Pleito Field has limited the number of wells and caused drilling problems (Crowder 1954).

The Chanac Formation at Pleito Field is a 2,315 foot thick interval of arkosic shales, gray-green sands, and stringers of oil sands (Crowder 1954). The dominant structure at Pleito Ranch is the San Emidio Anticline (Callaway and Rheem 1961a). The anticline is cut by two normal faults (east and west) with displacements of 300 and 400 feet, respectively (Crowder 1954). The main producing area of the Chanac Formation is in the northern part of Pleito Creek area and the Pleito Ranch area (Crowder 1954; Callaway and Rheem 1961a). Chanac sands are stratigraphic lenses on the crest of the anticline, while the underlying Santa Margarita sands form a blanket-type deposit with structural and fault closure (Callaway and Rheem 1961a). Oil is trapped in the Chanac Formation reservoir against the Wheeler Ridge Fault (Callaway and Rheem 1961a; California Oil and Gas Fields 1985). Oil from the Chanac reservoir averages 25° API gravity, and porosity and permeability average 28% and 58 mD, respectively (Callaway and Rheem 1961a; Crowder 1954). At the end of 1993, 10 wells were producing in the Ranch area of Pleito Field (Conservation Committee of California Oil and Gas Producers 1994).

White Wolf Field

White Wolf Field (see Fig. 3–23 and Table 3–6) was discovered in 1959–60 by Shell Oil company (Callaway and Rheem 1961b). The first producing interval was the Miocene Reef Ridge Formation at a depth of 2,800 feet (Callaway and Rheem 1961b; California Oil and Gas Fields 1985).

The Chanac Formation at White Wolf consists of undifferentiated Miocene-Pliocene sediments (California Oil and Gas Fields 1985). Structurally, the sediments form a folded anticline on the upthrown side of the Wheeler Ridge Fault. On the downthrown side of the fault, sediments form a homocline dipping to the north (Callaway and Rheem 1961b). The Chanac has an average depth of 815 feet at White Wolf Field (California Oil and Gas Fields 1985).

Heavy oil (14°–16° API) at White Wolf caused the first operations to be suspended in the early 1960s (Callaway and Rheem 1961b). In 1986 White Wolf Field became the first field in California to test electromagnetic well stimulation (Rintoul 1986). The techniques had been successfully used in Alberta by Husky Oil.

The technique, developed by ORS Development Corporation in Tulsa, OK, introduced an alternating electromagnetic current into a Miocene sand reservoir at 2,200 feet by using a downward pointing antenna (Rintoul 1986). The process works somewhat like a microwave and

requires 4–6 weeks to heat the reservoir to begin production. Based on the success of the original tests, the process was to be extended to all reservoirs at White Wolf Field (Rintoul 1986). A benefit of this method is that the electromagnetic process is environmentally benign (Rintoul 1986).

As of the end of 1993 seven wells at White Wolf Field were producing from the Miocene sediments of the Reef Ridge Formation (Conservation Committee of California Oil and Gas Producers 1994; California Oil and Gas Fields 1985). No current production is noted from the shallower Chanac Formation (Conservation Committee of California Oil and Gas Producers 1994)

Poso Creek Field

Standard Oil Company discovered Poso Creek Field (see Fig. 3–23 and Table 3–6) in 1919–20 (California Division of Oil and Gas 1973). The original area has been designated the Premier area (California Oil and Gas Fields 1985). Production from the Chanac Formation at the Premier and nearby Enas areas is defined as Class 5 (BPO TORIS 1995).

The Chanac Formation in the Premier area averages 250 feet thick at a depth of 2,500 feet (California Oil and Gas Fields 1985). At the Enas area the thickness averages 150 feet and the depth is 1,900 feet (California Oil and Gas Fields 1985). The shallower Enas area produces oil averaging 12° API, while from the Premier area oil ranges from 11°–15° API (California Division of Oil and Gas 1973; California Oil and Gas Fields 1985). Oil is trapped in the Premier area by a faulted homocline and permeability variations within the Chanac sands (California Division of Oil and Gas 1973). Porosities average 37% in these reservoirs, and permeabilities range up to 5,000 mD (Blonz and Corre 1982). A strong waterdrive was present during primary recovery, but productivity was poor with high water cuts.

Tests of steamdrive to produce the heavy oil began in the McVan area, northeast of the Premier and Enas areas, in 1981 (Blonz and Corre 1982). Two reservoirs, an upper in the Pliocene Age Etchegoin Formation and a lower in the Late Miocene Age Chanac Formation, are separated by impermeable shale barriers (Blonz and Corre 1982). Oil production in July 1980 from 16 wells was reported at 130 barrels per day with 3,340 barrels of water. Steamdrive improved oil production to 400–500 barrels per day with a cumulative steam-oil ratio of 6.7. At the end of 1993 the Premier area had 137 producing wells, and the smaller Enas area had two wells (Conservation Committee of California Oil and Gas Producers 1994).

3.3.1.3 Kern River Formation Reservoirs

The Kern River Formation is a coarse-grained clastic unit that forms a westward-thickening wedge up to 2,500 feet thick in the subsurface of the San Joaquin Basin (Bartow and Pittman 1982). Sediment source for the clastics was the Sierra Nevada Batholith. Sand and boulder

conglomerates contain well-rounded fragments of the major rock types found in the southern Sierra Nevada (Readdy and Skyllingstad 1982). Kern River sands are generally immature due to proximity and high relief of the source area (Lohmar 1984).

Four distinct lithofacies compose the Kern River Formation: conglomerate, coarse-grained sandstone, fine-grained sandstone, and mudstone (Readdy and Skyllingstad 1982). Often these facies are found in fining-upward sequence. Clay is rare other than in the distinct clay layers present in the upper part of the formation. Mudstones consist mainly of silt-sized material. Sand bodies are mostly lenticular. Thicker sand bodies are correlatable, but are interbedded with variable amounts of mudstone.

The Kern River has been variously interpreted as of alluvial fan and braided stream origin (Lohmar 1984; Graham et al. 1988). The formation contains alluvial point bar and channel sand deposits, lacustrine mudstones and fine sand deposits, and crevasse fan mudstone deposits (Readdy and Skyllingstad 1982). Gravelly deposits of the formation are interpreted as traction deposits representing braided stream bars, while poorly sorted and sandy nonfossiliferous mudstones probably represent overbank deposits. Graham et al. (1988) present evidence for glacial depositional conditions for the Kern River Formation. They assert that Cenozoic uplift of the southern Sierra Nevada along with a cooling climate caused an episode of glaciation during deposition of the upper Kern River Formation. The Kern River lacks fossils that would provide diagnostic climatic information, but evidence of glaciation is suggested by presence of faceted and polished cobbles and conchoidally fractured sand grains.

Kern River Field

The Kern River Field, third largest producing field in the lower 48 states, was discovered in 1899 as a hand dug well at a total depth of 73 feet (see Fig. 3–23 and Table 3–6) (Jones et al. 1995). Since that time, production from the Kern River Field has depended greatly on economic conditions relating to the demand for heavy crude oil. Currently the entire Kern River Field with over 7,000 active wells is almost entirely under steam flood. The Kern Front Fault in the northwestern part of the field strikes north 10° east and separates the Kern River from the deeper Kern Front Field. Permeability and porosity are high and reservoir pressure is low (Bursell and Pittman 1975).

Kern River produces a 12°–16.5° API oil from depths of 500 to 1,300 feet. The average oil viscosity of 4,000 cP at the reservoir temperature of 90°F is reduced markedly at increased temperatures. Laboratory tests indicate that heating the oil to 250°F by steam can decrease the viscosity by at least an order of magnitude with a corresponding increase in oil production rates (Lohmar 1984). Production rates, however, decline rapidly as cooling takes place.

The presence of swelling montmorillonite clays in the matrix of Kern River sands does not appear to retard steam injection, even though experiments showed that permeability was reduced to 10% of its original value when cores were contacted by fresh water at reservoir temperatures (Lohmar 1984). Waldorf (1965) determined that montmorillonite clays dehydrate and shrink when exposed to steam at temperatures above 350°F and as a result, the permeability

of montmorillonite-rich sands to steam is as high as that measured with air. Permeabilities decreased appreciably, however, when samples were re-exposed to water at lower temperatures. Rapid declines in producing rates following steam stimulation in the Kern River Formation are probably due to both clay swelling and increase in oil viscosity as the reservoir cools (Jones et al. 1995).

From discovery through the mid-1960s, the field produced under primary recovery. As of 1966, cumulative oil production was estimated to be 400 million barrels or 10% of OOIP (Jones et al. 1995). In 1962 Tidewater Oil Company (later Getty Oil Company, now Texaco, Inc.) began injecting hot water into four pilot wells. After two years of hot waterflood in the K1 Member of the Kern River Formation reservoir, the project was converted to steam displacement. Due to gravity segregation, the upper portion of the reservoir was preferentially swept resulting in a lower residual oil saturation when compared to the lower portion of the reservoir (Bursell and Pittman 1975). Recovery by steam was reported at 72% of OOIP from the pilot area. Another pilot was initiated by Getty Oil Company in March 1968 in the R1 Member of the Kern River Formation. A total of 5.2 million barrels of steam was injected to produce 1.4 million barrels of oil for a cumulative steam-oil ratio (SOR) of 3.6 (Bursell and Pittman 1975). The field pilot project showed that high recoveries were a function of oil viscosity reduction. In addition, the study concluded that with a less stratified, homogenous reservoir steam flooding could be very effective.

In September 1968 Chevron Oil Field Research Company and Standard Oil Company of California, Western Operations, Inc., initiated a 10-pattern steamflood field trial (Blevins and Billingsley 1975). The 10-pattern steamflood was conducted in section 3 of the Kern River Field. The field test was conducted in the bottom sand interval from 705 to 765 feet. The project area had an average permeability and porosity of 7,600 mD and 35%, respectively. Oil saturation prior to steamflooding was reported at 52%. The test incorporated 10 inverted seven-spot patterns covering 61 surface acres. All producing wells were steam stimulated immediately before steam injection started. In December 1971, the injection rate was 6,200 barrels per day of 70% quality steam with a corresponding rate of oil production of 1,490 barrels per day. In September 1973 the SOR was reported at 5.1 barrels of steam per barrel of produced oil for a cumulative SOR of 5.8 (Blevins and Billingsley 1975). In 1975, the cumulative production was reported at 2.3 million barrels of oil and 9.7 million barrels of water. Steam injection in the 10-pattern flood recovered 45% of OOIP compared to 15% by primary recovery.

In September 1975 the 10-pattern high-quality steamflood was converted to water injection. The process started by adding cold water to the injected steam thereby reducing the steam quality to zero, then lowering the injected water temperature to that of the cold water. By 1980 the total water injected was reported at 8.9 million barrels of water and cyclic steam. The incremental oil production due to water injection was 1.26 million barrels, representing recovery of an additional 15% of OOIP for an overall oil recovery of 62% of OOIP, or 5.2 million barrels (Oglesby et al. 1980). Post-steam water injection helped distribute residual heat, maintain reservoir pressure, and double the production (Ault et al. 1985). The post-steam water injection

Table 3–7
Kern River Field Oil Consumption by Steam Project Area (BOPD) (Source: Ault Et Al. 1985)

Field Name	High-Quality Steam	Low-Quality Hot Water
Monte Cristo II	175	70
American Naphtha	181	80
Section 3 10-pattern	N/A	0

process following steamflooding may recover up to 70% of OOIP. This process will work better if more oil is left in the reservoir at the end of the steamflood, but will only work if sufficient heat has been injected to provide a heat source for the water.

Two other steamdrive projects operated by Chevron in Kern River Field, the American Naphtha and Monte Cristo II, were converted from high-quality steam (greater than 40%) to low quality steam (10% quality steam at the wellhead) in September 1981 and February 1982, respectively (Ault et al. 1985). Oil production as a result of the steam conversion process increased substantially. For example, in the Monte Cristo II Field project, the production increased from 46 to 204 barrels of oil per day when steam was converted from 70% quality to 10% quality. Results from the field study indicated that, in both the American Naphtha and Monte Cristo II projects, higher temperatures were detected in the lower sands after conversion, which translated into a better sweep. In addition, converting from high-quality steam to low-quality steam or water injection reduced the produced oil consumption for steam generation, as indicated in Table 3–7.

In the mid-1980s low oil prices dictated a move toward use of low-quality steam or hot waterfloods to reduce fuel expenses and improve vertical sweep efficiency. Field expenses were reduced, but oil production also continued to decline. Low quality steam injection continued until 1990. In 1991 Santa Fe Energy Resources, Inc. (SFER) initiated innovative operating techniques by instituting an aggressive cyclic steam project in a strip along the Kern River that included its Rasmussen and Elwood Fee properties and its Kern County Land Company (KCL) lease (Jones et al. 1995). By recompleting the five-spot and nine-spot development wells, drilling infill wells, and implementing cyclic steam injection, the average daily oil production in the SFER Kern River property increased from 2,000 barrels per day at the end of 1989 to 3,500 barrels per day by mid-1994 (Jones et al. 1995).

Texaco is also using horizontal wells in the Kern River Field to improve the steamflooding economics. In 1990, Texaco drilled a horizontal well targeting the R-sand within the Kern River Sand series. Production data from the horizontal well were not reported in the literature (Haney 1992); however, Texaco reported that the production was below expectations due to probable steam zone influence on wellbore pressure gradient and drainable oil in place.

The following advantages of horizontal completions in Kern River Field were reported by Haney (1992):

- Greater reservoir contact area for thin reservoir zones
- Less drawdown per unit length reduces sand production and fluid coning problems
- Oil in normally inaccessible steamflood locations may be producible
- Improved sweep efficiencies and gravity drainage recoveries in association with steam injection process

The following disadvantages of horizontal completions in Kern River Field were found:

- Limited engineering and operating experience
- Recompletion into vertically adjacent zones more difficult
- Greater costs by a factor of three to five times
- Difficult and more expensive wellbore isolation and workover operations
- Productivity reduced by low vertical permeability

Edison Field

The Edison Field, discovered in 1931, is located on the eastern side of San Joaquin Valley (Sullwood 1953) (see Fig. 3–23 and Table 3–6). Over half of the current production in the Main area of the Edison Field comes from the Kern River Formation at depths of 700 to 2,000 feet. The formation is about 650 feet thick in the central part of the Main area, but thins to less than 400 feet over a basement high at the eastern end of the field. The upper 550 feet consists of coalescing alluvial fan deposits of the middle and upper Kern River Formation. The lower Kern River is about 100 feet thick and is interpreted as a sequence of offshore bar deposits. The trapping mechanism in the field is a series of tilted fault blocks.

The alluvial fans of the middle and upper Kern River Formation were deposited in two cycles, suggesting periodic uplift of the adjacent mountain front. Each cycle begins with well-sorted lenticular sands deposited around the toe of the fan (Lohmar 1984). These distal fan deposits are overlain by prograding conglomeratic sands of the middle and upper fan. Each cycle is capped by a clean, well-sorted sand that probably represents reworking in a marine environment. The middle Kern River Formation was deposited as a series of coastal alluvial fans while the upper Kern River sands, which contain much less oil, are interpreted as terrestrial alluvial fan deposits (Lohmar 1984).

Permeabilities range from 2 mD to 3,000 mD. Reservoir quality is controlled by the amount of montmorillonite and depositional sorting. Depositional controls on reservoir quality are evidenced by differences between the permeability of the well sorted offshore bar deposits, with

a uniform distribution of permeabilities and a median value of 1,500 mD, and the more highly skewed distribution of permeabilities in the poorly sorted alluvial fan deposits, with a lower median value of 700 mD (Lohmar 1984).

Water saturation is affected by grain sorting and abundance of clay (Lohmar 1984). Capillary pressure measurements indicate that irreducible water saturations in the Kern River Formation range from 30% to 60%. Examination of the reservoir sands in thin section suggests that the high saturations are due to poorly sorted sand grains compacting in a ductile clay matrix during burial, which reduces most of the intergranular space to water-saturated microporosity.

Because of their dehydration during drying for lab measurements, clays make conventional permeability and porosity measurements inaccurate. Loss of adsorbed water results in shrinkage of clay matrix and an increase in apparent porosity and permeability.

Oil gravity ranges from 14.9° to 19° API in the Kern River sands at Edison Field, where oil is mainly produced by cyclic steam stimulation. Steam improves producing rates by lowering oil viscosity from 300 cP at initial reservoir temperatures to 10 cP after steaming. Cyclic steam stimulation has more than doubled the cumulative production of oil from the Kern River Formation (Lohmar 1984).

3.3.1.4 Tulare Formation Reservoirs

The Tulare Formation was deposited during the Pleistocene, when a major portion of the central San Joaquin Basin was covered by a large freshwater lake (Lennon 1990). The Tulare sands were deposited along the shores of the lake as beaches and deltas and west of the lake as alluvial sands. Tulare deposits attain thicknesses of 2,500 feet and consist of fluvial to lacustrine sandstones, lacustrine clays, siltstones, gypsum, and tuff (Lennon 1990). The sands are very poorly consolidated to unconsolidated with porosities as high as 30% to 37% and permeabilities measured in darcies. Burial depth of sands in producing fields ranges 500–2,500 feet. The sands are usually 2–50 feet thick and are separated by clay units of similar thickness. At a few locations the sands are a few hundred feet thick (Lennon 1990).

Midway-Sunset Field

The Midway-Sunset Field, located at the southwest end of the San Joaquin Basin (see Fig. 3–23 and Table 3–6), is the top producing field in the lower 48 states. Discovered in 1894, it ranks fifth among U.S. oil and gas fields on the basis of ultimate recovery at 2,252 million barrels (California Oil and Gas Fields 1991). The field has over 10,000 producing wells covering over 21,800 productive acres.

Production in the field comes from a variety of units ranging from the Upper Miocene Monterey Formation to the Pleistocene Tulare Formation. Maximum well depths in the field are greater than 14,000 feet, but Tulare production is generally in the range of 500–2,500 feet (California Oil and Gas Fields 1991).

Structures responsible for the trap at Midway-Sunset were formed by compressional forces active periodically throughout the Tertiary (Lennon 1990). Sediments along the west side of the basin were deformed in a series of anticlines and structural noses with axes oriented generally northwest-southeast. Midway-Sunset Field is made up of at least five of these structures. A number of smaller scale trapping mechanisms are present in the field also. They include facies changes, sand pinchouts, tar seals, onlap and overstepping unconformities, and porosity and permeability variations. Faulting is of only minor importance in trapping hydrocarbons at Midway-Sunset.

The Tulare oil is very low gravity, ranging from 8° to 12° API. The tar-like nature of the oil has often led to poor or unacceptable economics for the zone. When producible Tulare oil is found overlying Miocene pays, it is often produced along with them. It is therefore difficult to determine the true productive characteristics of the Tulare.

No significant discoveries have been made in Midway-Sunset since 1962, but the yearly production of oil has increased 3.5 times, to approximately 55 million barrels in 1985, due to implementation of steamsoak and steamdrive recovery techniques. At least three separate steamflood projects are currently being conducted in the Tulare, accounting for 86% of the production (Pacific Oil and Gas World 1993). In 1993 average production from the field was reported at 126,900 barrels of oil per day at an average steam injection rate of 346,200 barrels per day (Pacific Oil and Gas World 1993). Cumulative oil production was 2,120 million barrels of oil.

Use of horizontal wells is an advanced recovery technology currently being applied in conjunction with steamflooding at Midway-Sunset. Horizontal well technology can result in both higher productivity and lower water coning effects. Although none of the horizontal wells in the Midway-Sunset Field targeted the Tulare Sand, it is worthy to note the advantages of applying this technology as a recovery process.

In the early 1990s, UNOCAL drilled a horizontal injection well in the Potter C-Sand, a non-Class 5 reservoir underlying the Tulare Sand (Livingston et al. 1992). Continuous steam injection into the horizontal well brought about a rapid, localized temperature rise in the sand lobe targeted for sweep improvement (Livingston et al. 1992). Production increases in the horizontal well project had not been detected at the time UNOCAL published the results.

Shell drilled several short and medium radius horizontal wells in the Upper Miocene Sub-Hoyt E Sand to enhance the productivity of steamflooding. Early results indicated that production from three short-radius horizontal wells was on the average three times that of an average vertical well (Sande 1992). Due to steam injection over the years, steam override has reduced the gross oil sand thickness to an average of 200 feet from an average of 400 feet. Horizontal wells

exhibited the potential to accelerate production, improve recovery efficiency, and improve steam-oil ratio. In addition, the results of Shell's horizontal well application indicated that horizontal producers and injectors can be designed to target thinning pay sections and delay steam breakthrough.

Another horizontal well study conducted by Shell in thermal reservoirs concluded that horizontal wells in low-pressure steamdrive reservoirs are economically superior to vertical well completions. The longer the lateral, the less is the cost per foot and the greater the production (Speirs and Warren 1994). The study also concluded, that if a vertical well required a gravel packed liner, then a horizontal well could be completed with a prepacked liner. On the other hand, if a vertical well required a liner only, a horizontal well could be completed open hole. This finding could be critical in the design, drilling, and completion of future horizontal wells.

Simulation studies conducted by Shell in 1994 on the effect of short- and medium-radius horizontal wells on a mature steamflood concluded that the optimum design for a horizontal well should take into consideration drilling long laterals near the oil-water contact (OWC) to minimize water coning and create a more uniform OWC surface (Kuhach and Myhill 1994). Shell concluded that results of this study could apply to other thermal recovery projects, because most thermal reservoirs are similar in having heavy oil, steep dip, and inactive bottom water zones.

South Belridge Field

The South Belridge Field, the second largest field in the lower 48 states in terms of production, is located in Kern County about 40 miles west of Bakersfield (see Fig. 3–23 and Table 3–6). It was discovered in 1911 (Small 1986). Currently, Mobil Oil Corporation and Shell Oil Company operate the majority of the leases in the field. The Tulare Sand is the major Class 5–producing reservoir in South Belridge. Cores from the Tulare contain sandstones, siltstones, and conglomerates, all of which are poorly sorted (Lennon 1976). Produced oil from the Tulare has 13° API gravity, with a viscosity of 2,700 cP at formation temperature (87°F). Average formation porosity is 21% with an oil saturation ranging between 30% and 50%. The Tulare is divided into two sections, the upper Tulare controlled by a strong edgewater drive, and the lower Tulare controlled by gravity drainage. In the upper Tulare, 20 steamflood projects were conducted between 1963 and 1979, 16 of which were still in progress when Shell acquired Belridge Oil Company holdings in 1979. In the lower Tulare, five steamflood projects have been conducted since 1965. Results from the lower Tulare projects were generally less favorable because reservoir-quality sands were not extensively continuous (Dietrich 1988).

In 1956 Mobil initiated an in situ combustion field experiment in the lower Tulare Sand (Gates et al. 1978). Prior to in situ combustion, the field had (in 1944) an average daily production of 1,100 barrels of oil per day from 29 wells developed on five-acre spacing. By 1963 oil production had declined to an average rate of 150 barrels per day from 24 producing wells. Cyclic steam injection was tested in two patterns in conjunction with in situ combustion. Results indicated improvement in the oil recovery process. Analysis of the produced gas from the in situ

combustion experiment indicated that oxygen utilization was essentially 100%. In addition, tests showed that injection profiles ranged from poor to excellent. Attempts were made to convert poor profiles by perforation washing or reperforating. Limited entry perforation techniques allowed superior distribution of injected air to the individual sands (Gates et al. 1978). A limited entry perforation technique was also utilized by Shell in all their new steam injection wells in the Tulare Sand in South Belridge (Small 1986) thereby making it possible to identify a perforation impairment problem without running a steam injection survey.

Oil recovery from the in situ combustion project area, in the 22 years before the start of in situ combustion, was 2.6 million barrels or 9.1% of OOIP (OOIP calculated at 29 million barrels). After 12 years of in situ combustion operations, the total recovery was 6.4 million barrels. In situ combustion, drilling of new wells, and using cyclic steam resulted in the production of 3.8 million barrels of oil while injecting 21.4 billion cubic feet of air over 12 years. Cumulative air-oil ratio was 5.6 thousand cubic feet per barrel of oil produced, cumulative cyclic steam used was 2.5 million barrels. In addition, oil recovery results indicated that the actual oil displaced was far more than the volume of oil from the burned zone, as a result of reduced oil saturation in the unburned sand below and beyond the burned zone (Gates et al. 1978).

Dietrich (1988) reported on results of steam injection projects in the upper and lower Tulare sands. In the lower Tulare sands project, the upper 31 feet of the lower Tulare pay zone received most of the hot fluid (total pay is 170 feet). The uppermost 6 feet received about 50% of the injected hot fluid. During the 13-year period, the pilot recovered about 38% of the OOIP from the project area (OOIP calculated at 247,000 barrels) at a cumulative steam-oil ratio of 5.2. Due to the water influx in the upper Tulare sands, the reservoir pressure was maintained at 275 psi. Steamflooding recovered 31% of OOIP with a steam-oil ratio of 2.7. Oil cuts were lower in the upper Tulare than in the lower Tulare due to the edgewater drive. Also, it was determined that the ratio of production capacity to injection capacity was a critical operating variable in edgewater drive steamflood projects.

Another problem that faces any steamflood project is wellbore cleanup and stability. A typical steamflood Tulare Sand producer is completed with an open hole, gravel packed, slotted liner across several or all of the sand intervals. Clay and shale in the Tulare Sand were found to impair the cleanup and stimulation of Tulare wellbores. Shell reported on the success of foamed high-concentration acid when compared to mud acid (Dominquez and Lawson 1992). The foamed acid had a 65% success rate, compared to 20% for the mud acid stimulation in the Tulare Sand, with very positive economic implications.

3.3.2 Ventura Basin

The Ventura Basin is located south of the San Joaquin Basin and north of the Los Angeles Basin in the Transverse Ranges physiographic province (see Figs. 3–21 and 3–24) (Huftile 1991; Slatt et al. 1993). The Transverse Ranges cut across the grain of both the northwest-trending California Coast Ranges north of the Ventura Basin and the Peninsular Ranges of the Los Angeles Basin

(Yeats et al. 1994). The Ventura Basin is a structural basin which can be divided into western, central, and eastern portions. References in the geologic literature frequently refer to the East Ventura Basin and West Ventura Basin (Yeats et al. 1994), the latter including the central section of the upper Ojai Valley (Huftile 1991). The northern boundary of the Ventura Basin is the San Cayetano and Red Mountain Fault zones east of Santa Barbara (Huftile 1991). The West Ventura Basin extends offshore into the Santa Barbara Channel (Yeats et al. 1994). The southern boundary of the Ventura Basin is formed where the Oxnard Plain meets the Santa Monica Mountains (Yeats et al. 1994).

The Ventura Basin formed in the Late Miocene to Early Pliocene (Huftile 1991). Throughout the Middle to Late Tertiary, rapid erosion of the Precambrian and Paleozoic igneous and metamorphic mountains to the east and north caused high sedimentation rates within the restricted boundaries of the Ventura Basin. Figure 3–24 shows the complex structure of the Ventura Basin and the basement rocks which were the source of clastic sediments. The West Ventura Basin has over 20,000 feet of Pliocene-Pleistocene sediments, the thickest section of this age in the world (Huftile 1991).

Complex folding, ramping, and tectonic movements along thrusts in the central and western Ventura Basin have caused a shortening of 9.5 miles with deformation extending to a depth of 10.5 miles to the brittle-ductile transition (Huftile 1991). This complex deformation has had a significant effect on oil migration. The main source of oil in the Ventura Basin is the Monterey Shale represented by the Modelo Formation (Huftile 1991; Conservation Committee of California Oil and Gas Producers 1994).

The Ventura Basin has nine TORIS oil fields (see Table 3–8) which produce from Class 5 fluvial/alluvial environments. Ojai Field is in the West Ventura Basin producing from the Pleistocene Saugus Formation (see Figs. 3–25 and 3–26). Cascade Field in the East Ventura Basin also

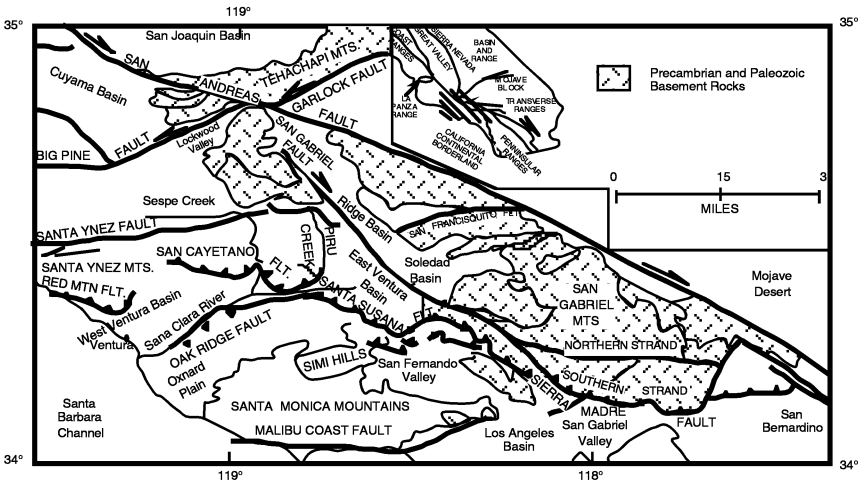


Figure 3–24 Geologic and Physiographic Setting of the Ventura and Los Angeles Basins (Modified from Yeats et al. 1994)

Table 3–8
Reservoir Characteristics for Class 5 Fields in California's Ventura Basin (Source: California Oil and Gas Fields 1991; Conservation Committee of California Oil and Gas Producers 1994)

Field	Formation	Additional Reference	Trap Type	Depth, Feet	Zone Thickness, Feet	Porosity, %	Permeability, mD	Gravity, °API
Cascade	Saugus	Roth & Sullwold 1958	Structural	2,733	395	12–35	537	
Ojai	Saugus	Huftile 1991 Mitchell 1968	Structural	750	350	25–40		14
Oak Park	Sespe	Munger 1969	Combination	800–1,500	400	20	235	
Oxnard	Sespe		Structural	6,500		28		26
Santa Susana	Sespe	Mitchell & Wolff 1971	Structural	6,500	500			36
Shiells Canyon	Sespe	Konopnicki et al. 1979	Structural	2,250–4,300	230	18	100–140	31–34
South Mountain	Sespe		Combination	3,500	1,000	15	24	20
South Tapo Canyon	Sespe	Watkins et al. 1987	Combination	2,200	140	25	25	18
West Montalvo	Sespe	Hardoin 1961	Structural	11,000	2,500	21	243	17

produces Class 5 oil from the Saugus Formation. The remainder of the TORIS fields in the Ventura Basin produce from the Sespe Formation. Five of the fields are located along the Santa Susana Fault (see Fig. 3–24); Santa Susana, and South Tapo Canyon fields east of the fault; and Oak Park, Shiells Canyon, and South Mountain fields west of the fault. West Montalvo Field is located on the coastline south of the Oak Ridge Fault, and Oxnard Field is on the Oxnard Plain in the southwest part of Ventura Basin.

3.3.2.1 Saugus Formation Reservoirs

The Pleistocene Saugus Formation is widespread in the Ventura Basin. It is composed of nonmarine conglomerates, sandstones, silty sandstones and sandy siltstones (Levi et al. 1983). The Saugus Formation grades upward from marine to brackish water to nonmarine sediments with coarser conglomerates predominant in the area west of the San Gabriel Fault (Huftile 1991). The Saugus has its greatest thickness in the West Ventura Basin where tilted beds form a narrow syncline which plunges steeply westward (Huftile 1991).

AGE	VENTURA BASIN FORMATIONS
PLEISTOCENE	Saugus ●
UPPER PLIOCENE	Pico
LOWER PLIOCENE	Repetto
UPPER MIOCENE	Modelo
MIDDLE MIOCENE	Topanga
LOWER MIOCENE	Vaqueros
OLIGOCENE	Sespe ●

● CLASS 5 OIL PRODUCTION

Figure 3–25 Ventura Basin Tertiary Stratigraphic Column for Class 5 Reservoirs (Modified from Conservation Committee of California Oil and Gas Producers 1994)

Ojai Field

The Ojai Valley in the West Ventura Basin boasts the first commercial well in California in 1866 (Mitchell 1969). This well was drilled in a tar seep along Sisar Creek. Drilling was sporadic in the area through the 1890s with the first significant production from Ojai Field in 1900 (Mitchell 1968). The first completion in the Saugus Formation was in 1907 with a gravity of 15° API (Mitchell 1968).

Ojai Valley has undergone extensive folding and ramping. It is a tectonic depression between opposing reverse faults; the San Cayetano Fault which crosses Ojai Field on the north and the Lion Fault which forms the southern border of the Valley (Huftile 1991). Ojai Field is located on the Sulphur Mountain anticlinorium, which is made up of Upper Oligocene to Lower Miocene highly ductile mudstones which have been tectonically thickened in hinge folds (Huftile 1991). The Pleistocene Saugus Formation in contrast is gently folded in the subsurface, but buried by Middle Tertiary sediments where the San Cayetano Fault overrides the Lion Fault (Huftile 1991).

The Sisar Creek area of Ojai Field (see Fig. 3–26) produces mainly from the Saugus Formation. Peak production from Sisar Creek was in 1911, but production continued through the 1960s when cyclic steam recovery methods were applied to recover the heavy oil (14° API). The best

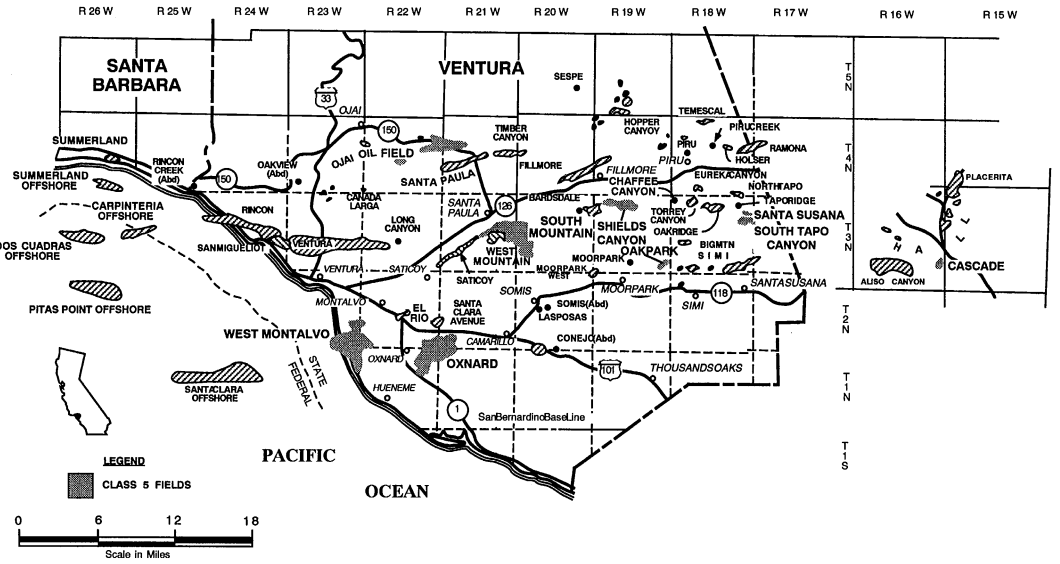


Figure 3–26 Class 5 Oil Fields in the Ventura Basin (Modified from California Oil and Gas Fields 1991)

production has come from the basal Saugus along the unconformable contact with the Miocene Monterey (Mitchell 1968). The trapping mechanism at Ojai Field is porosity loss against fine-grained facies of the Saugus which restrict vertical and lateral flow (Huftile 1991).

Cascade Field

Cascade Field (see Fig. 3–26 and Table 3–8) is located on the southeast flank of the Santa Susana Mountains in the East Ventura Basin in northern Los Angeles County (Ingram 1963). Originally considered part of Aliso Canyon Field, the fields were divided in 1956 when new wells allowed for an updated structural interpretation of the area (Ingram 1963).

Cascade Field produces from poorly sorted fine- to coarse-grained, pebbly sand at depths of 2,531–2,766 feet (Ingram 1963). The basal Saugus Formation represents alluvial fan and braided stream deposition. Roth and Sullwold (1958) described the Sunshine Member of the Saugus at Cascade Field as a fluvial and near-shore marine conglomerate. The single producing zone at Cascade Field averages 500 feet thick (Ingram 1963). Oil is trapped in a plunging anticline with Cascade Field averages 500 feet thick (Ingram 1963). Oil is trapped in a plunging anticline with updip closure caused by a large cross fault (Roth and Sullwold 1958). Porosity (12%–35%) and permeability (537 mD) are good (Ingram 1963), but the producing intervals in the conglomerate are discontinuous.

3.3.2.2 Sespe Formation Reservoirs

Seven fields in the Ventura Basin produce oil from the TORIS Class 5 Oligocene Sespe Formation (see Fig. 3–25). The Sespe is a sequence of interbedded mudstones, sandstones, and pebbly sandstones representing widespread alluvial fan, braided stream, and meandering stream deposition (Schwartz and Colburn 1987). The Sespe sediments are poorly sorted friable, with shale stringers (Hardoin 1958).

The upper Sespe is finer grained and has much thinner beds than the lower Sespe intervals (Schwartz and Colburn 1987). The Sespe Formation is divided into 1st, 2nd, 3rd, and 4th Sespe zones (Mitchell and Wolff 1971). The upper Sespe equates to the 2nd and 3rd, and the lower Sespe equates to the 4th (California Oil and Gas Fields 1991). The 1st and 2nd Sespe produce only minor amounts of oil (Hardoin 1958). Over most of the East Ventura Basin the Sespe Formation conformably overlies the Eocene Llajas Formation (Hall et al. 1967; Bailey 1982), and is conformably overlain by the Miocene Vaqueros (Mitchell and Wolff 1971). East of the Oak Ridge and Santa Susana thrust faults at Santa Susana Field, the Sespe unconformably overlies the Eocene Tejon Formation (Mitchell and Wolff 1971).

Production from the fluvial Sespe Formation ranges from shallow depths of 800–1,000 feet at Oak Park and Shiells Canyon fields to over 11,000 ft at West Montalvo Field. The greatest depths (Table 3–8) are at West Montalvo and Oxnard fields in West Ventura Basin, where faulting and deformation are coupled with high sedimentation rates (California Oil and Gas Fields 1991).

South Mountain Field

Because of extensive thrust faulting in the area of South Mountain Field (see Fig. 3–26 and Table 3–8), the Oligocene Sespe Formation overrides the Pliocene Pico Formation. The average depth of Sespe production is 3,500 feet, while the steeply inclined beds of the Bridge Zone of the Pico average 7,500 feet depth (California Oil and Gas Fields 1991). Throughout most of the South Mountain Field the Sespe overlies the Eocene Llajas Formation (Bailey 1982). The main Sespe reservoir at South Mountain Field has an average thickness of 1,000 feet (California Oil and Gas Fields 1991) which includes the 3rd and 4th Sespe zones. The producing pebbly sand lenses are highly discontinuous, and silty layers act as permeability barriers. The average oil gravity is 25° API, and paraffin plugging of lines and tubes constitutes a production difficulty (Bailey 1982).

Shiells Canyon Field

Shiells Canyon Field (see Fig. 3–26 and Table 3–8) produces from the upper Sespe at an average depth of 850 feet (Konopnicki et al. 1979). The net sand thickness averages 160 feet (Konopnicki et al. 1979). The Sespe conformably overlies the Eocene Llajas Formation at Shiells Canyon Field (Hall et al. 1967). The upper Sespe reservoir is a small (37 acre) fault block, bounded on the west

by the Oak Ridge Fault (Konopnicki et al. 1979). Thrust faulting and movement along the Oak Ridge Fault has placed the entire Eocene and Oligocene section over the Pleistocene Saugus near the fault zone (California Oil and Gas Fields 1991).

Shiells Canyon produces lighter gravity oil (35° API) than any other field in the Ventura Basin (Konopnicki et al. 1979; California Oil and Gas Fields 1991). Light oil combined with an average porosity of 21% and 140 mD permeability has enabled Shiells Canyon to have the highest number of producing wells in the Ventura Basin as of 1993 (California Oil and Gas Fields 1991; Conservation Committee of California Oil and Gas Producers 1994). The primary producing mechanism was a solution-gas drive which resulted in recovery of 267,000 barrels by 1972 of an estimated OOIP of 2.8 million barrels.

In March 1973 Texaco initiated a steamflood pilot project targeting the Sespe. The application of steamflood to light oil recovery was referred to as a "steam-distillation drive process." KCl was injected to reduce clay swelling and injection problems. Production rate prior to steam injection was reported at 12 barrels of oil per day compared to a post steamflood production of 230 barrels per day reported in August 1977. Water cut was reported at 50% after five years of flooding, with a steam-oil ratio of 4 (Konopnicki et al. 1979). Texaco concluded that steam distillation was a feasible recovery technique for light oil reservoirs. Steam distillation can produce residual oil saturations of less than 5%.

Santa Susana and South Tapo Canyon Fields

Santa Susana and South Tapo Canyon fields adjoin one another in Tapo Canyon on the south flank of the Santa Susana Mountains (see Fig. 3–26 and Table 3–8). Drilling began in the Tapo Canyon area in the 1940s. South Tapo Canyon Field was discovered in 1954 and Santa Susana in 1963, both by Union Oil (Hardoin 1958; Mitchell and Wolff 1971). The Sespe Formation attains a thickness of over 5,000 feet at South Tapo Canyon Field (Mitchell and Wolff 1971) with a net pay of 70 feet in the 2nd Sespe and 220 feet in the 3rd Sespe (California Oil and Gas Fields 1991). The dominant feature at Santa Susana and South Tapo Canyon fields is the Oak Ridge Anticline (Mitchell and Wolff 1971; Hardoin 1958).

Oil production at South Tapo Canyon Field, discovered in 1954, is from the 4th Sespe and from the 2nd and 3rd Sespe at Santa Susana Field. Hydrocarbon accumulation at both fields is controlled by faults which truncate permeable beds (Mitchell and Wolff 1971; Hardoin 1958).

The reservoir deposits in the upper Sespe at Santa Susana Field are of alluvial or floodplain origin (Mitchell and Wolff 1971). Cumulative production from the Sespe, reported in 1958, was 3.2 million barrels of oil, 1.16 million barrels of water, and 1,129 million cubic feet of gas (Hardoin 1958). Peak production at Santa Susana Field was in 1966, one year after enhanced recovery processes began (California Oil and Gas Fields 1991). Enhanced recovery was discontinued in 1982 (California Oil and Gas Fields 1991).

The 4th Sespe Zone at South Tapo Canyon can reach thicknesses of up to 4,000 feet, but net pay averages only 107 to 143 feet (Watkins et al. 1987). Faulting has thickened the section, particularly in the overlying Miocene Modelo Formation, where part of the Modelo is thrust over the Pliocene Pico Formation (California Oil and Gas Fields 1991).

The predominant deposits in the 4th Sespe at South Tapo Canyon, discovered in 1954, are braided stream deposits with strongly aggradational to progradational architectures (Watkins et al. 1987). The reservoir quality is complicated by minor faults, conglomerate lenses, and low permeability (25 mD) (Watkins et al. 1987). Faults act as flow barriers or steam thieves. A high clay content from 6% to 12% (mainly smectite and illite with minor amounts of kaolinite and chlorite), and low oil gravity, 14°–19° API, cause major problems in enhanced recovery (Watkins et al. 1987).

Between 1977 and 1980, several wells were completed to the 3rd and 4th Sespe zones as part of steam injection and fireflooding projects. Both projects were determined to be unsuccessful (Watkins et al. 1987). In the mid-1980s, UNOCAL initiated a pilot cyclic steam project in the 4th Sespe to determined the effect of clay and non-clay fines on the recovery process.

The 4th Sespe is a producing low-permeability zone (permeabilities less than 35 mD) containing an abundance of clay and non-clay fines. It is also characterized by rapid production decline and extreme water sensitivity. UNOCAL determined that cyclic steam injection for the purpose of heavy oil recovery can damage water-sensitive formations (Watkins et al. 1987). Well productivity can be impaired by clay swelling, migration of fines and pore throat plugging, alteration of minerals at high temperatures to produce fines, and gravel packing media and formation sand dissolution and later precipitation in the formation. Two newly developed processes were applied in the field tests to prevent these potential damage mechanisms. The processes consisted of the addition of stabilizing agents and were referred to as "Process A" and "Process B." Process A involved injection of a fines stabilizing chemical before steam stimulation and Process B involved continuous addition of a clay stabilizer to steam generator feedwater or effluent (Watkins et al. 1987).

The pilot area had an average permeability and porosity of 25 mD and 24%, respectively, and produced 15° to 19° API gravity oil from an average net pay thickness of 125 feet. As a result of testing the two processes, the overall pilot area achieved a maximum oil rate of 13 barrels of oil per day compared to an initial rate of 7 barrels per day. UNOCAL determined that steam stimulation in conjunction with fines stabilization treatments can significantly stimulate the wells beyond thermal effects (Watkins et al. 1987).

Oak Park Field

Oak Park Field (see Fig. 3–26 and Table 3–8) has a 5,000 foot section of Sespe rocks, but only the upper 550 to 1,300 feet are productive (Bright 1973). This upper zone, equating to the 3rd Sespe, is a medium- to coarse-grained conglomeratic sandstone (Bright 1973). The main structural feature at Oak Park Field is the Simi Anticline which trends east-west south of the field (Bright

1973). Oil is produced from a stratigraphic trap against the Airport Fault (Munger 1970; California Oil and Gas Fields 1991). The Sespe beds dip at a 30° angle (Bright 1973) with an average net pay of 400 feet (California Oil and Gas Fields 1991).

The environment of deposition at Oak Park Field is fluvial (Bright 1973). Deposition occurred during a damp, forested climatic period based on land mammal fossil evidence (Bright 1973).

West Montalvo and Oxnard Fields

West Montalvo and Oxnard fields (see Fig. 3–26 and Table 3–8) are located in the West Ventura Basin close to or on the coast. West Montalvo Field extends offshore into the Santa Barbara Channel (California Oil and Gas Fields 1991). Oxnard is an old field discovered in 1937, but production from the Sespe Formation began in 1952 following the discovery at nearby West Montalvo Field in 1951 (Bott 1966; Sadler 1988).

The Sespe producing reservoir at Oxnard Field is the McInnes Zone (California Oil and Gas Fields 1991), which is equivalent to the upper or 3rd Sespe Zone. The depth of the Sespe at Oxnard Field is from 6,500 to 10,000 feet, the McInnes being the upper 2,000 feet of the interval (California Oil and Gas Fields 1991). The McInnes Zone has 28% porosity, 24° API gravity oil, and no significant production difficulties. The overlying Pliocene Vaca Tar Zone, which produces heavy oil at 5°– 8° API with a sulfur content of 7.5% (Hallmark 1980), has received much of the attention at Oxnard Field, because of the difficulty of production. Production activity from Oxnard Field peaked in the late 1950s and 1960s, and continued in the Vaca Tar through the 1980s with only a few wells active as of 1993 (Conservation Committee of California Oil and Gas Producers 1994).

The depositional environment at Oxnard is commonly described only as nonmarine. TORIS defines the Sespe at Oxnard Field as braided streams. A stacked braided stream depositional environment is in keeping with the interpretation of nearby West Montalvo Field (Sadler 1988).

West Montalvo Field produces from the Colonia Zone of the Sespe Formation. The Colonia Zone is the upper 2,000 feet of the Sespe and consists of six sandstone units from 350 to 600 feet thick (Sadler 1988). The Colonia reservoir, discovered in 1961, extends offshore (Hardoin 1961) with a thickness of over 7,000 feet (Sadler 1988).

The Colonia was described in the 1960s as a thick nonmarine series of sand lenses interbedded with shales (Farley and Redline 1967). These sand and shale lenses are a series of fluvial facies representing; small braided streams, larger trunk streams, and broad shallow braided distributary streams (Sadler 1988). The broad, shallow, braided distributary stream deposits are the most oil prone facies. They are relatively thin with sharp bases and display continuous lateral and vertical stacking across the field (Sadler 1988).

The combination of rapid sedimentation into a restricted fault bounded area, and the cut and fill processes of braided streams has created interconnected fluid pathways (Sadler 1988). These pathways allow for updip migration and accumulation of oil (Sadler 1988). Oil is trapped along the flanks of the Montalvo Anticline and the McGrath Fault Zone (Hardoin 1961).

A relatively high clay content (kaolinite, illite and montmorillonite) at West Montalvo Field reduced permeability and rendered the field unsuitable for then current injection methods in the mid 1960s (Farley and Redline 1967). By 1993 production from the Colonia Zone at West Montalvo Field was restricted to the offshore part of the reservoir (Conservation Committee of California Oil and Gas producers 1994).

3.3.3 Los Angeles Basin

The Los Angeles Basin (see Fig. 3–21) extends from the San Gabriel and San Bernardino Mountains in the east to the Pacific Ocean and south to the Peninsular Ranges (Slatt et al. 1993). The Peninsular Ranges trend northwest and abut against east-west trending Transverse Ranges. The intersection of these ranges contributes to the tectonic complexity of the Los Angeles Basin (Slatt et al. 1993). The maximum extent of the Los Angeles Basin occurred in the Miocene. It was then 45 miles wide and 65 miles long and essentially continuous with the contemporary Ventura Basin to the north (Slatt et al. 1993).

The Late Tertiary history of the Los Angeles Basin was dominated by the oblique subduction of an oceanic plate under the continent (Schwartz and Colburn 1987). Over the past 26 million years a series of small subbasins formed within the larger basin by deformation along transcurrent fault zones. These basins step progressively outward and downward (Slatt et al. 1993). This en echelon arrangement of oil fields in a northwest trending alignment can be seen in Figure 3–27, (California Oil and Gas Fields 1991).

Sedimentation in the basin alternated from continental to shallow marine as a function of sea level fluctuations from the Late Oligocene to Middle Miocene (Schwartz and Colburn 1987). The continental shelf built up during periods of rising sea level and high sea level stands, and muds were deposited in the deep marine part of the basin. During periods of falling sea level, channels were cut across the shelf and submarine fans were deposited in the deep basin (Schwartz and Colburn 1987). Throughout the Pliocene, sedimentation was dominated by submarine fans and turbidites (Slatt et al. 1993).

The oldest formations in the sedimentary sequence are the nonmarine to shallow marine Sespe and Vaqueros formations (see Fig. 3–28) (Schwartz and Colburn 1987). Deposition of the Sespe Formation in the Santa Monica Mountains extended from Late Eocene, through the Oligocene and Early Miocene (Schwartz and Colburn 1987). In the Los Angeles and Ventura Basins the Sespe Formation was restricted to the Oligocene. Overlying the Sespe is the Lower Miocene Vaqueros Formation, characterized primarily by shallow marine and barrier island facies. The

Mid-Miocene and Pliocene units in the Los Angeles Basin are represented by thousands of feet of submarine fans and turbidites in the Topanga, Puente, Repetto, and Pico formations (see Fig. 3–28).

At the top of the section in the Los Angeles Basin are the thick unconsolidated Pleistocene sediments of the La Habra and San Pedro formations. These are transitional marine to nonmarine sands, silts, and marls deposited in predominantly continental, shelf, and beach environments (Schwartz and Colburn 1987). At the basin margin the La Habra Formation contains fluvial deposits made up of reworked poorly consolidated older sediments (Schwartz and Colburn 1987). The La Habra Formation was deposited on a regional erosion surface (Schoellhamer and Woodford 1981). The terrace deposits of the San Pedro Formation conformably overlie the La Habra (Schwartz and Colburn 1987).

Two TORIS fields (see Table 3–9) in the Los Angeles Basin have fluvial-deposited sediments: Playa Del Rey on the coast, and Yorba Linda inland in the eastern part of the basin (see Fig. 3–27).

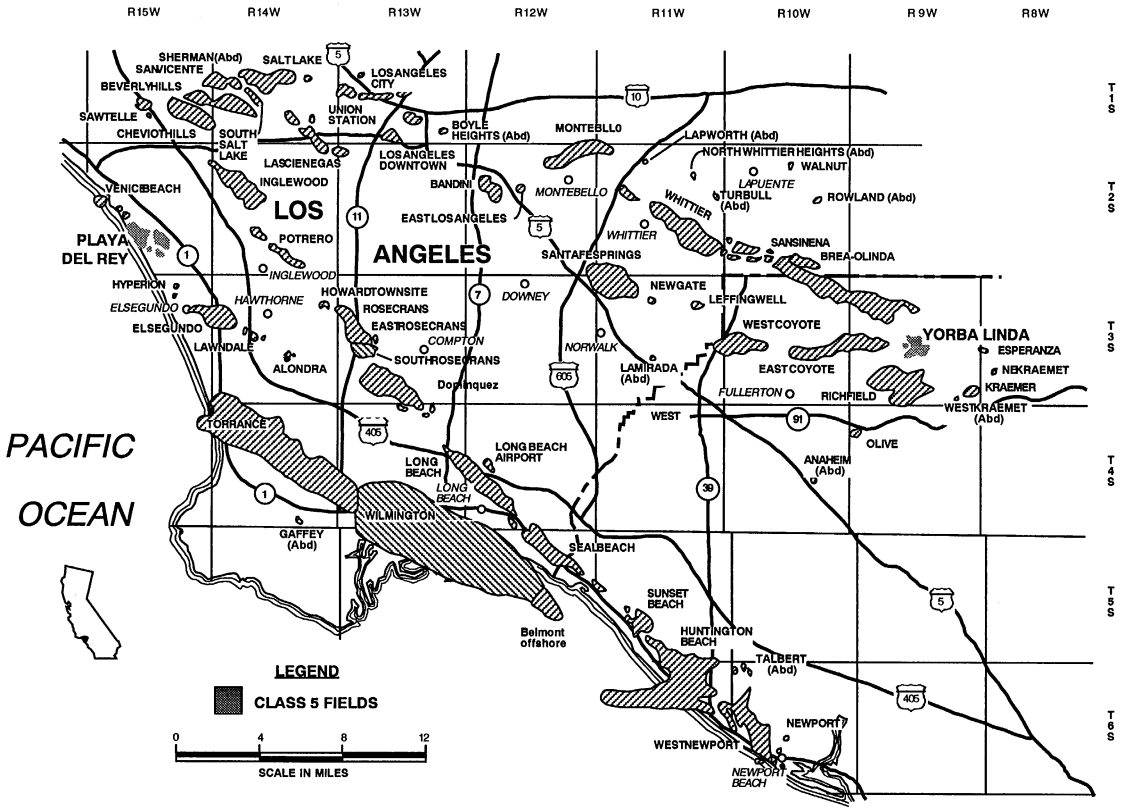


Figure 3–27 Class 5 Oil Fields in the Los Angeles Basin (Modified from California Oil and Gas Fields 1991)

AGE	LOS ANGELES BASIN FORMATIONS
PLEISTOCENE	San Pedro La Habra ●
UPPER PLIOCENE	Pico
LOWER PLIOCENE	Repetto
UPPER MIOCENE	Puente ●
MIDDLE MIOCENE	Topanga
LOWER MIOCENE	Vaqueros
OLIGOCENE	Sespe

● CLASS 5 OIL PRODUCTION

Figure 3–28 Los Angeles Basin Tertiary Stratigraphic Column for Class 5 Reservoirs (Modified from Conservation Committee of California Oil and Gas Producers 1994)

Table 3–9
Reservoir Characteristics for Class 5 Fields in California's Los Angeles Basin (Source: California Oil and Gas Fields 1991; Conservation Committee of California Oil and Gas Producers 1994)

Field	Formation (Reservoir)	Additional Reference	Trap Type	Depth, Feet	Zone Thickness, Feet	Porosity, %	Permeability, mD	Gravity, °API
Yorba Linda	La Habra	Evans 1975	Structural	200–650	250	25–30	50–2000	13
Playa Del Rey	Puente (Del Rey Hills)		Structural	6,200	200	26	500	22
Playa Del Rey	Puente (Venice)		Structural	4,000	180			22

Puente Formation (Playa Del Rey Field)

Playa Del Rey Field produces in two areas: the Del Rey Hills area and the Venice area on the ocean front. Each of these areas produces from a different zone in the Puente Formation (Metzner 1943). Oil was first discovered at Playa Del Rey Field in 1929 at 6,200 feet in the Del Rey Hills area (Barnds 1968). The Lower Pliocene oil bearing zone of the Puente lies between 4,000 and 5,200 feet at Del Rey Hills (Metzner 1943).

This lower zone of the Puente Formation, interpreted as of alluvial fan origin, consists of a basal conglomerate and schist-derived sands deposited in an anticlinal form over an eroded basement ridge of schist (Metzner 1943; Barnds 1968). The Puente basal conglomerate formed as the schist ridge continued subsidence begun in the Late Miocene (Metzner 1943). Middle and upper Puente deposition switched to submarine fans and turbidites as the ridge completely submerged.

The lower zone at Del Rey Hills was converted to natural gas storage in 1942 (Metzner 1943; California Oil and Gas Fields 1991). The upper zone of production in the lower Puente is in the Venice area (Barnds 1968). More oil has been produced from the Venice area than the Del Rey Hills area (California Oil and Gas Fields 1991). However, the upper zone at Venice is described as mostly shale (Metzner 1943). Peak production at the Venice area of the Playa Del Rey Field was in 1931 (California Oil and Gas Fields 1991). Enhanced oil recovery began in 1971 and closed in 1973 in the Venice area (California Oil and Gas Fields 1991).

LaHabra Formation (Yorba Linda Field)

A second field in the Los Angeles Basin producing from a Class 5 reservoir is Yorba Linda Field (see Fig. 3–27 and Table 3–9), where fluvial production is attributed to the shallow Pleistocene La Habra Formation (BPO TORIS 1995). Yorba Linda Field, operated primarily by Shell Oil Company, is at the base of the Chino Hills, which form the eastern boundary of the Los Angeles Basin (Evans 1975). Yorba Linda Field was discovered in 1930 and produces primarily from the Pliocene Repetto Formation (Cook 1975). Production from the shallow La Habra conglomerate zone began in 1954 (Cook 1975). OOIP at Yorba Linda was reported at 100 million barrels (Stokes and Doscher 1974). Yorba Linda Field is located on a faulted homoclinal structure dipping 15° to the southwest two miles south of the Whittier Fault zone (Evans 1975).

The original producing zones are lenticular sandstones of the Lower Pliocene Repetto Formation (Benzley 1958) and the Upper Pliocene Pico (Stokes and Doscher 1974). These zones contain five separate reservoirs at depths of 400–2,500 feet (Cook 1977). The reservoirs are composed primarily of submarine fan and channel turbidite deposits (Cook 1977).

The Pleistocene La Habra Formation is 500–1,500 feet thick and contains a conglomerate interval up to 400 feet thick in the upper part of the shallow zone underlying Holocene alluvium (California Oil and Gas Fields 1991). This upper conglomerate contains more than 70% of the OOIP and produces the lowest API gravity oil. It is a poorly sorted sand with pebble to cobble-

sized clasts interbedded in a complex of permeable sands and impermeable silts (Stokes and Doscher 1974). Net pay averages 300 feet with porosity approximately 30% and permeability of 600 mD (Cook 1977). The La Habra Formation is found only in the northeastern part (320 acres) of Yorba Linda Field (Evans 1975).

Production from the La Habra began in 1954, but it was slow due to the low gravity (12° to 15° API) and high viscosity (1,300 to 6,400 cP) of the oil (Stokes and Doscher 1974; Cook 1975). The individual sand lenses are discontinuous (Stokes and Doscher 1974), and silt layers create localized barriers to vertical permeability further complicating the production of Yorba Linda's heavy oil (Cook 1977). The original estimate of ultimate primary recovery was 5% (Cook 1975).

The reservoir was developed by gravity drainage as the primary recovery mechanism through 1959 using bottomhole heaters. In 1961 Shell initiated a steam-soak operation process through which the expected recovery efficiency was increased to 35%. In 1962, Gulf Oil Company initiated a pilot fire flood on their Yorba Linda Lease which proved to be unsuccessful (Evans 1975). In the same test, steam was injected in the producing well to increase fluid mobility and remove blockage. Results indicated a marked increase in oil production.

In 1971 a pilot steamdrive test in the upper conglomerate was initiated. The test was expanded in 1973 and 1974. Results from the steamdrive pilot test concluded that in the absence of vertical barriers to flow, injected steam migrated upward to the air zone. When vertical barriers were present, the high viscosity of the cold reservoir oil prevented formation of a significant bank (Stokes and Doscher 1974).

Oil production from Shell's full field steamdrive project was reported in 1975 at 9,000 barrels per day from 368 wells in the upper conglomerate (Cook 1975), compared to 7,000 barrels per day in 1971 (Stokes and Doscher 1974). In a study on the influence of silt zones on steamdrive performance in the upper conglomerate zones, Shell concluded that the greater the distance between the completed interval and a silt layer above it, the greater productivity potential the well will have. The study also concluded that producing wells must be steamsoaked adequately to prevent cold oil blockage between perforations and the overlying steam zone (Cook 1977).

As the economics for oil production using steamflooding began to diminish in the early to mid-1980s, the government shared the cost of an enhanced recovery project with industry to test the effect of injecting steamfoam rather than steam only, based on the premise that the economics must be optimized rather than the recovery maximized. The first application of a slug steamfoam method was initiated in February 1978 in Kern River Field by Getty Oil Company. Results from that application indicated that nearly 109,000 barrels of incremental oil were produced as a result of steamfoam injection (Eson and Cooke 1989). Results from the cost-shared project in the Yorba Linda Field indicated that incremental oil was produced as a result of the steam-diverting processes. The process produced bypassed oil that could not have been economically produced otherwise.

3.4 Fluvial/Alluvial Reservoirs Outside Alaska and California

Class 5 reservoirs outside Alaska and California occur throughout the United States in sediments of various ages and in basins with widely different developmental histories (see Fig. 3–2). The wide range of developmental histories is reflected in the diversity of fluvial/alluvial end member system types present (see Fig. 3–29). In terms of oil originally in place, braided stream and alluvial fan reservoirs are dominant, but reservoirs of meandering stream origin are better represented than in either Alaska or California. In terms of numbers of reservoirs, 67% of the TORIS Class 5 reservoirs (57 of 84 reservoirs) are located outside of Alaska and California (BPO TORIS 1995). Of more significance is the virtual absence (only 15.8 million barrels) of proved reserves compared to the 3,720 million barrels of remaining oil in place. A large number of these reservoirs are approaching economic limits or have already been abandoned.

For the purpose of discussion, Class 5 reservoirs in this diverse category have been grouped into five regions based loosely on similarities in large-scale stratigraphy and/or structural setting. These major geographic subdivisions are: (1) Northern Rocky Mountains, (2) Southern Rocky Mountains and Great Plains, (3) Permian and Fort Worth Basins, (4) Eastern Gulf Coast Basins, and (5) Eastern United States Basins.

3.4.1 Northern Rocky Mountains

Class 5 reservoirs occur in three regions in the Northern Rocky Mountains: (1) the Alberta Shelf–Sweet Grass Arch area of west-central Montana, (2) the United States part of the Williston Basin in eastern Montana and western North and South Dakota, and (3) in the intermontane basins of Wyoming. In the following sections TORIS Class 5 production from reservoirs in Montana, North Dakota, and Wyoming will be discussed.

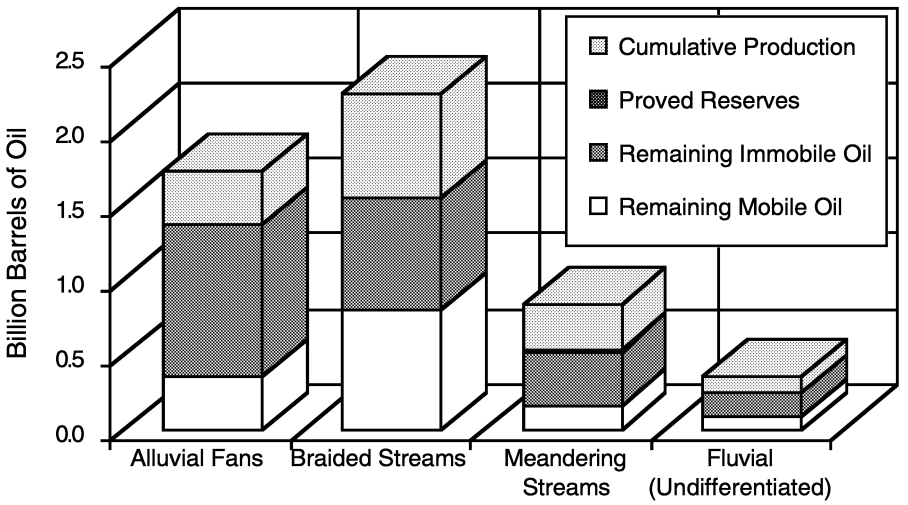


Figure 3–29 Distribution by Depositional System Type of Original Oil in Place in TORIS Class 5 Reservoirs in States Other than Alaska and California (Source: BPO TORIS 1995)

3.4.1.1 Montana

Class 5 Montana reservoirs have the largest reserves in the Northern Rocky Mountain region. ROIP is over 656 million barrels (BPO TORIS 1995). Class 5 production in Montana comes from two different structural settings and four formations. The Lower Cretaceous Kootenai and Dakota formations of west-central Montana produce from the flanks of the Sweetgrass Arch, a major positive element of the Alberta Shelf throughout most of the Paleozoic, Mesozoic, and Cenozoic (Peterson 1985) (see Figs. 3–30 and 3–31). In central and eastern Montana, Class 5 production is found on the western margin of the Williston Basin (Fanshawe 1985). Producing formations in the western Williston Basin, locally termed the Big Snowy Basin, are the Mississippian Tyler and Kibbey formations. Table 3–10 lists reservoir data from fields with fluvial production from the Kootenai and Dakota formations along the Sweetgrass Arch and fields in the Williston Basin.

The Sweetgrass Arch has a 350-mile north-south axis extending from west-central Montana into Alberta (Herbaly 1974). The southern part of the Sweetgrass Arch, the Kevin-Sunburst Dome, terminates just across the border into Alberta (Herbaly 1974).

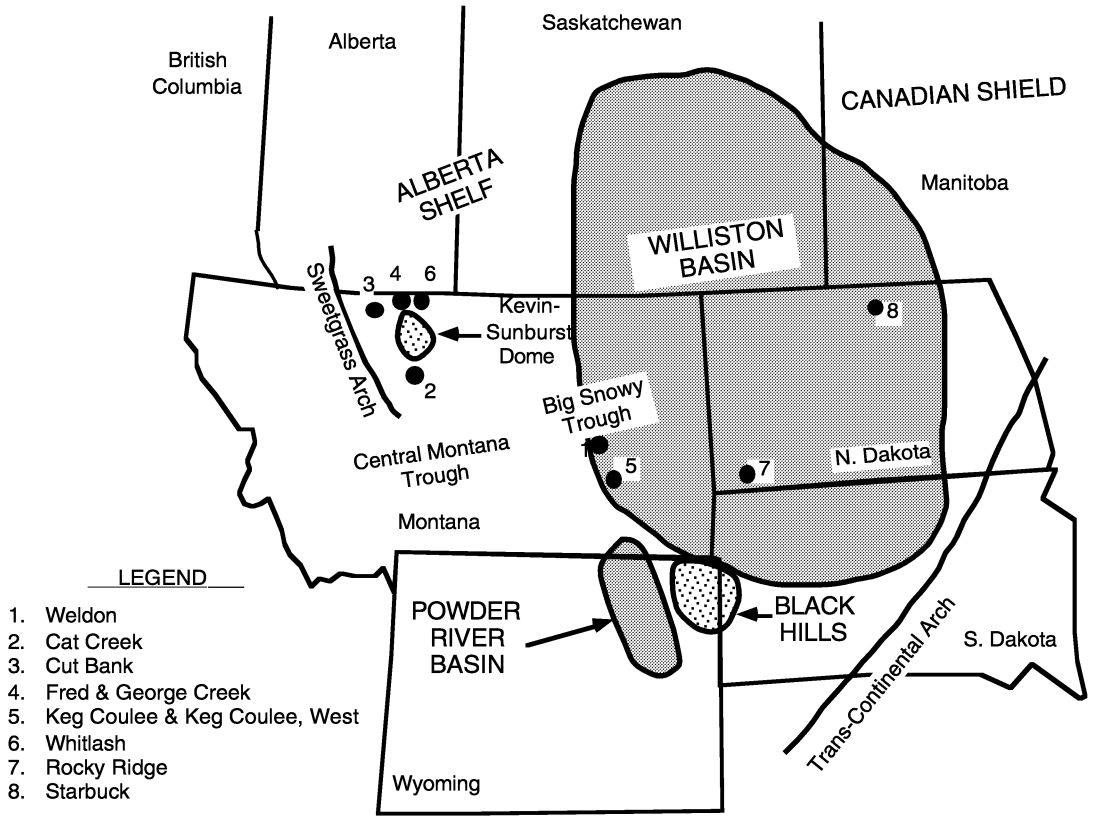


Figure 3–30 Map of the Northern Rocky Mountains Area with Major Basins, Structures, and Class 5 Oil Field Locations (Modified from Peterson 1985; Dolson et al. 1993)

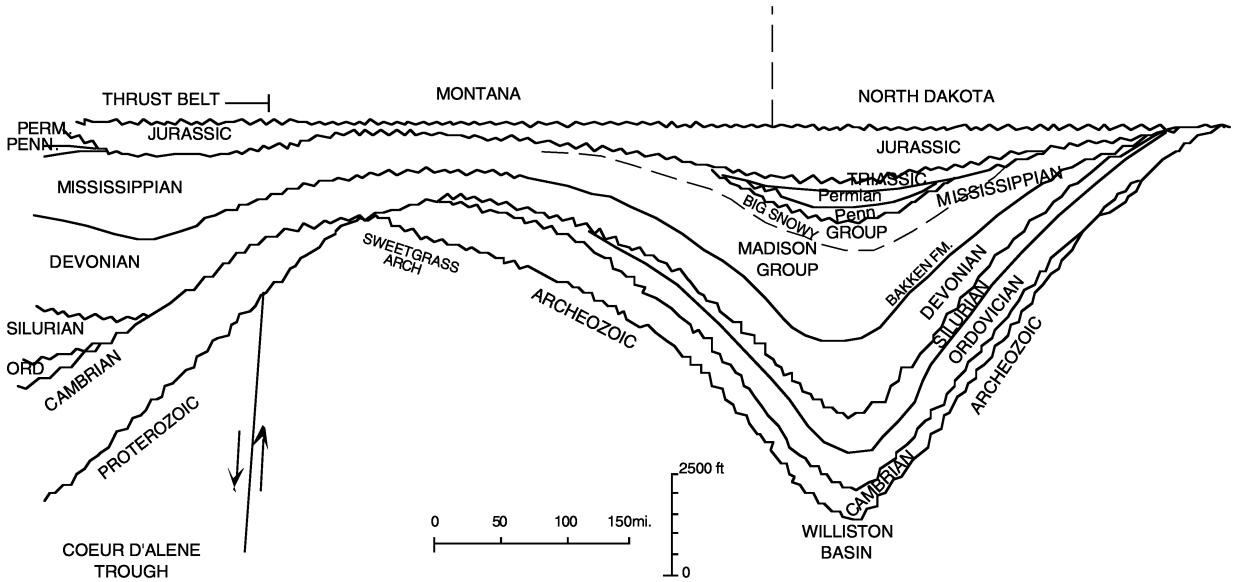


Figure 3–31 East-West Cross-Section Through Montana and North Dakota, Partially Restored to Show the Effects of Structure on Stratigraphic Thickness (Modified from Peterson 1985)

The Kootenai Formation was deposited as part of several thousand feet of Jurassic and Cretaceous sediments on the Alberta Shelf during the Laramide Orogeny (Weimer and Tillman 1982). The lower Kootenai Formation consists of the basal Cut Bank Member, the Sunburst Sand, and the Molton Sand (Shelton 1966). Above these producing horizons of the Kootenai, various authors include the Fuson Member and the Cat Creek Sand (usually described as part of the Dakota Formation) (Dolson et al. 1993). The maximum thickness of the Kootenai Formation is 650 feet. (Shelton 1966). The Kootenai is nonmarine, with the lower members described as meandering stream deposits (Farshori and Hopkins 1989). Meyers and O'Malley (1993) describe the basal Cut Bank Member as a conglomerate deposited by structurally controlled trunk rivers. The Cut Bank Member is widespread and is typically interpreted as a stacked point bar sandstone associated with meandering stream channels in a broad alluvial valley (Weimer and Tillman 1982). The top seal of the Cut Bank is a mudstone of floodplain origin. Weimer and Tillman (1982) noted that both the meander channels and the meander belt were 1–3 miles wide. Both the Cut Bank and the Sunburst are high-quality reservoirs. Permeability is low overall due to high kaolinite content (Farshori and Hopkins 1989) but locally reaches highs in excess of 1,000 mD (Dolson et al. 1993). The Sunburst is a cleaner, more porous sandstone than the Cut Bank (Herbaly 1974) but is thinner and capped with deltaic to shallow marine facies (Meyers and O'Malley 1993).

Four fields—Cat Creek, Cut Bank, Fred and George Creek, and Whitlash—are listed by TORIS as Class 5 fields producing from the Kootenai Formation.

Table 3–10
Reservoir Characteristics for Class 5 Fields along the Sweet Grass Arch in Montana and in the Williston Basin of Montana and North Dakota

Field	Formation	Reference	Trap Type	Depth, Feet	Net Pay, Feet	Porosity, %	Permeability, mD	Gravity, °API
Sweetgrass Arch								
Cat Creek	Kootenai	Montana Geol. Soc. 1985c	Structural	1,350	40	20	150	
Cut Bank	Kootenai	Heath & Kagie 1985 Farshori & Hopkins 1989	Stratigraphic	2,950	16	15–19	31	
Fred & George	Kootenai	Thompson 1966	Stratigraphic	2,000	30	28	1,600	40
Whitlash	Kootenai	Montana Geol. Soc. 1985b	Structural	3,100	13	18	50	39
Williston Basin								
Keg Coulee, W., Montana	Tyler	Carlson 1967	Combination	4,600	20	10	Variable	
Weldon, Montana	Kibbey	Montana Geol. Soc. 1985d	Combination	5,900	14	16	200	39
Rocky Ridge, North Dakota	Tyler	Hastings 1990	Structural		24	15	4	36
Starbuck, North Dakota	Spearfish	Oglesby & Fisher 1992	Stratigraphic	1,840	15	16.3	27	37

Cut Bank Field (587 million barrels of ROIP-BPO TORIS 1995) produces from the Cut Bank Member of the Kootenai (see Fig. 3–30 and Table 3–10). The Cut Bank Member is the basal Kootenai (Montana Geological Society 1985a). It rests unconformably on the Jurassic Morrison Formation and the Rierdon Shale (Meyers and O'Malley 1993; Dolson et al. 1993). In the Cut Bank Field area, the Cut Bank Sandstone rests on a scour surface where up to 60 feet of Jurassic Swift Formation has been eroded (Weimer and Tillman 1982). In parts of the field the underlying Rierdon Shale is incised by channels and the paleovalleys are filled by the Cut Bank Sandstone (Dolson et al. 1993). The Cut Bank Member is a thick basal conglomerate grading upward into fine- to medium-grained conglomeratic sandstone (Meyers and O'Malley 1993; Weimer and Tillman 1982). The Kootenai Formation ranges from 500 to 650 feet thick at Cut Bank Field. The producing Cut Bank Member, 80 feet thick on the western margin, pinches out at the eastern

boundary of the field (Shelton 1966). Cut Bank Field, located 25 miles west of the Kevin-Sunburst Dome, is 30 miles long and 10 miles wide paralleling the regional strike (Shelton 1966). Dip is 75 –100 feet per mile to the west-southwest.

Reed and Campbell (1985) consider the Sunburst Member at Fred and George Creek Field as age-equivalent to the Cut Bank based on regional paleoenvironmental reconstructions of northwest Montana (see Fig. 3–30 and Table 3–10). In other areas the Sunburst Member overlies the Cut Bank (Dolson et al. 1993). Depositional environments associated with the Sunburst Member in this area were coarse-grained meandering streams in the lower interval with braided streams in the upper interval (Flores et al. 1989). At nearby Whitlash Field, the Cut Bank Member is not present and the Swift Formation grades laterally into the Sunburst Member of the Kootenai Formation (Montana Geological Society 1985b). The Sunburst Member of the Kootenai at both Fred and George Creek and Whitlash fields is a pebbly, coarse-grained sandstone fining-upward to fine sand and siltstone with a maximum thickness of 30 feet (Farshori and Hopkins 1989).

Class 5 production at Cat Creek Field (see Fig. 3–30 and Table 3–10) is from the Cat Creek Sandstone members (1st and 2nd) which most authors place stratigraphically in the Dakota Formation (Dolson et al. 1993; Montana Geological Society 1985c). Schulte (1966) correlated the 2nd Cat Creek as age-equivalent to the Sunburst Member of the Kootenai Formation. TORIS classifies the Cat Creek Sandstone as part of the Kootenai Formation. The Cat Creek Sandstone members are in the upper portion of the Lower Cretaceous sequence unconformably overlying the Fuson Member of the Kootenai Formation (Dolson et al. 1993). The 2nd Cat Creek Sand is a medium-grained "dirty" sandstone with thickness of 10–60 feet. The overlying 1st Cat Creek is a fine-grained sandstone with shaly, bentonitic layers, averaging 40 feet thick (Schulte 1966).

Class 5 production is also present in Montana on the western margin of the Williston Basin, a large intracratonic basin containing over 16,000 feet of carbonate and siliciclastic rocks deposited during the Paleozoic (Gerhard et al. 1990) (see Fig. 3–30). However, the Mississippian Kibbey and the Mississippian-Pennsylvanian Tyler formations are the only sedimentary units containing fluvial deposits (Peterson 1985).

The Kibbey Formation consists of 200–300 feet of red shale, siltstone, and sandstone, primarily of nearshore and nonmarine origin (Peterson 1985). Weldon Field, discovered in 1964, is the most western field on the margin of the Williston Basin (Fanshawe 1985; Montana Geological Society 1985d). Weldon Field through its location and the fluvial nature of its deposits represents the depositional edge of the Kibbey Formation (Fanshawe 1985).

Keg Coulee and Keg Coulee West (see Fig. 3–30 and Table 3–10) are fields on the western Williston Basin margin in the geographical center of the Tyler Formation (Montana Geological Society 1985e). The Lower Pennsylvanian Tyler Formation includes marine, deltaic, fluvial, and lacustrine sandstones and shales and minor limestone units restricted to the Central Montana

Trough in the center of the Williston Basin (Maughan 1984; Peterson 1985). The terrigenous source for the fluvial and deltaic deposits was erosion of the Canadian Shield and Transcontinental Arch (Maughan 1984).

Kranzler (1966) describes the lower Tyler Formation in central Montana as of stream channel origin. Production is from a basal conglomerate unit which fines upward to coarse- and then fine-grained sandstone. There is pronounced heterogeneity in the Keg Coulee reservoirs due to oil entrapment in a number of stratigraphic traps associated with plunging structural noses, which effectually isolate point bar sands and fluvial channels (Montana Geological Society 1985e). Although there is a continuous thin sand cover, it lacks effective permeability, allowing trapping of oil in thicker sands over structural highs (Montana Geological Society 1985e).

3.4.1.2 North Dakota

The Williston Basin in North Dakota has two fields producing from Class 5 reservoirs: Rocky Ridge Field and Starbuck Field (see Fig. 3–30 and Table 3–10) (BPO TORIS 1995).

Sedimentation in the Williston Basin is mainly carbonate, but the Lower Pennsylvanian Tyler Formation is one of only a few clastic sequences (Hastings 1990). Mississippian and Devonian rocks were deposited in a cycle of rapid transgression and slow, episodic progradation (Gerhard et al. 1990). Then erosion of Mississippian carbonates and shales in the southern part of the basin led to incised drainage patterns accompanied by unconformable sedimentation in the western part of the basin and in the Big Snowy Trough of Montana (Hastings 1990).

The Tyler Formation has broad lateral extent in Montana and North Dakota. Production is mainly from deltaic and nearshore marine environments; but fields along the margin, Keg Coulee (see Section 3.4.1.1) in the west, and Rocky Ridge in the south are predominantly fluvial deposits. The fluvial-deltaic-barrier island sequences of the Tyler reflect the tectonics and sea level changes of the Mississippian and Early Pennsylvanian (Hastings 1990; Sturm 1987). The Tyler fluvial deposits interfinger with marine deposits indicating continued connections to the sea and sediment transport onto the Cordilleran shelf by way of the Central Montana Trough (see Fig. 3–30) (Gerhard et al. 1990).

Rocky Ridge Field, discovered in 1957, produces from the Tyler Formation at the south end of the highly productive Medora-Dickinson Trend. At Rocky Ridge Field the Tyler unconformably overlies the Mississippian Otter Formation. Two clastic units are present at Rocky Ridge, but only the Fritz Sand, as drillers call it, is productive (Sturm 1987). Maugham (1984) identified three members of the Tyler Formation: the basal Stonehouse Canyon Member (nonmarine conglomeratic sandstone), the Bear Gulch Member (dominantly marine), and the Cameron Creek Member (terrigenous sediments). The Fritz Sand is in the basal Stonehouse Canyon Member. Four stream channels were present at the Rocky Ridge Field forming two major tributaries feeding the Medora-Dickinson barrier island trend downdip to the north (Hastings

1990). The channels are discontinuous and are enclosed by estuarine and marine mudstones and shales. The tributaries are interpreted as belonging to a coarse-grained meander belt system (Hastings 1990).

Starbuck Field in northwestern North Dakota produces from the Triassic Spearfish Formation (Oglesby and Fisher 1992). The Spearfish Formation spreads from the west flank of the Black Hills in Wyoming across eastern Montana, western South Dakota, western North Dakota, and into Saskatchewan and Manitoba (Dow 1967). The facies progression at Starbuck Field from base to top is: coarse-grained sandstone; fine-grained, planar-bedded sandstones; fine- to very fine-grained current ripple-laminated sandstones; and abandoned channel fill (Oglesby and Fisher 1992). The main channel deposits were well cemented early in diagenesis and are nonreservoir rocks. As a consequence, oil migrating from the Charles Formation accumulated in less permeable, lower energy facies adjacent to the main channel deposits (Olgesby and Fisher 1992). Reservoir deposits at Starbuck Field essentially consist of point bar sandstones of a meandering river (Oglesby and Fisher 1992). Oil entrapment is stratigraphic in the area of active channel fill. The Spearfish is sealed by both lateral permeability barriers and overlying shales (Gerhard et al. 1990).

Oil recovery from fluvial deposits in the Spearfish has been relatively low because of a lack of active waterdrive. Production from other facies in the Spearfish has been higher due to an excellent edgewater drive (Oglesby and Fisher 1992).

3.4.1.3 Wyoming

The majority of the TORIS Class 5–producing fields in Wyoming are in the Powder River Basin of northeast Wyoming. Individual fields are also found in the Bighorn Basin, Laramie Basin, Denver Basin, and the Great Divide Basin of the Greater Green River Basin (see Fig. 3–32). The 20 fields in Wyoming with a combined ROIP of 353 million barrels are small compared to the Cut Bank Field in Montana with an ROIP of 587 million barrels (BPO TORIS 1995).

Figure 3–33 shows the stratigraphic relationship of Lower Cretaceous oil producing formations in the Powder River Basin and surrounding intermontane basins of Wyoming (Rasmussen et al. 1985). The Lakota Sandstone at the base of the Cretaceous unconformably overlies the Jurassic Morrison Formation. The Lakota is interbedded conglomerate and sandstones up to 300 feet thick (Rasmussen et al. 1985). The Dakota-Fall River Formation is a series of sands and shales thickening eastward in the basin and lying unconformably over the Lakota Formation. The Fall River name usually refers to the thicker sands in eastern Wyoming and is sometimes given formation status, while the Dakota is given group status. The Dakota as group or formation has widespread recognition throughout the entire central and northern Rocky Mountains. The Fall River is a complex of marine and nonmarine sands and shales ranging from 100 to 160 feet in thickness (Weimer et al. 1988).

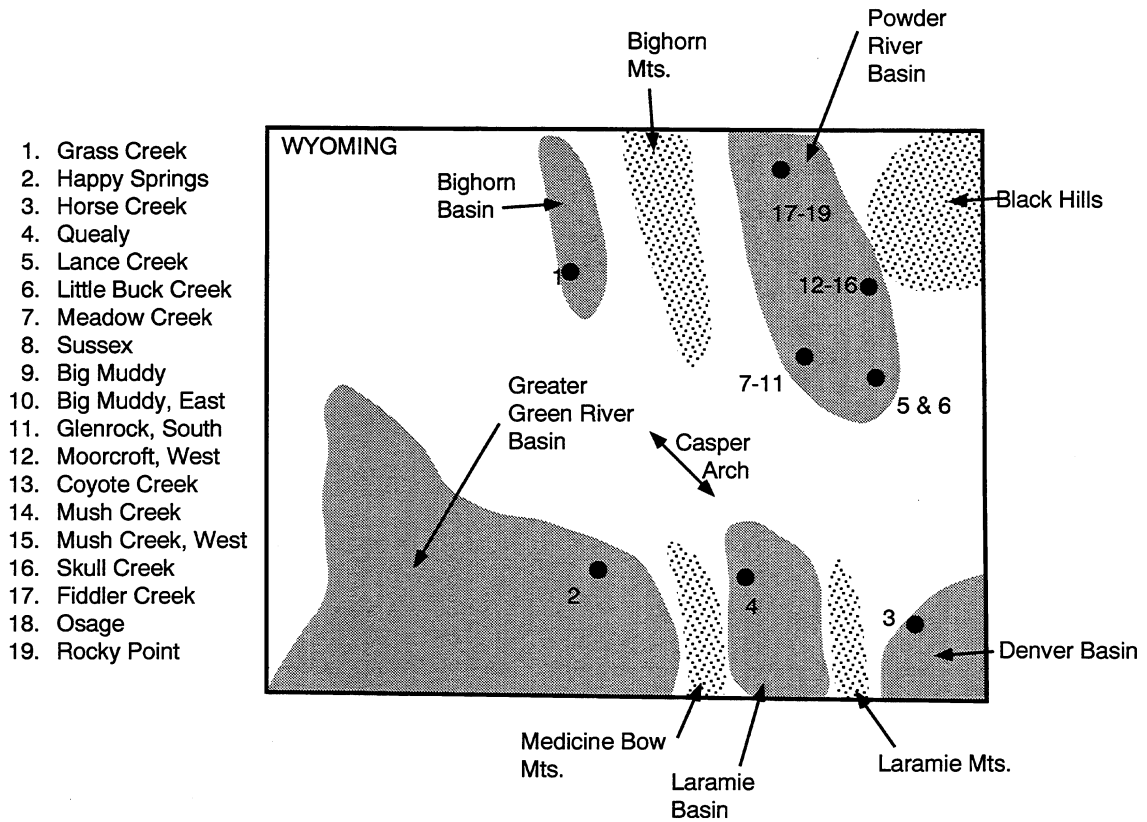


Figure 3–32 Map of Wyoming with Basins, Uplifts, Structures, and Class 5 Oil Field Locations (Modified from Lawyer et al. 1981; Peterson 1985)

The marine Skull Creek Shale which gradationally overlies the Dakota is also a regional marker across Wyoming. It reaches thicknesses of 260 feet (Weimer et al. 1988). The close of Skull Creek deposition represents a major regression, and its upper boundary with the overlying Muddy Formation is deeply incised and eroded. Muddy sandstones fill the incised valleys of the Skull Creek in a transgression from west to east (Waring 1976).

The Muddy Formation is a very widespread sequence of sandstone beds from Colorado north to Montana. In northeastern Wyoming and the Dakotas, the Newcastle Formation, of equivalent age to the Muddy, is often given formation status (Waring 1976; Rasmussen 1985). The Muddy Sandstone tends to be highly variable in thickness, containing both thin lenticular bodies and thick valley fills (Waring 1976). Muddy sands are a complex mixture of marine and nonmarine deposits ranging up to 100 feet or more in thickness (Weimer et al. 1988).

Table 3–11 summarizes reservoir data for the 20 Wyoming fields with TORIS Class 5 production. Average porosity for Wyoming Class 5 fields is relatively consistent ranging from 12% to 23%. Average permeability is much more variable, ranging from 20 mD to 500 mD. API oil gravity is

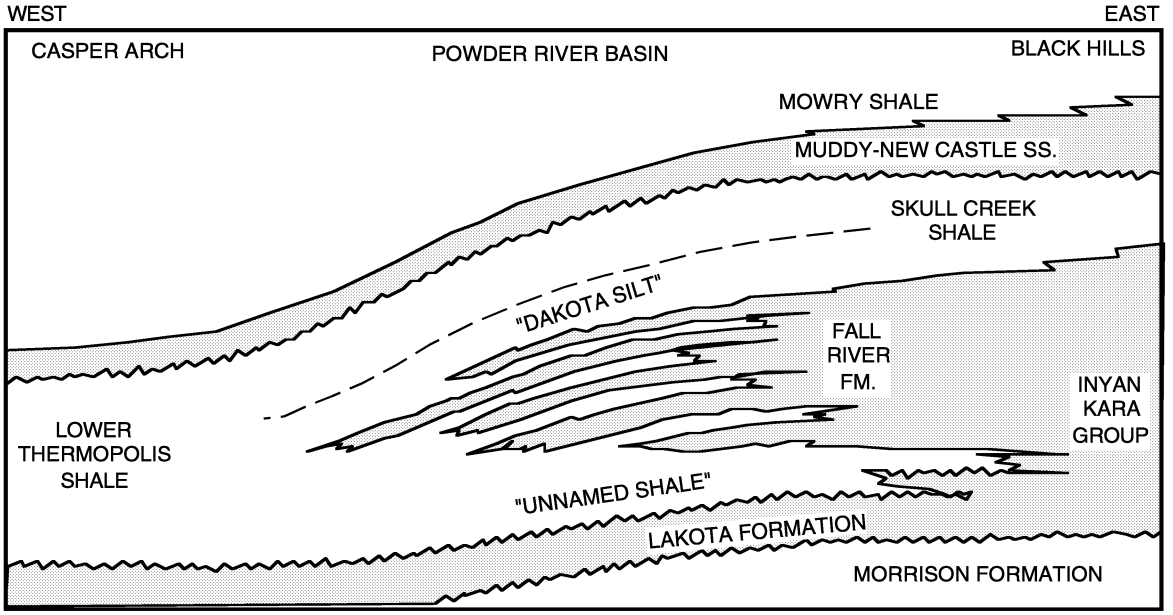


Figure 3–33 East-West Lower Cretaceous Stratigraphic Cross-Section Through the Powder River Basin (No Scale) (Modified from Rasmussen et al. 1985)

consistently between 35° and 45° except for a low of 17° reported from the most northern field in the region, Rocky Point. All the fields are producing from Lower Cretaceous reservoirs in the Lakota, Dakota, Muddy, and Newcastle formations, except for the Pennsylvanian Minnelusa Formation reservoir at Rocky Point.

Fluvial oil fields in Wyoming all tend to be small with a limited lateral facies distribution. Fluvial facies are restricted to the margins of the basins. The thick sedimentary fill of Wyoming intermontane basins is predominantly marine or near-shore sediments (deltaic and barrier island).

Oil entrapment in the Wyoming basins results from a combination of stratigraphic and structural factors. Underlying anticlines and structural noses influence the stratigraphic pinchouts in the Powder River Basin (Lawyer et al. 1981). Faulted anticlines are the main trapping mechanism for Class 5 reservoirs in the Bighorn, Denver, Laramie, and Great Divide basins (Lawyer et al. 1981).

The Powder River Basin has sixteen fields with Class 5 oil reservoirs (BPO TORIS 1995). These fields are located along the flanks of the basin and produce oil almost exclusively from Lower Cretaceous reservoirs. The four formations with TORIS Class 5 production from the Powder River Basin (Lakota, Dakota-Fall River, Muddy, and Newcastle) all have several depositional components. The environment along the margins of the Epicontinental Sea was one dominated by frequent transgressive cycles in which changes in sea level caused repeated sequences of fluvial, deltaic, and near-shore marine deposits. In the Powder River Basin, Meadow Creek and

Sussex fields produce from Class 5 reservoirs in the Lakota Formation. Lance Creek East, Little Buck Creek, Big Muddy, Big Muddy East, Coyote Creek, Glenrock South, and Rocky Point produce from the equivalent age Muddy Formation (see Fig 3.32 and Table 3–11).

The interbedded conglomerates, sandstones, and thin shales of the Lakota are fluvial and deltaic (Rasmussen et al. 1985). The Dakota-Fall River Formation is predominantly deltaic with some units of nearshore, open marine, and fluvial deposition (Rasmussen et al. 1985). The fluvial facies are overbank and crevasse splay deposits of the fluvial portion of the upper delta plain and channel fill or point bar deposits of meandering streams and deltaic distributary channels (Rasmussen et al. 1985). Lawyer et al. (1981) described the Dakota Formation in the southeast part of the Powder River Basin as fluvial in origin, but did not describe the facies present.

The Meadow Creek Field, a Class 5 reservoir discovered in 1950 by Conoco, Inc., has an average net pay of 15 feet with permeability and porosity averaging 37 mD and 15%, respectively. The Lakota produces 39° API gravity oil from an average depth of 7,555 feet. In April 1952 the initial reservoir pressure from a drillstem test was recorded at 2,000 psig. In 1981 the reservoir pressure from the Lakota was measured at 1,000 psig with a cumulative production of 3.95 million barrels of oil, 18.7 billion cubic feet of gas, and 3.3 million barrels of water. Waterflooding, implemented as a secondary recovery mechanism, accounted for 1.37 million barrels of oil and 2.73 million barrels of water of the reported cumulative production (Lawyer et al. 1981).

Considered the fourth largest oil field in Wyoming, the Lance Creek Field, which probably accounts for 12%–15% of all the oil produced in the Powder River Basin, was discovered in 1918 by Marathon Oil Company. Six sandstone horizons account for most of the production in the field. These are from deepest to shallowest: the Leo, First Converse, Sundance, Morrison, Dakota, and the Muddy sands. The Leo was the most prolific producer in the field with initial production as high as 3,000 barrels of oil per day. Another prolific producer was the Sundance with some initial completions producing at the rate of 2,000 barrels of oil per day. Most of the Leo and Sundance wells reached their economic limit and were shut in or recompleted to the Converse Zone (Myers and Arnold 1992).

The Dakota Sand accounts for less than 4% of the total cumulative production in the field with the Leo and Sundance accounting for 55.5% and 37% respectively (Hubbell and Wilson 1963). The Dakota in the Lance Creek Field produces a 44.7° API gravity oil having a very low sulfur content of 0.03%. The Dakota produces from an average net pay of less than 60 feet and is characterized as being fairly tight and water-wet.

No published information describes process application in the Dakota Sand. However, a gas injection program was reported as early as 1938 in the basal Sundance Sand. This program was followed by a similar one in the First Sundance Sand in 1947. Repressuring with gas considerably increased oil production for a time; however, published data are not available to verify the success of this process. Waterflooding was also tried in the basal Sundance, First Sundance, Morrison, and Muddy reservoirs and was reported as moderately successful (Hubbell and Wilson 1963).

Table 3–11
Reservoir Characteristics for Class 5 Fields in the Powder River, Bighorn, Denver, Laramie, and Great Divide Basins of Wyoming

Field	Formation	Reference	Trap Type	Depth, Feet	Net Pay, Feet	Porosity, %	Permeability, mD	Gravity, °API
Big Muddy	Dakota	Lawyer et al. 1981	Combination	1,000	13	16	20–120	35
Big Muddy E.	Dakota	Lawyer et al. 1981		5,300				36
Coyote Creek	Dakota-Fall River	Lawyer et al. 1981	Stratigraphic	6,400	40	14.5	200	
Fiddler Creek	Newcastle	Lawyer et al. 1981	Stratigraphic		15	Variable	Variable	39– 42
Glenrock S.	Lower Muddy	Lawyer et al. 1981	Stratigraphic	7,200	12.4	15	68	36
Glenrock, S.	Dakota-Fall River	Lawyer et al. 1981		7,250	25	14	33	36
Grass Creek	Lakota	Cardinal 1989	Structural		77	21	35	45
Happy Springs	Dakota	Cardinal 1989	Structural	4,600	30	20	400	37–39
Horse Creek	Lakota	Peters 1960		7,400		13.5		30
Lance Creek E.	Dakota-Fall River	Lawyer et al. 1981 Hubbell & Wilson 1963	Structural	4,000	30	15	0 –302	45
Little Buck Creek	Dakota-Fall River	Lawyer et al. 1981 McBane 1984	Combination			14	20	36
Meadow Creek	Lakota	Sims 1952 Hubbell & Wilson 1963	Structural	7,726	15	15	37	39
Moorcroft W.	Newcastle	TORIS	Stratigraphic	3,560	10	22	229	30– 32
Mush Creek	Newcastle	Lawyer et al. 1981	Stratigraphic	3,800	16	12	Variable	39– 46
Mush Creek W.	Newcastle	Lawyer et al. 1981	Stratigraphic	3,800				
Osage	Newcastle	Lawyer et al. 1981	Stratigraphic		15	Variable	Variable	39– 42
Quealy	Dakota	West 1953	Structural		30	Variable	Variable	35
Rocky Point	Muddy	Wyoming Oil & Gas 1972 Weimer et al. 1988	Stratigraphic	3,600	12	23	200	38
Rocky Point	Minnelusa	Wyoming Oil & Gas 1972 Weimer et al. 1988	Structural	5,500	28	20	50	17
Skull Creek	Newcastle	Lawyer et al. 1981	Stratigraphic	3,170	16	12	Variable	39–46
Sussex	Lakota	Sims 1952	Combination	7,700	26	17	50	39

In 1987 Marathon Oil Company initiated a hydraulic fracturing treatment in the recompleted Converse II-A Sand. By 1992 approximately 15 wells were recompleted by deepening or plugging back, then fracturing. These recompletions to the Converse II-A Sand improved the profitability of the Lance Creek Field by adding 625 thousand barrels of oil to the estimated recoverable reserves (Myers and Arnold 1992).

Muddy Sandstone environments are fluvial to marine in the Powder River Basin. Along the margins of the basin Muddy production is largely from point bar sandstones filling incised scours in the Skull Creek Formation (Merschat 1985). West of the Powder River Basin in the Wind River Basin, the fluvial component of the Muddy Sandstone is a northwest-flowing river system overlying deltaic deposits (Curry 1978).

Discovered in 1961, only Rocky Point Field in the Powder River Basin has production from two reservoirs: the main pool is Cretaceous and a lower unit is Pennsylvanian. The Muddy and Minnelusa formations are the major producing targets in the field. The Muddy, which according to TORIS is a Class 5 reservoir, produces from an average depth of 3,600 feet and has a net pay thickness of 12 feet, an average porosity of 23%, and an average permeability of 200 mD. Original pressure in the Muddy was reported at 1,150 psi with the pressure recorded in 1972 at 625 psi. The primary recovery mechanism is gas and water expansion with an estimated recovery of 285 barrels of oil and 500 thousand cubic feet of gas per acre-foot (Wyoming Oil and Gas Conservation Commission 1972). In 1980 the cumulative 38° API gravity oil produced from the Muddy was reported at 8.81 million barrels (Weimer et al. 1988).

The fields and reservoirs in the Powder River Basin are highly discontinuous. Facies quickly change between marine and nonmarine within a relatively limited distance laterally and vertically indicating many heterogeneities and opportunities for significant compartmentalization of reservoirs.

Grass Creek Field in the Bighorn Basin (see Fig. 3–32 and Table 3–11) was discovered in 1914 and has produced from eleven formations from Mississippian to Cretaceous in age. Much of the production at Grass Creek Field has been gas from the deep Darwin-Madison interval and the shallow Muddy Formation (Cardinal 1989). Hydrocarbons are entrapped in a fault bounded asymmetrical anticline. Depositional environments at Grass Creek Field are predominantly marine, and only the Lakota Formation has fluvial facies. The Lakota has an average net pay of 77 feet with average permeability and porosity of 35 mD and 21%, respectively. Initial reservoir pressure was reported at 400 psi. The field cumulative production reported in 1989 was 44.4 million barrels of oil and 7.52 million cubic feet of gas of which 447 thousand barrels of oil was produced from the Lakota. Of the total-field cumulative production, 35 million barrels of oil is from primary recovery and 17.2 million barrels is due to waterflood recovery methods (Cardinal 1989).

Happy Springs Field is located on the south side of the Granite Mountains in the Great Divide Basin, a subbasin of the Greater Green River Basin (see Fig. 3–32 and Table 3–11) (Cardinal 1989). Happy Springs was discovered in 1950 and has production from one Permian and four

Cretaceous formations. Oil is trapped in a faulted anticline at Happy Creek. Most of the production at Happy Springs has been gas from the Upper Cretaceous Frontier Sandstone (Cardinal 1989). Fluvial facies are identified in the Dakota Formation (BPO TORIS 1995). The Dakota Sandstone production is from a small area (300 acres) with an average thickness of 30 feet of pay sand.

Horse Creek Field, found by an early seismic survey in 1940, was the first field discovered in the Wyoming portion of the Denver Basin (Peters 1960). Oil has been produced from the Lower Cretaceous Muddy and Lakota formations, primarily from the Muddy. The Lakota at Horse Creek is listed as undifferentiated fluvial deposits (BPO TORIS 1995). Production from the field declined rapidly and the field was largely closed by the 1950s.

Quealy Field (see Fig. 3–32 and Table 3–11) is in the western part of the Laramie Basin adjacent to the Medicine Bow Mountains. Oil entrapment is in a long narrow anticline modified by thrust faulting (West 1953). Discovered in 1921, the field was developed slowly, but by the early 1950s, 23 wells were producing from Cretaceous Muddy, Lakota, and Dakota intervals (West 1953). The field area is small (200 acres), and the producing intervals are interrupted by frequent faults, making the reservoirs discontinuous (West 1953). The Dakota pay section is about 30 feet thick and that of the Lakota is about 50 feet thick. The two sand sections are separated by 10 to 20 feet of shale. These sands are quite porous and permeable producing a 35° API gravity oil. The reservoir produces by a waterdrive mechanism. Most of the wells flowed initially at rates up to 500 barrels of oil daily. Due to water encroachment, several of the wells completed to the Lakota-Dakota were plugged back to produce from the shallower Muddy Sand (West 1953).

3.4.2 Southern Rocky Mountains and Great Plains

Class 5 fluvial/alluvial sedimentation in the Southern Rocky Mountains comes from fluvial systems on the flanks of major intermontane basins located in Wyoming, Colorado, and Utah. The major basins in the Southern Rocky Mountains are the Greater Green River and Denver Basins. Sediments range in age from Late Jurassic to Eocene in northern Colorado. However, fluvial deposits are predominantly Cretaceous in age and were deposited by transgressions of the Epicontinental Sea covering the area at the time.

Fluvial sedimentation in the Great Plains is found in the Anadarko Basin of Kansas and Oklahoma and in the Arkoma Basin of Oklahoma and Arkansas. These large southern basins received sediments from the ancestral Southern Rocky Mountains to the west and from the Ouachita Uplift to the south. Fluvial and alluvial deposits in the Anadarko and Arkoma basins are Lower Pennsylvanian.

Figure 3–34 shows the major structural features in the Southern Rocky Mountains and Great Plains and the location of TORIS Class 5 oil fields. Reservoir characteristics for fields in the Southern Rocky Mountains and Great Plains are given in Table 3–12.

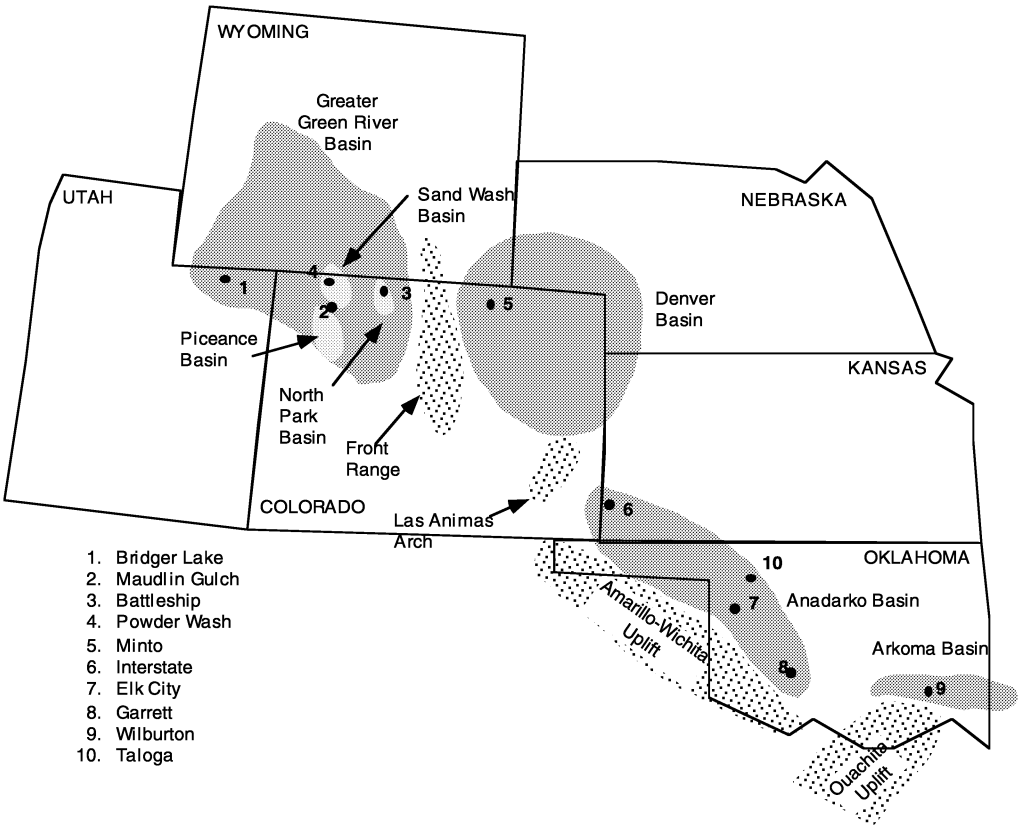


Figure 3–34 Map of the Southern Rocky Mountains and Great Plains Area with Major Basins, Structures, and Class 5 Oil Field Locations (Modified from Rascoe and Adler 1983; Lyday 1985; Sonnenberg 1990; Roehler 1992)

3.4.2.1 Colorado and Utah

The intermontane basins of Utah and Colorado have much in common. They are structural lows associated with the mountain forming tectonics of the Laramide Orogeny. The mountains bounding the intermontane basins are Precambrian. Sedimentary deposits date from Late Paleozoic through Middle to Late Tertiary. Paleozoic sediments in the basins, such as the North Park Basin, show intense folding and deformation (Haverfield 1970). As the mountains rose and the basins deepened, thousands of feet of Upper Cretaceous and Lower Tertiary sediments were deposited. Paleozoic and Mesozoic sediments range from predominantly marine to nearshore marine becoming transitional to nonmarine at the end of the Mesozoic (Webb 1975).

Colorado and Utah have five Class 5 fields (BPO TORIS 1995) producing from Upper Jurassic, Cretaceous, and Eocene sediments in the Denver and Greater Green River basins. Maudlin Gulch Field, located between the Sand Wash and Piceance basins in northern Colorado, produces from the Upper Jurassic Morrison Formation. Battleship Field produces from the Lower Cretaceous Lakota Formation in the North Park Basin, Colorado, and Bridger Lake Field

Table 3–12
Reservoir Characteristics for Class 5 Fields in the Greater Green River and Denver Basins of Utah and Colorado, the Anadarko Basin of Kansas and Oklahoma, and the Arkoma Basin of Oklahoma

Field	Formation	Reference	Trap Type	Depth, Feet	Net Pay, Feet	Porosity, %	Permeability, mD	Gravity, °API
Utah								
Bridger Lake	Dakota	Parker 1966 Westerdale 1978	Stratigraphic	15,754		13	80	39
Colorado								
Battleship	Lakota	Haverfield 1970; Grote 1957 Oburn 1968	Structural	4,654	46	18.5	145	33
Maudlin Gulch	Morrison	Gibbs 1982	Combination	6,350	17	20	83	35.5
Minto	Muddy J	Ethridge & Dolson 1989	Stratigraphic	4,822	15	24	1,160	40
Powder Wash	Wasatch	Roehler 1992	Stratigraphic	2,150	23	20	40	45
Kansas								
Interstate	Morrow	Sonnenberg 1990	Structural	4,200	24	18	219	39
Oklahoma								
Elk City	Hoxbar	Sneider et al. 1976	Stratigraphic	9,900	85	17	173	45
Garrett	Red Fork	TORIS	Stratigraphic	3,668	20	14	10	40
Taloga	Morrow	TORIS	Structural	4,808	20	15	145	42
Wilburton	Morrow	TORIS	Structural	4,428	12	16	4	44

in nearby Utah produces from the Dakota Formation in the Greater Green River Basin. Minto Field in the Colorado portion of the Denver Basin produces from the Lower Cretaceous J Sandstone, part of the Muddy Formation. Powder Wash Field produces from the Eocene Wasatch Formation in the Sand Wash Basin (Roehler 1992). North Park, Sand Wash, and Piceance are small intermontane subbasins in the Colorado portion of the Greater Green River Basin (Roehler 1992).

Green River Basin Fields

The westernmost Class 5 field in the Southern Rocky Mountain region is Bridger Lake Field, Utah. Bridger Lake is located south of Rock Springs, Wyoming, on the Utah side of the border in the southern Greater Green River Basin (Webb 1975). It lies on the northern flank of the Uinta

Mountains at an elevation of over 9,000 feet (Burt 1971). Bridger Lake Field was discovered in 1965 and developed by Phillips Petroleum. It was first described as a highly complex folded and faulted structural trap (Parker 1966), but later geologic investigations describe it as a stratigraphic trap (Webb 1975; Burt 1971). Bridger Lake produces oil from the Lower Cretaceous Dakota Sandstone at a depth of nearly 16,000 feet (Westerdale 1978).

The Dakota Formation unconformably overlies the Morrison Formation and is overlain by the Mowry Shale (Webb 1975). These are widespread formations deposited throughout the Epicontinental Sea, and all are recognized from Montana, south to New Mexico. The Dakota reflects nonmarine transitional, and nearshore marine depositional environments. The basal Dakota is a coarse, fining-upward conglomerate that represents fluvial deposition (Webb 1975).

The Dakota at Bridger Lake (see Fig. 3–34 and Table 3–12) was deposited as clean, well-sorted sands with good initial porosity and permeability (Webb 1975). Oil migration into the Dakota was early, but it was followed by secondary precipitation of kaolinite clay which filled those pores not already filled by fluids (Webb 1975). This diagenetic event reduced the permeability of the fluvial channel sandstones and caused heterogeneities affecting fluid flow.

Original oil in place calculated by material balance was 63 million stock tank barrels. Oil of 40° API gravity was produced at 15,600 feet from the Dakota Formation whose average porosity and permeability were 13% and 79 mD, respectively. The average initial water saturation was 25%. Original reservoir pressure was estimated at 7,230 psi with a bubblepoint pressure of 2,692 psi at the reservoir temperature of 225°F. Gas solubility was 859 standard cubic feet per stock tank barrel. Oil viscosity was 0.53 cP at 7,300 psi (Burt 1971).

Due to reservoir pressure depletion as a result of fluid withdrawal, several enhanced recovery methods were investigated such as waterflooding, gas cycling, and miscible gas displacement. Waterflooding was not selected due to the lack of an abundant supply of water of suitable quality for injection. Gas cycling was eliminated as a recovery process for Bridger Lake due to its low recovery potential (Burt 1971).

Miscible gas displacement was considered and initiated in April 1970 (Burt 1971). Prior to the initiation of the gas injection project, the unit had produced 3.66 million barrels of oil by primary recovery. Cumulative gas injection through 1971 was reported at 3.9 million cubic feet with injection rates and pressures varying from 6.2 million to 15 million cubic feet per day and from 3,900 to 4,800 psi. Prior to the initiation of the gas displacement project, production was reported at 2,900 barrels per day. At the end of December 1970, production was 3,200 barrels per day. Eight producing wells, one injection well, and one water disposal well constituted the unit at this time. Production dropped to 2,050 barrels per day in April 1971, due to restriction of production from some wells. By January 1978 the field had produced 9.4 million barrels of oil (Westerdale 1978). It was estimated that when miscibility was reached, the reservoir would produce 4,450 barrels of oil per day. Early studies indicated that the project life, including blowdown, would be about 34 years.

In 1989 field data reported in DOE's EOR Database (Pautz et al. 1992), indicated an average daily production of 686 barrels of oil per day, 9.8 million cubic feet of gas per day, and 500 barrels of water per day from six producing wells. Cumulative gas injection was reported in 1989 at 2.6 billion cubic feet using one injection well.

Maudlin Gulch Field is on the crest of the Danforth Hills Anticline at the southern tip of Sand Wash Basin just north of the Piceance Basin (see Fig. 3–34 and Table 3–12) (Gibbs 1982; Richard 1986). Class 5 production is from the Jurassic Morrison Formation. In this western region of Morrison deposition the sands are fine-grained with calcareous cement and interbedded thin shales and siltstone units (Gibbs 1982). The Morrison reaches a thickness of 160 feet and is overlain by marine to transitional and nonmarine (mostly deltaic) facies of the Dakota Sandstone (Gibbs 1982). The reservoir at Maudlin Gulch Field consists of a sequence of channel and point bar deposits (Gibbs 1982). The sand bodies are small isolated lenses which limit the areal extent of production (Gibbs 1982).

Battleship Field (see Fig. 3–34 and Table 3–12), discovered in 1954, is located in the North Park Basin at an elevation of 8,060 feet (Grote 1957). It is a narrow, two-mile-long structurally controlled field along a northwest trending fold (Haverfield 1970). The Class 5–producing formation is the Lower Cretaceous Lakota, part of a section of over 9,500 feet of sediments filling the basin (Haverfield 1970). The Cretaceous sequence at Battleship Field begins with the basal Lakota sands overlying the Jurassic Morrison and alternates upward between marine shales and continental sandstone units: Lakota Sandstone, Fuson Shale, Dakota Sandstone, Thermopolis Shale, Muddy Sandstone, and Mowry Shale (Haverfield 1970). All the sandstone formations produce oil (Haverfield 1970).

At Battleship the Lakota is a fine- to coarse-grained sand grading downward into a chert pebble conglomerate with sand matrix at the base. The depositional environment was first described as marine (Oburn 1968), but later studies (Haverfield 1970) recognized a large fluvial component.

Powder Wash Field (see Fig. 3–34 and Table 3–12) is located just south of the Wyoming-Colorado border in the Sand Wash Basin (Roehler 1992). The Class 5 production at Powder Wash Field is from the Eocene Wasatch Formation. The Wasatch is a widespread continental deposit, predominantly fluvial in origin (Roehler 1992). The Wasatch ranges from less than 1,000 feet thick along the northern Rock Spring Uplift to over 9,000 feet thick in the northern Greater Green River Basin. In the Sand Wash Basin the Wasatch averages over 6,000 feet in thickness (Roehler 1992).

The stratigraphy of the Wasatch is complex, with several formal members and numerous intertongues with the lacustrine Green River Formation (Roehler 1992). The nature of the vertical and lateral stacking of fluvial bodies to form the thick Wasatch deposits suggests multiple stream channels with abundant source materials. These fluvial deposits accumulated along the margins of shallow Eocene Lake Gosiute (Roehler 1992). The Wasatch is composed largely of conglomerates, coarse, poorly sorted sands, and mudstones suggesting braided stream deposition.

Denver Basin Fields

The Denver Basin has much the same Paleozoic and Mesozoic stratigraphy as the intermontane basins of western Colorado and Utah. The Denver Basin covers a wide area of Colorado, Wyoming, Nebraska, and Kansas. Fifteen subbasins have been described within this area (Pruit 1978). The Denver Basin is a north-south structural basin with a gently dipping eastern flank and steeply dipping western flank (Higley and Schmoker 1989). The deepest part of the basin, with over 13,000 feet of accumulated sediments, is along the Front Range (see Fig. 3–34) (Sonnenberg and Weimer 1981).

As of 1984, 90% of the oil in the Denver Basin had come from the Lower Cretaceous J Sandstone of the Dakota Group and the Upper Cretaceous D Sandstone (Collins et al. 1992). The J Sandstone, locally called the Muddy J, is recognized as an informal member of the Muddy Formation (Higley and Schmoker 1989). Numerous fields producing from channel sands in the Muddy Formation in the Denver Basin represent distributary channels and interdistributary deposits of the delta plain (Weimer and Sonnenberg 1989; Land and Weimer 1978). The lower Fort Collins Member of the J Sandstone is primarily deltaic and marine and is separated by a major unconformity from the fluvial and estuarine upper Horsetooth Member (Weimer and Sonnenberg 1989).

Depositionally the Class 5–producing interval, the J-2 Sandstone of the Horsetooth member, represents a point bar, crevasse splay, and floodplain sequence of a meander belt stream (Ethridge and Dolson 1989). These fluvial channel sandstones in the J-2 form traps in incised valley fills by stratigraphic pinchouts and draping over structural highs (Weimer and Sonnenberg 1989; Collins et al. 1992).

Minto Field (see Fig. 3–34 and Table 3–12) in the northwestern part of the Denver Basin is the only field in Colorado with Muddy Sandstone production attributed to Class 5 (BPO TORIS 1995). Minto Field is producing from fluvial sediments at a relatively shallow depth, 4,800 feet (BPO TORIS 1995), and has near the maximum porosity observed for the J Sandstone, 24% (Higley and Schmoker 1989).

3.4.2.2 Kansas and Oklahoma

The southern Great Plains includes Class 5 fields in Kansas and Oklahoma producing from sediments of the Anadarko and Arkoma basins. The Anadarko Basin of Oklahoma, Kansas, southern Colorado, and the Texas Panhandle is a deep Paleozoic basin trending northwest-southeast, paralleling the Amarillo-Wichita Uplift (see Fig. 3–34) (Lyday 1985). The Arkoma Basin is an east-west trending basin in eastern Oklahoma and central Arkansas (Rascoe and Adler 1983). These basins were formed by major orogenies which occurred during the Late Devonian and Late Mississippian. Figure 3–35 is a stratigraphic column for the Anadarko and Arkoma basins. Table 3–12 summarizes the reservoir characteristics of Kansas and Oklahoma fields producing from these basins.

SYSTEM	SERIES	GROUP/Formation (informal unit)
PENNSYLVANIAN	VIRGILIAN	(granite wash) ●
	MISSOURIAN	
	DESMOINESIAN	CHEROKEE
	ATOKAN	Atoka dolomite ●
	MORROWAN	U. Morrow Chert Congl. ●
		L. Morrow
	SPRINGERAN	Springer
MISSISSIPPIAN	CHESTERIAN	Chester
	MERAMECIAN	Meramec
	OSAGEAN	Osage
	KINDERHOOKIAN	Kinderhook
DEV.	CHATTANOOGAN	Woodford
SIL.	(undifferentiated)	HUNTON/ Limestone
ORDOVICIAN	CINCINNATIAN	Sylvan
	CHAMPLAINIAN	Viola
		SIMPSON
	CANADIAN	ARBUCKLE/ Dolomite
CAMB.	CROIXAN	Reagan
	(undifferentiated)	(extrusive igneous rocks)
PRECAMBRIAN		(granite)

● CLASS 5 OIL PRODUCTION

Figure 3–35 Stratigraphic Column for the Anadarko and Arkoma Basins (Kansas and Oklahoma) (Modified from Lyday 1985)

Anadarko Basin

The main structural elements of the Anadarko Basin formed during the Wichita Orogeny in the Pennsylvanian. In the Morrowan (Early Pennsylvanian) the western Anadarko Basin received clastic sediments from the Las Animas Arch in Colorado (Shirley 1984). Class 5 reservoirs are found in the upper Morrow Formation, the Atoka Dolomite, and the Late Pennsylvanian granite wash sediments (Lyday 1985). Pennsylvanian fill in the Anadarko Basin has a large component of coarse conglomerates eroded from surrounding uplifts (Lyday 1985; Shelby 1980).

In western Kansas there is TORIS Class 5 production from the Pennsylvanian Morrow Formation. The Morrow lies unconformably at the base of the Pennsylvanian (Sonnenberg and Weimer 1981). It is a transgressive sequence 440 feet thick divided into three informal units (Sonnenberg 1990). The lower unit, 110 feet thick, is composed of terrigenous clastic sediments; the middle unit, 85 feet thick, is limestone and shale; the upper unit, 235 feet thick, is shale with thin sand beds.

Interstate Field (see Fig. 3–34 and Table 3–12), discovered in 1954, lies south of the Denver Basin along the western edge of the Hugoton Embayment of the Anadarko Basin (Sonnenberg 1990). The field produces from a pronounced structural nose formed in the Permian. At Interstate the upper Morrow chert conglomerate is primarily a gas reservoir (Shelby 1980). Oil production comes from the upper Morrowan upper Purdy Sandstone (Sonnenberg 1990). The Purdy Sandstone is interpreted as of fluvial valley-fill origin. The reservoir is sealed by marine shales (Sonnenberg 1990).

Exploration in the Anadarko Basin in the 1980s revealed that many of the productive sands of the Morrow Formation were point bar sands (Shirley 1984). South of Interstate Field in the Texas-Oklahoma Panhandle region, the Morrow becomes a thick chert conglomerate formed as a fan delta along the Amarillo-Wichita Mountain front in a shallow marine basin (Shelby 1980).

Taloga Field (see Fig. 3–34 and Table 3–12) is on the northern flank of the Anadarko Basin in Oklahoma (Slate 1962). Taloga Field produces oil from Pennsylvanian Age rocks in the Morrow Series, Atoka Series, Des Moines Series, and Missouri Series. The Morrow Sandstone has been identified as a meandering stream depositional environment at Taloga Field (BPO TORIS 1995). A major structure in the area influencing oil production at Taloga is the North Custer City Fault, which has a throw of from 180 to 470 feet at depth and disrupts fluid flow (Slate 1962).

Dolomite and chert conglomerates of Atokan and Late Pennsylvanian Age contain a Class 5 reservoir along the Elk City structure at Elk City Field, Oklahoma (see Fig. 3–34 and Table 3–12). The Hoxbar Formation at Elk City Field is primarily a sequence of coarse conglomerates and sandstones with some interbedded siltstones. Class 5 production is from fluvial channel deposits laid down by high-gradient braided streams (Sneider et al. 1976). The sediments of these braided stream deposits are reworked from exposed dolomites of Atokan Age (Lyday 1985). The conglomerate at Elk City Field is poorly sorted, compacted, and cemented. Porosity changes markedly in different beds due to the degree of sorting and the amount of cementation. Fine-grained well sorted sandstones have the highest porosities, and coarser sands and conglomerates have lower porosities (Sneider et al. 1976). The fluvial channel deposits are linear and at right angles to the depositional strike of marine deposits located farther basinward (Sneider et al. 1976). Berlin Field, located just north of Elk City Field but deeper in the basin and further downdip from the Amarillo-Wichita uplift source area, is a marine-dominated fan delta (Lyday 1986).

Garrett Field (see Fig. 3–34 and Table 3–12) in southern Oklahoma in the Anadarko Basin produces from fluvial deposits of the Middle Pennsylvanian Red Fork Formation (BPO TORIS 1995). The Red Fork Sandstone is a very fine- to fine-grained sand (Cornell 1991). The Red Fork Sandstone has two major depositional trends, and the environments range from continental to marine. Along the eastern flank of the Anadarko Basin the lower Red Fork is interpreted as a deltaic complex with distributary channel, distributary mouth-bar, and interdistributary bay facies (Hough 1978). Similarly, the Wakita Trend on the northern shelf of the Anadarko Basin is a low energy transgressive barrier bar (O'Reilly 1986). Only the updip section of the Red Fork

contains alluvial plain deposits, and these progress downdip into deltaic and then slope/basin submarine fans (Cornell 1991). Garrett Field is on the updip, fluvial portion of the deltaic complex.

Arkoma Basin

The Arkoma Basin (see Fig. 3–34) did not receive the exploratory interest invested in the Anadarko Basin because it contains far more gas than oil, and prices for gas lagged in the first half of the 20th century (Whitmire 1990). The Morrow Sandstone was the first oil-producing horizon discovered in the Arkoma Basin (Whitmire 1990).

Wilburton Field (see Fig. 3–34 and Table 3–12), discovered in 1931, is located in the western part of the Arkoma Basin in southeast Oklahoma, east of the Anadarko Basin (Rascoe and Adler 1983). Wilburton produces from the clean sandstones of the Lower Pennsylvanian Morrow Formation (Rascoe and Adler 1983; Whitmire 1990). The Morrow Sandstone at Wilburton Field is interpreted as meandering stream deposition (BPO TORIS 1995). Although Morrow sands are still productive, recent developments at Wilburton have involved deep drilling to increase gas production from the Ordovician Age Arbuckle Trend (Hook 1990; Whitmire 1990; Gatewood and Fay 1992).

3.4.3 Permian and Fort Worth Basins

The Permian Basin of Texas and New Mexico and the Fort Worth Basin of Texas are two major Paleozoic hydrocarbon producing basins in the western Gulf Coast. Much of the oil in these basins is from carbonate facies in the Permian Basin and slope/basin submarine fan deposits in both basins. Some of the marginal basin areas, however, have alluvial fan and fluvial deposits (BPO TORIS 1995). Figure 3–36 shows the structural elements of the Permian and Fort Worth basins and the locations of major Class 5 oil fields within this region. Table 3–13 summarizes the reservoir characteristics of New Mexico and Texas fields producing from these basins.

3.4.3.1 Permian Basin

The Permian Basin is bounded by the Bend Arch on the east, the Amarillo-Wichita Uplift on the northeast, the Pedernal Massif on the northwest, the Diablo Platform on the southwest, and the Marathon folded belt on the south (Waldschmidt 1966). Within the Permian Basin additional structure elements include the Delaware, Midland, Palo Duro, Val Verde, and Marfa subbasins; the Matador Arch; the Northwestern and Eastern Shelves, and the Ozona and Central Basin Platforms (Waldschmidt 1966). A stratigraphic column for the Permian Basin is shown in Figure 3–37. Fluvial sands are rare.

The Grayburg-San Andres trend extends in a west-to-east curve from north of Carlsbad, New Mexico, into the Central Basin Platform of west Texas (Galloway et al. 1983). The San Andres and overlying Grayburg belong to the Lower Guadalupe Series of Mid-Permian Age (Galloway et al.

1983; Young 1966). Five major facies are recognized in the Grayburg-San Andres sequence: (1) shallow wackestone and terrigenous sandstone, (2) fusulinid wackestone, (3) oolitic-bar grainstone, (4) dolomitized wackestone and interbedded sandstone, and (5) sabkha anhydrite, dolomite, and red shale (Galloway et al. 1983).

Loco Hills Field (see Fig. 3–36 and Table 3–13), discovered in 1939, is located north of Carlsbad, New Mexico, on the flank of the Grayburg-Jackson monocline in the Artesia-Vacuum trend of the Grayburg-San Andres (Darden and Cook 1962). The reservoir is a stratigraphic trap limited by permeability pinchouts on three sides and a static water table on the fourth side (Darden and Cook 1962). Secondary recovery began in 1958.

The producing fluvial interval at Loco Hills is in the West Unit (a wackestone and terrigenous sandstone facies) of the Grayburg Formation (Darden and Cook 1962). The sand interval at Loco Hills is described as a continuous, uniform deposit (Darden and Cook 1962).

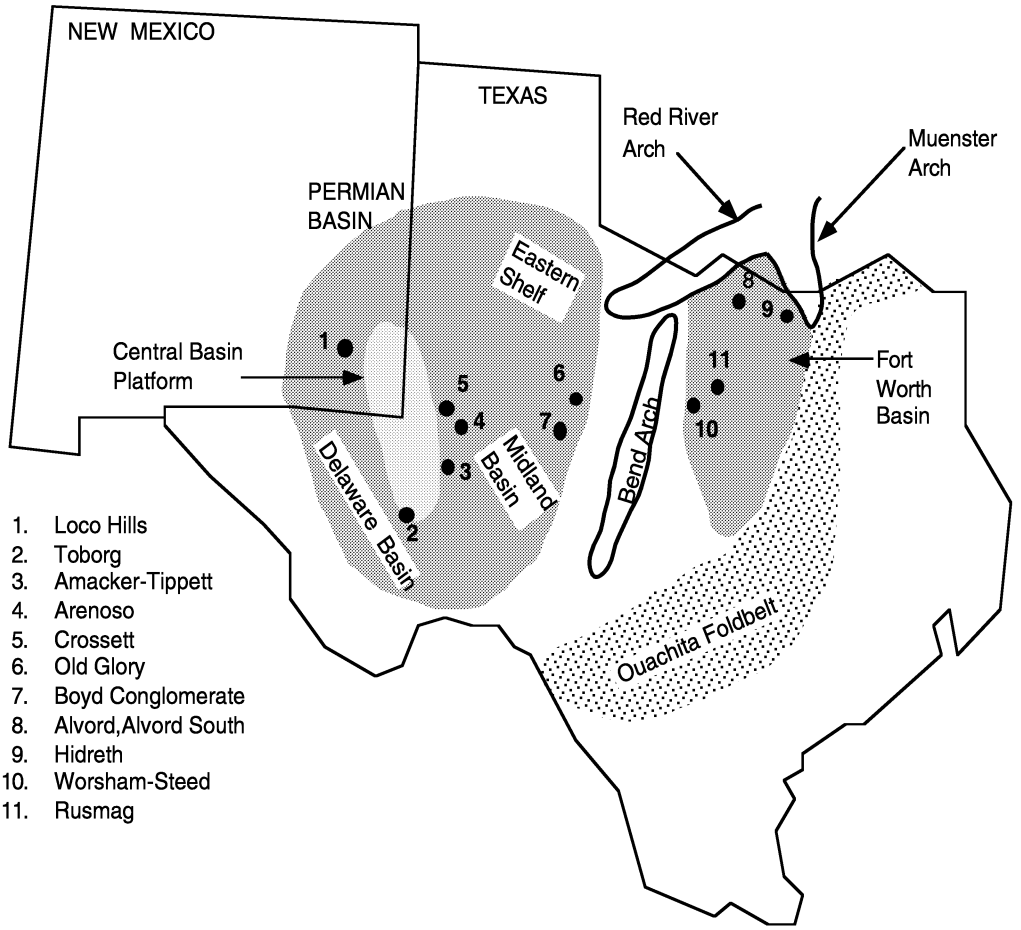


Figure 3–36 Map of the Permian and Fort Worth Basins (New Mexico and Texas) with Structures and Class 5 Oil Field Locations (Modified from Brown 1969; Galloway et al. 1983)

Table 3–13
Reservoir Characteristics for Class 5 Fields in the Permian Basin of New Mexico and West Texas and in the Fort Worth Basin of Texas

Field	Formation	Reference	Trap Type	Depth, Feet	Net Pay, Feet	Porosity, %	Permeability, mD	Gravity, °API
Permian Basin								
New Mexico								
Loco Hills	Grayburg	Darden & Cook 1962	Stratigraphic	2,665	23	20	49	36
Texas								
Amacker-Tippett	Wolfcamp	Galloway et al. 1983	Structural	9,218	37	11	17	44
Arenoso	Strawn	TORIS	Structural	8,587	24	10	73	38
Crossett	Wolfcamp	TORIS	Structural	4,900	28	15	14	42
Old Glory	Bend Cong.	Galloway et al. 1983	Structural	5,900	25	17	49	40
Boyd Cong.	Bend Cong.	Galloway et al. 1983	Structural	6,000	35	14	55	40
Toborg	Toborg	Galloway et al. 1983	Structural	500	27	30	86	22
Forth Worth Basin								
Alvord	Bend Cong.	Frazier et al. 1982		3,000	10	20	46	41
Alvord South	Bend Cong.	TORIS		5,800	30	12	45	44
Etter	Bend Cong.	TORIS		5,760	19	16	52	41
Hildreth	Bend Cong.	Galloway et al. 1983	Structural	7,500	16	14	257	41
Rusmag	Bend Cong.	Galloway et al. 1983	Stratigraphic	4,600	15	12	19	41
Schick	Bend Cong.	TORIS		6,100	16	17	1,456	42
White Flat	Bend Cong.	TORIS		5,516	31	10	150	46
Worsham Steel	Bend Cong.	Galloway et al. 1983	Stratigraphic	4,700	20	14	50	41

Toborg Field (see Fig. 3–36 and Table 3–13), discovered in 1925, is located in the Yates area on the southwestern flank of the Central Basin Platform (Galloway et al. 1983). Production is from the Toborg Sandstone (BPO TORIS 1995), a unit of the Lower Cretaceous Trinity Group (Galloway et al. 1983). The shallow Cretaceous reservoirs of the Toborg Sand had very high flow rates which led to an early production boom (Galloway et al. 1983). The Toborg reservoir sands are poorly cemented, discontinuous, and have fluvial depositional characteristics (Galloway et al. 1983).

Amacker-Tippett, Arenoso, and Crossett fields (see Fig. 3–36 and Table 3–13) are TORIS Class 5 fields located on the eastern margin of the Central Basin Platform in the Midland Basin. Amacker-Trippett and Crossett fields produce from the Lower Permian Wolfcamp Formation, while Arenoso production is from the Middle Pennsylvanian Strawn (Galloway et al. 1983). These fields produce from alluvial fan deposits (BPO TORIS 1995) derived from erosion of the exposed Central Basin Platform in a section predominated by shallow carbonate shelf deposition.

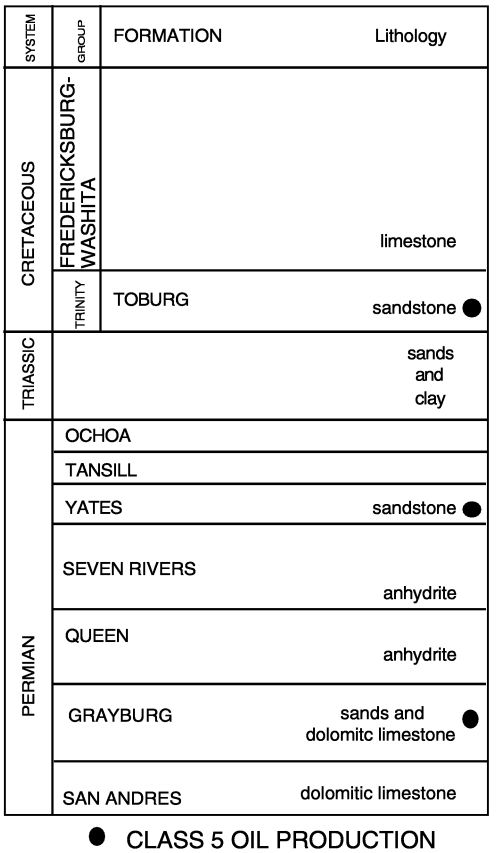


Figure 3–37 Stratigraphic Column for the Permian Basin (Texas and New Mexico) (Modified from Galloway et al. 1983)

Brown (1969) generally defined the rocks of the Upper Pennsylvanian and Lower Permian of the Eastern Shelf (see Fig. 3–36) of North-Central Texas as fluvial, deltaic, interdeltaic, and open shelf facies. Oil entrapment in the fields of the Eastern Shelf is mainly through anticlinal closure and productive areas are limited in size by the irregular distribution of porous facies (Galloway et al. 1983).

At Old Glory and Boyd Conglomerate fields (see Fig. 3–36 and Table 3–13) extensive faulting along a northwest-southeast trend led to oil entrapment (Reed 1972). The Bend Conglomerate (see Section 3.4.3.2) was deposited over existing Mississippian fault scarps which remained active in the Pennsylvanian (Reed 1972).

3.4.3.2 Fort Worth Basin

The Fort Worth Basin of north-central Texas (see Fig. 3–36) contains eight TORIS Class 5 fields (see Table 3–13) producing from reservoirs in the Bend Conglomerate. The Fort Worth Basin is a 200 mile wide Paleozoic Basin with preserved sedimentary thickness of over 12,000 feet (Lahti and Huber 1982). In the Early Paleozoic, the Fort Worth Basin occupied an embayment on the western margin of the Ouachita geosyncline; from Late Mississippian to Middle Pennsylvanian it subsided as a foreland basin west of the Ouachita Fold Belt (Lahti and Huber 1982).

The Bend Conglomerate play covers a broad area of the Fort Worth Basin extending westward to the Bend Arch and onto the Eastern Shelf of the Permian Basin (Galloway et al. 1983). The Bend Arch is a flexure and structural high formed by subsidence of the Fort Worth Basin and Late Paleozoic tilting of the Eastern Shelf (Ng 1979).

The Bend Conglomerate is an Early to Middle Pennsylvanian Atokan Age sequence of coarse clastic detritus, sands, and muds. It is generally friable with good porosity and permeability (Reed 1972; Galloway et al. 1983).

The Bend Conglomerate unconformably overlies Mississippian terrain and in some areas, fills incised valleys (Staples 1986). Deposits of the Bend are primarily the result of interaction between the Epeiric Sea and the Ouachita Orogeny and are characterized by the frequent alternation of eroded detritus with shales and limestones (Ng 1979). The repetitive sequence suggests that sediment accumulation took place in a tectonically low setting and that the base level fluctuated frequently (Burn and Carr 1994). Clastic sediments were deposited as coarse-grained alluvial fans, fan deltas, and deltaic facies, with the majority of sediments being derived from the Ouachita Uplift to the southeast and the Muenster and Red River Uplifts to the north (Galloway et al. 1983).

The sandstones of the Bend Conglomerate in the Fort Worth Basin and on the Eastern Shelf of the Midland Basin area are local, elongate bodies, oriented east-west. These sand bodies occur in interbedded sequences with clay-shales and thin limestones (Brown 1969). Sandstone reservoirs in the Bend occur as numerous thin (10–20 foot) intervals within the Atokan (1,000+ foot) section (Burn and Carr 1994).

All nine TORIS Class 5 fields producing oil from the Bend Conglomerate are of alluvial fan origin. This places them up-dip from the more widespread coarse-grained fluvial-deltaic facies derived from the uplift areas to the north, east, and south of the Fort Worth Basin (Galloway et al. 1983). Traps range from anticlines to facies-controlled porosity pinchouts to stratigraphic and structural combinations (Galloway et al. 1983). Reservoir characteristics for the Fort Worth Basin fields are listed in Table 3–13. The major hydrocarbon production from the Bend Conglomerate is gas. Oil reservoirs tend to have moderate to low recovery efficiencies (Galloway et al. 1983).

The Alvord Field, discovered in the mid 1950s, is located in the north-central part of the Fort Worth Basin (see Fig. 3–36). Original oil in place (OOIP) from the 3,000 foot deep reservoir is estimated at 1.84 million stock tank barrels (STB). Net productive thickness of the reservoir is 9.8 feet with a permeability of 46 mD and porosity of 20%. The produced 41° API gravity oil has a viscosity of 0.95 cP and a formation volume factor of 1.17 reservoir barrels per STB (Frazier and Todd 1982).

When waterflooding began in 1966, 404,000 STB, or 22% of OOIP, had been produced by primary means. Waterflooding contributed an additional 262,000 STB. In June 1980 the project reached its economic limit, thus terminating waterflood operations.

In December 1979 a detailed reservoir simulation study was initiated to determine feasibility of a liquefied petroleum gas (LPG) miscible process (Frazier and Todd 1982). Results of early economic analysis indicated that the DOE tertiary incentive program would be critical to the project's success. In the LPG-slug process, the LPG is generally miscible with the oil, and the drive gas is miscible with the LPG. Drive gas is generally not miscible directly with the oil. Of the total reservoir volume of 2,138 acre-feet, 1,570 acre-feet were included in the LPG simulation.

The process was simulated using a one-eighth nine-spot pattern to inject LPG for 180 days or 20% of the total reservoir hydrocarbon pore volume (whichever comes first), followed by a gas drive. The maximum allowable injection pressure was set at 2,400 psi with a 50 psi backpressure on the producing wells. Oil saturation was modeled at the waterflood residual saturation of 32%. Simulation results indicated that the potential oil recovery from the process would be between 100 and 130 thousand barrels (Frazier and Todd 1982).

In July 1980 the tertiary recovery project began. Propane was injected as the LPG slug, followed by a dry residue gas as the drive gas. A total of 259,000 barrels of propane were injected representing 16% of the pattern hydrocarbon pore volume. At the end of 1981, 51,000 barrels of tertiary oil had been recovered and 111,257 barrels of injected propane produced back at a rate of 208 barrels per day (Frazier and Todd 1982).

The project clearly showed that the LPG process can recover a significant volume of oil unrecoverable by waterflooding using a large slug of LPG. Also, results indicated that the best tertiary responses occurred in areas where the waterflood was most successful. In 1992 DOE's EOR Database reported that the project was terminated with 164,100 barrels of incremental tertiary oil production leaving 1.17 million barrels of remaining oil in place (Pautz et al. 1992).

The Alvord South Field (see Fig. 3.36 and Table 3–13) was discovered in October 1961; the Alvord South Unit was formed in December 1966. It covers 2,291 acres and produces from five layers, three of which have significant areal extent (Craig 1985).

The reservoir is 5,700 feet deep, producing light oil with 44° API gravity from a net pay thickness of 25 feet and having a reservoir temperature of 154°F. Reservoir permeability and porosity were estimated at 55 mD and 13.68%, respectively. OOIP was estimated at 22 million STB with a formation volume factor of 1.45 reservoir barrels per STB (Craig 1985).

Waterflooding activities were reported as successful with a peak oil production rate of over 2,000 barrels of oil per day in 1977. The ultimate recovery due to primary and secondary operations was estimated at 32% of OOIP. Carbon dioxide miscible flooding began in September 1983, with the objective of recovering 1.8 million STB of the 15.9 million STB of OOIP in the flood area (Craig 1985). The flood area covered an areal extent of 750 acres and was implemented through an inverted seven-spot pattern using 10 injection and 23 production wells. The CO_2 flood area was surrounded by water injection wells for containment. A halogen compound was used as a tracer to determine the sweep efficiency of CO_2. In July 1984 field injection of tracers began in order to estimate the sweep efficiency for each pattern. The sweep efficiency had been originally estimated based on a simplistic assumption that one-sixth of the pattern injection enters each segment. These initial estimates predicted a sweep efficiency of 15.3% of the hydrocarbon pore volume, compared to a 4.7% sweep efficiency estimated by reservoir modeling based on tracer test results. Observations made during the tracer test led to an altered injection scheme to improve the observed sweep efficiency (Craig 1985). DOE's EOR Database reported that results of the CO_2 injection test, where 1.265 million barrels of oil were recovered, were encouraging (Pautz et al. 1992).

3.4.4 Eastern Gulf Coast Basins

Class 5–producing reservoirs are located in sixteen fields in east Texas, Arkansas, Louisiana, and Mississippi (see Fig. 3–38). Stratigraphically they are all Cretaceous in age ranging from the Lower Cretaceous Pine Island Formation in Arkansas, the upper Lower Cretaceous Paluxy in Texas and Louisiana, the basal Upper Cretaceous Tuscaloosa in Mississippi, to the upper Upper Cretaceous Nacatoch Formation in Louisiana. A stratigraphic column of the Mesozoic section is given in Figure 3–39. Reservoir characteristics for the East Gulf Coast Basin fields are given in Table 3–14.

The Eastern Gulf Coast Basins formed as embayments of the Gulf of Mexico during the Mesozoic. Sediments were derived from the major uplifts located north and west of the embayments. Orogenic movements and sea level fluctuations have caused extensive faulting and repeated uplift and subsidence of arches and basins across the region.

The major structural elements (see Fig. 3–38) in the Gulf Coastal Plain are (1) the Sabine Uplift (with the East Texas Basin to the west and the North Louisiana Salt Basin to the east), (2) the Mexia-Talco Fault zones on the western and northern sides of the East Texas Basin, (3) the Monroe Uplift in northeast Louisiana and southeast Arkansas on the eastern margin of the North Louisiana Salt Dome Basin, and (4) the Mississippi Salt Basin in southwest Mississippi and east-central Louisiana (Nichols 1958; Galloway et al. 1983).

3.4.4.1 East Texas

Three TORIS Class 5 fields are located along the Talco Fault Zone in the East Texas Basin (Galloway et al. 1983). Located from west to east along the Talco Fault (see Fig 3.38), Sulphur Bluff, Talco, and Prewett Ranch fields produce from a region termed the Paluxy Fault Line (Galloway et al. 1983).

Lower Cretaceous Paluxy Formation sediments were derived from sedimentary rocks to the north and deposited in the northern part of the East Texas Embayment of the Gulf Basin (Caughey 1977). The Paluxy ranges from 200 to 400 feet thick and contains thin but continuous

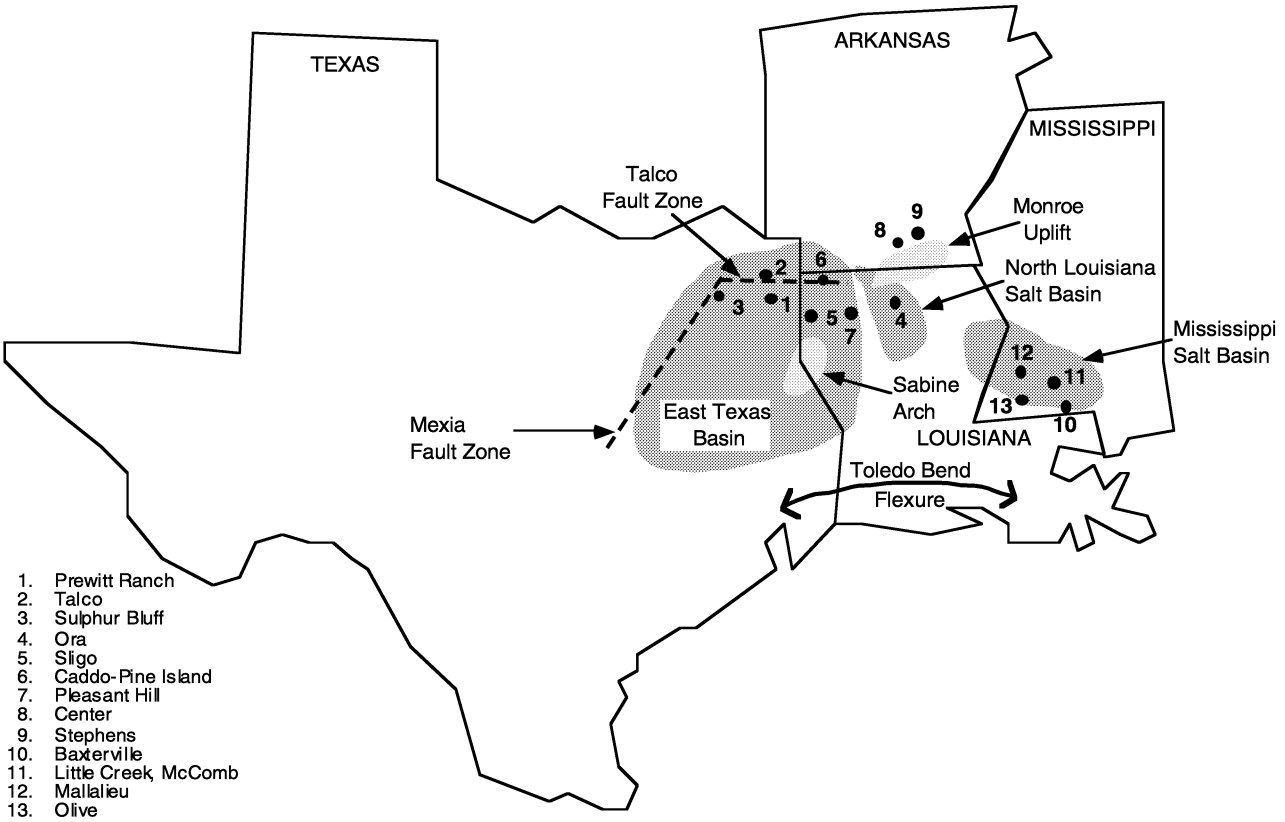


Figure 3–38 Map of the Eastern Gulf Coast Area with Major Basins, Structures, and Class 5 Oil Field Locations (Modified from Caughey 1977; Galloway et al. 1983; Yurewicz et al. 1993)

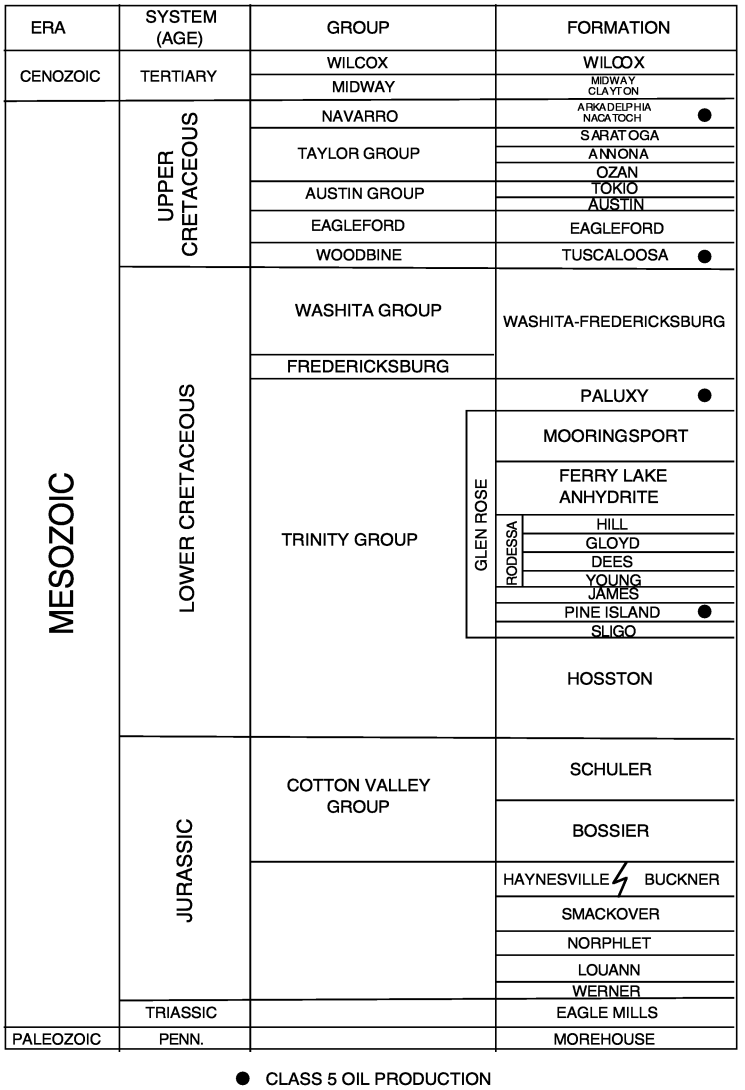


Figure 3–39 Stratigraphic Column of Mesozoic Strata for East Texas, Louisiana, Arkansas, and Mississippi (Modified from Shreveport Geological Society 1980)

units of sandstone and shale (Caughey 1977). Three major environments are represented in the Paluxy; a fluvial system to the north, a delta system in the center, and a strandplain to the west (Caughey 1977). Oil production along the Talco Fault Zone is from thick reservoirs deposited as fluvial channel-fill sequences (Galloway et al. 1983). Caughey (1977) defines the productive sandstones as meander belt facies, which constitute less than half the 140–250 foot thick section.

The three fields along the Talco Fault Zone are the major TORIS Class 5 fields in the Mid-Continent or Southern Rockies to produce heavy oil. The high permeabilities in these fields (see Table 3–12) have allowed the production of heavy oil, but recovery of the original oil in place has been inefficient (Galloway et al. 1983).

Table 3–14
Reservoir Characteristics for Class 5 Fields in Eastern Gulf Coast Basins of East Texas, Louisiana, Mississippi, and Arkansas

Field	Formation	Reference	Trap Type	Depth, Feet	Net Pay, Feet	Porosity, %	Permeability, mD	Gravity, °API
Texas								
Prewitt Ranch	Paluxy	Galloway et al. 1983	Structural	4,300	29	24	2,460	19
Sulphur Bluff	Paluxy	Galloway et al. 1983	Structural	4,500	29	25	4,000	21
Talco	Paluxy	Galloway et al. 1983	Structural	4,300	46	26	2,000	22
Lousiana								
Caddo Pine Island	Paluxy	Billingsley 1964	Stratigraphic	2,760	29	35	456	42
Ora	Nacatoch	Meadows et al. 1962	Structural	2,100	12	29	1,150	33
Pleasant Hill	Paluxy	TORIS	Stratigraphic	3,192	12	25	220	41
Sligo	Paluxy	TORIS	Stratigraphic	3,000	7	25	80	40
Arkansas								
Center	Pine Island	Whitfield 1963	Stratigraphic	3,172	2	30		28
Stephens	Pine Island	Whitfield 1963	Stratigraphic	3,190	15	28	2,970	35
Mississippi								
Baxterville	Lower Tuscaloosa	Berg & Cook 1968	Structural	8,690	97	23	680	16
Little Creek	Lower Tuscaloosa	Werren et al. 1990	Combination	10,770	29	24	100	39
Mallalieu	Lower Tuscaloosa	Berg & Cook 1968	Structural	9,990	19	27	55	38
Olive	Lower Tuscaloosa	Wiygul & Young 1987	Stratigraphic	10,500	25	27	54	39

Talco Field, discovered in 1936, has greater production than all other Paluxy Formation fields combined (Galloway et al. 1983). Winters et al. (1991) describe the facies at Talco Field as progressing from braided stream upward into flood plain sands and shales, and then to brackish to shallow marine mudstones. Talco Field is a high-side fault trap on the north-dipping Talco Fault (Winters et al. 1991).

3.4.4.2 Louisiana

In northern Louisiana the eastward extension of the Talco Fault Zone of the Paluxy Fault trend is represented by three fields with TORIS Class 5 production; Sligo, Caddo Pine Island, and Pleasant Hill. The fluvial sands of the Paluxy represent sea level highstand deposition on the shelf during deposition of the transgressive Lower Cretaceous Fredericksburg Group (Yurewicz et al. 1993). The Paluxy persists as a thick sandstone wedge extending from the East Texas Basin across northern Louisiana. Individual fluvial sands of the Paluxy have typical fining-upward cycles but are discontinuous and tend to pinch out downdip (Galloway et al. 1983).

Caddo Pine Island Field (see Fig 3.38 and Table 3–14), discovered in 1900, has been enormously productive; however, most of the production is from carbonate intervals; the Annona Chalk, the Goodland Limestone, and the Ferry Lake Anhydrite. The Ferry Lake reservoir was not discovered until 1984, but has been a major producer since then. Production from sandstone intervals began early. The Nacatoch Sand was drilled in 1905, and Paluxy oil was discovered in 1916 (Billingsley 1964). Independent companies were the predominant developers at Caddo Pine Island Field; only 30% of the wells were operated by majors in 1964 (Billingsley 1964).

At Caddo Pine Island the Paluxy Sandstone produces from an interval at depths from 2,000 to 2,700 feet (Billingsley 1964). Sand bodies are lenticular and discontinuous with thin shale and clay streaks (Billingsley 1964). The Paluxy Sandstone is sealed by the unconformably overlying Eagleford Shales (Billingsley 1964). The main producing interval of the Paluxy is restricted to the uppermost few feet of sediments.

Sligo Field (see Fig. 3–38 and Table 3–14) is south of Caddo Pine Island Field on the flank of the Sabine Uplift (Yurewicz et al. 1993). The upper Lower Cretaceous Paluxy Formation produces oil from fluvial sands in two reservoirs at Sligo (BPO TORIS 1995). The Paluxy had uniform thickness across the Sabine Arch, which suggests the Arch was not a topographic high during Paluxy deposition (Jackson and Laubach 1991).

The TORIS Class 5 Ora Field (see Fig. 3–38 and Table 3–14) in the North Louisiana Salt Basin produces from the Upper Cretaceous Nacatoch Formation. The field is 5 miles long by 1 mile wide and lies at a depth of 2,140 feet (Meadows et al. 1962). Listed as of braided stream origin in DOE's TORIS database, the Nacatoch is a fine-grained sand with thin clay streaks. It contains localized areas of calcium carbonate cement when no hydrocarbons are present (Billingsley 1964). The productive interval of the Nacatoch grades laterally into a nonpermeable chalk (maximum thickness-20 feet), which divides the field into two units (Meadows et al. 1962). Porosity in the Nacatoch at Ora ranges from 20% to 30% and permeability ranges from 1 to 3,000 mD (Billingsley 1964). Initial reservoir pressure was estimated at 985 psig. The produced 32.6° API oil had a viscosity of 5 cP, an initial formation volume factor of 1.1 reservoir barrels per stock tank barrel (STB), and an initial solution gas-oil ratio of 250 standard cubic feet per barrel. Initial oil in place was estimated at 7.37 million STB with 1,842 million standard cubic feet of solution gas (Meadows et al. 1962).

A total of 206 oil wells were completed in the Nacatoch reservoir at Ora Field on a 10-acre spacing (Meadows et al. 1962). Early well production histories indicated a limited natural waterdrive. However, in parts of the reservoir, the waterdrive was not adequate to maintain the desired production rates and reservoir pressure. Reservoir pressure dropped from an estimated 985 psig in 1947 to 100 psig in 1954. As a result of this pressure drop, and in order to improve productivity from this reservoir, a pilot water injection program was started in June 1954 and was later expanded in January 1957 to a full-scale water injection using irregular five-spot patterns. As of January 1960, a total of 2,056,995 barrels of water were injected, resulting in a secondary oil recovery of 104,606 barrels of oil. Almost 20 barrels of water were injected for every barrel of oil produced. Estimated recoverable oil from the Ora Unit by primary depletion was 1.99 million barrels, approximately 27% of OOIP. Total oil recovery after water injection accounted for 4.9% of the cumulative oil produced. A major operational problem encountered during the injection period was severe bypassing of injected water through a highly permeable section in the lower part of a depleted oil zone (Meadows et al. 1962).

3.4.4.3 Arkansas

A few miles north of the Louisiana-Arkansas border in south-central Arkansas two TORIS Class 5 fields produce from the Pine Island Formation of the Lower Cretaceous Trinity Group (see Figs. 3–38 and 3–39 and Table 3–14). Both Center and Stephens fields are north of the Monroe Uplift (Yurewicz et al. 1993). The Pine Island Formation is predominantly marine shales, part of a transgressive sequence including the overlying James Limestone (Yurewicz et al. 1993). The most northern reach of the Trinity seas in the Gulf Embayment is represented by this transgression which reached the present-day area of central Arkansas (Whitfield 1963). The primary source area for the Trinity Group clastics was the Ouachita Uplift (Yurewicz et al. 1993). The sediment load derived from this feature created subsidence in the basins of East Texas and Louisiana. Trinity sediments in Arkansas, however, mainly represent erosion of the Monroe Uplift. The northern and eastern facies of the Trinity Group are dominantly red beds of nearshore coarse clastics; the downdip and southwestern beds are more marine, limy, and nonclastic sediments (Whitfield 1963).

The Pine Island Shale is a dark gray shale interbedded with fine sand and gray limestone in northern Louisiana, becoming redder and more sandy and shaly northward into Arkansas (Whitfield 1963). The Hogg Sand Member, the producing reservoir at Center and Stephens fields, is at the base of the Pine Island Formation (Whitfield 1963). The Hogg Sand reaches a maximum thickness of 61 feet in central Louisiana and Arkansas and feathers out westward (Whitfield 1963). At Stephens Field the depositional environment of the Hogg is described as a lenticular sand bar (Whitfield 1963). The Hogg reservoir at both Center and Stephens fields is identified as of meandering stream origin in DOE's TORIS database.

3.4.4.4 Mississippi

Four TORIS Class 5 fields in Mississippi (see Fig. 3–38) are located along the southwestern margin of the Mississippi Salt Basin (Berg and Cook 1968; Werren et al. 1990). Fluvial sandstone production at these fields is from the Upper Cretaceous lower Tuscaloosa Formation (see Fig. 3–39) (Wiygul and Young 1987). The productive trend across southern Louisiana, Mississippi, and Alabama is called the lower Tuscaloosa Fairway (Anderson 1980).

The Tuscaloosa Fairway is a structurally controlled shelf forming the boundary between two distinct tectonic elements; the central Gulf Subbasin, and the Mesozoic Shelf (Anderson 1980). The Gulf Subbasin is underlain by oceanic crust with depositional depths ranging from abyssal plain to continental rise and continental slope. The Mesozoic Shelf consists of thick continental crust modified by the Ouachita deformed belt. The Mesozoic Shelf has sediments representing both continental shelf and low coastal plain deposition (Anderson 1980). To the landward side of the Fairway the deposits have normal pressures; downdip on the shelf, deposits are geopressured (Anderson 1980).

The lower Tuscaloosa trend primarily consists of terrigenous clastics eroded from the Ouachita fold belt forming a sequence of braided and meandering stream deposits (Werren et al. 1990). The fluvial deposits of the lower Tuscaloosa (Berg and Cook 1968) occur along the inland margin of the Toledo Bend Flexure (see Fig. 3–38) where lower Tuscaloosa shales wedge out and are replaced by massive sands updip toward the Sabine and Monroe uplifts (Anderson 1980). Sandstones in the productive lower Tuscaloosa are very fine- to medium-grained, moderately to well sorted, and range from consolidated to semiconsolidated (Werren et al. 1990).

Hersch (1987) notes that structural traps are unusual in the lower Tuscaloosa trend, and that stratigraphic entrapment is the norm. However, many hydrocarbon traps along the lower Tuscaloosa Trend are combined structural and stratigraphic traps. The early discovery of Mallalieu and Baxterville fields (salt dome features) was based on structure (Berg and Cook 1968).

Little Creek, Olive, Mallalieu, and Baxterville fields (see Fig. 3–38 and Table 3–14) all produce from fluvial intervals of the lower Tuscaloosa. Mallalieu and Baxterville fields were discovered in 1944. Little Creek Field was discovered in 1958 based on geological models of meandering streams by Bernard and Major (1963). Olive Field was discovered in 1981 based on further exploration in the Little Creek area (Wiygul and Young 1987).

Three sandstone horizons are described for the lower Tuscaloosa at Mallalieu Field (Berg and Cook 1968). Horizon C is a thick point bar sandstone horizon, B is a braided stream channel fill sandstone, and horizon A represents fine-grained floodplain or crevasse splay deposits. The well developed and productive point bar sequence in horizon C has been interpreted as a meandering stream deposit at Mallalieu Field (Berg and Cook 1968). The braided stream interval (horizon B at Mallalieu) is the main producing horizon at nearby Baxterville Field (Berg and Cook 1968; BPO TORIS 1995).

A miscible CO_2 injection project was conducted by Shell Oil in the West Mallalieu Field in Mississippi in late 1986 by injecting CO_2 into the lower Tuscaloosa over an area of 5,760 acres (Martin and Taber 1992). This project accounted for 1,500 barrels of increased production per day of 38° API gravity oil. A total of 14 production and four injection wells were used to recover an estimated 18%–19% of OOIP with a net CO_2 utilization of 5 to 6 thousand cubic feet per STB. The project area had an average porosity of 25%, an average permeability of 20 mD, and an initial oil saturation of 21% (Pautz et al. 1992).

Production at Olive Field is from the Stringer Member of the lower Tuscaloosa Formation which immediately overlies the Washita-Fredericksburg at this locality (Wiygul and Young 1987). The lower units of the Stringer Sandstone at Olive Field are point bar and channel sands of a meandering stream (Wiygul and Young 1987). Diagenetic processes, particularly dissolution and reprecipitation of silica resulting in quartz overgrowths, have reduced initial porosity at Olive Field (Wiygul and Young 1987).

At Little Creek Field, production is from four separate point bar sandstones 3,770–5,910 feet long and 26–35 feet thick (Schenk 1992). Compositionally, sands are composed primarily of quartz and igneous rock fragments with some chert, mica, and pyrite (Werren et al. 1990). Cementation is locally important with ferroan dolomite, quartz overgrowths, and siderite being the dominant cements (Werren et al. 1990). Diagenetic changes occurred relatively early, and chlorite present throughout the reservoir played an important role in inhibiting growth of quartz cement and in partially preventing compaction (Thomson 1979). Reservoir quality is generally very good because of favorable original depositional facies and fortuitous diagenetic events (Werren et al. 1990).

The Little Creek Field, among the largest in the lower Tuscaloosa trend, witnessed two major recovery process applications: a waterflood pressure maintenance program in 1962 and a CO_2 flood in 1973 (Cronquist 1968; Hansen 1977).

Early estimates of OOIP indicated reserves at 102 million STB from the lower Tuscaloosa. Primary recovery was estimated at 25 million STB of 39° API gravity oil, approximately 24.5% of OOIP (Cronquist 1968). The primary producing mechanism was liquid expansion and solution-gas drive. During primary recovery, the bottomhole pressure dropped rapidly from an original reservoir pressure of 4,840 psi to below 3,000 psi by the end of 1959.

In April 1962, Shell Oil Company initiated a peripheral line-drive waterflood in the 10,750-foot lower Tuscaloosa Sand. Daily water injection was close to capacity and equaled about 125 percent of voidage (Cronquist 1968). As a result of the waterflooding program, the downward trend in reservoir pressure was reversed, and the gas-oil ratio (GOR) returned to normal. During the waterflood, most of the production was taken from wells with high productivity index and low GOR. Wells with GORs in excess of 1,100 cubic feet per barrel were shut in. Oil producers were shut in at 50% water cut to minimize backward cusping of oil. Shut-in wells were tested periodically and were converted to injection when they tested 100% salt water. Areas of free gas saturation were reduced rapidly. By the end of 1963, when the field GOR returned to normal,

cumulative production was 44.8 million barrels of oil (obtained with a sweep efficiency of 90%–92%), 25.1 billion cubic feet of gas, and 8.6 million barrels of water (Cronquist 1968). Total cumulative injection was 51.3 million barrels of water.

During the waterflood, a uniform advancement of the flood front was detected with advance rates varying from 0.7 to 12.0 feet per day. These advance rates illustrated that the flood fronts were nearly vertical. Also, as a result of this waterflood, bottomhole pressures increased rapidly, and production rates commonly increased fourfold before breakthrough. Response after breakthrough was equally dramatic; most of the wells went to 100% water within three months of flood front breakthrough (Cronquist 1968).

Waterflooding operations were discontinued in February of 1970, although production from a gradually declining number of wells continued. In August 1973 preliminary operations were initiated for a CO_2 miscible displacement field test (Hansen 1977). The pattern chosen was an inverted nine-spot, which appeared to yield the best process recovery efficiency of those patterns available with existing field development (Hansen 1977). A semiconfined quarter nine-spot symmetry element was selected for the pilot test. Pilot operations began August 31, 1973, with the initiation of water injection in all five wells (based on quarter nine-spot pattern) of the pilot test area to increase the reservoir pressure to 5,500 psig. CO_2 was injected in the injection well at a rate of 3.6 million cubic feet per day with a surface tubing pressure of 2,400 psig. One of the pilot wells had an oil production rate of 87 barrels of oil per day and 193 barrels of water per day with a GOR of 4,000 standard cubic feet per barrel (58% CO_2) (Hansen 1977).

Approximately one year after the start of the pilot test, a series of problems including tubing leaks, sand plugging, packer failure, asphalt-paraffin plugging, CO_2 injection system mechanical problems, and well damage from workover fluids combined to significantly curtail production as well as injection operations in the pilot (Hansen 1977). These problems contributed to an average production downtime of 50%. The resolution of the above problems and the reinjection of produced pilot gas caused a resurgence in production rates by mid-1975 when pilot oil production peaked to average daily rates of 195 barrels. At the end of June 1977, pilot production declined to 35 barrels of oil per day with 297 barrels of water per day and 1.4 million cubic feet of gas. Most of the pilot wells produced salt water and the purchase of CO_2 was discontinued. Despite all the operational problems that caused significant production curtailments and shutdowns during the early stages of pilot performance, a considerable amount of tertiary oil was produced. A total of 122,199 barrels of oil were produced from the pilot along with 923,906 barrels of water and 2,209 million cubic feet of gas (Hansen 1977). A total of 3,373 million cubic feet of gas was injected, of which 1,590 million cubic feet was purchased CO_2.

In 1985 Shell expanded its operations beyond the pilot test area and conducted a full-field CO_2 miscible project. This project was considered among the 15 largest CO_2 miscible projects in the United States. The project covered an area of 6,200 acres and oil production from the lower Tuscaloosa reservoir was reported at 3,900 barrels of oil per day (Martin and Taber 1992). The projected increase in recovery due to the CO_2 flood was reported at 23.5% with a net CO_2 utilization of 5 to 6 thousand cubic feet per STB.

The McComb Field (see Fig. 3–38 and Table 3–14), discovered in 1959 and also producing from the lower Tuscaloosa trend, is located less than 15 miles southwest of the Little Creek Field (Fletcher et al. 1967; Cronquist 1968). Laboratory analyses of cores showed that water content of the producing sand averaged 60% of the total pore volume. Reservoir fluid analysis and core data indicated 380 STB of 41° API gravity oil originally in place per net acre-foot of sand. Core analysis indicated an average porosity of 22.9% and an average reservoir permeability of 91 mD. PVT data recorded at bubblepoint pressure indicated a formation volume factor of 1.87 reservoir barrels per STB, a solution GOR of 1.335 thousand cubic feet per barrel, and a fluid viscosity of 0.251 cP (Fletcher et al. 1967).

The initial reservoir pressure at 10,493 feet was measured at 4,909 psi. Six months after the discovery of the field, the reservoir pressure was declining at a rate of 6 psi per calendar day. The severe pressure decline indicated very little natural waterdrive or very little OOIP. In addition, the high gas saturation pressure resulted in excessive GOR and a waste of energy early in the primary life of the field, thus threatening a loss of recoverable oil reserves (Fletcher et al. 1967).

An immediate decision was made to stop the sharp decline of pressure by reducing production to 300 barrels per day per well (Fletcher et al. 1967). Later this allowable was further reduced to 50 barrels per day per well. The need for a long-term solution for this sharp decline in reservoir energy by putting a pressure maintenance program into operation prompted the need to adopt a unique plan of unitization at a time when the field was only partially developed. Several options were considered for the proposed program. A technical and economic evaluation of flue gas versus water injection was performed. As a result, the operators selected water pressure maintenance for the McComb Field. A fieldwide injection system was designed and implemented.

Water injection started on May 4, 1961, but the pressure maintenance program was faced with both injection and production problems (Fletcher et al. 1967). The individual production units in the early life of the field created many producing problems. For example, each of the producing tracts required its production be separated from other units, resulting in the necessity for additional equipment installations. Some of the injection problems were caused by the poor quality of the produced water, which was used to augment the supply water. Two main types of injection problems occurred: mechanical problems with pumps and plugging of injection wells. Production problems were mainly from casing leaks in the production string. The casing leaks problem was resolved by setting packers to isolate the leaks.

The field produced at an allowable of 12,000 barrels of oil per day from November 1, 1961, to March 1965. Oil production declined until it averaged 8,000 barrels of oil per day in April 1966. Primary oil recovery was estimated at 18% of OOIP, with an ultimate recovery of 39% under the water pressure maintenance program (Fletcher et al. 1967).

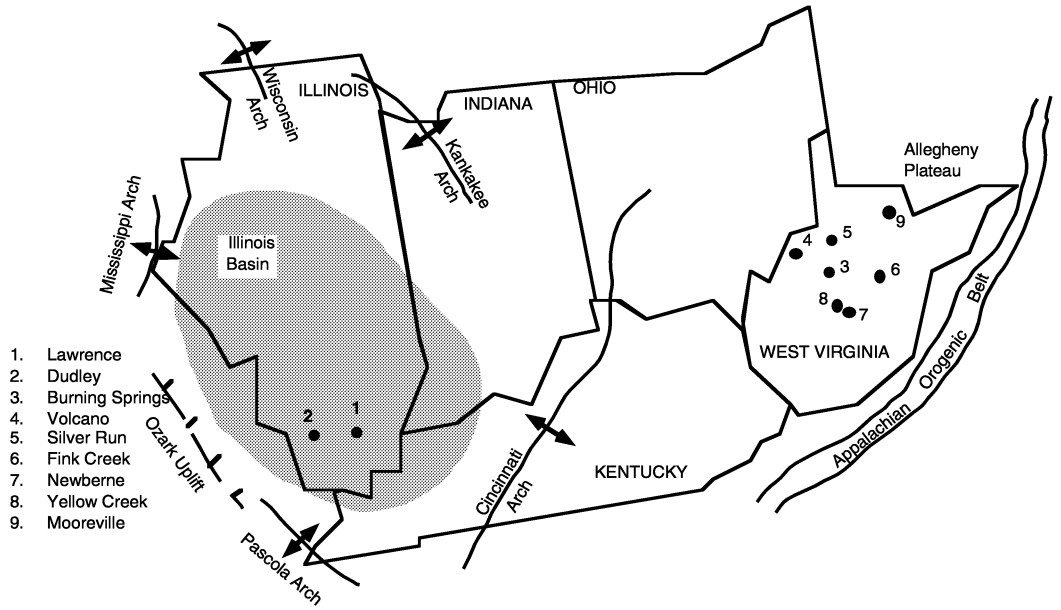


Figure 3–40 Map of the Eastern United States Area with Major Basins, Structures, and Class 5 Oil Field Locations (Modified from Cardwell 1977; Zuppann 1988; Nelson 1989)

3.4.5 Eastern United States Basins

Two areas in the Eastern United States have TORIS Class 5 production (see Fig. 3–40). Two fields in the Illinois Basin in southern Illinois, and seven fields on the Allegheny Plateau of the northern Appalachian Basin in West Virginia are designated in DOE's TORIS database as producing from meandering stream deposits.

3.4.5.1 Illinois Basin

The Illinois Basin is a deep cratonic sag basin covering a large area of southern Illinois, southern Indiana, western Kentucky, and eastern Missouri (see Fig. 3–40). The sediments are Paleozoic in age with great thicknesses of Cambrian, Ordovician, and Mississippian carbonates and shales (Bethke et al. 1991). The sedimentary section at the center of the Illinois Basin is over 15,000 feet thick (Zuppann 1988).

The Illinois Basin began to subside slowly in the Cambrian and developed as an elongate embayment trending northeast from the open sea (Bethke et al. 1991). The Illinois Basin is completely bounded by uplifted areas; the Cincinnati Arch to the east, the Kankakee and Wisconsin Arches to the north, the Mississippi River Arch and Ozark Uplift to the west, and the Pascola Arch in the south (see Fig. 3–40) (Zuppann 1988). Throughout its history it has been characterized by gentle downwarping, and the broad, regional domes and arches around its margins have at times been only weakly positive (Swann and Bell 1956).

Fluvial production in the Illinois Basin comes primarily from the Lower Pennsylvanian Morrowan basal unit, the Caseyville Formation, which unconformably overlies rocks of the Mississippian Chester Series (Jacobson 1987). The Caseyville Formation is confined to the southeastern part of the Illinois Basin where it attains a maximum thickness of 575 feet (Nelson et al. 1990). The erosional surface developed on the Mississippian contains incised valleys up to several hundred feet deep filled with Caseyville sediments (Jacobson 1987). The Caseyville Formation consists of two sandstone units: (1) conglomerates with well-rounded granules and small quartz pebbles and (2) gradationally overlying the conglomerates, thin bedded sandstones and silty shales with thin coal, and limestone stringers (Jacobson 1987; Nelson and Weibel 1989).

Formal member names have been given to Caseyville outcrop units (Nelson 1989). However, the reservoir names used by the drillers, Dudley, Buchanan, and Ridgley, are not formal stratigraphic names. The two lower units of the Caseyville pinch out and are overlapped by younger rocks in southwestern Illinois (Nelson et al. 1990). In cores and well cuttings, the Caseyville is recognized as clean quartz sandstones and conglomerates. Recent studies indicate that portions of the Caseyville are largely of deltaic and shallow marine origin (Nelson et al. 1990). In outcrop the three members of the Caseyville have been described primarily as distributary channel deposits (Nelson 1989). However, in the subsurface, portions of the Caseyville are still considered to be fluvial in origin (Bandy 1992). Two distinct units are recognized in the Buchanan Sandstone, the informally named basal unit of the Caseyville Formation. These units consist of a paleovalley fill and younger fluvial sands deposited on the flanks of the paleovalley (Bandy 1992). Shallow Pennsylvanian reservoirs at Dudley and Lawrence fields were discovered in the 1980s in fields which already had a long history of production from Lower Paleozoic horizons (McCaslin 1988; Palmer and Burk 1989). Dudley and Lawrence fields in southern Illinois have a total of three reservoirs producing from the Caseyville Formation (see Table 3–15), the lower Dudley reservoir at Dudley Field, and the Buchanan and Ridgley reservoirs at Lawrence Field (BPO TORIS 1995).

3.4.5.2 West Virginia Portion of the Appalachian Basin

Seven oil fields in West Virginia have produced from TORIS Class 5 Paleozoic reservoirs (see Fig. 3–40). Most were discovered in the early 1900s and are inactive, abandoned since the 1950s or early 1960s (Cardwell 1977). The fields are in the Pittsburgh-Huntington Basin, sometimes called the Allegheny Basin (Rodgers 1963), and more often referred to as part of the Allegheny Plateau (Filer 1986). The Pittsburgh-Huntington Basin is a restricted subbasin of the much larger Appalachian Basin or geosyncline composed of thick Paleozoic strata. This region of West Virginia has undergone intense orogenic movement to form its numerous valleys and ridges. The ridges and valleys, a result of imbricated folding, have been formed by repeated thrusting and tectonic ramping (Loomis 1982). Folds in West Virginia tend to lie parallel to one another in a northeast to southwest trend (Rodgers 1963).

Table 3–15
Reservoir Characteristics for Class 5 Fields in the Eastern United States in the Illinois Basin of Illinois and on the Allegheny Plateau of West Virginia

Field	Formation	Reference	Trap Type	Depth, Feet	Net Pay, Feet	Porosity, %	Permeability, mD	Gravity, °API
Illinois								
Dudley	Caseyville	TORIS	Stratigraphic	410	20	20	100	24
Lawrence (Buchanan)	Caseyville	TORIS	Stratigraphic	1,280	20	19	650	33
Lawrence (Ridgley)	Caseyville	TORIS	Stratigraphic	1,175	8	21	330	36
West Virginia								
Burning Springs	Allegheny	Cardwell 1977; TORIS	Structural	700		29		
Fink Creek	Berea	Cardwell 1977; TORIS	Structural	1,480	8	28		
Mooresville	Hampshire	Cardwell 1977; TORIS	Structural	2,815	5	10		
Newberne	Berea	Cardwell 1977; TORIS	Structural	2,200	8	10		
Silver Run	Pottsville	Cardwell 1977; TORIS	Structural	1,405	8	10		
Volcano	Pottsville	Cardwell 1977; TORIS	Structural	360	25	10		
Yellow Creek	Berea	Cardwell 1977; TORIS	Stratigraphic	2,300	8	10	10	42

Class 5 oil has been produced from the following stratigraphic intervals in West Virginia: the Upper Devonian Hampshire Formation, the Lower Mississippian Berea Sandstone, the Lower Pennsylvanian Pottsville Formation, and the Middle Pennsylvanian Allegheny Formation (BPO TORIS 1995). Reservoir characteristics for the TORIS Class 5 fields in West Virginia are given in Table 3–15.

Mooreville Field in northern West Virginia was drilled in 1915 and abandoned in 1950 after producing over 2.5 million barrels of oil. Oil was produced from the Fifth reservoir (a local drillers' term) of the Hampshire Formation (Cardwell 1977). The Hampshire is a thick-bedded sandstone composed mostly of point bar sequences with alternating thin flood-plain mud pebble conglomerates at the base. It represents the avulsions of a meandering river (Fichter 1986).

Fink Creek, Newberne, and Yellow Springs fields are located in central West Virginia. Fink Creek Field was discovered in 1894 and converted to gas storage in the 1960s (Cardwell 1977). Cumulative production before conversion was over 7 million barrels. Newberne Field was discovered in 1900 and has been inactive since 1960 (Cardwell 1977). It produced over 3.5 million barrels of oil over its lifetime and is also being used for gas storage. Yellow Springs or Big Springs Field was discovered in 1901 and has been inactive since the 1960s (Cardwell 1977). All three fields produced Class 5 oil from the Berea Sandstone (BPO TORIS 1995). The Mississippian Berea Sandstone is a thick terrigenous sand of fluvial channel origin with numerous cross-stratified and planar-bedded intervals (Hannibal and Feldmann 1987). Some sections of coarser conglomeratic sands are also present.

Silver Run and Volcano fields are located in western West Virginia along the Ohio River (Cardwell 1977). Silver Run has been inactive since 1960, and the last well drilled at Volcano Field was in 1966 (Cardwell 1977). Production in both fields was from the Salt Sand reservoir of the Pottsville Formation. The Pottsville is a massive sandstone 130–270 feet thick (Edmunds 1992). It has been dated as Middle Pennsylvanian (Morrowan) and rests unconformably on the Mississippian Mauch Chunk Formation (Edmunds 1992). The Pottsville has three formal members, each containing fining-upward sequences beginning with conglomerates (Levine and Slingerland 1987). The middle member is finer grained than the other two, contains coal beds (Levine and Slingerland 1987), and represents deltaic deposits. The coarser-grained upper and lower members of the Pottsville represent fluvial deposition.

Silver Run Field was discovered in 1903 and produced more than 2.1 million barrels through 1960. In 1959 the West Virginia Geological and Economic survey reported an inactive gas drive in the Salt Sand that was initiated prior to 1944 (Avery 1995).

Volcano Field was discovered in 1864. Cumulative production through 1960 was reported at 2.52 million barrels of oil. The last well drilled in the field was in 1966 (Cardwell 1977). A small pilot waterflood project was initiated in 1965, covering an area of 70 acres and using an irregular line drive (Avery 1995). A total of 17 injection and 15 production wells were part of this field demonstration project, which was reported as economically unsuccessful due to the inability to form an oil bank. The project was terminated in 1971 (Avery 1995).

Hydrocarbon exploration has a long history in West Virginia, but only Burning Springs Field has remained active or has been reactivated throughout that long history. Drilled in 1860, it was destroyed by Confederate soldiers in 1863 and not redrilled until 1900 (West Virginia Bureau of Mines 1963). Burning Springs saw periods of abandonment and new drilling in the 1930s, 1940s, 1950s, and in the 1980s (Filer 1986). Burning Springs Field has been drilled repeatedly as new

techniques allowed deeper wells. Expansion of the Burning Springs Field in 1983 was related to a deep drilling program in West Virginia targeting Devonian Shales (Patchen et al. 1985). Burning Springs Field also has historical significance as the site where Andrews (in 1861) developed the theory of anticlinal exploration for petroleum (Filer 1986). The Burning Springs Anticline has been much studied since the 1860s, partly because of its unique north-south orientation, contrary to the typical northeast-southwest orientation of the folds and valleys of the Appalachian foreland (Loomis 1982). The Burning Springs Anticline also displays dips up to 70° and has a structural relief of over 1,600 feet, compared to typical dips of 2° and a relief of 200 feet for other structures in the region (Filer 1986).

Early production was from the shallower Pennsylvanian formations including the Allegheny Formation (West Virginia Bureau of Mines 1963). The Burning Springs reservoir of the Allegheny Formation is found at a depth of 729 feet and is 50 feet thick (West Virginia Bureau of Mines 1963). The Burning Springs is a very fine- to medium-grained sandstone with kaolinite cement. Its prevailing depositional environment was a meandering river as listed in DOE's TORIS database.

The field covers an area of 6,600 acres and mainly produced from the Burning Springs reservoir. In 1963 the Bureau of Mines (West Virginia Bureau of Mines 1963) conducted a reservoir evaluation program to evaluate the possibilities of increasing ultimate recovery by secondary recovery methods. The study concluded that due to extremely low permeability (average 0.8 mD) and porosity (average 7.7%), high water saturation (56.8%), and low hydrocarbon content, secondary recovery was not economically feasible. The West Virginia Geological and Economic Survey reported that between 1917 and 1932 the field was producing on a "Vacuum Secondary Recovery." Additional details are not available as to the type of process and its recovery potential (Avery 1995).

3.5 Comparison and Contrast of Class 5 Plays and Reservoirs

In this section, Class 5 geological and production characteristics will be compared and contrasted between reservoirs in different geographic locations, or more specifically, between reservoirs in different basin development situations. The geological characteristics discussion in Section 3.5.1 is intended to provide the basis for determining research needs to increase heterogeneity predictability in Class 5 reservoirs. The production characteristics discussion in Section 3.5.2 will provide the basis for developing research and improved oil recovery process applications to address (1) problems that are universal to all Class 5 reservoirs, (2) problems that are unique to Class 5 reservoirs in specific geographically or geologically defined areas, and (3) problems that are unique to specific geologic (e.g., depositional) Class 5 reservoir types.

3.5.1 Geological Characteristics

The naturally occurring sources of heterogeneity in Class 5 and other reservoirs fall into four basic categories: depositional environment, diagenetic history, tectonic/structural history, and fluid content. A detailed discussion of these sources of heterogeneity is presented in the 1994 Class 4 Department of Energy report: *Research Needs for Strandplain/Barrier Island Reservoirs in the United States* (Cole et al. 1994). The discussions in the following sections concentrate on heterogeneities or differences arising from depositional, diagenetic, and tectonic origin. Documented differences in fluid content in Class 5 reservoirs are related primarily to heavy oil in reservoirs in California and Texas.

3.5.1.1 Depositional Characteristics

Class 5 reservoirs in Alaska are characteristically of braided stream origin, a reflection of the scale of recent and past tectonic activity. Reservoirs are extensive both laterally and vertically, and have internal heterogeneities typical of extensive braided stream deposits.

California Class 5 reservoirs display stacked vertical architectures commensurate with deposition in narrow rapidly subsiding basins. Stacking results in thick producing intervals. Most of the Class 5 reservoirs in California produce from coarse-grained deposits classified as of alluvial fan origin.

In other states, a variety of fluvial/alluvial environments are reflected in Class 5 reservoirs, but many are classified as of meandering stream origin with comparatively limited areal extent and thickness. These reservoirs are often effectively isolated from surrounding permeable deposits by abundant overbank fines.

The extremely wide variation in depositional energies associated with flood versus nonflood stages of flow is characteristic of all fluvial/alluvial deposition and is abundantly evident in all Class 5 reservoirs. Among the most commonly imposed geological sources of heterogeneity (i.e., depositional, diagenetic, and structural), heterogeneities of depositional origin are identified in the TORIS database as by far the most important in Class 5 reservoirs (see Fig. 3–41).

3.5.1.2 Diagenetic Characteristics

Diagenetic variation among Class 5 reservoirs shows the influence of burial depth, composition of initial sedimentary materials, and specific basin development history.

Alaska reservoirs display the extremes in terms of the effects of initial sedimentary material. The Prudhoe Bay reservoir, despite its age (Paleozoic), and 9,000 foot burial depth, has experienced relatively little diagenetic alternation. Porosities and permeabilities are remarkably well preserved. This phenomenon results from the fact that the sands initially deposited at Prudhoe Bay were very clean, consisting almost entirely of quartz grains derived from previously existing sedimentary deposits. The lack of mineralogically unstable grains has led to relatively little

diagenetic alteration. Deposits of the Cook Inlet, on the other hand, contained large initial volumes of mineralogically unstable grains (e.g., volcanic rock fragments, plagioclase feldspars, etc.) that readily altered with burial to produce a variety of porosity-reducing cements. This phenomenon occurred despite comparatively shallow burial and the much younger age of the sediments involved. A large percentage of the effective porosity in these reservoirs is of secondary or leached origin.

California reservoirs are characterized by their relative shallowness, young age, and rapid deposition. These factors combine to yield poorly consolidated reservoir deposits. Preservation of depositional quality porosities and permeabilities is the rule (see Tables 3–6, 3–8, and 3–9). California reservoirs have the highest average porosity and permeability of any Class 5 reservoirs, despite a relatively high content of mineralogically unstable grains. Their young age, shallow burial depth, and early emplacement of hydrocarbons are probably largely responsible.

In areas other than Alaska and California the specific expression of diagenesis is mainly a function of local source area and basin development. Many of these Class 5 reservoirs consist of relatively low volumes of permeable reservoir rock encased in much larger volumes of overbank fines or other nonpermeable deposits. Diagenetic fluids produced as the basin develops tend to preferentially migrate through these more permeable deposits, resulting in ample opportunity for porosity and permeability reduction by precipitation of cements. In many cases the more permeable reservoir units have been tightly cemented, leaving only poor quality reservoir rock for hydrocarbon accumulation.

In general terms, the development history of specific basins has the greatest influence on diagenesis of Class 5 reservoirs. Reservoirs sharing the same basin development history have a good probability of having at least some similarities in their patterns and sequences of diagenetic alteration, but reservoirs in different basins have an equally strong probability of having

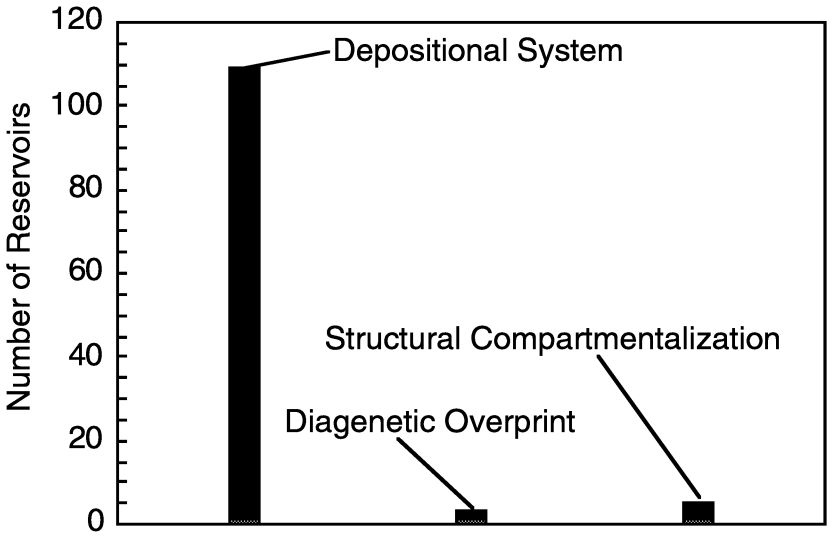


Figure 3–41 Most Important Sources of Heterogeneity in Class 5 Reservoirs (Source: BPO TORIS 1995)

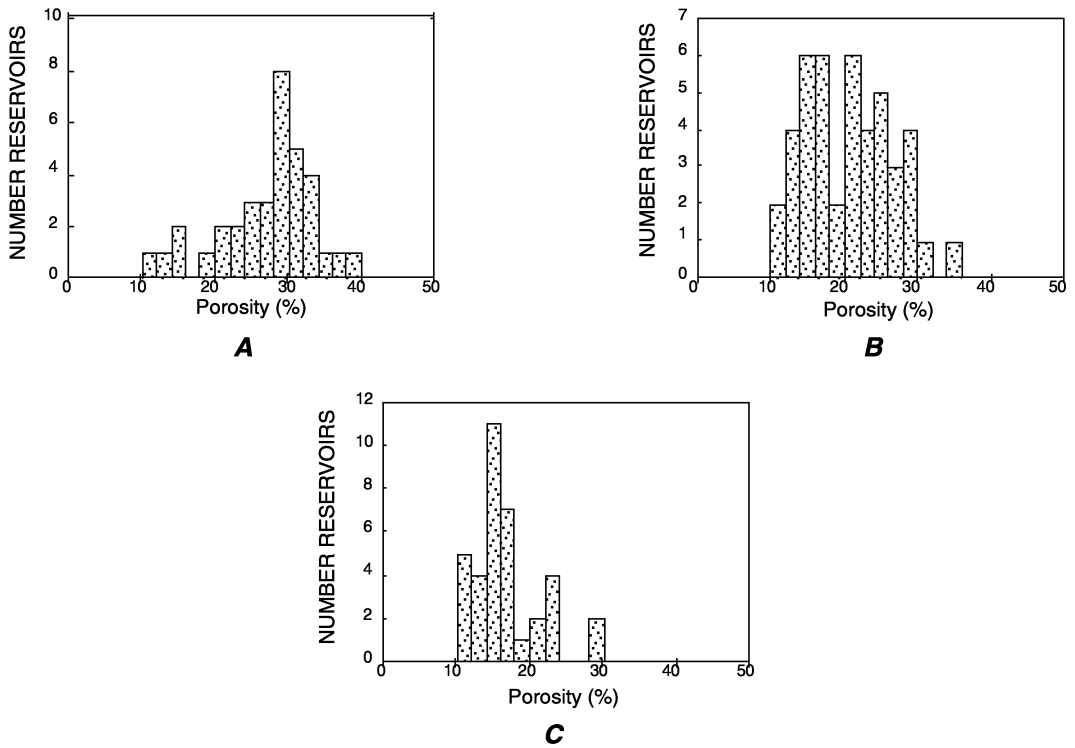


Figure 3–42 Porosity Distribution in Class 5 Reservoirs. (*A*) Reservoirs of Tertiary Age, (*B*) Reservoirs of Cretaceous Age, (*C*) Reservoirs of Paleozoic Age

dissimilar patterns and sequences. One generality that does seem to apply well to Class 5 reservoirs is that older reservoirs have undergone more diagenesis. This conclusion can be drawn from observation of the distribution of porosity in Class 5 reservoirs of various ages (see Fig. 3–42). Paleozoic Class 5 reservoirs in the TORIS database have lower average porosities than do younger reservoirs. If we can assume that diagenesis is the most probable reason for variation in average reservoir porosities, the distribution of porosities reflects greater diagenetic effects through longer and deeper burial for older Class 5 reservoirs.

3.5.1.3 Tectonic Characteristics

Tectonics controls essentially all aspects of reservoir development from deposition to diagenesis and fluid emplacement.

Large scale tectonic movements in both Alaska and California are responsible for stacked architectures, areally extensive deposits, and large scale traps associated with Class 5 reservoirs in those states. Tectonic controls on provenance and basin development have had strong influences on diagenetic alteration in these areas also.

Class 5 reservoirs in other areas are influenced by a wide variety of individual basin development tectonic regimes. At the time of their deposition, a fair number of these Class 5 reservoirs were associated with the less pronounced, but perhaps more erratic, tectonic influences associated with development of continental interior basins. Such associations may account for the more common occurrence in these areas of meandering stream deposits and of incised valleys and valley-fill deposits. These areas have also undergone repeated tectonic activity and reactivation of older structures to further compartmentalize reservoirs and increase heterogeneity.

3.5.2 Production Characteristics

A large number of Class 5 reservoirs are effectively isolated from extensive aquifers and thus have had to rely on less than ideal drive mechanisms (e.g., solution gas, gas cap expansion) that have led to lower recoveries. This problem becomes particularly acute in the case of meandering stream deposits, which are typically limited in overall size and are often effectively isolated from each other and from other permeable deposits by overbank fines. Fluvial deposits occurring as incised valley fills are also frequently and effectively isolated from other permeable deposits. Pressure maintenance in many Class 5 light oil reservoirs has been required (whether actually performed or not) from shortly after inception of production. Lack of reservoir energy has led to early abandonment of many Class 5 reservoirs.

Internal depositional heterogeneities on several scales have led to inefficient recoveries by primary, secondary, and tertiary means. Overbank fines, abandoned channel plugs, and mud drapes result in nonuniform drainage and flooding patterns, leaving behind large quantities of mobile oil (in large to small pockets as a function of heterogeneity scale) not accessed by existing wells and recovery mechanisms. Wide variations in grain size corresponding to variations in depositional energy within permeable units leads to nonuniform patterns as well. The common occurrence of fining-upward sequences, reflecting waning depositional energy after flood events, leads to aggravated channeling problems in waterflood operations because of the tendency of water to underride oil due to gravity and relative permeability effects.

3.6 Summary of Improved Oil Recovery Process Applications in Class 5 Reservoirs

Class 5 domestic reservoirs display fairly significant differences from region to region in terms of their size, geometry, and internal facies configurations, but the major differences in approach to improved oil recovery have largely been a function of the gravity of the oil they contain. Although development of both heavy-oil (less than 20° API) and light-oil (greater than 20° API) Class 5 reservoirs has experienced challenges due to geological reservoir heterogeneities, the influence of oil gravity and viscosity requires completely different approaches to production at all phases of reservoir development.

3.6.1 Light Oil Reservoirs

Rapid reservoir pressure decline has been the prevalent production problem in Class 5 light oil reservoirs as a whole. In many fields discovered in the early part of the century, or even before, the need for pressure maintenance to promote efficient recovery was not realized, and remedial measures were applied late, if at all. A second critical problem in Class 5 light oil production has been high heterogeneity resulting in bypassed oil and poor recovery efficiency.

Pressure decline problems are consistent with the isolation of many reservoirs from one another and from regional aquifers by overbank fines. Failure to maintain reservoir pressure has led to lowered recovery efficiencies and probable premature abandonment in many Class 5 reservoirs. Solutions to pressure maintenance problems took various forms, but generally involved injecting fluids into the reservoir to restore reservoir energy. In many instances injected fluids also functioned as floods to sweep oil to producing wells. Injected fluids included dry gas, liquefied petroleum gas (LPG), water, and CO_2. Injecting LPG and CO_2 under miscible conditions had additional recovery benefits above and beyond those that could be realized by reservoir pressure maintenance or simple oil displacement alone.

Floods of various types frequently performed inefficiently due to reservoir heterogeneity. This problem was particularly notable in waterflood operations where early breakthrough of injected water was frequently observed. In some cases, waterflood was made completely uneconomic by the inability to form an oil bank. Demonstrated solutions to the problem of reservoir heterogeneity have been few. Infill drilling that targets untapped reservoir compartments has been the most successful ploy, but this technique has not been applied in widespread fashion. Other techniques of dealing with reservoir heterogeneity have included recompletion of wells and application of hydraulic fractures.

3.6.2 Heavy Oil Reservoirs

With the exception of three fields in the East Texas Basin, one in Mississippi, and one in Wyoming, most TORIS Class 5 heavy oil reservoirs are in California. California reservoirs are primarily of alluvial fan origin and have characteristically high permeabilities. Application of thermal processes to mobilize oil by decreasing its viscosity has been the primary approach to improved recovery in these and other California reservoirs. Major EOR processes applied include in situ combustion, downhole heaters, hot water injection, cyclic steam injection, and steamflood. These techniques have been used in various combinations with each other and with advanced secondary recovery techniques such as infill drilling and horizontal drilling to sustain production.

From a rather slow experimental phase startup in the 1950s and early 1960s, prior to which industry had concentrated mostly on near-wellbore heating with downhole heaters and huff and puff operations, production from steam injection grew rapidly in the late 1960s. In 1968 Chevron began a significant multipattern field test in the Kern River Field. The end of the 1960s witnessed

the startup era for steamflooding with companies such as Shell, Chevron, Texaco, Mobil, Getty, and UNOCAL. The momentum of steamflooding application in California carried through the 1970s. During the 1970s oil production due to steamflooding was enhanced by implementing infill drilling technology to improve sweep efficiency.

Declining oil-steam ratio in the mid-1980s, accompanied with a drop in oil prices and stringent environmental constraints, led to some innovative applications of steamflooding, such as converting projects from high-quality steam injection (70% quality or higher) to low-quality steam (10% quality) or hot water injection. Also, the low productivity of steamflood projects contributed to development of technologies such as steamfoam injection and foamed high-concentration acid treatments.

The early 1990s witnessed the emergence of horizontal well drilling technology as the most favorable recovery process for steamflooding. Off-the-shelf horizontal well technology is currently available for drilling and completing horizontal wells in steamflood projects. Of paramount importance to the application of this technology are reservoir characterization studies to determine the various factors controlling the heterogeneity and productivity of these mature reservoirs.

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CHAPTER 4
IMPROVED OIL RECOVERY (IOR) POTENTIAL FOR CLASS 5 AS PREDICTED BY TORIS MODELS

Original oil in place (OOIP) for the Class 5 reservoirs which are included in the DOE Tertiary Oil Recovery Information System (TORIS) database totals 39 billion barrels. Cumulative production from these reservoirs reached 13.7 billion barrels of oil as of the end of 1993, or 35% of the OOIP (see Fig. 1–5). Proved reserves for these reservoirs are estimated at 3.9 billion barrels of oil, based on TORIS predictions assuming abandonment as current operations reach economic limits. The ultimate recovery from the TORIS Class 5 reservoirs at the projected termination of current production operations is 17.6 billion barrels (45% of OOIP), leaving an estimated 21.3 billion barrels of oil in the ground. This remaining oil in place volume is the target for the future application of improved oil recovery (IOR) technologies. Based on TORIS estimations, about 23% of this resource, or 4.9 billion barrels, is estimated to be unrecovered mobile oil, which is the target for advanced secondary recovery technologies (ASR). ASR technologies include infill drilling, profile modification or conformance control, and polymer flooding for mobility control. The remainder of the unrecovered oil resource, 16.4 billion barrels, is considered to be immobile or residual oil, the target for enhanced oil recovery processes (EOR). EOR technologies include the following processes: microbial, alkaline and alkaline-surfactant-polymer, surfactant, steam, in situ combustion, carbon dioxide miscible and immiscible, and other processes aimed at recovering residual oil. This chapter discusses the TORIS prediction of the recovery potential which could result from the future application of improved recovery processes in Class 5 reservoirs.

4.1 Combined Potential of All IOR Processes

The recovery potential which could result from the future application of improved recovery technologies in the Class 5 reservoirs included in the TORIS database was estimated using the TORIS predictive and economic models. The TORIS database and predictive models were originally developed by the National Petroleum Council (see Appendix C) and are maintained and updated by the DOE Bartlesville Project Office. TORIS is used to analyze the recovery potential for various improved oil recovery processes on a reservoir-by-reservoir basis using the average reservoir parameters and historical recovery data in the database and the individual process screening and predictive models. The ASR technologies considered in the TORIS analysis include infill drilling, polymer flooding, and profile modification. The EOR technologies considered in this analysis include chemical flooding (alkaline and surfactant), miscible CO_2 injection, steam injection, and in situ combustion processes. A detailed discussion of the TORIS screening and predictive models is included as Appendix C of this report.

The recovery potential for the Class 5 TORIS reservoirs was evaluated for the implemented and advanced technology cases (described in Appendix C) at oil prices of $12, $20, and $30 per barrel. The total recovery potential for Class 5 ranges from 228 million to 4.4 billion barrels of oil, depending upon the prevailing oil price and the level of technology advancement, as summarized in Table 4–1 and displayed in Figure 4–1. For the implemented technology case, which is essentially the future application of existing recovery technologies, the recovery potential ranges from 228 million barrels at $12 per barrel to 2.4 billion barrels at $30 per barrel. If reasonable technological advancements can be achieved, the recovery potential increases significantly for Class 5, ranging from 905 million to 4.4 billion barrels at oil prices of $12 and $30 per barrel, respectively. The majority of the advanced technology case potential is attributable to the application of ASR technologies in the $12 and $20 per barrel cases, but EOR technologies have the greater impact in the $30 per barrel case.

Table 4–1
Recovery Potential for TORIS Class 5 Reservoirs (Source: BPO TORIS 1995)

Oil Price ($/Bbl)	Advanced Secondary Recovery		Enhanced Oil Recovery		Total Potential	
	Implemented Technology (Million Bbl)	Advanced Technology (Million Bbl)	Implemented Technology (Million Bbl)	Advanced Technology (Million Bbl)	Implemented Technology (Million Bbl)	Advanced Technology (Million Bbl)
$12/Bbl	108	467	120	438	228	905
$20/Bbl	181	2,053	742	1,655	923	3,708
$30/Bbl	998	2,087	1,377	2,352	2,375	4,439

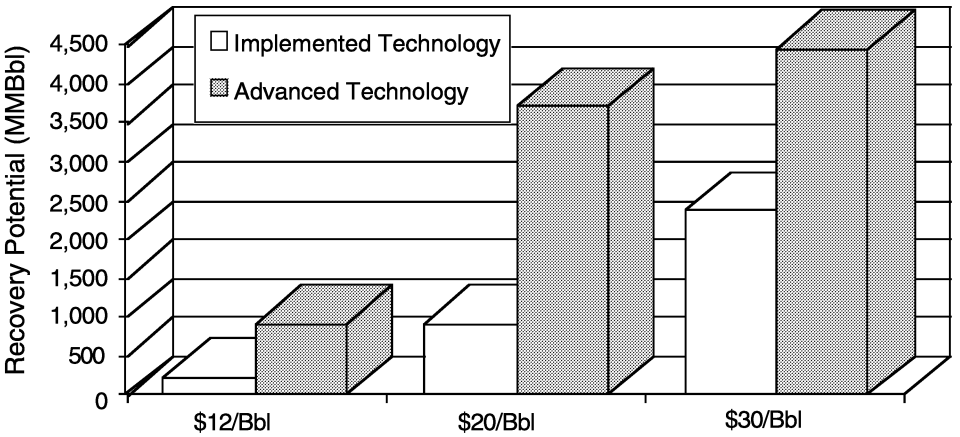

Figure 4–1 Total Recovery Potential for Class 5 Reservoirs (Source: BPO TORIS 1995)

4.2 Abandonment Risk

A significant portion of the Class 5 resource is at risk of abandonment, meaning that many of the reservoirs that have potential for future application of improved recovery technologies could be abandoned prior to the initiation of these projects. For the implemented technology case considered in this analysis, nearly 24% of the 228 million barrel recovery potential at $12 per barrel is at risk of abandonment by the year 2000 (see Fig. 4–2). At $30 per barrel, about 21% or 500 million barrels of the 2.4 billion barrel potential could be abandoned by the year 2000. For the advanced technology case (see Fig. 4–3), about 400 million barrels (43%) of the 905 million barrel recovery potential at $12 per barrel could be abandoned by the year 2000, while about 800 million barrels (19%) of the 4.4 billion barrel potential at $30 per barrel is at risk of abandonment. Only a minor portion of the implemented and advanced technology recovery potential is at risk of abandonment after the year 2000 and before the year 2005, with the only significant volume being an additional 300 million barrels at risk of abandonment by 2005 in the $30 per barrel advanced technology case. The magnitude of the Class 5 recovery potential which is at risk of abandonment in the near future illustrates the urgent need for the development and demonstration of cost-effective recovery technologies.

4.3 Improved Recovery Potential by Process

The improved oil recovery potential which could be achieved through the future application of recovery processes in Class 5 reservoirs is fairly evenly distributed between the advanced secondary recovery processes and the enhanced oil recovery processes (see Figs. 4–4 and 4–5 and Table 4–1).

The advanced secondary recovery potential for Class 5 increases from about 100 million barrels at $12 per barrel to almost 1.0 billion barrels at $30 per barrel for the implemented technology case, while the recovery potential for the advanced technology case increases from 467 million to

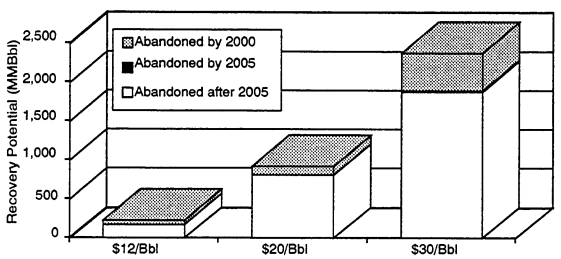

Figure 4–2 **Total Potential at Risk of Abandonment—Implemented Technology (Source: BPO TORIS 1995)**

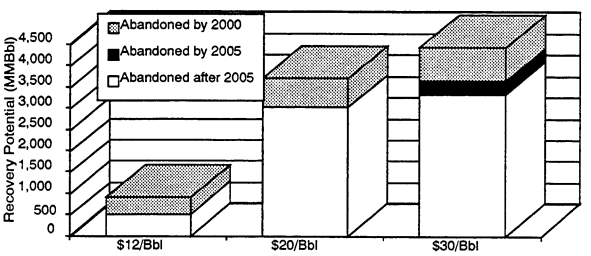

Figure 4–3 **Total Potential at Risk of Abandonment—Advanced Technology (Source: BPO TORIS 1995)**

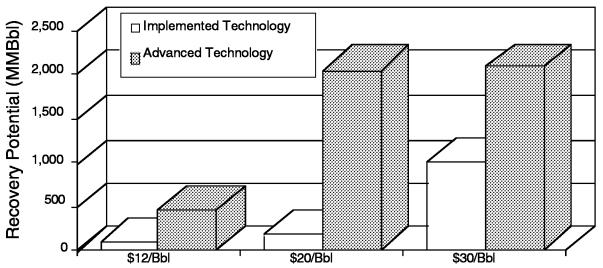

Figure 4–4 Advanced Secondary Recovery (ASR) Potential (Source: BPO TORIS 1995)

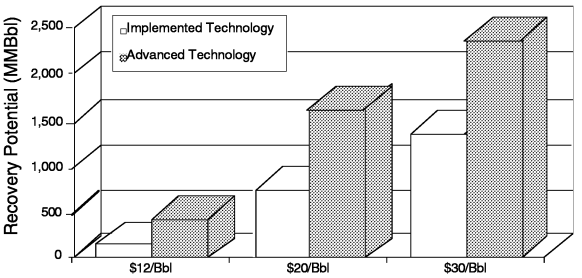

Figure 4–5 Enhanced Oil Recovery (EOR) Potential (Source: BPO TORIS 1995)

2.1 billion barrels as the price increases from $12 per barrel to $30 per barrel (see Fig. 4–4). Most of this ASR potential is attributable to infill drilling alone and in combination with polymer flooding and profile modification.

A large percentage of Class 5 reservoirs and ROIP fall within the recommended temperature and salinity ranges (less than 180°–200°F and less than 100,000 ppm, respectively) for application of current or implemented enhanced oil recovery (EOR) technologies (see Figs. 4–10 and 4–11 and Appendix C, Section C.2). In the case of advanced EOR technology applications (temperatures less than 200°–250°F and salinities less than 200,000 ppm) nearly all Class 5 reservoirs and virtually all ROIP fall within the recommended range. The enhanced oil recovery potential (see Fig. 4–5) for Class 5 increases from 120 million barrels at $12 per barrel to 1.4 billion barrels at $30 per barrel for the implemented technology case, while the recovery potential for the advanced technology case increases from 438 million barrels to nearly 2.4 billion barrels as the price increases from $12 per barrel to $30 per barrel. Most of the EOR potential results from the application of thermal recovery processes.

The TORIS predictions for improved recovery potential by process assess the viability of various recovery processes for Class 5 reservoirs. Table 4–2 and 4–3 summarize the recovery potential for each of the advanced secondary recovery and enhanced oil recovery processes. These data are represented graphically in Figure 4–6 and 4–7 for the implemented and advanced technology cases, respectively. In the implemented technology case, steam injection has the highest recovery potential at all oil prices analyzed. In the advanced technology case, the recovery potential for steam injection and in situ combustion is high, but infill drilling in combination with polymer flooding and profile modification demonstrates the highest recovery potential.

Examination of the data in Tables 4–2 and 4–3 reveals that the recovery potential for the individual processes does not necessarily increase as the oil price increases. This phenomenon is a result of the TORIS selection methodology (see Appendix C). At each oil price, TORIS selects the recovery process for each reservoir in order to maximize oil recovery. For any given reservoir, the selected recovery process may be different at one oil price than at another. For example, infill drilling may be the selected process in a given reservoir at $12 or $20 per barrel, but at $30 per

Table 4–2
Class 5 Advanced Secondary Recovery Process Potential (Source: BPO TORIS 1995)

	Recovery Potential in Millions of Barrels					
	Implemented Technology			Advanced Technology		
Recovery Process	$12/Bbl	$20/Bbl	$30/Bbl	$12/Bbl	$20/Bbl	$30/Bbl
Polymer Flooding	1	20	22	4	21	4
Profile Modification	9	9	3	13	7	7
Infill Drilling	0	0	790	0	6	7
Infill & Polymer	87	94	62	359	1,907	1,929
Infill & Profile	11	58	121	91	112	140
Total	108	181	998	467	2,053	2,087

Table 4–3
Class 5 Enhanced Oil Recovery Process Potential (Source: BPO TORIS 1995)

	Recovery Potential in Millions of Barrels					
	Implemented Technology			Advanced Technology		
Recovery Process	$12/Bbl	$20/Bbl	$30/Bbl	$12/Bbl	$20/Bbl	$30/Bbl
Alkaline	0	0	0	21	41	39
Surfactant	0	3	25	0	182	200
CO_2 Miscible	0	10	47	0	10	60
Steam Injection	120	729	1,259	417	1,025	1,555
In Situ Combustion	0	0	46	0	397	498
Total	120	742	1,377	438	1,655	2,352

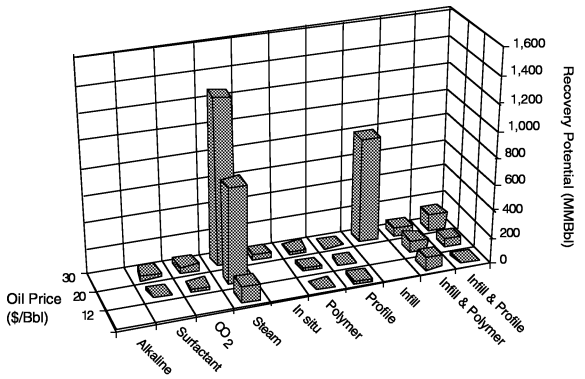

Figure 4–6 **Recovery Potential by Process—Implemented Technology (Source: BPO TORIS 1995)**

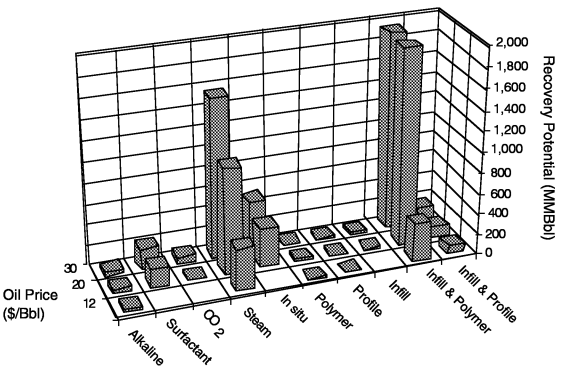

Figure 4–7 **Recovery Potential by Process—Advanced Technology (Source: BPO TORIS 1995)**

barrel, one of the other ASR processes may recover more oil economically than infill drilling. The end result is that the overall recovery potential for the Class 5 reservoirs does increase as the oil price increases, and oil recovery is maximized.

4.4 Improved Recovery Potential by Geographical Area

The purpose of this section is to define the predicted recovery potential for the application of improved recovery technologies in Class 5 reservoirs in the most significant geographical areas, as defined in this report. The TORIS recovery potential by process is presented for Class 5 reservoirs in Alaska, California, and states other than Alaska and California for both the implemented and advanced technology cases, in Figures 4–8 through 4–13.

Improved recovery potential for Alaska varies significantly depending upon the level of technology advancement and the prevailing oil price. In the implemented technology case, as shown in Figure 4–8, there is no recovery potential at $12 per barrel and only minimal recovery potential for polymer flooding as prices increase to $20 per barrel. If oil prices climb to $30 per barrel the recovery potential for Alaska increases to 846 million barrels, the majority obtained through infill drilling, with minor potential for carbon dioxide and polymer flooding and for infill drilling in combination with profile modification. In the advanced technology case (see Fig. 4–9), the improved recovery potential is predominantly for infill drilling in combination with polymer flooding. This potential increases from 326 million barrels at $12 per barrel to over 1.8 billion barrels as the oil price increases to $30 per barrel. There is also minor potential in this case for carbon dioxide and polymer flooding and for infill drilling in combination with profile modification.

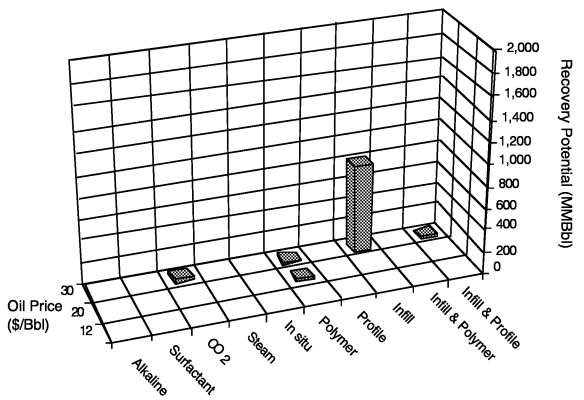

Figure 4–8 Recovery Potential by Process for Alaska Class 5 Reservoirs—Implemented Technology (Source: BPO TORIS 1995)

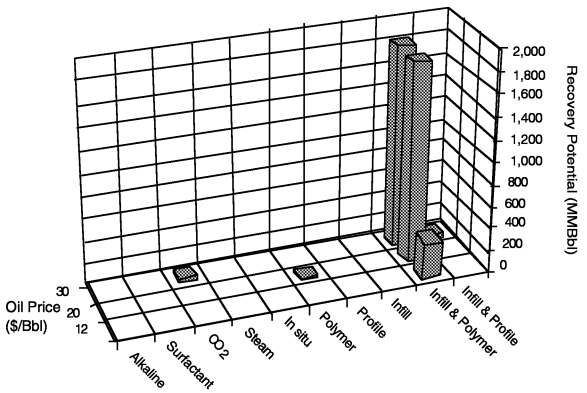

Figure 4–9 Recovery Potential by Process for Alaska Class 5 Reservoirs—Advanced Technology (Source: BPO TORIS 1995)

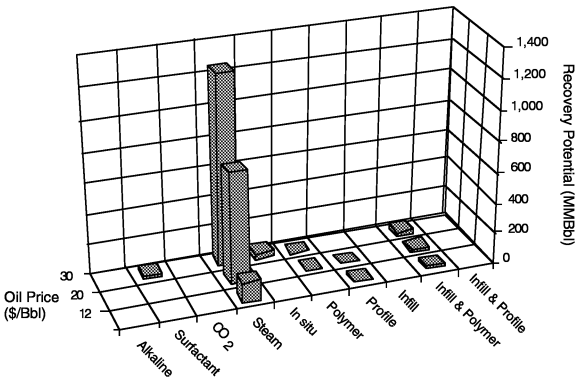

Figure 4–10 Recovery Potential by Process for California Class 5 Reservoirs—Implemented Technology (Source: BPO TORIS 1995)

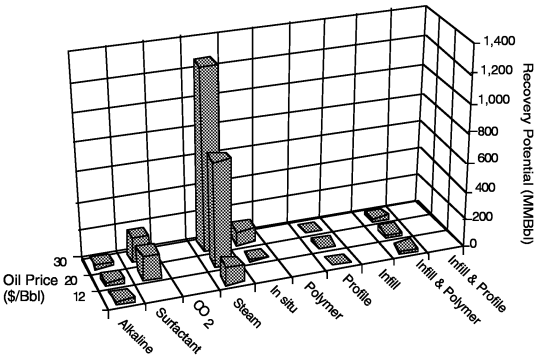

Figure 4–11 Recovery Potential by Process for California Class 5 Reservoirs—Advanced Technology (Source: BPO TORIS 1995)

The improved recovery potential for Class 5 reservoirs in California in the implemented (see Fig. 4–10) and advanced (see Fig. 4–11) technology cases results predominantly from the application of thermal recovery processes. Overall recovery potential for California in the implemented technology case ranges from 142 million barrels at $12 per barrel to almost 1.4 billion barrels at $30 per barrel. Minor potential results from the application of in situ combustion, chemical flooding, and infill drilling in combination with polymer flooding. In the advanced technology case, overall recovery potential increases slightly, ranging from 167 million

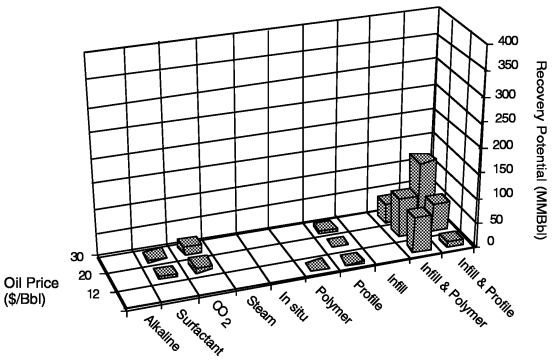

Figure 4–12 Recovery Potential by Process for Class 5 Reservoirs in States Other than Alaska and California—Implemented Technology (Source: BPO TORIS 1995)

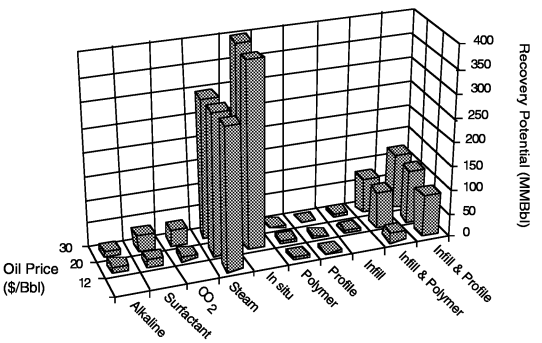

Figure 4–13 Recovery Potential by Process for Class 5 Reservoirs in States Other than Alaska and California—Advanced Technology (Source: BPO TORIS 1995

barrels at $12 per barrel to 1.6 billion barrels as the oil price increases to $30 per barrel. Steamflooding accounts for the majority of this potential, with only minor additional potential resulting from chemical flooding, in situ combustion, profile modification, and infill drilling in combination with polymer flooding.

For oil prices at $12 and $30 per barrel, Class 5 reservoirs in states other than Alaska and California account for improved recovery process potential of 86 and 175 million barrels, respectively, in the implemented technology case, and 412 and 975 million barrels, respectively, in the advanced technology case (see Figs. 4–12 and 4–13). The majority of the potential from implemented technology results from the future application of infill drilling in combination with polymer flooding and profile modification in Class 5 reservoirs in Louisiana, Montana, Oklahoma, Texas, and Wyoming. A significant portion of the advanced technology case recovery potential (see Fig. 4–13) results from the future application of thermal processes in Class 5 reservoirs in Texas and Louisiana. Infill drilling potential (alone and in combination with polymer flooding and profile modification) is attributable to Class 5 reservoirs in Kansas, Louisiana, Montana, Oklahoma, Texas, and Wyoming. A minor amount of chemical flooding potential (alkaline and surfactant) is attributable to reservoirs in Illinois, Montana, Texas and Wyoming, and there is a small amount of carbon dioxide flood potential in Kansas reservoirs.

4.5 Improved Recovery Potential by Depositional System

Of the three major depositional systems which make up the fluvial/alluvial class of reservoirs, the majority of the recovery potential is attributable to reservoirs in the alluvial fan and braided stream categories. In the implemented technology case, alluvial fan reservoirs account for well over 50% of the recovery potential for Class 5 at all oil prices considered in the analysis (see Fig. 4–14). In the $12 per barrel case, alluvial fan reservoirs account for 62% of the potential while

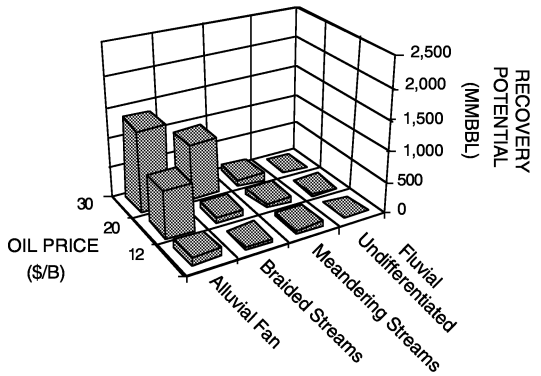

Figure 4–14 **Recovery Potential by Fluvial/Alluvial Depositional System Type—Implemented Technology (Source: BPO TORIS 1995)**

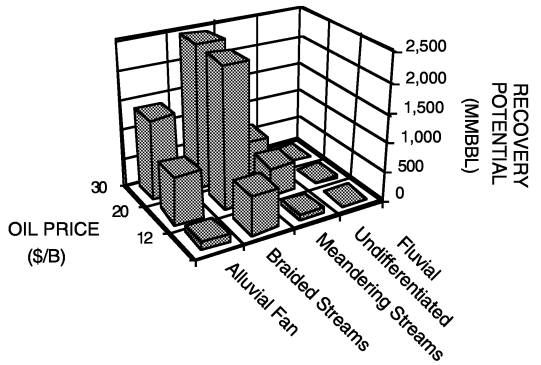

Figure 4–15 **Recovery Potential by Fluvial/Alluvial Depositional System Type—Advanced Technology (Source: BPO TORIS 1995)**

meandering stream reservoirs account for over 28%. In the $20 per barrel case, 82% of the nearly one billion barrel recovery potential is attributable to alluvial fan reservoirs. In the $30 per barrel case, alluvial fan reservoirs account for 56% and braided stream reservoirs contribute 38% of the total 2.4 billion barrel potential. In the advanced technology case, braided stream systems contribute more significantly to the recovery potential than any other depositional system at all oil prices considered (see Fig. 4–15). In the $12 per barrel case, braided stream reservoirs account for 73% of the nearly one billion barrel potential. In the $20 and $30 per barrel cases, braided stream reservoirs account for about 60% of the four billion barrel potential, with the alluvial fan and meandering stream reservoirs contributing the remainder.

4.6 Reference

BPO TORIS, 1995, Tertiary Oil Recovery system: Department of Energy, Bartlesville Project Office, Bartlesville, OK.

CHAPTER 5
RESEARCH, DEVELOPMENT, AND DEMONSTRATION (RD&D) NEEDS FOR CLASS 5

Chapter 5 draws heavily on the specific history and characteristics of Class 5 reservoirs presented in Chapters 2 and 3 and on the results of TORIS predictive model analysis presented in Chapter 4. The more salient research needs in the general areas of reservoir management, reservoir characterization, recovery processes, simulation, and wellbore and facilities are presented in Section 5.1. Then, in Section 5.2, research needs from the discussions in Section 5.1 that are specifically applicable to Class 5 reservoirs are identified. Section 5.3 identifies the environmental considerations that affect efforts to recover additional oil from Class 5 and all other reservoirs in the United States. Section 5.4 summarizes research, development, and demonstration that could potentially have the greatest effects on improving Class 5 recoveries and prolonging access to Class 5 reservoirs.

5.1 General RD&D Needs

General RD&D needs for Class 5 are those that, if addressed, will result in additional and/or more efficient recovery from fluvial/alluvial reservoirs as well as from reservoirs of other geologically defined classes. Needs fall into several distinct RD&D areas including reservoir management, reservoir characterization, process-related, reservoir simulation, and wellbore and facilities.

5.1.1 The Need for Reservoir Management Methodologies

A number of definitions and approaches to reservoir management have evolved over the years. Thakur (1991) defines reservoir management as "the judicious use of available resources to maximize economic recovery." Wiggins and Startzman (1990) define reservoir management as "the application of state-of-the-art technology to a known reservoir system within a given management environment." Reservoir management is not just preventive maintenance nor problem solving. It is not a depletion plan and/or a development plan, but rather a comprehensive, integrated strategy for reservoir exploitation (Wiggins and Startzman 1990). Regardless of the precise definition, nearly all discussions of reservoir management agree on the following as characteristics of reservoir management: (1) it requires and makes use of resources, (2) it is continuous and long-term, over the life of a reservoir, and (3) it concentrates on economic optimization. Reservoir management can be viewed as a time series of choices that are made throughout the life of a reservoir to optimize the economic recovery of petroleum. A plan,

therefore, is an important and necessary central concept to reservoir management. A reservoir management plan (1) specifies a schedule of implementation activities; (2) projects timing and volumetric performance of production and injection wells, performance of facilities and equipment, and environmental and other regulatory compliance; and (3) specifies a system of data collection, storage, and analysis to monitor performance in each of the preceding areas.

A more detailed description of reservoir management including discussions of economic and organizational contexts and characteristic activities and procedures may be found in the 1994 Class 4 Department of Energy report: *Research Needs for Strandplain/Barrier Island Reservoirs in the United States* (Cole et al. 1994).

RD&D needs for reservoir management are primarily in methodology development and demonstration for (1) design of data and information management systems, (2) formulation of reservoir management plans, and (3) technology transfer. Computer-based information management systems are needed for storage, retrieval, and analysis of all types of reservoir management data (i.e., technological, reservoir description and performance, reservoir management economic and organizational data). Computer-based systems would also be useful to provide guidance in building an appropriate reservoir management plan tailored to the particular context of a reservoir, and to aid in subsequent collection and interpretation of surveillance data as specified by the plan. Such computer-based systems may also provide appropriate reservoir management training if designed with that objective in mind, but design and development of cross-training programs for reservoir management personnel (e.g., managers, engineers, geologists, field personnel, etc.) are also definite needs.

5.1.2 Needs in Reservoir Characterization

The purpose of reservoir description or characterization is to assemble information about type, distribution, and magnitude of heterogeneities that can be used to convey a knowledge of subsurface fluid flow. To the extent that the information available is incomplete, imperfect, or at an inappropriate scale, knowledge of subsurface fluid flow will be correspondingly uncertain. An appropriately detailed and accurate (i.e., with acceptable degree of uncertainty) identification of heterogeneity distribution, type, and magnitude can relax reservoir description constraints on recovery by allowing the operator to avoid the deleterious effects of heterogeneities and/or exploit them to best economic advantage. Above all then, reservoir characterization is a tool used to avoid costly errors in reservoir decision making.

More detailed discussions of the (1) sources of reservoir heterogeneity, (2) component sources of information for reservoir characterization, (3) degree of uncertainty associated with each source, and (4) integration of those sources for improving recovery by more accurate fluid-flow prediction may be found in the 1994 Class 4 Department of Energy report: *Research Needs for Strandplain/Barrier Island Reservoirs in the United States* (Cole et al. 1994).

Two aspects of general research needs in reservoir characterization will be addressed briefly in the sections following. Section 5.1.2.1 reviews needs related to the construction of reservoir characterization models. Section 5.1.2.2 discusses needs related to the methodologies involved in performing reservoir characterization.

5.1.2.1 General Reservoir Characterization RD&D Needs in Model Development

A reservoir characterization model is a representation or estimate of reservoir reality. It represents not only the three-dimensional extent or bounds of the reservoir, but the qualitative (presence or absence) and quantitative (magnitude) values of rock, fluid, and other reservoir parameters affecting fluid flow at every location in the volume of the reservoir. The degree of uncertainty associated with placement and magnitude of fluid-flow parameters is an important facet of the model.

In the past, the aim of reservoir characterization generally has been to create a single "most probable" representation of the reservoir to be used as input to subsequent decision making. The need for a small number of more extreme but reasonably probable representations to serve as input to decision-making tools is now becoming recognized as a useful if not critical addition. This approach allows bracketing the range of reasonably expected recovery and economic outcomes. The primary objective of reservoir characterization model construction is to accurately represent and minimize, as far as is economically feasible, the range of uncertainty in our knowledge of reservoir parameters that affect fluid flow.

Three types of information can generally be called upon for model construction in reservoir characterization.

- Conceptual information is derived from analogous situations. Direct transferability of observed or measured properties is assumed, but associated uncertainty is an inverse function of the overall similarity or appropriateness of the analogous situation.
- Stochastic information is also derived from an analog source, but also attempts to represent the small-scale variability of properties observed in that source. Given an equal degree of analog similarity, a stochastic model can provide less uncertainty through heterogeneity representation at a finer scale.
- Deterministic information involves direct acquisition of data from the reservoir, with no question of transferability and a degree of uncertainty in heterogeneity representation limited only by the scale of measurement and the resolution of the measuring tool.

In practice, information of any one or more of the three basic information types (i.e., conceptual or analog, stochastic, or deterministic) can be used to build a reservoir characterization model. Choosing the appropriate blend of information types depends on the (1) availability of each type of information, (2) degree of uncertainty that can be tolerated, and (3) cost to obtain additional information. Information types are employed in a complementary fashion, using "hard" or

deterministic information to constrain and calibrate conceptual or stochastic models based on analogs, and using "soft" or analog-based conceptual or stochastic information to extend or interpolate deterministic information.

Conceptual Models

For all reservoir classes, carefully focused depositional analog studies have potential for increasing understanding and predictability of critical sedimentary features such as (1) external reservoir and facies geometries and (2) relative location, frequency, and magnitude of internal depositional heterogeneities likely to influence fluid flow. Such studies may identify correlations between those critical features and simpler, readily observable characteristics, such as facies properties, sedimentary structures, or other reservoir data, that might be obtained from a single well or a small number of wells.

Diagenetic analog models are needed for various depositional reservoir types (Szpakiewicz et al. 1989; Jackson and Tomutsa 1991). Development of general conceptual diagenetic models is needed basin-by-basin to cover those aspects of diagenesis influenced by basin-scale tectonics, heat flow, and fluid movements. Basin-scale subsurface fluid flow and its link to regional patterns of diagenesis, sedimentary ore deposits, and hydrocarbon migration and accumulation have become the subjects of increasing research during the past decade (Gregg et al. 1994). Because relatively little research has been done on basin-scale, the methodologies employed to study diagenetic characteristics at this scale will also be valuable. Research should continue along the lines of current activities, including the study of (1) evolution through time and space of the geochemistry of basinal fluids, and the factors controlling that evolution; (2) origin, evolution, and distribution of fluid flow pathways in sedimentary basins; (3) present flow patterns on regional and basinwide scales; (4) nature of subsurface rock-fluid interactions; and (5) interaction of basin development factors (e.g., tectonics, heat flow, sediment fill) that affect the pressure and temperature history of basins. Studies are also needed to determine what diagenetic sequences are shared among reservoirs exposed to similar burial histories in different basins. Basin-scale to local-scale tectonic analog models may help increase predictive understanding of reservoir fluid content, diagenetic sequences, and internal heterogeneities due to faulting and/or joints and fractures.

Stochastic Models

Methodologies for selecting and implementing both discrete and continuous stochastic models at interwell and larger scales, using data of various types and based on analog reservoirs, outcrops, and modern deposits are definite needs. A combined modeling approach employing discrete techniques to simulate the spatial distribution of sediment packages with subsequent continuous stochastic assignment of sediment properties within packages may be useful as described by Jackson (1993). Such approaches, probably based on analog outcrop data, have the potential to give the most realistic representation yet available of the spatial interrelationships of sediment properties affecting fluid flow.

Deterministic Models

Deterministic models are those based on actual measurement of reservoir properties. The following sections address RD&D needs for several of the common deterministic tools used in reservoir characterization. However, not all potentially relevant tools and techniques are discussed. A number of additional approaches (e.g., electromagnetic mapping, remote sensing, surface and borehole gravity surveys, aerial and surface magnetic surveys, surface geochemical sampling surveys, etc.) may have good potential in characterizing Class 5 and other reservoirs with additional RD&D.

Rock and Fluid Sampling: More cost-effective techniques are needed to obtain rock and fluid samples at different reservoir locations during all stages in the life of the reservoir. Special consideration for obtaining native-state and oriented cores should be emphasized, as should methodologies for: selecting core sites, handling and analysis of cores, and distribution and fingerprinting methodologies for fluids. Fluid sampling considerations might further include avoidance of H_2S absorption and special techniques for accurate sampling of condensates (Pande et al. 1993). Further development of slimhole drilling techniques may be helpful in pursuing these ends.

Analytical tools and methodologies also are needed to make maximum use of existing sample data. Continued development of laboratory tools and techniques for determination of critical rock, and rock-fluid interaction parameters from small samples such as drill cuttings would prove useful in the analysis of many existing (especially older) reservoirs where no other samples are available. Better wettability-restoration procedures for nonnative-state rock materials are also needed to make more realistic assessments of rock-fluid interaction from existing samples.

Refinement and development of new laboratory analytical tools and methodologies are needed for cheaper, quicker, and more accurate determination of reservoir parameters for practical applications, especially under reservoir conditions (i.e., with reservoir pressure, temperature, and formation fluids). Finally, continued development of quality assurance procedures and standards for (1) field collection and handling of samples and (2) for laboratory collection and analysis of rock, fluid, and geochemical and engineering rock-fluid interaction data is needed.

Development of correlations or predictive links between critical reservoir fluid-flow properties and other more readily obtained data or with the components of conceptual models would be useful. For example, a spatial relative permeability predictive capability for reservoirs of a particular play could be built by cataloging any observed relationships between depositional or diagenetic facies and measured relative permeabilities. Such models, developed for specific plays or subplays, could be made more valuable by performing relative permeability measurements at native-state conditions.

Pande et al. (1993) suggest the following additional research areas for fluids: (1) developing better understanding of multiple liquid phase behavior, (2) predictive models for asphaltene precipitation, (3) fluid history modeling on a reservoir scale, and (4) developing correlations for reservoir fluid properties.

Production and Injection Data: To maximize the utility of production and injection data, widespread, accurate, and complete data are required. Accurate records of all reservoir operational activities affecting production and injection must be kept, as well as records of all appropriate production and injection data for the entire reservoir. Low-cost data collection equipment, standard data collection protocols, and low-cost, readily available database management and analysis systems to handle data storage and retrieval tasks and assist with automated display, analysis, and interpretation of production and injection data in a reservoir characterization context are needed.

A need exists for further advancements in analysis of decline curves and injection data, but additional needs are (1) to investigate new ways to extract reservoir descriptive information from existing conventional data or data permutations and (2) to identify any new production, injection, or related data that can be recorded to extract more or better reservoir information in the future. Class 5 contains reservoirs in mature producing areas, in which production or injection data are the most abundant available sources of reservoir information. Techniques that maximize the reservoir-descriptive utility of existing data from such reservoirs would be of great value. Demonstrations of large scale and complete integration of production and injection information with information derived from other sources of reservoir characterization data would also be desirable.

Wireline Log Data: New wireline logging tools to measure desired reservoir properties are under constant development (Prensky 1994). Enhanced resolution of thin sands is being made possible by development of tools such as the laminated sand analysis (LSA™) tool (DOE 1991). Fluid chemistry and saturations, bound waters in clays, and pore structures in the vicinity of the borehole are now being measured by electromagnetic propagation and nuclear magnetic resonance tools (DOE 1991; Jackson 1984; Prensky 1994). Spectrometric tools have been developed to provide more detailed compositional information than ever before available (Hertzog et al. 1987). The stratigraphic high-resolution dipmeter and formation microscanner tools allow identification of heterogeneities at the scale of sedimentary structures.

New tools or tool combinations are yet needed, however, to measure critical reservoir properties such as permeability in both clastic and carbonate reservoirs (Jackson 1984; Worthington 1991). New tools and tool improvements are also needed to estimate traditionally measured parameters such as composition, saturation, and porosity with increased vertical resolution and at greater distances from the borehole in the interwell region (Jackson 1984). Further development of tools is needed for resurvey applications in older fields for cost-effective and accurate measurement of all critical reservoir parameters in steel-cased-holes with variable styles and quality of completion (Prensky 1994). Work on new tools should be begun immediately to accomplish effective progress in the midterm.

Over the short-term, methodologies are needed (1) to optimize logging suite selection for various stages of reservoir development, (2) to provide cost-effective quality control for log data acquisition, and (3) to optimize extraction of information from existing wireline log data. The kinds and amount of information required from geophysical wireline logs for proper reservoir management will vary according to the stage of development of the reservoir. It is critical, however, that baseline distributions of certain reservoir parameters (e.g., saturations) be obtained early in reservoir development for comparison at later stages. Selection of appropriate cased-hole tools to be run as complements to existing old E-logs in mature fields is also an important consideration.

Different reservoir depositional types or classes will require different logging suites and acquisition strategies. Reservoirs in certain basins or plays may require additional considerations due to special diagenetic or structural features they may have in common. Finally, there may be factors specific to individual reservoirs that dictate the need for highly customized logging programs.

In obtaining wireline log data, there is always a tradeoff between cost and accuracy. The cost of obtaining data (e.g., borehole drilling and preparation, operator selection, tool calibration, number and speed of logging runs, etc.) must always be weighed against the present and future utility of the information. The acceptance of inaccurate or incomplete determinations of important reservoir parameters at the open-hole stage of development, although it may achieve a short-term cost savings, may prove to be extremely noncost-effective at later stages of reservoir development.

Definite quality control protocols for logging programs should be developed early and strictly adhered to for every reservoir. The methodology for establishing these protocols is an important research area for all reservoir classes.

Existing wireline logs in many instances may be the only data available due to economic or technical constraints. Many of these logs, especially those obtained in the last 20 years, are of reasonably good quality and may contain significant unrealized information. Wendt et al. (1986) and Hearn et al. (1986) used multivariate statistical techniques to identify flow facies and flow units and to predict permeability from digital wireline log data. Research on the use of parametric and nonparametric statistics as well as neural net approaches to extraction of lithofacies and fluid-flow facies information from digital wireline log data was recommended by Jackson (1993). Development of methodologies for extraction from log data of reservoir fluid-flow parameters may lead in the midterm to delineation of desired characteristics for new logging tools and suites of logs. Further development of practical, affordable methods for conversion of existing paper logs to digital form is an additional research need.

Development of nonparametric and neural net approaches for extracting important quantitative and/or qualitative reservoir information from old E-logs may be especially useful. Such techniques would aid recovery from many older, mature reservoirs where little other subsurface information is available.

Pressure Transient Test Data: Pressure transient tests must be carefully designed to answer specific questions about the reservoir, and a measurement sequence must be formulated that will satisfy the objectives of the test in a cost-effective manner (Ehlig-Economides et al. 1990). Even with optimum design, well test results may often have nonunique interpretations. Numerous models are available in the literature, but expertise and experience are needed along with guidance from other data such as well logs, seismic, or a geological conceptual model, to select the correct model for interpretation (Ehlig-Economides et al. 1990; Ramey 1990). Kamal (1990) and Gringarten (1986) suggested increased use of sophisticated computer analysis and expert system guidance in selection of models and in interpretation and validation of results. Expert systems should also prove useful in selection and design of appropriate tests to answer specific reservoir questions.

Kamal (1990) suggested more rigorous application of pressure transient test techniques in reservoirs known to be heterogeneous to further develop tools and methodologies. Recent advances in computer-aided well-test interpretation expand the capability of the method to more complex cases such as composite and naturally fractured reservoirs with additional capabilities to quantify the reliability of interpretations (Horne 1994). Both Kamal (1990) and Ehlig-Economides et al. (1990) recommended better efforts and documentation in the integration of pressure transient testing with other reservoir characterization techniques.

Tracer Test Data: A typical present-day application of tracers is to inject them in aqueous fluids after waterflooding to evaluate fluid flow pathways for EOR. Water-based fluids have a strong tendency to follow water-saturated zones, however, and test results may be biased (Jackson and Tomutsa 1991). Tracer applications for use in different zones, and in reservoirs at different stages of development need to be investigated more thoroughly. Different tracer carrier fluids may be required.

Similar to other techniques that directly measure physical properties, results of tracer tests often do not have unique interpretations. Other data such as seismic, well log, or geological models (e.g., lithology, porosity, diagenesis, relative permeability, etc.) must provide guidelines for interpretation (Jackson and Tomutsa 1991). Applications of tracer test techniques in reservoirs with significant heterogeneities are needed for the purpose of development of (1) test design and interpretation methodologies and (2) techniques for integration of well test results with findings and predictions from other data sources and types.

At present, tracer tests are comparatively inexpensive and in common use. The search for efficiently performing, low-cost, reactive and nonreactive tracers should continue to achieve more widespread application of the technology.

Seismic Data: Research needs in 3D seismic are those that will refine the tool to increase the power and ease of its application and lower costs. Robertson (1991) suggests the following areas for attention: (1) development of methodologies for data collection design for specific target reservoirs, (2) implementation of 3D three-component seismic surveys to exploit shear-wave and converted-wave data, (3) increase use of computer automation and expert guidance systems in many aspects of 3D seismic technology application, (4) development of more powerful computational capabilities to implement more sophisticated processing algorithms, and (5) development of 3D seismic applications with downhole sources and receivers with higher frequencies which can lead to higher resolution and better reservoir description in the interwell region.

Seismic data have a long history of application in determination of subsurface structure and stratigraphy, but more recently, characteristics of seismic waves, such as amplitude and phase, and interval velocity changes between seismic events have been correlated with reservoir properties such as porosity, fluid type, lithology, and pay thickness (Jackson and Tomutsa 1991). The information content of seismic data, and thus the ability to represent reservoir properties, will increase with recording, in addition to the conventional compressional waves (P-waves), the shear waves (S-waves) by special three-component geophones.

Although seismic amplitude versus offset (AVO) techniques are being developed primarily as exploration tools for natural gas (Shirley 1994), the capability of AVO for targeting small anomalies (Allen et al. 1993) indicates that research in this area may also have application in EOR fluid monitoring. Theoretical and laboratory petrophysical studies of acoustical energy inversion over varying offset would provide invaluable information for interpreting fluid saturation (Poggiagliolmi and Allred 1994).

Measurement of seismic attributes at any appreciable depth using surface seismic surveys suffers from attenuation and loss of higher signal frequencies resulting in the loss of resolving power. Placement of source and receivers in subsurface boreholes enhances retention of higher frequencies with subsequent increased resolution capabilities and is appropriate for measurement of interwell-scale heterogeneities. Downhole seismic surveys include approaches such as vertical seismic profiling (VSP), cross-well seismic reflection surveys, and cross-well transmission tomography. All of these downhole techniques can benefit from research discussed previously aimed at extraction of rock and fluid properties.

A vertical seismic profiling run with source and receivers in a single borehole has good potential for illuminating heterogeneities at the interwell scale with a resolution not attainable by surface surveys or by traditional VSP surveys with the source located on the surface. Order of magnitude higher frequencies are attainable (Paulsson 1991). Surveys with source and receivers in the borehole do not have the depth limitations of traditional VSP surveys. VSP is also a good method for calibration of well and seismic data, probably much better than calibrations attempted from sonic logs alone. Methodology development for routine design and use of these approaches in characterizing interwell heterogeneities is a definite need.

Cross-well reflection surveys with source and receivers located in the subsurface in different boreholes share the same advantages as downhole VSP techniques over surface surveys (Paulsson 1991). Such surveys have a definite interwell-scale advantage over downhole VSP techniques and can complement or supplement downhole VSP and surface seismic in characterizing the interwell region. Again, practical methodology development is a primary research need.

Cross-well transmission seismic tomography involves use of P-wave first arrivals to compute images from the spatial distribution of seismic velocities that are influenced in turn, by reservoir heterogeneity. Heterogeneities in lithology, porosity, structure, and fluid content are candidates for imaging by this technique (Jackson and Tomutsa 1991).

One of the major constraints of applying cross-well tomographic methods is the requirement for boreholes to extend below the interval to be imaged a distance roughly equal to the spacing between wells. Progress in relieving this constraint would make the techniques more valuable in many older reservoirs where wellbores do not extend below the producing interval. The spatial resolution of the technique needs significant (order of magnitude) improvement for use as a stratigraphic tool in reservoir characterization.

Because seismic data can be obtained from every location within a reservoir, attempts to link seismic response with other reservoir parameters measured only at wellbores have been numerous. Geostatistical techniques of various kinds have been proposed and attempted; they include: kriging and regression analysis, kriging with external drift, cokriging, and cokriging with the Markov-Bayes indicator formalism. In their evaluation of the above techniques, Araktingi et al. (1993) found that the products of these integrations showed features not evident from well data alone, but none of the above techniques provided entirely satisfactory results. Much research yet needs to be done on the statistical and mathematical integration of data at different scales.

5.1.2.2 RD&D Needs in Reservoir Characterization Methodology

Discussions in the sections below briefly address research needs associated with specific reservoir characterization steps or tasks and needs in the more general sense related to development of approaches for reservoirs of different types or reservoirs in different stages of development.

Specific Task-Related Needs

Database management systems are needed for reservoir characterization that allow storage, retrieval, and combination of information based on data gathered from different sources at different scales, and with varying degrees of uncertainty (Jackson and Tomutsa 1991). The need for further development of techniques for determining the degree of mutual support or conflict within such information is also required. Further development of methodologies for addressing effective transfer of information stored on finer or coarser scales to the scale of simulator gridblocks is another critical area for research (Jackson and Tomutsa 1991; Tomutsa et al. 1993).

Comprehensive Methodologies

Comprehensive reservoir characterization methodologies need to be developed and demonstrated for different reservoir types. A possible approach might be to develop methodologies for reservoirs in which heterogeneities are predominantly of the same depositional, diagenetic, or structural type. It would also be useful to develop methodologies for reservoirs at different stages of reservoir development. Methodologies for youthful reservoirs might focus on judicious selection of data types and amounts for long-term utility, the interplay of engineering and geoscience information in confirming features of the reservoir characterization model, or other aspects of an "idealized" reservoir characterization approach. Methodologies for older, mature reservoirs being considered for IOR could focus on making maximum use of existing data (e.g., "old E-logs" and production data) or identifying the most cost-effective ways to obtain or approximate critical reservoir information in cases where records have not been properly kept or have been lost.

Because the methodology of reservoir characterization is complex, multidisciplinary, and reiterative, and because the methodology is not widely practiced or understood throughout the industry, it is a prime candidate for technology transfer by a computer-based or expert system approach. Honarpour et al. (1989) describe a simple deterministic system developed to advise users how to properly collect geoscience and engineering data for building a reservoir characterization model. More complete coverage of the various facets of reservoir characterization methodologies by such tools would be helpful to operators seeking to define their reservoir characterization needs.

5.1.3 Improved Oil Recovery (IOR) Process-Related General RD&D Needs

Recent research on individual IOR processes is reviewed in detail in Appendix D. The next discussion reviews potential research areas that could result in increased recovery of oil from domestic reservoirs regardless of their depositionally-defined class assignment.

5.1.3.1 Infill Drilling

Infill drilling can be applied to improve recovery as a stand-alone process or in conjunction with other improved oil recovery processes. The key to the success of infill drilling is identifying the reservoir heterogeneities and complexities which limit recovery potential at current well spacing and understanding the relationship of these complexities to recovery at reduced well spacing. The research needs specific to infill drilling include the following:

- Development and demonstration of improved methods for assessing and predicting the recovery potential for infill drilling through definition of interwell continuity and sweep efficiency improvements which can be attained by infill drilling. The application of improved reservoir characterization methods for defining these improvements is a key research need which could impact the oil recovery potential for infill drilling.

- Development and demonstration of improved methods for predicting reservoir characteristics between existing wells using geostatistical methodologies. The prediction of porosity, permeability, and fluid saturations between known datapoints is a significant research need for defining reservoir continuity and sweep efficiency and for determining infill drilling potential.

5.1.3.2 Conformance Control Technologies

Research needs for gel polymer applications fall within process, modeling and simulation, environmental, and demonstration realms. Because gel polymer applications are economically viable at moderate oil prices and have the potential for extending reservoir economic life, these research needs are all considered near-term needs. The highest priority research needs are directed toward developing environmentally acceptable systems as alternatives to the conventional chromium redox system and reducing the uncertainty associated with gel polymer usage.

Process

System development work in gel polymer or conformance control applications takes two directions: (1) systems which are stable in higher temperature and salinity environments and (2) more environmentally acceptable systems. Because Class 5 reservoirs generally fall within the temperature and salinity guidelines of implemented technology, the primary system development focus, at least for Class 5 applications, should be toward developing alternative, environmentally acceptable systems. Ongoing research with organic crosslinking systems, surfactant-alcohol systems, and alternative precipitation systems appears on target with those needs.

Advances in several areas are needed to reduce the uncertainty associated with gel polymer applications. On the basic research end of the spectrum, an improved understanding of rheological properties is needed. Further mechanistic studies regarding gel placement and treatment design, involving both laboratory and simulation work, are important. Current research activity appears to address these needs.

Successful applications depend on reservoir problem definition, gel system selection, and treatment design. Field-oriented research addressing these needs will help reduce uncertainty and foster increased usage of gel polymer applications. Seright and Liang (1994) note the need for a better understanding of treatment sizing guidelines. Their work (Seright 1993) also noted (1) the gap between tracer need and tracer application and (2) the need for monitoring and evaluation approaches to more quickly evaluate the success or failure of injection-well treatments. Well-documented field applications are needed to address these issues.

Further guidelines regarding problem definition, candidate selection, matching gel systems to reservoir problems, treatment design, and performance prediction are needed to assist operators in developing optimum treatments. The problem definition, candidate selection, gel system selection, and treatment design processes are amenable to an expert or knowledge-based system approach, especially if the system incorporated statistical data on technical and economic success rates of different gel systems in different environments. Statistical data imply development of a well-documented database of field treatment results, a significant research need alone. For maximum utility, the knowledge-based system would need to be linked to a permeability modification simulator to provide predictive capacity. A comprehensive written report documenting information in the above areas would represent a logical precursor to development of an expert system.

Modeling and Simulation

The publicly available, PC-based permeability modification simulator developed by NIPER (see Appendix E, Section E.1.4) has proven to be a valuable tool for mechanistic studies of gel permeability applications. Although some validation of model predictions with field data has been performed, additional validation under a variety of application environments is needed. Maximum utility of the simulator will come as it is linked with a treatment database and knowledge-based system.

Environmental

Seright and Liang's survey (1994) of operators indicated that over 50% of gel treatments used polyacrylamides, with most treatments using the chromium (VI) redox process. Considering the high usage level and environmental problems associated with this process, a strong driving force exists for developing alternative conformance control systems. Current research is focusing on systems using organic crosslinkers, surfactant-alcohol systems relying on chromatographic separation, thermal- and alcohol-initiated precipitation systems, and brine- or pH-initiated gels. Considering the strength of the driving force, research on these several fronts should be continued.

Demonstration

Field demonstration projects serve to validate new or improved technologies, and, as such, are important for reducing uncertainty and changing operator perceptions. Field demonstration, an important final step in the development process, optimizes development, builds confidence levels, and fosters increased application. The following technology concepts would benefit from field demonstration:

- Tracer applications to assist in problem definition and treatment sizing
- Sizing guidelines for field applications addressing different reservoir problems

- Monitoring and evaluation approaches for injection-well treatments to more quickly discern success or failure of injection well treatments
- Knowledge-based system (if developed) for problem definition, gel system selection, treatment design, and performance prediction
- Improved gel systems or alternative conformance control technologies as they become ready for field application

Although gel polymer and conformance control technologies are proven, more widespread application and improved success rates in field applications depend on additional research, field demonstration, and effective technology transfer.

5.1.3.3 Polymers for Mobility Control

In a 1991 study, NIPER and K&A (1991) listed four near-term research needs for polymer flooding:

- Improved injection protocols
- Improved polymers with better injectivity, higher salinity and temperature limits, and better propagation
- Better knowledge of factors affecting injectivity and propagation
- Environmentally acceptable biocides

Technology thrusts addressing these needs are described in Appendix D, Section D.3. For Class 5 reservoirs, many of which are in a very mature stage of production, research associated with improved injection protocols, polymer propagation, and polymer injectivity should have the highest priority. Additional effort is needed to improve the TORIS polymer predictive model so that more reliable estimates of potential oil recovery from polymer floods can be made.

5.1.3.4 Microbial Processes

According to Bryant (1993), MEOR technology research needs exist in the following areas:

- Improving the predictability of MEOR technology, by integrating laboratory and field data, and performing appropriate modeling and simulation work
- Obtaining microbially enhanced field data in reservoirs with higher remaining oil saturations, i.e., don't just test MEOR processes in reservoirs that are in the advanced secondary stage.
- Developing more cost-effective nutrients
- Selecting or adapting microorganisms for harsher temperature and salinity environments

5.1.3.5 Alkaline and Alkaline-Surfactant-Polymer (ASP) Processes

Research needs related to the alkaline and ASP processes are listed below:

- Develop an improved understanding of injection strategy, specifically addressing the issue of polymer and alkali-surfactant interactions
- Develop a database of fluid and reservoir data required for screening reservoirs for the ASP process (mineral content, oil characteristics, brine characteristics, CO_2 content, cation exchange capacity, etc.)
- Conduct well-documented field tests of the ASP process in less heterogeneous reservoir classes
- Continue surfactant and mixed surfactant research striving to reduce the costs of effective surfactant systems

5.1.3.6 Surfactant Processes

In 1993 DOE sponsored a chemical EOR workshop for the purpose of assessing chemical EOR research needs (NIPER/DOE 1993). Identified research needs specific to surfactants include:

- Additional evaluation of large slug, low concentration processes (like low-tension polymer floods) which aid economics by reducing front-end chemical costs
- Further investigation of horizontal well applications to lower front-end cost loading or target reservoir sections having higher oil saturations (Taber 1993)
- Increased investigation of combination processes (like the ASP process, gel polymer and surfactants), preferably combinations which exhibit synergism
- Investigation of foam mobility control in addition to polymer mobility control
- Further development of PC-based chemical simulators, including horizontal well models
- Investigation of chemical flooding applications in fractured reservoirs

The continued research need for improved chemical systems underlies the above specific research items. To some extent, ongoing research is constrained by limited supplies of new chemical formulations as chemical manufacturers divert their efforts to other more profitable arenas. Chemical supply becomes even more critical for potential field applications.

5.1.3.7 Steam Processes

Many technological advances are needed in the future to extend the application of steamflood technology to difficult reservoir settings and to improve process efficiency. Additional understanding of basic reservoir properties and geology, refinement of data gathering

instruments, improved heat management practices, improved mobility control techniques, and performance prediction techniques must be developed if the large amount of additional domestic resources are to be recovered economically. Selected research needs include:

- Improved methods for measuring and controlling steam quality
- Improved methods for splitting steam uniformly at pipe branches
- Improved steam injection profiling and control methods
- Better techniques for heat management and steam generation
- Improved subsurface equipment and completion techniques
- Improvement in horizontal well completion and sand control techniques for the high-temperature environment
- Cost-effective methods to deplete bypassed zones
- Development of thermal techniques to recover heavy oil from environmentally sensitive areas

5.1.3.8 In Situ Combustion Processes

In situ combustion has many attractive features and, from the energy utilization point of view, is the most efficient of all thermal methods. The process is equally applicable to thin and thick reservoirs as well as to deep formations containing very light oil. In situ combustion is the only EOR process proved to be effective for recovering oil from reservoirs underlain by water (Horne et al. 1982). The performance of in situ combustion, however, is reservoir-specific, and the operating conditions must be tailored to the reservoir under consideration (Moore et al. 1988).

While considerable progress has been made in understanding the kinetics of in situ combustion and the mechanisms that lead to combustion failure, further research is needed to understand the interrelationship between the kinetics of thermal cracking and low temperature oxidation reactions. According to Farouq Ali (1994), a concerted research effort is needed in the following areas:

- Definition of the effects that reservoir heterogeneities (geology, mineralogy, rock parameters) have on air and fluid flow in the reservoir and their effect on process performance
- Development of reliable numerical simulators that take into consideration both reaction kinetics and complex geological features of the reservoir

It is well known that in situ combustion projects are plagued with operational problems, and technological advances are needed to overcome these problems. Miller (1994) lists the following as the primary in situ combustion operation problems:

- Explosion hazards

- Injection well failures
- Inadequate compression volume
- Poor sweep efficiency with high volume inert gas production
- Corrosion in high GOR wells
- Flue gas disposition with hydrogen sulfide content
- Poor compressor design leading to low efficiency and frequent failure

While progress has been made in recent years to mitigate some of those problems, the solutions are far from satisfactory.

5.1.3.9 Carbon Dioxide (CO_2) Processes

Chung (1993) summarized the state of the art and listed research needs for CO_2 processes. These research needs are primarily related to mobility control or improved understanding of phase behavior and the displacement process. Combination applications with horizontal well technologies also represent a research need. Specific mobility control needs are for improved channel-block methods, improved understanding of foams, and other novel permeability modification methods. Mobility control and combination horizontal well applications represent the greatest research needs. Well selection and application guidelines need additional development.

5.1.4 General Reservoir Simulation Research Needs

Reservoir simulation commonly plays a critical part in reservoir management and reservoir characterization. Simulation is often used to verify a reservoir characterization model by using the model to predict the reservoir pressure, production, and/or injection performance history. Once verified, the reservoir characterization model can be used as a basis for further simulation of future reservoir performance. Details of the iterative use of simulation in refinement and predictive application of reservoir characterization models are presented in the Class 4 Department of Energy report: *Research Needs for Strandplain/Barrier Island Reservoirs in the United States* (Cole et al. 1994). A summary of current simulator capabilities and public versus commercial availability of reservoir simulators is enclosed as Appendix E of this report.

Research needs for improved reservoir simulation capabilities mainly relate to improving the cost-effectiveness and availability of reservoir simulators for predicting the performance of improved recovery processes. The industry as a whole has exploited the advancing capabilities of desktop and mainframe computer systems to develop simulators that are more user-friendly, more accurately predict recovery process performance, and more effectively display simulator output. However, these simulators are not available to many operators due to the cost of purchasing the simulators, the cost of contracting simulation services, or the lack of technical expertise.

The continued development of more accurate, cost-effective, and user-friendly publicly available simulators is probably the most significant research need for the industry. The IMPES method used by current publicly available simulators has limitations in modeling certain reservoir conditions (i.e., coning, near bubble-point conditions, steep concentration gradients). The accuracy of publicly available simulators would benefit from the development of fully implicit models. If accurate, cost-effective, and user-friendly simulators can be made readily available to the industry, many operators would utilize these tools to design or evaluate improved recovery processes. A system should be developed to allow less sophisticated operators access to technical experts who can provide guidance for the development of input datasets, the operation of the simulators, and the interpretation of results. These objectives could be met through DOE funding support to the Petroleum Technology Transfer Council, NIPER, universities, and other research institutions.

5.1.5 Wellbore and Facilities RD&D Needs

The demonstration of improved technologies for reducing the costs of drilling, completing, recompleting, and stimulating wells and operating production and injection facilities is a significant research need for extending the economic life of producing fields and improving the recovery of oil. The industry as a whole has always focused on developing ways to reduce development and operating costs and to improve production, but often the transfer of these technologies does not effectively occur, so that many operators are unaware of the benefits of implementing these technologies. This is especially the case with the smaller operators and independent operators who tend to lack the technical expertise to define and implement newer methods. This section describes some of the areas where the demonstration of improved technologies would benefit the operators of Class 5 reservoirs and the industry as a whole. This chapter does not assume to define the state-of-the-art in all areas related to drilling and production operations. Rather, this section presents some of the more obvious technologies which operators could focus on to improve recovery operations.

5.1.5.1 Drilling Technology

Drilling techniques have improved significantly since the days of cable tool rigs, with significant improvements in drilling systems and procedures, particularly the advent and improvement of directional and horizontal drilling methods and the development of innovative drilling measurement systems. The demonstration and transfer of these technologies could benefit the industry through reducing the costs of drilling, completing, and operating.

Improved Drilling Systems

The industry has developed many innovative systems for reducing the cost of drilling wells and improving the integrity of wells before and after completion. Improved drill bits have been developed by the industry to increase penetration rates through various formations and to

facilitate the transport and removal of drill cuttings. For example, the development of polycrystalline diamond (PCD) bits has greatly improved drilling efficiency in certain formations and could, through further development, improve penetration rates and drilling efficiency by as much as four times in certain vertical well applications (Joshi 1991). The development of improved tubular goods for drilling and completion in harsh environments could also reduce drilling costs through reduction of failures and long-term well costs through reducing corrosion problems. The continued development of slimhole drilling methods can also reduce drilling costs through the use of smaller hole size. The development of effective coiled tubing drilling systems will allow dramatic reductions in drilling costs through the reduction of rig time for vertical, deviated, and horizontal wells (Schuh and Joshi 1991). Advanced mud systems continue to be developed to improve drilling hydraulics and cuttings transport and to reduce formation damage in sensitive formations. More importantly, in these times of increasingly stringent regulatory requirements, the development of environmentally safe drilling systems is paramount, especially for use in environmentally sensitive areas such as wetlands and offshore.

Directional Drilling Methods

Improvements in directional drilling methods provide the benefits of increased accuracy in the placement of deviated wellbores and the capability to drill extensions or laterals from existing wellbores to improve recovery. Advancements in steering tools, downhole assemblies, and drilling methodologies have improved directional drilling capabilities to the point where resolution is well within 20 feet of the target (Joshi 1991). Drilling costs are reduced as accuracy and equipment are improved since fewer steering runs are required for course correction and since longevity of the downhole assemblies and steering tools is extended. The further development of capabilities to cost-effectively drill ultrashort to long radius extensions from existing wells could provide cost reduction for placing new, clean wellbores in desired locations instead of drilling new wells. Ultrashort radius extensions (up to 200 feet), short radius extensions (100–450 feet), medium radius extensions (500–3,000 feet), and long radius extensions from existing wellbores have applications in primary, secondary, and enhanced oil recovery projects for the improvement of ultimate recovery.

Horizontal Drilling Methods

Horizontal drilling and completion technologies have advanced rapidly in the last decade, which has resulted in the expanded application of horizontal wells, improvements in well productivity, and the reduction of costs associated with drilling and completing horizontal wells. The demonstration of improved methods for designing, drilling, evaluating, and completing horizontal wells will help to further reduce costs and expand applicability of horizontal wells. Horizontal wells have been successfully employed in the following applications: (1) naturally fractured reservoirs to intersect fracture systems, (2) thin or low permeability reservoirs to increase area to flow, (3) gas storage reservoirs to meet peak deliverability demands, (4) more

permeable reservoirs to solve gas or water coning problems, and (5) as injection or production wells in waterfloods and EOR projects to increase injection rates or to improve sweep efficiency (Mutalik and Joshi 1993; Coffin 1993; and Taber and Seright 1992). Although horizontal wells are more expensive than vertical wells, the productivity increases and recovery improvements typically more than justify the increased expenditures (JPT 1993). Horizontal drilling costs have fallen as innovative methodologies have been developed and applied, and as operators gain experience in drilling in particular fields.

The constraints that affect the successful application of horizontal wells relate primarily to reservoir characterization, completion technologies, and cost implications. Understanding the factors which impact horizontal well productivity and the proper characterization of target reservoirs has a significant impact on the success of horizontal wells. Significant factors which impact horizontal well productivity include reservoir thickness, reservoir heterogeneities, and permeability anisotropies, all of which impact the length and location of the lateral section of horizontal wells (Crouse 1992). Improvements in the understanding of these factors and methods of characterizing target formations could increase the applicability and productivity of horizontal wells. Productivity could also be improved through the development of improved methods for completing, stimulating, and working over horizontal wells, and the development of a better understanding of the formation damage mechanisms in horizontal wells. The reduction of horizontal drilling and completion costs could also increase the applicability of horizontal wells. The effective transfer of improved horizontal well technologies as the industry moves up the learning curve is a significant factor in continued cost reductions.

Drilling Measurement Systems

The capability to obtain real time data as wells are drilled has advanced significantly in the last decade. Improvements in the reliability and accuracy of measurement while drilling (MWD) systems has significantly reduced drilling costs by reducing the number of trips that must be made to remove the drillstring and obtain data. Further advancements in pulsed mud, acoustic, and "look ahead" systems could further improve drilling efficiency and supply more reliable formation data. Significant drilling cost savings can also be realized through improvements in the capability to more accurately steer the drillstring during directional drilling, reducing the number of check shot runs and directional correction maneuvers required for a well. The capability to accurately analyze formation fluids and test formation flow rates and pressures with drillstem tests more cost-effectively and reliably could also improve drilling costs. Likewise, the reliability and accuracy of coring and open-hole logging techniques coupled with drill systems could improve overall drilling costs, since logging equipment failures continue to be a significant source of lost rig time. Many drilling measurement system advancements are being made by the oil companies and service sector alike, but the demonstration of some of the more innovative cost-saving methodologies and equipment could help to expand the applicability and utilization of these technologies. Benefits to the industry at large include drilling cost savings, prevention of formation damage or loss in well productivity or injectivity, and improvements in formation data accuracy.

5.1.5.2 Well Completion and Recompletion Technology

The industry can benefit from the development and demonstration of improved, cost-effective methods for completion, recompletion, workover, and stimulation of wells. Often the expense of such operations prevents operators from implementing projects that could significantly improve recovery and extend field life. Many operators have developed improved methods for the completion, recompletion, workover, and stimulation of wells, but the transfer of these methods to other operators is often not achieved.

Completion Methods

The development and demonstration of innovative completion methods continues to be an area where advancements in design and procedures can yield cost savings, improvements in well productivity and longevity, and improved recovery of oil. Specific areas where improvements can be of the most benefit are tubular and cementing systems, perforation systems, sand control, and corrosion control. The advent of slimhole drilling systems allows cost reduction through the use of smaller tubing strings, while improved tubulars can increase the longevity of wells in harsh environments. The advancement of casing and liner cementing systems can improve cement bond to prevent the behind-pipe migration of produced or injected fluids and eliminate the need for block squeezing. The optimization of perforation systems can improve completion efficiency by reducing formation damage and increasing injectivity or productivity. The industry has continued to improve perforation gun design and efficiency to ensure that optimum perforations are placed in desired locations in wellbores. The development of underbalanced completion methods helps to prevent formation damage and improve perforation cleanup. Improved completion fluids can also reduce the likelihood of formation damage. Finally, design and optimization of corrosion control and chemical programs can ensure quality completions for the life of projects.

Recompletion and Workover Methods

The development of improved or innovative recompletion and workover techniques can improve project economics and optimize recovery. Recompletion programs are often required for injectors and producers to enhance the performance of improved recovery processes. Project performance can be enhanced from both the recovery and economic standpoints through the development and demonstration of improved methods for the isolation of thief zones, the plugging of high water production zones, and increased injection into unswept zones. (Specific research needs for conformance control technologies are outlined in Section 5.1.3.2). Workover programs are often required in older fields to repair mechanical problems in wells. Cost-effective, low-risk workover methods for repairing casing and tubing leaks or correcting communication problems could provide benefits to many operators. Also important is the development of improved sand control methods.

Well Stimulation Methods

The development and demonstration of improved well stimulation methods to enhance well productivity can significantly benefit operators, especially in marginal production operations. The industry continues to develop innovative methods for hydraulic fracturing, matrix stimulation, and wellbore cleanup. The development of improved fracturing systems and methodologies, computer programs for design optimization, and quality control instrumentation and procedures can reduce hydraulic fracturing costs and help to optimize fracture placement to improve well injectivity or productivity. Matrix stimulation techniques, such as acidizing and acid fracturing, continue to be employed by the industry to improve well productivity and injectivity. Innovative, reservoir-specific acidizing methodologies could reduce the cost and frequency of acid jobs and improve poststimulation performance. The industry could also benefit from the demonstration of reduced-cost wellbore cleanup methods for removing scale, asphaltenes, paraffin build-up, or for correcting other near-wellbore problems that limit productivity or injectivity. Well testing techniques and pressure transient analysis software are important tools for diagnosing problem wells and optimizing treatments.

Production and Injection Facilities

Surface facility limitations and problems often result in lost production, reduced well productivity, and environmental problems. Many facility problems result from the use of outdated or nonfunctional equipment, improper facility design, and poor operator practices. The implementation of improved methods of operation and the modification of surface facilities can often result in immediate cost savings and extend the life of fields. For instance, simple operational modifications can often result in significant power savings, which is typically a dominant component of operating costs (Pellegrino and Scott 1989). The demonstration of improved systems and operating procedures for fluid separation and treatment, distribution and gathering, and artificial lift could encourage many operators to implement cost-saving practices.

Separation and Treatment Facilities

The proper design and operation of surface separation and treatment facilities are becoming increasingly important to operators as production from many fields approaches the economic limit and, more importantly, as more stringent regulatory restrictions are implemented. Separation equipment optimization efforts to improve the separation of produced oil, water, and gas can often result in cost savings (e.g., water treatment) and can even result in well productivity increases through optimization of system pressures. Gas recovery systems can be improved to reduce emissions and to increase gas supply for on-site use. One of the most significant operating costs in many fields is for water treatment and disposal, so improved systems for cleaning up produced water and innovative disposal methodologies have wide applicability. Also, demonstration of systems to improve injection water quality could help to increase waterflood recovery in many fields. Since water treatment and injection costs account

for a significant portion of typical operating costs, it is important to demonstrate methods for attaining an economic balance between the increased recovery resulting from improved water quality and the costs required to achieve the desired level of water quality.

Distribution and Gathering Systems

The improvement or modification of production gathering systems and injection distribution systems can also afford operators significant cost savings and improve recovery. The gathering systems in many fields were designed for full field operations, and as economic limits are approached, the systems are often inefficient. Many gathering systems are beyond design life and are poorly maintained, so operators are at risk from an environmental standpoint. Unfortunately, most operators cannot afford to replace gathering systems, so development of innovative ways to modify these systems could be of benefit. Cost reductions on the production and gathering side can also be achieved through the use of automatic well test systems and well pump-off controllers. Improvements in injection distribution systems can also improve operating costs and recovery. Many water injection systems are simply turned around gathering systems, which often leads to the injection of the debris which has accumulated on the inside of the old flow lines or bacterial growth in the injection water. These can result in excessive pumping costs and in the plugging of injection wells, which necessitates remedial action. The development of cost-effective injection systems and system treatment methods can significantly reduce operating costs. Injection system optimization in enhanced recovery projects is also important for extending the productive life of fields.

Artificial Lift Methods

Optimization of artificial lift methods is also important for reducing operating costs and extending field life. Improved methods for analyzing and optimizing beam pumping unit performance can result in immediate and significant cost reductions. Many fields utilize more expensive hydraulic pumping systems which can also be optimized through innovative methods to improve recovery and reduce costs. An example is the use of jet pumps to lift higher volumes of fluids in waterflood operations. High volume lift equipment (i.e., electric submersible pumps) can also be utilized in waterflood or improved recovery projects to improve recovery and lifting costs.

Field Operations and Reservoir Management

The critical components of proper reservoir management include: (1) the thorough analysis of field drilling, completion, recompletion, workover, and facilities operations, (2) the identification of problem areas and the subsequent selection of appropriate improved technologies and practices, and (3) the implementation of these technologies and practices in the field. The development and implementation of reservoir management strategies can result in significant reductions in operating costs and increases in production and reserves. The optimization of field

operations requires the integration of knowledge of the reservoir, geological, and production characteristics of the field, the history and status of wellbores, and the condition and operation of injection and production facilities. An interdisciplinary approach to field optimization is required, an approach which utilizes the expertise of drillers, reservoir engineers, geologists, production engineers, and field personnel to develop strategies for reducing costs, increasing production, and improving recovery. Field optimization should be a continuous process during the life of any field, but often operators do not have the knowledge, manpower, or financial resources required to undertake such efforts. The demonstration of the development and implementation of innovative field optimization strategies and the subsequent transfer of results to operators could have a significant and positive impact on the domestic oil industry.

5.2 Class 5—Specific RD&D Needs

This section identifies and summarizes the research, development, and demonstration needs that are specifically applicable to Class 5 reservoirs. Its structure somewhat parallels that of Section 5.1, but here an effort is made to incorporate the history and characteristics of Class 5 reservoirs (discussed in Chapters 2 and 3) and the results of the TORIS predictive analysis (Chapter 4) to focus research needs on specific Class 5 opportunities. Section 5.2.1 focuses on development of conceptual and stochastic reservoir characterization models, and Section 5.2.2 summarizes needs for better application of improved oil recovery processes that have been identified as having the best potential for improving recovery from Class 5 reservoirs.

5.2.1 Reservoir Characterization Model Development

The use of reservoir characterization models and general research needs in building them are briefly reviewed in Section 5.1.2.1. A more detailed discussion of reservoir characterization modeling may be found in the 1994 Class 4 Department of Energy report: *Research Needs for Strandplain/Barrier Island Reservoirs in the United States* (Cole et al. 1994). Specific Class 5 needs for reservoir characterization modeling are related to creation of conceptual models (Section 5.2.1.1) and stochastic models (Section 5.2.1.2).

5.2.1.1 Conceptual Models

Conceptual modeling needs for Class 5 revolve around each of the four naturally occurring sources of reservoir heterogeneity: depositional origin, diagenetic history, tectonic history, and variations in fluid content. In the sections following, RD&D needs for modeling each of these sources of heterogeneity will be discussed.

Depositional Sources of Heterogeneity

Class 5 reservoirs, because of their association with depositional processes whose energy levels vary greatly in magnitude with time, are characteristically highly heterogeneous. The predominance of heterogeneities associated with depositional origin over those of other origin is shown in Chapter 3, Figure 3–41 for TORIS Class 5 reservoirs. A large number of Class 5 reservoirs, regardless of their end member depositional type, have experienced severe pressure decline problems from early in their development. These problems, probably arising from depositional isolation of the reservoirs from more extensive permeable units by overbank fines, if solved or at least made more predictable by stratigraphic and sedimentological models, could lead to more efficient development of both new and existing Class 5 resources.

Major fluvial/alluvial depositional system types (i.e., alluvial fans, braided streams, meandering streams) have characteristically different external geometries and different degrees and types of internal depositional heterogeneities. Work is needed to better define simple observations that can be made on limited and readily available or easily obtainable subsurface data that will allow rapid and accurate identification of system type.

Detailed studies of individual end member fluvial/alluvial system types in the subsurface, in outcrop, and in modern environments will result in better models for predicting external geometries and the magnitude and distribution of internal heterogeneities. Models that will aid in predicting the volume and distribution of fines (both overbank and within channels) will best address this goal. Detailed models may also increase the predictability of high permeability streaks or thief zones, a universal concern in advanced secondary and enhanced recovery operations in Class 5 reservoirs.

In parallel, further studies of valley-fill deposits (see Chapter 2, Section 2.5) are also needed. The goal should be to develop better predictive capabilities concerning (1) when to expect valley fills to be of the fluvial/alluvial type, (2) what end member fluvial/alluvial system type or types to expect, and (3) the different heterogeneity types and distributions that are characteristic of fluvial/alluvial deposits in valley-fill situations.

Diagenetic Sources of Heterogeneity

Fluvial/alluvial reservoirs, as a result of their nonmarine depositional origin, have potential for similarities in early burial stage diagenetic influences. Studies of ancient and modern fluvial/alluvial deposits may yield predictive links between end member fluvial/alluvial system types, depositional mineralogy, and resulting early diagenetic events and products. A number of diagenetic scenarios, each linked to particular depositional system types and to particular climatic conditions, may have to be developed. Sediments of many alluvial fan and braided stream deposits, particularly those formed under semi-arid to arid conditions, may be exposed to strongly oxidizing conditions resulting in reddish coloration of sediments from iron compounds in the oxidized state. Other deposits associated with humid conditions may be exposed in early burial to reducing conditions associated with percolating waters derived from

floodplain swamps or other overbank environments. Development of such models of early diagenetic change for fluvial/alluvial deposits may aid in identifying the scale and distribution of additional heterogeneity types in addition to providing further criteria for recognition of fluvial/alluvial deposits.

Analog models of early diagenesis may have good transferability to the subsurface, but it is probable that later diagenetic events associated with different basin development histories will add their own influences. These later influences may in some instances mask or remove early diagenetic effects. Detailed analysis of later burial phase diagenetic sequences within individual Class 5 plays or basins could lead to complete diagenetic models for the class. These models could then be used in other Class 5 reservoirs in the same play or basin to predict diagenetic effects when limited subsurface data are available.

Tectonic/Structural Sources of Heterogeneity

Tectonic and/or structural models on the scale of plays or basins may help increase the predictability of reservoir, trap, and seal types, diagenetic sequences, reservoir fluid content, and the distribution of internal heterogeneities due to faulting, joints, and fractures. A special Class 5 need is in relating prevailing tectonic/structural conditions to prediction of overall deposit architecture (including end member fluvial/alluvial system types) as well as to prediction of internal facies architecture.

Fluid Content

Class 5 research needs in fluid content modeling can be met by careful comparison and analysis of existing reservoirs, both within and between plays and basins. It would be useful to know if hydrocarbon and/or brine composition varied in some predictable way between plays, between reservoirs in a play, or within individual reservoirs as a function of depositional, diagenetic, or structural heterogeneities. Observed differences in fluid composition should be related to basin and reservoir development. Differences in observed brine composition might be used as clues to (1) locating migration pathways and untapped hydrocarbon compartments, (2) improve interpretation of log signatures, and (3) evaluation of oil saturations based on salinity-resistivity relationships. Variations in water salinity have been used to identify barriers within a reservoir, and have been shown to greatly affect oil saturation calculations from wireline logs (Jackson et al. 1993).

5.2.1.2 Stochastic Models

Stochastic models attempt to express probability or expected variations in properties or features. Stochastic models, for the most part, are probabilistic expressions of conceptual or analog models, and their output represents or realizes the spatial distribution of either the qualitative (discrete) or quantitative (continuous) characteristics of the conceptual model. Stochastic modeling does not create new information, but expresses variability of existing information

derived from the source of the analog model. Most techniques can generate numerous realizations in map or cross-section form, which then can be evaluated by numerical simulation or other means to yield potential reservoir performance.

Stochastic models considering depositional, diagenetic, and tectonic and structural aspects built specifically for Class 5 reservoirs and based on analogous subsurface reservoirs, outcrops, and modern deposits may prove very useful for improved oil recovery (IOR) evaluation. Models could be discrete or continuous, or a combination of the two types. Detailed methodologies for constructing Class 5–specific models addressing commonly encountered heterogeneity types would be an important part of this research.

Equally relevant would be basin- or play-specific stochastic models. Such models would have more restricted application, i.e., within the same basin or play, but transferability of data to other reservoirs might be greater due to greater similarities in diagenetic and structural history.

5.2.2 Improved Oil Recovery (IOR) Process Development and Application

Past experience of Class 5 operators coupled with TORIS model predictions (see Chapter 4 and Appendix C) serve to identify several advanced secondary recovery (ASR) and enhanced oil recovery (EOR) processes that have good potential for recovering significant amounts of the remaining Class 5 reserve. Sections 5.2.2.1 through 5.2.2.5 present a summary of the more important processes identified by TORIS and past experience. The fact that a large majority of Class 5 reservoirs fall well within ASR and EOR screening criteria limits of temperature and salinity indicates that, on a reservoir by reservoir basis, other processes may be feasible to apply. This list, therefore, is presented as a guideline for how the greatest potential recoveries for Class 5 might be realized, not as a recipe for addressing Class 5 improved oil recovery.

5.2.2.1 Infill Drilling

The high degree of heterogeneity exhibited by Class 5 reservoirs on almost all scales makes infill drilling a natural choice for improved recovery. In fact, infill drilling has been employed with economic success in a wide variety of Class 5 reservoirs, including reservoirs in Alaska where drilling costs are high and reservoirs in California developed on less than 5-acre spacing. Infill techniques have included geologically targeted wells and the drilling of directional and horizontal wells, in addition to traditional pattern infill drilling of vertical wells. TORIS predictive models, however, indicate that in most cases future recovery from Class 5 reservoirs could be maximized by coupling infill drilling with other advanced secondary recovery (ASR) processes such as profile modification or polymer flooding.

5.2.2.2 Infill Drilling and Profile Modification

This ASR process was selected by the TORIS models as having good potential under both implemented and advanced technologies for Class 5 reservoirs in states other than Alaska and California (see Chapter 4, Section 4.3 and Figure 4–12 and Figure 4–13). In the advanced technology case in these reservoirs, the potential from infill drilling with profile modification exceeds that predicted for infill drilling combined with polymer flooding. Potential combinations with CO_2 or surfactant processes, which gain in importance at higher oil prices and advanced technology levels can also be foreseen.

5.2.2.3 Infill Drilling and Polymer Flooding

The greatest Class 5 potential for this process, according to TORIS model predictions could be realized in Alaska reservoirs under advanced technology and high oil price conditions. The technology also is predicted to have good potential in states other than Alaska and California, where recovery from this process may be roughly comparable to that achieved by infill drilling in combination with profile modification. Polymer flooding and gel polymer applications are often combined for mobility and conformance control in field projects.

5.2.2.4 Steam

Steam processes have a long history of successful application in the Class 5 heavy oil reservoirs of California, and the TORIS models predict their continued dominance as the most desirable recovery mechanism for those reservoirs under both implemented and advanced technologies at all oil prices (see Chapter 4, Section 4.3 and Figure 4–10 and Figure 4–11). In reservoirs in states other than Alaska and California, primarily in reservoirs along the Talco Fault Zone in the East Texas Basin, (see Chapter 3, Section 3.4.4.1), steam processes under advanced technologies are predicted to make a very substantial contribution (greater than all advanced secondary processes combined) at all oil prices (see Fig. 4–13).

5.2.2.5 In Situ Combustion

This process, tested with limited success in the early years of thermal recovery applications in California, has, according to TORIS model predictions, only limited potential for future application to Class 5 reservoirs in that state. The process, however, has higher potential under the advanced technology case than any other ASR or EOR process in heavy oil reservoirs in the East Texas Basin (see Chapter 4, Section 4.3 and Figure 4–13).

5.2.2.6 Other Processes

TORIS models predict that carbon dioxide (CO_2) miscible processes have some potential for improving recovery in Class 5 reservoirs in states other than Alaska and California. Additional recovery can be realized both under implemented and advanced technologies at oil prices of $20 per barrel and higher. TORIS estimates do not include potential recovery from cyclic stimulation (huff 'n' puff) or immiscible CO_2 floods. Miscible CO_2 floods have proven successful in several Class 5 reservoirs in the past, but lack of available local CO_2 sources and low oil prices have deterred widespread application of the technology.

When oil prices are moderate to high, TORIS models predict that surfactant processes will contribute significantly (under advanced technologies) to recovery from Class 5 reservoirs in all areas outside Alaska. Alkaline processes make a small contribution under nearly the same circumstances. Technology development efforts will benefit from synergism between alkaline-surfactant-polymer (ASP) and surfactant research. TORIS models do not currently consider advances associated with the ASP process. Considering the cost and performance advantages of the ASP process, future recovery potential from Class 5 reservoirs using alkaline techniques is probably underestimated.

5.3 Environmental Considerations

Operators face a plethora of environmental regulations. Public perceptions of the oil industry are bolstered by major events such as the Valdez oil spill. Although perceptions may be inaccurate, operators face increased scrutiny from both regulators and the public. Rather than discussing specific environmental regulations, this section discusses environmental issues at the conceptual level. Readers refer to Appendix F or original legislation for information regarding specific regulations. Where possible, discussion is focused on the Class 5 resource.

A prior NIPER study (Crocker et al. 1991) focused on specific environmental RD&D needs associated with oil and gas production. The majority of identified needs were associated with drilling and injection operations. The following analysis discusses these and other issues associated with future IOR operations within the context of four subject groupings: (1) project and well development issues, (2) project operational issues, (3) improved oil recovery (IOR) process-specific issues, and (4) general industry environmental trends.

5.3.1 Project and Well Development Issues

In implementing an IOR project in mature fields, an operator must be cognizant of the environmental aspects of past activities on the lease and of the effects of previously abandoned and shut-in wells on future IOR operations. Since most IOR projects will involve drilling new or replacement wells, drilling environmental concerns must also be considered.

5.3.1.1 Environmental Risk Assessment

The Comprehensive Environmental Response Compensation and Liability Act of 1980 (CERCLA) assigns responsibility for clean-up of hazardous substances to owners and operators of a facility or property. Both current and past owners can be liable, regardless of whether the party was directly involved in the polluting activity. Environmental risk assessments establish baseline data for a given lease. This baseline data is important for measuring the environmental impacts of IOR operations and for "due diligence" liability protection (McNeill et al. 1993). In contemplating a future IOR project, an operator must assess environmental risk exposure and the potential effects of that risk exposure on the overall company (Wright 1994). Demonstration of actions that limit environmental risk exposure, thus increasing IOR project potential, continues to be a research need.

5.3.1.2 Previously Abandoned Wells

Previously abandoned wells present potential communication problems. Because of these communication problems, the potential exists for contaminating surface or freshwater zones. Besides being an environmental liability, communication problems can impair sweep efficiency and result in loss of costly injection fluids. In mature fields abandoned wells may require rework. Cost-effective procedures for identifying, testing, and reworking previously abandoned wells need further demonstration.

5.3.1.3 Shut-in Wells

Because of declining production and poor economics, many existing wells may be shut in or temporarily abandoned. Industry studies indicate that, if these wells are permanently abandoned within the next few years, the economics of reentry or redrilling may preclude future IOR projects. Although regulatory agencies have made efforts to spell out temporary abandonment terms, conditions, and procedures (Smith et al. 1993), the industry trend is still towards shortening the time period between well shut-in and permanent plug and abandonment.

Casing salvage practices associated with conventional plugging practices usually preclude future reentry. Haynes (1994) outlines how revised procedures leaving the casing in the hole could still satisfy environmental concerns while preserving the option of well reentry. Development of low-cost, environmentally acceptable abandonment procedures which preserve future access is a critical research need. Gaining regulatory agency *acceptance* is a crucial aspect of research in this area.

5.3.1.4 Drilling

According to the TORIS estimate, infill drilling, alone or in combination with polymer or profile modification techniques, has the most future potential for Class 5 reservoirs (see Chapter 4, Section 4.2). New projects in mature Class 5 reservoirs may also involve significant redrilling. Drilling-related wastes represent about 2% of the U.S. exploration and production waste (Thurber 1992). Drilling wastes represent a small percentage of total wastes because produced water is considered part of the waste stream. Although a small percentage, drilling waste is quite visible and can contain multiple hazardous materials. Drilling practices exert a major influence on both the hazard and volume of drilling waste. Considering the importance of drilling to future Class 5 potential, drilling practices will heavily influence development costs and potential environmental liabilities of future IOR projects.

Thurber (1992) subdivided drilling waste management practices into four areas: (1) selecting lower-toxicity drilling additives, (2) using high-performance, drilled-solids-removal equipment, (3) proper arrangement of equipment, and (4) proper wellsite water management. Multiple managed reserve pit systems process waste as it is generated and isolate wastes of differing degrees of contamination (Ballantine 1993). Annular reinjection methods can be utilized to dispose of solid wastes as a slurry in appropriate subsurface formations (Andersen and Witt 1993). Dry drilling locations can be achieved by integrating mud engineering, solids control, and dewatering technologies to minimize volume and reduce whole mud cost (Wojtanowicz 1993a). Considering waste disposal costs, reduced-waste drilling practices may be less costly as well as more environmentally acceptable. According to Thurber (1992), closed-loop mud systems are justified when drilling fluid, drilling fluid dilution, and fluid-disposal costs exceed about $6 to $10 per barrel.

Well design and drilling equipment also affect waste minimization. The type of drilling fluid can affect solids volumes (Bieler et al. 1993). In general, the more quickly a well is drilled, the less the environmental impact. Well designs which downsize wellbore sections decrease waste volumes. Slimhole drilling technologies can reduce drilling time and drilling fluid and solids volumes. Slimhole wells, however, may not meet Class II injection well requirements (see Section 5.3.2.3). Future conversion to injection should be considered in drilling any new well in a new IOR project.

By using a systems approach, industry has improved drillsite management practices. Yet, optimized drillsite management practices are not routinely applied. Technology transfer through demonstration of optimum practices tailored to given geographic regions and reservoirs is needed to realize the Class 5 drilling-related potential.

5.3.1.5 Remedial Workovers and Stimulation Treatments

IOR projects often require remedial workovers in existing wells. Stimulation treatments are required in new wells, and many existing wells are restimulated. The chemicals and materials used in workovers and stimulation treatments require safe handling procedures prior to and

during treatments. Excess or spent treating fluids may require special disposal. In disposal, care must be taken to prevent contaminating a larger volume of fluids.

5.3.2 Project Operational Issues

Changes inherent to IOR projects cause certain operational activities to increase, and increased activity creates some environmental issues. Areas where environmental concerns may arise include: (1) production chemical usage, (2) radioactive tracers, (3) Class II injection wells, (4) leak and spill prevention, and (5) naturally occurring radioactive material (NORM) contamination.

5.3.2.1 Production Chemical Usage

Increased fluid volumes associated with IOR injection projects generally cause increased usage of production chemicals. Production chemicals include corrosion inhibitors, scale inhibitors and scale removal chemicals, biocides, demulsifiers, defoamers, etc. Issues to be addressed include chemical handling procedures, disposal of excess chemical when treating chemicals are changed, drum or container disposal, and toxicity of the oil, water, and solids where portions of the chemicals end up. Just like with drilling, Caudle and Bansal (1993) recommend a systems approach where design either reduces, optimizes, or eliminates chemical usage. Demonstration of the interaction between system design and chemical usage and of cost-effective, comprehensive compliance programs represents a research need.

5.3.2.2 Radioactive Tracers

Radioactive tracers in inter-well tracer studies, injection profile surveys, and completion (both fluid- and solid-tagging) fluids are important tools for reservoir management. As regulatory requirements have increased, radioactive tracer services have become a contract service offered by wireline companies or specialized vendors. Of the different applications, the common injection profile survey using ^{131}iodine represents one of the more hazardous applications (Abernathy et al. 1994). Safe operations require a joint effort between the tracer service contractor, the pumping service operator, the wireline contractor, and the well operator. Postjob monitoring and procedures are an important aspect of radioactive tracer applications (Abernathy et al. 1994).

Although injection profile surveys using radioactive tracers are widely accepted by industry, environmental concerns with attendant costs are renewing interest in alternative injection profile methods, such as the differential temperature survey. Development and demonstration of nonradioactive injection profile techniques represent a research need for IOR processes.

Although interwell radioactive tracers, when properly applied, are not as hazardous as radioactive injection profile surveys (Abernathy et al. 1994), environmental concerns are still directing applications towards nonradioactive tracers. Brookhaven National Laboratory is

researching perfluorocarbon tracer technologies for IOR applications (ACTI 1994). Vapor phase tracers have been developed, and research is continuing on aqueous phase tracers. Other inorganic chemicals like nitrate are also commonly used for interwell tracer studies.

5.3.2.3 Class II Injection Wells

Injection wells in waterflooding and IOR operations are classified as Class II injection wells, and, as such, are subject to mechanical integrity tests (MITs). Mechanical integrity means both the absence of leaks in the tubing (internal mechanical integrity) and the absence of flow from the injection zone through channels in the cement (external mechanical integrity). External mechanical integrity is normally demonstrated initially through cementing records (Browning and Smith 1993). Wireline logging techniques are available for evaluating channeling or fluid flow beyond casing (Crocker et al. 1991). Internal mechanical integrity testing can be performed by a variety of methods. Required frequency of mechanical integrity testing depends on the layers of protection provided by well design and whether the injection well is a new or existing well. EPA has proposed more stringent standards for newly drilled or converted Class II injection wells which could affect development and operating costs (Worrell 1994; Smith and Browning 1993).

Recent studies indicate the magnitude of the MIT problem. Browning and Smith (1993) report failure rates of 3%–12% with actual rates known to be higher due to operator pretesting to ensure wells pass the MIT test. Browning and Smith concluded that nearly two-thirds of MIT failures are due to casing failures, with one-fifth of those casing failures allowing injection fluids outside the casing. A 1986 study by the Oklahoma Corporation Commission provided similar statistics (OCC 1986). In Browning and Smith's study, about one-fourth of those wells with casing failures were plugged within 60 days from the MIT test. Development and demonstration of cost-effective workover procedures for reestablishing mechanical integrity in injection wells represents a research need for IOR injection operations.

5.3.2.4 Leak/Spill Prevention

Increased fluid production and injection volumes, installation of injection systems, expansion of lease facilities, and overall increased lease activity provide increased opportunities for leaks and spills. Design, maintenance, and operations practices all influence the probability of leaks and spills occurring. Knowing that leaks and spills can occur, contingency plans must be in place, both for regulatory purposes and for safety and environmental considerations.

5.3.2.5 NORM Contamination

IOR projects frequently involve significant reworking of the production facilities. Tubular goods, flowlines, separators, and tanks are often upgraded or resized. Naturally occurring radioactive material (NORM), when present, often concentrates in scale or sludge in the equipment. The

presence of NORM contamination is considered a nonlinear event; that is, absence now does not mean NORM contamination will never be present (MacDowell and Gray 1993). Since scaling can increase with injection projects, the potential for NORM contamination increases in injection projects. NORM-contaminated materials require special handling procedures to reduce exposure. Decontamination may be required before equipment disposal. Decontamination processes, which can be either mechanical or chemical (Diyashev et al. 1994), are costly and present hazards themselves. Operators have a fiduciary and legal responsibility to establish an effective NORM management program (MacDowell and Gray 1993). Experience indicates that NORM can be managed (Smith 1987), but demonstration of cost-effective NORM monitoring and management programs represents a research need.

5.3.3 IOR Process-Specific Issues

Environmental issues vary depending on the nature of the IOR process. More important issues for the IOR processes discussed in Appendix D are included for conformance control systems, chemical floods, CO_2 processes, and thermal operations.

5.3.3.1 Conformance Control

Past and current conformance control applications rely heavily on gel polymer applications using the hazardous chromium redox system. Safety issues provide a strong driving force for developing alternative, less hazardous chemical systems. Continued research for alternative systems is critical to realizing the profile modification/infill drilling potential estimated by TORIS for Class 5 reservoirs.

5.3.3.2 Chemical Flooding

Storage and handling concerns must be addressed in any chemical flooding operation. Waste management practices (see Section 5.3.4.1) heavily influence the degree to which storage and handling become an environmental concern. Polymers for mobility control are a common element in chemical floods. Acrylamide polymers in particular are subject to bacterial degradation and usually require increased system treatment with biocides. Biocides by nature are hazardous chemicals. Continuing research for effective, but less hazardous, biocides is important. Significant advances could reduce the environmental costs associated with processes using polymers.

Polymers, surfactants, and alkaline agents may require special handling and storage requirements. From a human exposure standpoint, polymer and surfactant requirements are similar to those required for production chemicals. Alkaline agents used in the alkaline or alkaline-surfactant-polymer processes require additional handling precautions.

5.3.3.3 CO_2 Processes

The CO_2 processes pose a variety of environmental and safety hazards. CO_2 is a heavier-than-air gas which, if released to the environment in large quantities, can settle in low places endangering health. CO_2 is also a "greenhouse" gas which may, according to some opinions, contribute to global warming. Recycle operations involving gas compression and other processing equipment present air quality concerns. Produced gas from cyclic CO_2 stimulation treatments may become contaminated with CO_2 requiring separation and processing equipment or making flaring difficult. Corrosion problems associated with CO_2 operations may increase equipment failures causing increased spill and leak frequency. Demonstration of improved procedures for CO_2 operations are an important research need relevant to environmental issues.

5.3.3.4 Thermal Processes

Thermal IOR operations present both air and water quality concerns. Air-pollutant sources include steam generators, compressor exhaust gases with in situ combustion projects, and wellhead emissions. Site-preparation activities themselves can generate significant quantities of air pollutants (Sarathi 1991). Wellhead emissions associated in the past with steam operations can be controlled by casing-vapor-recovery systems (Peavy and Braun 1991). Air quality concerns represent the main environmental concern associated with thermal operations. In certain areas, fresh water is in short supply, and produced water disposal is difficult. Completion technologies must consider the thermal stresses encountered in steam and in situ combustion projects. Well failures can endanger fresh water zones.

5.3.4 General Industry Environmental Trends

In the environmental arena, general industry effort is focused in waste management practices and integrated engineering design. Waste management practices influence both the hazard and volume of wastes. Integrated engineering design affects the hazard, quantity, and disposal costs of wastes. Taken together, waste management and integrated engineering design influence cost. Field demonstration of environmentally responsible practices increases technology transfer and is valuable for image management.

5.3.4.1 Waste Management (Minimization) Practices

Waste management involves waste reduction, reuse (reclaim and reuse materials in their original form), recycling, treatment, and responsible disposal (Owens 1994). Waste minimization, both in quantity and hazard, are primary objectives. Although drillsite waste-reduction practices may be most visible, significant opportunities for waste minimization exist in routine operations. Source reduction is the optimum choice but reuse and recycling play a role. In recycling, care should be taken to determine if recycling is actually disposal which may be creating environmental

problems (i.e., burning for energy recovery). A waste management program requires management commitment in terms of dollars and staff time. Implementation costs include equipment, development of operating procedures, and staff training.

Source reduction techniques, the most important component of waste management, may involve: (1) product substitution, (2) inventory control, (3) reduced water use, (4) housekeeping and routine inspection, (5) equipment maintenance and repair, (6) in-process recycling, (7) preplanning, (8) segregation of wastes, (9) contractor selection, and (10) other innovations (Savage 1993). In addition to environmental benefits, the revised operating practices may improve efficiency and equipment life.

All operators practice waste management. However, demonstration of the economic benefits (and reduced liabilities) from comprehensive waste management programs represents a special research need for mature operations.

5.3.4.2 Integrated Engineering Design

Wojtanowicz (1993b) coined the term environmental control technology to refer to a preventive, design function in environmental management. The premise behind the approach is that when petroleum engineers and other industry professionals examine the environmental aspects of the processes, they can find ways to change the processes (including reservoir fluid production and injection) to minimize interactions between the oilfield and its environment. Although waste management is a part of environmental control technology, many other, more comprehensive concepts are included. The key strategy is to minimize the problem through engineering and design rather than dealing with the problem's aftermath.

5.3.4.3 Field Demonstration

Armstrong (1994) indicates that “sustainable development” is the environmental vision for the next century. Sustainable development means “development that meets the needs of the present without compromising the ability of future generations to meet their own needs.” To change perceptions that the oil industry is not compatible with sustainable development, companies have to demonstrate individual responsibility, be more active in a public relations and educational role, and reduce their own energy use and consumption (Armstrong 1994).

Industry practices and public perceptions of the oil industry change only through education and visible action. Field demonstrations incorporating sound environmental practices transfer technology to others in industry. Increased knowledge leads to usage, which results in improved industry credibility.

5.4 Summary of RD&D That Will Most Benefit Class 5

Even with contributions from large reservoirs developed by major oil companies over the last few decades in Alaska and California, production from Class 5 reservoirs in general is in a state of severe decline. For the Class as a whole, TORIS models predict that between 13% and 43% of the total recovery potential is at risk of abandonment by the year 2000. Production profitability in both Alaska and California is under pressure from environmental and oil price concerns, but in other parts of the United States the situation is much more serious.

Most of the Class 5 resources in states other than Alaska and California were developed in the early part of the twentieth century, and some fields were already producing for many years at the turn of the century. It is not surprising that most of these Class 5 reservoirs, many of which are operated by independent oil companies, are in the mature stage of their developmental history. Production decline is steep, proved reserves are small, and current production is approaching economic limits. A number of Class 5 reservoirs listed in the TORIS database have already been abandoned. There is a marked trend for smaller operators, with lower overhead but less access to new technologies, to acquire Class 5 production being divested by major oil companies as production continues to decline. Cost-effective techniques are needed to select and appropriately apply new and existing technologies to extend the productive life of these fields.

This section addresses those research needs that are most critical to accomplishing the goals of postponing abandonment and increasing economic recovery of oil from Class 5 reservoirs. Section 5.4.1 summarizes critical needs in reservoir management and reservoir characterization, Section 5.4.2 summarizes improvements in improved oil recovery processes and their application, and Section 5.4.3 summarizes other factors that may contribute to the achievement of these ends.

5.4.1 Reservoir Management and Reservoir Characterization

Reservoir management is a very broad consideration involving the carefully planned and calculated use of reservoir characterization in conjunction with reservoir monitoring and economic and environmental awareness to optimize removal of hydrocarbons. Reservoir characterization is also very broad in scope, involving use of a diversity of tools and activities to model and predict the effects of reservoir heterogeneity. Both endeavors use sophisticated technologies for information gathering and complex methodologies for collection, analysis, and synthesis of that information for reservoir decision making. The sections following deal with methodological needs for both reservoir management and reservoir characterization (Section 5.4.1.1), and with specific Class 5 needs for reservoir characterization model development (Section 5.4.1.2).

5.4.1.1 Methodological Needs

Efficient reservoir management may be the single most important contributor to increasing production from most Class 5 reservoirs. Selecting the most suitable process and applying it correctly, optimally, and consistently with the properties of the reservoir can make the difference between technical and economic success or failure. Development and demonstration of methodologies for design, implementation, and revision of reservoir management plans and strategies are critical research needs for Class 5. In addition to general methodologies, those methodologies specific to the design and development of information management databases are also important through their contribution to reservoir management efficiency.

Methodologies for integration by comparison, combination, correlation and/or other means of various geoscience and engineering data types in creation of reservoir characterization models are also fundamental. Closely related is a need for methodologies to accurately adjust the scale of various information types to assure their proper representation at simulator grid-block scale for accurate prediction of reservoir performance. Methodologies for design and construction of databases that have the flexibility to incorporate and identify information of different origins, scales, and quality are an additional need.

All of the above methodologies can be considered to be short-term needs which would benefit recovery from Class 5 reservoirs. Development and demonstration of these methodologies should carry over into the midterm and beyond as well. Extraction of methodologies pertaining to reservoir management and demonstration should be performed on all projects supported by the field demonstration program. Efficient transfer of the technology represented by these complex methodologies, perhaps by computer-based systems as well as more conventional means, will also be important.

5.4.1.2 Specific Needs for Reservoir Characterization Models

Class 5 reservoirs will definitely benefit from research in general reservoir characterization model development as discussed in Section 5.1.2.1, however, Class 5 reservoirs also have very specific needs in reservoir model development. Conceptual, stochastic, and deterministic models all should be considered.

Conceptual Models

Conceptual level models need to be developed and demonstrated for Class 5 reservoirs covering the depositional, diagenetic, tectonic or structural, and fluid content aspects of reservoir heterogeneity. These models can be developed at the basin, play, or individual reservoir scale as a function of the probable transferability from the analog source (see Section 5.1.2.1). Specific needs for models from analog sources include the following:

- Depositional conceptual models, perhaps for end member fluvial/alluvial system types (see Chapter 2), are needed to make predictable: (1) gross deposit architecture; (2) external geometry of facies, including the geometry of fine-grained deposits that serve

to completely or partially separate more permeable units; and (3) distribution of smaller scale depositional heterogeneities such as shale drapes or high permeability zones that cause nonuniform fluid flow. All features of these models should be considered in terms of prevailing geological controls (e.g., tectonics, sediment supply, climate, etc.). Criteria should also be developed to identify end member fluvial/alluvial system types from readily obtainable stratigraphic and sedimentologic data.

- Conceptual-level diagenetic studies are needed to further determine at what scale (basin, play, or reservoir) diagenetic analog information is transferable among the various Class 5 reservoirs. Appropriate diagenetic models then need to be built to provide analog information on diagenesis for all Class 5 reservoirs. Relating early diagenetic features to depositional conditions, tectonics, etc., may reveal some predictable similarities in diagenetic features between reservoirs in basins with different development histories.
- Tectonic or structural models are important because they are related to prediction of depositional and diagenetic features, but also because they may predict important internal fluid-flow heterogeneities, such as faults and fractures.
- Study of hydrocarbon and formation water composition variation, both within reservoirs and among reservoirs in the same and different plays and basins, may lead to predictive analog models for detection of fluid migration pathways and reservoir compartmentalization.

Conceptual models in the areas discussed will also form the basis of stochastic models for application in Class 5 reservoirs. Demonstration of the methodologies for development of the various Class 5 conceptual models will be important byproducts benefiting Class 5 as well as other reservoir geologic classes. Conceptual-level models developed in larger more modern reservoirs such as those in Alaska and, to some extent, in California, will apply to many smaller and older Class 5 reservoirs, in which deterministic data are sparse and economics cannot generally justify large or sophisticated data collection projects. Conceptual model needs should be addressed in the short-term with continuation of efforts into the midterm and beyond.

Stochastic Models

When transferable analog or conceptual sources of information appropriate for a Class 5 basin, play, or reservoir have been established, stochastic models of depositional, diagenetic, tectonic, etc., heterogeneities for application in Class 5 reservoirs can be constructed.

- Stochastic models for representation of Class 5 interwell-scale heterogeneities are a definite RD&D need. Analog sources may include subsurface deposits, outcrops, or deposits in modern environments where information on the variability of the desired features or properties is available at the scale needed for modeling.
- As in the case of conceptual models, demonstration of the methodologies for construction of stochastic models is a significant byproduct.

Stochastic model development is another short-term need with opportunity for continued development in the midterm.

Deterministic Models

Class 5 specific needs in the deterministic or data acquisition and analysis areas of reservoir characterization are mostly short-term and methodological in nature.

- In general terms, routine and innovative application of current and emerging technologies and demonstration of the appropriate associated methodologies for collection, analysis, and interpretation of data are the primary Class 5 research needs.
- In the reservoir sampling area, methodologies for rock and fluid sampling guided by Class 5 depositional, diagenetic, etc., conceptual models need to be formulated and demonstrated. Methodologies are needed for linking difficult and expensive-to-measure reservoir properties, such as relative permeability, to more readily predictable features, such as components of a Class 5 conceptual model like depositional or diagenetic facies.
- Production and injection data collection protocols, databases, and data analysis systems for Class 5 reservoirs need to be developed. Methodologies for development of these products for various Class 5 regions, basins, plays, etc., are an important byproduct of these efforts. Identification and collection from Class 5 reservoirs of new production- or injection-related data types and development of new techniques for extracting information on reservoir heterogeneities from existing Class 5 data are other pursuits that may prove beneficial.
- Guided by appropriate Class 5 conceptual models, optimum open- and cased-hole wireline logging suites for various Class 5 reservoirs, plays, etc., can be established. Appropriate quality control protocols for data collection can be established in a similar manner. Methods for optimizing derivation of information from existing Class 5 wireline log data need to be demonstrated. Many Class 5 reservoirs could benefit from application of such procedures to old E-logs.
- Class 5 reservoirs can benefit from demonstration of Class 5 customized methodologies for design, application, and interpretation of pressure transient and tracer tests. The specific integration of these tests with other available data types in characterizing typical Class 5 heterogeneities is an additional methodology requiring development and demonstration.

In the context of application to Class 5 reservoir characterization, seismic techniques, including (1) 3D surface and high-resolution techniques, (2) techniques involving extraction of reservoir properties from seismic signals, and (3) downhole, reflection, and cross-well techniques have potential to make significant contributions to identification and recovery of the Class 5 resource.

- Each of the techniques listed above will require Class 5 specific application methodology development. Each technique will require unique designs and approaches for data collection, processing, and interpretation. Those designs and approaches will be integrated with knowledge of the reservoir obtained from other data and from Class 5 conceptual or analog models.
- Demonstration of the methodologies for developing these designs and approaches is a definite Class 5 need.

5.4.2 Improved Oil Recovery Process Applications

Based on past experience in process applications and TORIS predictions, a number of advanced secondary recovery (ASR) and enhanced oil recovery (EOR) processes have good potential for increasing recovery from Class 5 reservoirs. These processes, discussed in greater detail in Section 5.2.2, include: (1) infill drilling (including targeted drilling and directional or horizontal wells), especially when used in combination with profile modification and/or polymer flooding; (2) steam processes, (3) in situ combustion, (4) CO_2 miscible processes, (5) alkaline floods, and (6) surfactant floods. Development of further improvements in these technologies, as well as demonstrations of optimal application techniques, will contribute substantially to improved recovery from Class 5 reservoirs.

ASR technologies (i.e., infill drilling coupled with profile modification or polymer flooding) have considerable economic application potential across the spectrum of oil prices ($12 to $30 per barrel) under the current state of technology as well as under advanced technologies. The same may be said of the application of steam processes in the heavy oil reservoirs of California. Carbon dioxide miscible processes have good applicability at moderate to high oil prices both under current and advanced technologies. Advances in technology will probably be required for successful Class 5 application of in situ combustion (primarily in heavy oil reservoirs in the East Texas Basin), surfactant, and alkaline processes.

5.4.3 Additional Factors

Other areas of research and development, although of a more general nature, may have positive influence on Class 5 recoveries if addressed. These include improvements in the areas of reservoir simulation, wellbore and facilities, and environmental considerations.

5.4.3.1 Simulation

The petroleum industry has continued to exploit the advancing computational capabilities of desktop and mainframe computer systems to develop simulators that are more user-friendly, that more accurately reflect process performance, and more effectively display simulator output. However, these simulators are not necessarily available to, or utilized by, many operators due to

the cost of purchasing the simulator, availability of simulation services, or the lack of required technical expertise. Specific research needs relative to numerical simulation include the following:

- Development of more accurate, cost-effective, and user-friendly publicly available simulators is probably the most significant simulation research need for operators of Class 5 reservoirs. These types of simulators should be made more readily available. Many operators could utilize these tools to design and evaluate improved recovery processes.
- A system should be developed to allow less sophisticated operators access to technical experts who can provide guidance for the development of input datasets, the operation of simulators, and the interpretation of results. These objectives could be met through DOE funding support to the Petroleum Technology Transfer Council, NIPER, universities, and other research institutions.

5.4.3.2 Wellbore and Facilities

The demonstration of improved technologies for reducing the costs of drilling, completing, recompleting, and stimulating wells, and operating production and injection facilities is a significant research need for extending the economic life of producing fields and improving the recovery of oil. Specific areas where the demonstration and transfer of improved methodologies and equipment could benefit operators include the following:

- Demonstration of improved drilling systems for reducing the cost of drilling wells and improving the integrity of wellbores after drilling, which could reduce long-term operating costs. This includes the demonstration of environmentally safe drilling systems and improved drilling measurement systems.
- Demonstration of innovative directional and horizontal drilling techniques and the development and demonstration of methodologies for determining the applicability and potential for horizontal or deviated wells.
- Development and demonstration of improved, cost-effective methods for completion, recompletion, workover, and stimulation of wells and the transfer of these methods to other operators to reduce costs and increase the economic life of wells.
- Demonstration of improved systems and operating procedures for fluid separation and treatment, distribution and gathering, and artificial lift could encourage many operators to implement cost-saving practices. The demonstration of reservoir management methodologies, which includes the optimization of production and injection facilities, would benefit many smaller operators.

5.4.4 Environmental

Environmental research needs impact all of the Class 5 resource. Increased scrutiny of operators by the public and regulators requires operators to demonstrate ever-increasing environmental responsibility. Of the multiple environmental concerns, the following research needs are most important for the Class 5 oil resource:

- Demonstration of cost-effective waste management (minimization) practices, especially in drilling-related operations.
- Demonstration of integrated engineering design concepts in which petroleum engineering and environmental factors are considered in IOR project design.

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APPENDIX A
GLOSSARY OF GEOLOGICAL TERMS

The purpose of this glossary of geological terms is to complement and supplement the discussion presented in Chapter 2 by providing sufficient background and explanation for key stratigraphic and sedimentological terms. These definitions allow the reader with a basic familiarity with natural processes to understand the origin and subsequent accumulation of fluvial-alluvial deposits. Most definitions in this glossary have been taken or modified from the following works: Gary et al., 1974; Friedman and Sanders 1978; Nilsen 1982; and Blair and McPherson 1994. Many of these definitions have been tailored to apply specifically to fluvial/alluvial systems or simplified for a general audience.

Absolute Sea Level Change	An observed change in the mean level of the sea not attributable to local tectonic effects.
Aggrade	The building up by vertical accretion of channel and/or overbank deposits of a fluvial or alluvial system.
Alluvial	In this document, pertaining to processes, morphologies, and deposits associated with alluvial fan environments.
Alluvial Fan	A low, outspread, relatively flat to gently sloping mass of loose rock material, shaped like an open fan or a segment of a cone deposited by a stream at the place where it issues from a narrow mountain valley upon a plain or broad valley.
Anisotropies	Variations in physical properties in different directions within a medium; in sedimentary deposits generally referring to directional differences in fluid conductivity.
Apex	The highest point on an alluvial fan, usually the point where the stream that formed the fan emerges from the mountain front or from confining canyon walls.
Attrition	In this document, the mutual wear and tear that loose rock fragments or particles undergo by rubbing, grinding, knocking, scraping and bumping against one another while being moved about by running water. Attrition results in a reduction in size and an increase in roundness of particles.

Avulsion	A sudden change in course of a stream or river in which the stream deserts its old channel for a new one.
Bar (Fluvial)	A ridge-like accumulation of sand, gravel, or other sediment formed in the channel or along the banks of a river or stream.
Base Flow	The sustained or fair-weather flow of a stream or river.
Base Level	The theoretical limit or lowest level toward which erosion of the earth's surface constantly progresses but seldom, if ever, reaches.
Bed Load (or Traction Load)	That portion of the total sediment transported by flowing water that is moved along or just above the bottom of the flow by rolling, sliding, or jumping.
Bedform	In this document, any deviation from a flat bed generated by flowing water.
Boulder	A rock fragment larger than a cobble, having a diameter greater than 256 mm, or about 10 inches.
Braided Stream / River	A stream or river that divides into or follows an interlacing or tangled network of numerous small, branching, and reuniting shallow channels separated from each other by islands or bars, resembling in plan the strands of a complex braid.
Chute	A narrow erosional channel through which water flows rapidly in a direct downstream direction in a meandering stream or river during flood stage.
Chute Bar	A high-energy sedimentary deposit formed in a chute as flood waters recede and flow returns to its normal channel in a meandering stream or river.
Cobble	A rock fragment larger than a pebble and smaller than a boulder, having a diameter in the range of 65–256 mm or about 2.5–10 inches.
Colluvium	An unconsolidated mass of material consisting of a mixture of rock materials, clays, and other soil components produced by weathering.
Competence	The ability of a current of water to transport sediment, measured as a function of maximum particle size rather than amount.

Compositional (Mineralogic) Maturity	A sedimentary deposit descriptor defined in terms of the relative abundance of physically and chemically weak and unstable particles versus the abundance of quartz particles.
Crevasse Splay	A lobate body of sediment deposited on the floodplain of a stream or river by flood waters pouring through a breach in a natural levee.
Cutbank	The steep erosional bank formed on the outside of a meander loop.
Cycle of Erosion	The complete, progressive, and systematic sequence of natural changes or stages in a landscape from the start of its erosion on a newly uplifted or exposed surface through its dissection into mountains and valleys until it has been reduced in the final stage to a low, featureless plain that limits the activity of the agents involved.
Debris Flow	A mass of sediment consisting of coarse clasts supported by a mud matrix transported downslope as a density flow and originating with the entrainment of water and/or air into a sediment mixture containing abundant clay.
Density Flow	A gravity-induced flow in which water and air mix intimately with fine-grained sediment (usually clays) to create a dense mixture with fluid-like properties capable of plastic flow and able to transport large rock fragments in suspension (e.g., debris flows and mud flows).
Distal	Adjective describing those sediments within a sedimentary system that are farthest from the sediment source.
Downdip (depositionally)	Referring to a direction, specifically the direction seaward or toward more open marine deposits.
Drainage Basin	The whole area that gathers water originating as precipitation and contributes it to a particular stream channel or system of channels.
Ephemeral Sedimentary Structures	In this document, sedimentary structures commonly associated with upper flow regime deposition from flood waters that are replaced by structures of the lower flow regime as flooding wanes.
Ephemeral Stream/ River	A stream or river or a reach of a stream or river that flows briefly only in direct response to precipitation in the immediate locality.
External Facies Architecture	The three-dimensional external shape and size of a sedimentary deposit.

Facies	A sediment or rock type defined as having certain recognizable characteristics (e.g., having distinctive: color; mineralogic makeup; suite of sedimentary structures; faunal suite). Often facies are named genetically, i.e., based on their environments of origin.
Fan Radius	The distance from the apex of an alluvial fan to the most distal fan deposits.
Feeder Stream Feeder Channel	In an alluvial fan setting, the principal tributary in the fan's drainage basin leading out of the highland drainage basin onto the fan itself.
Flood	A rising body of water that overtops its normal confines and covers land not normally under water.
Flow Regime	The aggregate of relationships prevailing among a water current, the shape of the water/sediment interface, the mode of sediment transport, the process of dissipation of energy within the current, and the phase relationships between the morphologic features at the water/sediment interface and the water surface.
Fluvial	In this document, pertaining to processes, morphologies, and deposits associated with streams or rivers.
Glacial Outwash Plain	A broad, outspread, flat or gently sloping sheet of material "washed out" from a glacier and deposited in front of the glacier, formed by the coalescence of outwash fans.
Grade	A stream is said to be at grade when it has achieved a condition of balance between erosion and deposition. Under these conditions a stream is just capable of transporting the sediment supplied to it.
Gradient	The slope of a feature (e.g., an alluvial fan or a stream/river bed) measured against the horizontal.
Gravel	An accumulation of sedimentary particles greater than sand size (i.e., greater than 2 mm or 1/12 inch) in diameter.
Highland	A relatively large area of elevated or mountainous land standing prominently above adjacent low areas.
Imbrication	The slanting or overlapping arrangement of tabular or flat particles (in the manner of tiles or shingles on a roof) in response to flowing water.

Incised Stream/ River	A stream or river that has eroded downward into the surface over which it flows, often producing a narrow, steep-walled valley.
Internal Facies Architecture	The three-dimensional arrangement or distribution of facies within a sedimentary deposit.
Intersection Point	The point downfan from the apex of an alluvial fan at which an incised feeder stream channel emerges at the fan surface.
Lag Deposits	A residual deposit of coarse-grained material that is rolled or dragged along the bed of a stream and is left behind by attenuating currents still capable of moving finer material.
Laminar Flow	Water flow in which parts of the fluid slide over one another along surfaces that conform to the shape of the fluid boundaries.
Landslide	A general term covering a wide variety of mass-movement landforms and processes involving moderately rapid to rapid downslope movement by gravity stresses of soil and rock material en masse.
Lateral Accretion	Deposition and accumulation of sediment in a horizontal direction, characteristic of point bar deposits.
Lower Flow Regime	A low-energy flow regime in which (1) the water-sediment interface is shaped into ripples and/or sandwaves which are out of phase with undulations of the water surface, (2) resistance to flow is large, and (3) volume of bottom sediment transport is small, primarily by saltation or jumping movement of grains up the upcurrent sides of ripples and sandwaves and avalanching or falling down their downcurrent faces.
Meander Amplitude	The distance, measured in a direction normal to the general course of the meander belt, between the points of maximum curvature of successive meanders.
Meander Length	The distance between corresponding parts of successive meanders of the same phase (i.e., on the same side of the stream or river), measured along the general course of the meanders.
Meandering Stream/River	A stream or river characterized by having a series of somewhat regular, sharp, freely developing, sinuous curves, bends, loops, turns, or windings in its course produced as it shifts its course from side to side through its flood plain through a process of lateral erosion and redeposition.

Mud Flow	A mass of sediment consisting of sand size and finer particles in a mud matrix transported downslope as a density flow and originating with the entrainment of water and/or air into a sediment mixture containing abundant clay.
Natural Levee	A long, broad, low ridge or embankment of sediment built by a stream or river on its floodplain along the banks of its channel during times of overbank flooding.
Pebble	A rock fragment having a diameter in the range of 4–64 mm or about 0.17–2.5 inches.
Perennial Stream/ River	A stream or river that flows continuously throughout the year.
Pool	Deeper water area in a meandering channel associated with the outside portion of a meander loop, located at the base of the cutbank.
Progradational	In this document, deposits building seaward or away from the sediment source with time.
Provenance or Source Area	The area from which the constituent materials of a clastic sedimentary deposit are derived.
Proximal	Adjective describing those sediments within a sedimentary system that are closest to the sediment source.
Reach	In this document, a continuous or extended portion of a stream or river as chosen between two specified points.
Retrogradational	In this document, deposits building landward or toward the sediment source with time.
Riffle (or Crossover)	A relatively shallow water area of moderate flow velocity located between meander loops.
Rivulet	A small stream or river; a brook or streamlet.
Rock Avalanche	A mass of pulverized rock fragments that has resulted from the very rapid downslope flowage of rock materials originating as a rockfall or a rockslide.
Rockfall	A mass of rock that has moved by a newly detached segment of bedrock free falling from a cliff or other very steep slope.

Rockslide	A mass of newly detached segments of bedrock that has moved rapidly downslope by sliding or slipping over an inclined surface of weakness, such as a bedding plane, joint, or fault surface.
Sheetflood	An expanse of moving, generally storm-borne water flowing over an area in an unconfined manner (i.e., not concentrated into well defined channels).
Streamflow	That part of surface runoff traveling in a stream or river (i.e., confined to a channel).
Suspension Load	That portion of the total sediment transported by flowing water that is carried for most of the time in suspension, free from contact with the stream bed.
Talus or Scree	Rock fragments of any size or shape, but usually coarse and angular, found lying at the base of a cliff or steep slope or mantling the surface of a steep slope.
Textural Maturity	A sedimentary deposit descriptor defined in terms of uniformity of particle size and perfection of rounding independent of mineral composition.
Turbulent Flow	Water flow in which flow paths are complex and parts of the fluid move in curved and or spiral paths (called eddies and vortices) that do not conform to the shape of the fluid boundaries.
Updip (depositionally)	Referring to a direction, specifically the direction landward or toward nonmarine deposits farther removed from the sea.
Upper Flow Regime	A high-energy flow regime in which (1) the water/sediment interface is plane or shaped into ephemeral undulations which are in phase with undulations of the water surface, (2) resistance to flow is small, (3) volume of bottom sediment transport is large, primarily by continuous rolling of particles along in sheets a few grain diameters in thickness.
Vertical Accretion	Deposition and accumulation of sediment in a vertical direction.

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APPENDIX B
LISTING OF CLASS 5 TORIS RESERVOIRS*

STATE	FIELD NAME	RESERVOIR NAME	FORMATION NAME	PLAY NAME
ALASKA	PRUDHOE BAY	SADLEROCHIT	IVISHAK	Sadlerochit Fluvial/Deltaic Sandstones
ALASKA	GRANITE POINT	MIDDLE KENAI	TYONEK	West Foreland/Hemlock/Tyonek Fluvial Sandstone
ALASKA	MCARTHUR RIVER	HEMLOCK	HEMLOCK	West Foreland/Hemlock/Tyonek Fluvial Sandstone
ALASKA	MCARTHUR RIVER	TYONEK MIDDLE KENAI G ZONE	TYONEK	West Foreland/Hemlock/Tyonek Fluvial Sandstone
ALASKA	MCARTHUR RIVER	WEST FORELAND	WEST FORELAND	West Foreland/Hemlock/Tyonek Fluvial Sandstone
ALASKA	MIDDLEGROUNDSHOAL	TYONEK-HEMLOCK E,F,& G	TYONEK/HEMLOCK	West Foreland/Hemlock/Tyonek Fluvial Sandstone
ALASKA	SWANSON RIVER	HEMLOCK	HEMLOCK	West Foreland/Hemlock/Tyonek Fluvial Sandstone
ARKANSAS	CENTER	HOGG	PINE ISLAND	Cretaceous
ARKANSAS	STEPHENS	HOGG	PINE ISLAND	Cretaceous
CALIFORNIA	EDISON	MAIN AREA UPPER	CHANAC	Chanac Fluvial/Alluvial Sandstones
CALIFORNIA	EDISON	WEST AREA CHANAC SANTA MARGARITA	CHANAC	Chanac Fluvial/Alluvial Sandstones
CALIFORNIA	FRUITVALE	ETCHEGOIN-CHANAC	CHANAC	Chanac Fluvial/Alluvial Sandstones
CALIFORNIA	KERN FRONT	MAIN	CHANAC&ETCHEGOIN	Chanac Fluvial/Alluvial Sandstones
CALIFORNIA	PLEITO	RANCH AREA	CHANAC	Chanac Fluvial/Alluvial Sandstones
CALIFORNIA	POSO CREEK	ENAS AREA	CHANAC	Chanac Fluvial/Alluvial Sandstones
CALIFORNIA	POSO CREEK	PREMIER AREA MAIN (ETCHEGOIN & CHAUSE)	ETCHEGOIN&CHANAC	Chanac Fluvial/Alluvial Sandstones
CALIFORNIA	ROSEDALE RANCH	CHANAC	CHANAC	Chanac Fluvial/Alluvial Sandstones
CALIFORNIA	WHITE WOLF	PLIOCENE	CHANAC	Chanac Fluvial/Alluvial Sandstones
CALIFORNIA	KERN RIVER	KERN RIVER SERIES SAND	KERN RIVER	San Joaquin/Kern River/Deltaic/Lacustrine
CALIFORNIA	MCKITTRICK	MAIN AREA UPPER	TULARE	San Joaquin/Tulare/Deltaic/Lacustrine
CALIFORNIA	MIDWAY-SUNSET	TULARE-BASAL & UPPER COMBINED	TULARE	San Joaquin/Tulare/Deltaic/Lacustrine
CALIFORNIA	SOUTH BELRIDGE	TULARE	TULARE	San Joaquin/Tulare/Deltaic/Lacustrine
CALIFORNIA	FRESNO GR-RAISIN CITY	TAR MIOCENE	ZILCH	Olcese/Zilch Fluvial/Alluvial Sandstones
CALIFORNIA	RAISIN CITY FIELD	ZILCH SAND	ZILCH	Olcese/Zilch Fluvial/Alluvial Sandstones
CALIFORNIA	PLAYA DEL REY	DEL REY HILLS AREA	PUENTE	Playa Del Rey Platform Schist Sandstones
CALIFORNIA	PLAYA DEL REY	VENICE AREA	PUENTE	Playa Del Rey Platform Schist Sandstones
CALIFORNIA	CASCADE	PLIOCENE (CASCADE)	SAUGUS	Plio/Pleistocene Fluvial/Alluvial Sands
CALIFORNIA	MONTALVO WEST	COLONIA	SESPE	Sespe Fluvial Sandstones
CALIFORNIA	OAK PARK	SESPE UPPER	SESPE	Sespe Fluvial Sandstones
CALIFORNIA	OXNARD	MCINNES	SESPE	Sespe Fluvial Sandstones

* Although this listing comes primarily form DOE's TORIS database, several changes have been incorporated based on information acquired during preparation of this report.

STATE	FIELD NAME	RESERVOIR NAME	FORMATION NAME	PLAY NAME
CALIFORNIA	SANTA SUSANA	SECOND AND THIRD SESPE	SESPE	Sespe Fluvial Sandstones
CALIFORNIA	SHIELLS CANYON	SESPE	SESPE	Sespe Fluvial Sandstones
CALIFORNIA	SOUTH MOUNTAIN	SESPE MAIN	SESPE	Sespe Fluvial Sandstones
CALIFORNIA	TAPO CANYON SOUTH	4TH SESPE	SESPE	Sespe Fluvial Sandstones
CALIFORNIA	OJAI GR - SISAR AREA	(UNNAMED)	SAUGUS	Non-defined
CALIFORNIA	YORBA LINDA	SHALLOW	LA HABRA	Non-defined
COLORADO	MINTO	J SAND	DAKOTA	Denver Basin Cretaceous D-J sands
COLORADO	MAUDLIN GULCH	MORRISON	MORRISON	Uinta-Piceance Basin Morrison Sands
COLORADO	POWDER WASH	WASATCH	WASATCH	NW CO Eocene Wasatch Sands
COLORADO	BATTLESHIP	LAKOTA	LAKOTA	Park Basin Lakota Sands
ILLINOIS	LAWRENCE	RIDGLEY	CASEYVILLE	Pennsylvanian Fluvial-Deltaic
ILLINOIS	DUDLEY	LOWER DUDLEY	CASEYVILLE	Sub-Pennsylvanian Paleovalley
ILLINOIS	LAWRENCE	BUCHANAN	CASEYVILLE	Sub-Pennsylvanian Paleovalley
KANSAS	INTERSTATE(WESTERN KANSAS)	UPPER MORROW-PURDY	MORROW	Morrow Sandstones
LOUISIANA	CADDO PINE ISLAND	PALUXY	PALUXY	Cretaceous
LOUISIANA	PLEASANT HILL	PALUXY	PALUXY SAND	Cretaceous
LOUISIANA	SLIGO	PALUXY HEROLD J	PALUXY	Cretaceous
LOUISIANA	SLIGO	PALUXY I4	PALUXY	Cretaceous
LOUISIANA	ORA	NAC	NACATOCH	Upper Cretaceous
MISSISSIPPI	BAXTERVILLE	LOWER TUSCALOOSA OIL POOL	TUSCALOOSA	Lower Tuscaloosa Stratigraphic Play
MISSISSIPPI	LITTLE CREEK	LOWER TUSCALOOSA	LOWER TUSCALOOSA	Lower Tuscaloosa Stratigraphic Play
MISSISSIPPI	MALLALIEU, WEST	LOWER TUSCALOOSA WMU 'C'	LOWER TUSCALOOSA	Lower Tuscaloosa Stratigraphic Play
MISSISSIPPI	OLIVE	LOWER TUSCALOOSA	LOWER TUSCALOOSA	Lower Tuscaloosa Stratigraphic Play
MONTANA	CUT BANK	CUT BANK SAND	KOOTENAI	Sweetgrass Arch Kootenai Stratigraphic Trap
MONTANA	FRED & GEORGE CREEK	SUNBURST	KOOTENAI	Sweetgrass Arch Kootenai Stratigraphic Trap
MONTANA	WHITLASH	SWIFT-SUNBURST	SWIFT/KOOTENAI	Sweetgrass Arch Kootenai Stratigraphic Trap
MONTANA	CAT CREEK	CAT CREEK SANDS	KOOTENAI	Central Montana Structural Traps
MONTANA	KEG COULEE	TYLER	TYLER	Tyler Sandstones
MONTANA	KEG COULEE WEST PORTION	TYLER	TYLER	Tyler Sandstones
MONTANA	WELDON	KIBBEY	KIBBEY	Brocton-Froid
NORTH DAKOTA	ROCKY RIDGE	FRITZ SAND	TYLER	Medora-Fryburg
NORTH DAKOTA	STARBUCK	SPEARFISH - CHARLES	SPEARFISH & CHARLES	NE Flank Williston Basin

STATE	FIELD NAME	RESERVOIR NAME	FORMATION NAME	PLAY NAME
NEW MEXICO	LOCO HILLS	WEST UNIT	GRAYBURG	Northwest Shelf Morrow
OKLAHOMA	ELK CITY	HOXBAR	HOXBAR	Anadarko Basin Missourian
OKLAHOMA	GARRETT NW	REDFORK	REDFORK	Nemaha Ridge Desmoinesian
OKLAHOMA	TALOGA	MORROWAN	MORROW	Morrow Sandstones
OKLAHOMA	WILBURTON	MORROWAN	MORROW	Morrow Sandstones
TEXAS	PEWITT RANCH	PALUXY	PALUXY	Paluxy Fault Line
TEXAS	SULPHUR BLUFF	PALUXY	PALUXY	Paluxy Fault Line
TEXAS	TALCO	PALUXY	PALUXY	Paluxy Fault Line
TEXAS	ALVORD, SOUTH	CADDO CONGL.	CADDO CONGL.	Bend Conglomerate
TEXAS	ALVORD, SOUTH	CADDO CONGLOMERATE	TX	Bend Conglomerate
TEXAS	BOYD CONGLOMERATE	BEND CONGLOMERATE	BEND CONGLOMERATE	Bend Conglomerate
TEXAS	ETTER	CONGLOMERATE UPPER	CONGLOMERATE UPPER	Bend Conglomerate
TEXAS	HILDRETH	2 CONGLOMERATE UNIT	2 CONGLOMERATE UNIT	Bend Conglomerate
TEXAS	OLD GLORY		BEND CONGLOMERATE	Bend Conglomerate
TEXAS	RUSMAG		TX	Bend Conglomerate
TEXAS	SCHICK	BEND CONGLOMERATE	BEND CONGLOMERATE	Bend Conglomerate
TEXAS	WHITE FLAT		TX	Bend Conglomerate
TEXAS	WORSHAM-STEED	BEND CONGLOMERATE	BEND CONGLOMERATE	Bend Conglomerate
TEXAS	ARENOSO	STRAWN DETRITUS	STRAWN DETRITUS	Central Basin Platform Unconformity
TEXAS	CROSSETT, SOUTH	WOLFCAMP DETRITAL	WOLFCAMP DETRITAL	Central Basin Platform Unconformity
TEXAS	TOBORG	TORBORG SAND	TORBORG SAND	Yates Area
TEXAS	AMACKER-TIPPETT, SW	WOLFCAMP	WOLFCAMP	Wolfcamp Platform Carbonate
TEXAS	COMO	COKER	COKER	Miscellaneous
TEXAS	CORDELE		M-2 SAND	Miscellaneous
TEXAS	MERIGALE-PAUL		TX	Miscellaneous
TEXAS	MILLER BLOCK B-29	PENNSYLVANIAN	PENN	Miscellaneous
TEXAS	EASTLAND COUNTY REGULAR	COMINGLED PRODUCTION	TX	Shelf Sandstone
UTAH	BRIDGER LAKE	DAKOTA A & C SANDS	DAKOTA	Moxa Arch Dakota Sands
WEST VIRGINIA	FINK CREEK (DRY FORK)	BEREA	BEREA SANDSTONE	Berea Channel Sandstone
WEST VIRGINIA	NEWBERNE	BEREA	BEREA SANDSTONE	Berea Channel Sandstone
WEST VIRGINIA	YELLOW CREEK (BIG SPRINGS)	BEREA	BEREA SANDSTONE	Berea Channel Sandstone
WEST VIRGINIA	BURNING SPRINGS	BURNING SPRINGS	ALLEGHENY	Lower and Middle Pennsylvanian Fluvial Sands

STATE	FIELD NAME	RESERVOIR NAME	FORMATION NAME	PLAY NAME
WEST VIRGINIA	SILVER RUN	SALT	POTTSVILLE	Lower and Middle Pennsylvanian Fluvial Sands
WEST VIRGINIA	VOLCANO	SALT	POTTSVILLE	Lower and Middle Pennsylvanian Fluvial Sands
WEST VIRGINIA	MOORESVILLE	FIFTH	HAMPSHIRE	Upper Devonian Deltaic Sandstone
WYOMING	HAPPY SPRINGS	DAKOTA	DAKOTA	Lower Cretaceous Dakota Channel Sands-SW WY
WYOMING	QUEALY	DAKOTA	DAKOTA (CLOVERLY)	Lower Cretaceous Dakota Channel Sands-SW WY
WYOMING	HORSE CREEK	LAKOTA	LAKOTA	Lower CretaceousLakota Fluvial Sandstones
WYOMING	GRASS CREEK	LAKOTA	LAKOTA (CLOVERLY)	Lower Cretaceous Lakota Fluvial Sandstones
WYOMING	FIDDLER CREEK, WEST UNIT	NEWCASTLE	NEWCASTLE SANDSTONE	Lower Cretaceous Fluvial and Estuarine Sands
WYOMING	GLENROCK SOUTH	LOWER MUDDY B CONOCO ONLY	MUDDY SANDSTONE	Lower Cretaceous Fluvial and Estuarine Sands
WYOMING	MOORCROFT, WEST	NEWCASTLE	NEWCASTLE	Lower Cretaceous Fluvial and Estuarine Sands
WYOMING	MUSH CREEK	NEWCASTLE	NEWCASTLE SANDSTONE	Lower Cretaceous Fluvial and Estuarine Sands
WYOMING	MUSH CREEK, WEST	NEWCASTLE	NEWCASTLE SANDSTONE	Lower Cretaceous Fluvial and Estuarine Sands
WYOMING	OSAGE	NEWCASTLE	NEWCASTLE SANDSTONE	Lower Cretaceous Fluvial and Estuarine Sands
WYOMING	ROCKY POINT	MUDDY AND MINNELUSA	MUDDY SANDSTONE	Lower Cretaceous Fluvial and Estuarine Sands
WYOMING	SKULL CREEK	NEWCASTLE	NEWCASTLE SANDSTONE	Lower Cretaceous Fluvial and Estuarine Sands
WYOMING	BIG MUDDY	DAKOTA	DAKOTA (FALL RIVER)	Lower Cretaceous Dakota Deltaic Deposits
WYOMING	BIG MUDDY, EAST	DAKOTA	DAKOTA (FALL RIVER)	Lower Cretaceous Dakota Deltaic Deposits
WYOMING	GLENROCK SOUTH	DAKOTA (CONOCO ONLY)	DAKOTA	Lower Cretaceous Dakota Deltaic Deposits
WYOMING	GRASS CREEK	LAKOTA	LAKOTA (CLOVERLY)	Lower Cretaceous Lakota Fluvial Sandstones
WYOMING	LANCE CREEK, EAST	DAKOTA	DAKOTA (FALL RIVER)	Lower Cretaceous Dakota Deltaic Deposits
WYOMING	LITTLE BUCK CREEK	DAKOTA	DAKOTA (FALL RIVER)	Lower Cretaceous Dakota Deltaic Deposits
WYOMING	COYOTE CREEK	DAKOTA	DAKOTA (FALL RIVER)	Lower Cretaceous Lakota Fluvial Sandstones
WYOMING	MEADOW CREEK	LAKOTA	LAKOTA	Lower Cretaceous Lakota Fluvial Sandstones
WYOMING	SUSSEX	LAKOTA	LAKOTA	Lower Cretaceous Lakota Fluvial Sandstones

APPENDIX C
OVERVIEW OF THE TORIS PREDICTIVE METHODOLOGY

The recovery potential that could result from the future application of improved recovery technologies in the Class 5 reservoirs included in the TORIS database was estimated using the TORIS predictive and economic models. The TORIS database and predictive models were originally developed by the National Petroleum Council (NPC 1984) and are maintained and updated by the DOE Bartlesville Project Office. TORIS is used to analyze the recovery potential for various improved oil recovery processes on a reservoir-by-reservoir basis using the average reservoir parameters and historical recovery data in the database and the individual process predictive models, as discussed in this section.

Appendix C is included in this report to provide some background and insights into the TORIS predictive methodology in an effort to illuminate the validity of the Class 5 improved recovery potential presented in Chapter 4. Simply stating the TORIS recovery potential and not describing the assumptions underlying these predictions does not provide any degree of confidence in the numbers. This section describes the more significant assumptions used in the TORIS prediction and includes a brief summary of the TORIS methodology, a detailed discussion of the screening criteria used in TORIS, an overview of each TORIS predictive model, and a discussion of some of the important economic considerations in the TORIS analyses.

C.1 Summary of TORIS Methodology

The TORIS reservoir database contains the average geologic and reservoir parameters for over 2,500 reservoirs in the country. The database contains volumetric original oil in place values for each reservoir, cumulative production data, and historical production data from 1970 forward. The ultimate recovery from the continued operation of each reservoir is established using decline curve models, and then the target remaining mobile and immobile oil in place volumes are calculated. The decline curve analysis also determines the projected reservoir abandonment dates with respect to the timing of future improved recovery projects.

The reservoir parameters contained in the database are screened by the TORIS system to determine the recovery processes applicable to each reservoir. The enhanced oil recovery screening criteria used in TORIS are those established by the 1984 National Petroleum Council (NPC 1984) study. The screening criteria for advanced secondary recovery processes were developed by DOE after the NPC study (see Section C.2.2). The implemented technology case is considered to be the state-of-the-art case while the advanced technology case assumes a relaxation of some of the screening criteria due to reasonable technological improvements. For

example, the profile modification screening criteria in the advanced technology case assume that the conformance control chemicals are stable at higher reservoir temperature and water salinity than in the implemented technology case. The advanced technology case also assumes some recovery process efficiency improvements, such as decreased chemical retention, increased injectant sweep efficiency, or improved overall process displacement efficiency (see the 1984 NPC study for details on the assumed individual process improvements between the implemented and advanced technology cases and for more details on the predictive models themselves).

The predictive models for each of the applicable recovery processes in each reservoir are run using the average reservoir parameters in the TORIS database. The TORIS predictive models are discussed in detail in Section C.3. Results are obtained for both the implemented and advanced technology cases. The resultant injection and production streams are then used as input to economic models. The economic models consider the capital investments and operating costs required to implement and maintain the individual recovery projects. The economic models examine project economics at various oil prices using West Texas Intermediate as the benchmark. The project economics for the applicable recovery processes in each reservoir are compared at each oil price, and the optimum process is selected based on oil recovery volumes and projected rates of return. The recovery processes are considered to be viable in TORIS if the project rate of return exceeds defined minimum hurdle rates. Because the goal of the DOE R&D efforts is to maximize the recovery of the remaining oil resource, TORIS is set up to select the viable process that recovers the most oil from each reservoir, rather than to select the process with the best economics. The maximum oil recovery potential for a group of reservoirs can then be defined for both the implemented and advanced technology cases.

C.2 Discussion of TORIS Screening Criteria

The 1984 National Petroleum Council EOR study defined most of the process screening criteria used in the TORIS recovery process predictive analyses. The NPC screening criteria were developed to determine the applicability of chemical flooding processes (polymer, surfactant, and alkaline), miscible gas injection processes, and thermal recovery processes (steam drive and in situ combustion). Screening criteria were developed for both an implemented technology case and an advanced technology case. The implemented technology case screening criteria were developed based on the review of known successful projects. The advanced technology case screening criteria were developed assuming that reasonable technological advancements could be achieved as a result of focused research and development efforts. After the NPC study, DOE developed process predictive models as well as implemented and advanced case process screening criteria for profile modification and infill drilling processes. The process screening criteria are discussed in detail in this section, and the criteria are summarized in Tables C–1 and C–2.

Table C–1
Screening Criteria for Improved Recovery Processes, Implemented Technology Case
(Source: NPC 1984)

Screening Parameters	Units	Profile Modification	Polymer Flooding	Surfactant Flooding	Alkaline Flooding	Miscible Flooding (CO_2)	Thermal Recovery	
							Steam	In Situ Comb.
Oil Gravity	°API	--	--	--	<30	≥25	10 to 34	10 to 35
In Situ Oil Viscosity (μ)	cP	<100	<100	<40	<90	--	≤15,000	≤5,000
Depth (D)	Feet	--	--	--	--	--	≤3,000	≤11,500
Pay Zone Thickness (H)	Feet	--	--	--	--	--	≥20	≥20
Reservoir Temperature (T_r)	°F	<180	<200	<200	<200	--	--	--
Porosity ($\varnothing$)*	Fraction	--	--	--	--	--	≥0.20	≥0.20
Permeability, Average (K)	mD	>20	>20	>40	>20	--	250	35
Transmissibility (Kh/μ)	mD/ft-cP	--	--	--	--	--	≥5	≥5
Reservoir Pressure (P_r)	psi	--	--	--	--	≥MMP†	≤1,500	≤2,000
Minimum Oil Content at Start of Process ($S_o\ \varnothing$)	Fraction	--	--	--	--	--	≥0.10	≥0.08
Salinity of Formation Brine (TDS)	ppm	<100,000	<100,000	<100,000	<100,000	--	--	--
Rock Type	--		Sandstone or Carbonate	Sandstone	Sandstone	Sandstone or Carbonate	Sandstone or Carbonate	Sandstone or Carbonate

* Ignored if oil saturation—porosity product ($S_o\varnothing$) criterion is satisfied.

† MMP denotes minimum miscibility pressure, which depends on temperature and crude oil composition.

C.2.1 Process Screening Criteria Developed by NPC

The screening criteria for chemical, miscible gas, and thermal recovery processes are described in detail in the 1984 NPC study. The discussion below summarizes the information included in the NPC study. The screening criteria for the application of polymer, surfactant, and alkaline flooding processes are primarily based on the characteristics of the rock (permeability and lithology), oil (viscosity and API gravity), and formation brine (ppm dissolved solids), and on the reservoir temperature. Application of miscible gas injection processes is primarily related to the capability to attain miscibility between the crude oil and CO_2, or the minimum miscibility pressure (MMP), and on the oil gravity. The screening criteria for the applicability of thermal processes are based on the characteristics of published successful projects and include formation depth, current reservoir pressure, net pay, porosity, oil content, oil gravity, oil viscosity, formation permeability, and formation transmissibility.

Table C–2
Screening Criteria for Improved Recovery Processes, Advanced Technology Case
(Source: NPC 1984)

Screening Parameters	Units	Profile Modification	Polymer Flooding	Surfactant Flooding	Alkaline Flooding	Miscible Flooding (CO_2)	Thermal Recovery	
							Steam	In Situ Comb.
Oil Gravity	°API	--	--	--	<30	≥25	--	--
In Situ Oil Viscosity (μ)	cP	<150	<150	<100	<100	--	--	≤5,000
Depth (D)	Feet	--	--	--	--	--	≤5,000	--
Pay Zone Thickness (H)	Feet	--	--	--	--	--	≥15	≥10
Reservoir Temperature (T_r)	°F	<250	<250	<250	<200	--	--	--
Porosity (Ø)*	Fraction	--	--	--	--	--	≥0.15	≥0.15
Permeability, Average (K)	mD	>10	>10	>10	>10	--	≥10	≥10
Transmissibility (Kh/μ)	mD/ft-cP	--	--	--	--	--	--	--
Reservoir Pressure (P_r)	psi	--	--	--	--	≥MMP†	≤2,000	≤4,000
Minimum Oil Content at Start of Process (S_o Ø)	Fraction	--	--	--	--	--	≥0.08	≥0.08
Salinity of Formation Brine (TDS)	ppm	<200,000	<200,000	<200,000	<200,000	--	--	--
Rock Type	--		Sandstone or Carbonate	Sandstone or Carbonate	Sandstone	Sandstone or Carbonate	Sandstone or Carbonate	Sandstone or Carbonate

* Ignored if oil saturation—porosity product (S_oø) criterion is satisfied.
† MMP denotes minimum miscibility pressure, which depends on temperature and crude oil composition.

Polymer Flooding: The NPC determined that historical polymer flooding projects were only successful when permeability was greater than 20 mD, oil viscosity was less than 100 cP, formation brine salinity was less than 100,000 ppm, and formation temperature was less than 200°F. These criteria represent the implemented technology case. Polymer flooding was assumed to be applicable in both sandstone and carbonate reservoirs. The permeability limit reflects the fact that high molecular weight polymers cannot be effectively propagated through low permeability rock. Lower molecular weight polymers in higher concentrations could possibly be used in low permeability rock to achieve the desired viscosity or resistance factors, but the low injectivity would increase project life and adversely affect the project economics. The NPC also found that polymer applications were not effective when oil viscosity exceeds 100 cP, since higher polymer concentrations are required and lower injection rates are experienced, both of which affect economics. The brine salinity limitation reflects the fact that most synthetic polymers have not been demonstrated to be effective when brine salinity is above 100,000 ppm, although some biologically produced polymers are relatively insensitive to salinity. The temperature limitation for polymers is significant due to thermal degradation which results in

the loss of viscosifying capabilities. In the advanced technology case, the NPC assumed that the cost-effectiveness and stability of polymers could be improved, if polymer flooding could extend to reservoirs with permeability greater than 10 mD, oil viscosity less than 150 cP, formation brine salinity less than 200,000 ppm, and formation temperatures less than 250°F.

Surfactant Flooding: The NPC determined that surfactant-flooding projects were only successful when permeability was greater than 40 mD, oil viscosity was less than 40 cP, formation brine salinity was less than 100,000 ppm, and formation temperature was less than 200°F. These criteria represent the implemented technology case. Surfactant flooding was not considered applicable in carbonate reservoirs in the implemented technology case. As in the case of polymer flooding, the permeability of the formation affects surfactant flooding due to the adverse effects on injectivity, project life, and economics at low permeabilities. The success of surfactant-flooding processes when oil viscosity is greater than 40 cP is limited by the costs associated with the higher polymer concentrations required for mobility control. The success of surfactant flooding is severely limited by the brine salinity and formation temperature together due to the adverse impacts on both the surfactants and the associated polymers. In the advanced technology case, the NPC assumed that improvements in the cost-effectiveness and stability of surfactants and polymers could extend applicability to reservoirs with permeability greater than 10 mD, oil viscosity less than 100 cP, formation brine salinity less than 200,000 ppm, and formation temperatures less than 250°F. The advanced technology case also assumes that surfactants could be applicable to both sandstone and carbonate reservoirs.

Alkaline Flooding: The NPC determined that alkaline flooding projects were only successful when permeability was greater than 20 mD, oil viscosity was less than 40 cP, oil gravity was less than 30° API, formation brine salinity was less than 100,000 ppm, and formation temperature was less than 200°F. These criteria represent the implemented technology case. Alkaline flooding was not considered applicable in carbonate reservoirs in either the implemented or advanced technology case due to the adverse chemical/rock interactions. The permeability, salinity, and temperature criteria reflect the limitations of the polymers used in the alkaline flooding process. The oil viscosity limitation reflects the fact that successful field tests have not been achieved when oil viscosity was greater than 90 cP. The oil gravity limitation was established to correspond to the acid number of the oil which, at that time, was considered essential for alkaline flooding. In the advanced technology case, the NPC assumed that if cost-effectiveness and stability of alkaline chemicals, cosurfactants, and polymers could be improved, alkaline flooding could be used in reservoirs with permeability greater than 10 mD, oil viscosity less than 100 cP, and formation brine salinity less than 200,000 ppm. The oil gravity and formation temperature limitations were determined to be the same for the implemented and advanced technology cases.

Miscible Flooding: The primary limitation for applying miscible gas injection processes was the ability to achieve miscibility in the reservoir between the crude oil and the injected solvent (CO_2). The minimum miscibility pressure (MMP) for the TORIS reservoirs was estimated by the NPC using two correlations. The first correlation estimates the molecular weight of the C_{5+} portion of the crude oil using oil gravity (Lasater 1958). The second correlation estimates the MMP using

the molecular weight of the C_{5+} portion of the crude oil and the formation temperature (Holm and Josendal 1974; Mungan 1981). The NPC assumed that candidate reservoirs must have an MMP less than the original or maximum operating pressure. The NPC also evaluated reservoirs where the MMP was greater than 200 psi above the current reservoir pressure to determine the feasibility of repressurization. In addition, the NPC assumed that miscible gas injection was not viable for crude oil with gravity less than 25° API and was applicable in both sandstone and carbonate reservoirs. The advanced technology case uses the same screening criteria, but the NPC assumed that higher ultimate recovery could be achieved through the use of larger CO_2 slug sizes and mobility control agents in more heterogeneous reservoirs.

Steamflooding: The NPC determined that steamflooding was successful only in projects with formation depth less than 3,000 feet, current reservoir pressure less than 1,500 psi, net pay greater than 20 feet, porosity greater than 20%, oil content (oil saturation-porosity product) greater than 0.1, oil gravity in the range of 10°–34° API, oil viscosity less than 15,000 cP, formation permeability greater than 250 mD, and formation transmissibility (kh/μ) greater than 5 mD-ft/cP. These criteria represent the implemented technology case. Steamflooding was assumed to be applicable in both sandstone and carbonate reservoirs. The depth limitation is important because heat losses increase with increasing depth. The net pay limitation is important because excessive heat losses occur in thin reservoirs. Porosity is important because as porosity decreases more energy is required to heat the larger volume of rock. The oil content criterion (oil saturation-porosity product saturation) was established since there must be sufficient oil in the reservoir to justify the cost of the steamflood. The oil viscosity and gravity limitations were established to ensure that minimum oil mobility requirements are achievable. The reservoir permeability and transmissibility limitations were established to ensure that steam injectivity is high enough to successfully propagate the steam front. The advanced technology case screening criteria were developed assuming that reasonable steamflooding techniques and equipment could be developed to extend the process to reservoirs with depth less than 5,000 feet, current reservoir pressure less than 2,000 psi, net pay greater than 15 feet, porosity greater than 15%, oil content (oil saturation-porosity product) greater than 0.08, and formation permeability greater than 250 mD.

In Situ Combustion: The NPC determined that in situ combustion was only successful in projects with formation depth less than 11,500 feet, current reservoir pressure less than 2,000 psi, net pay greater than 20 feet, porosity greater than 20%, oil content (oil saturation-porosity) greater than 0.08, oil gravity in the range of 10°–35° API, oil viscosity less than 5,000 cP, formation permeability greater than 35 mD, and formation transmissibility (kh/μ) greater than 5 mD-ft/cP. The importance of the in situ combustion screening criteria parallels those for steamflooding. The advanced technology case screening criteria were developed assuming that reasonable in situ combustion techniques and equipment could be developed to extend the process to reservoirs with current reservoir pressure less than 4,000 psi, net pay greater than 10 feet, porosity greater than 15%, and formation permeability greater than 10 mD.

C.2.2 Screening Criteria for ASR Processes

Subsequent to the NPC study, DOE developed additional predictive models for TORIS for the recovery of unrecovered mobile oil (UMO) that are called advanced secondary recovery (ASR) processes (ICF/BEG 1990; IOGCC 1993). Predictive models were developed to define the possible recovery from profile modification and infill drilling processes. The screening criteria developed for profile modification were essentially those that the NPC developed for polymer flooding, except that the temperature limitation for the implemented technology case was reduced to 180°F. This reflects the fact that cost-effective polymers for profile modification applications above 180°F are still achieving limited success in the developmental stage due to thermal degradation of the polymers. No screening criteria were developed specifically for infill drilling, rather the economics of reducing the well spacing in waterflood reservoirs determines the applicability, with the recovery improvement based on the improvement in reservoir continuity. Polymer flooding is also considered to be an ASR process, and the screening criteria are those discussed previously.

C.3 Discussion of TORIS Predictive Model Methodologies

The predictive models used by the NPC and currently used in TORIS were developed by Scientific Software-Intercomp for DOE. Predictive models were developed to assess the recovery potential and economics for chemical flooding, miscible flooding, steam flooding, in situ combustion, and polymer flooding. Subsequent to the NPC study, predictive models were developed for profile modification and infill drilling. The general characteristics of these predictive models are discussed in this section.

C.3.1 Chemical Flood Predictive Model

The Chemical Flood Predictive Model (CFPM) was developed by Scientific Software-Intercomp for DOE to predict the recovery performance and economics of micellar-polymer (surfactant) floods. This publicly available model was modified somewhat by the NPC for the 1984 EOR study, and TORIS currently uses the modified model to predict the results of both surfactant and alkaline floods.

The CFPM predicts the overall recovery efficiency of a chemical flood based on the displacement efficiency, vertical sweep efficiency of the surfactant, and the sweep efficiency of the polymer. The displacement efficiency is determined by the capillary number, which is calculated as a function of the permeability, depth, and well spacing of a reservoir. A constant micellar phase-oil phase interfacial tension of 10^{-3} dyne/cm is used. The vertical sweep efficiency of the surfactant is estimated from correlations derived from simulation results which considered surfactant slug size, surfactant adsorption, and reservoir heterogeneity. The polymer sweep efficiency is empirically derived from numerical simulation results which considered polymer slug size and vertical sweep efficiency. The estimated overall recovery efficiency is then corrected to take into

consideration the effects of crossflow between layers based on numerical simulation considering the ratio of vertical to horizontal permeability. Oil-water fractional flow theory is used to predict breakthrough, peak oil production rate, and project life. The NPC modified the model slightly to predict the performance of alkaline floods, but basically the alkaline flood results are assumed to be a fraction of the surfactant flood results.

The CFPM generates an oil rate versus time relationship for a single five-spot pattern in a surfactant flood or alkaline flood, and the results are then scaled up to represent the performance of a reservoirwide project using a specified pattern development schedule. The after-tax cash flow for each project is then calculated, taking into account the capital costs for drilling, well conversions, chemical and injectant costs, operating costs, depreciation, royalties, and taxes. (See DOE/BC-86/11/SP and Paul et al. 1982 for details of the model methodology.)

C.3.2 Miscible Flood Predictive Model

Scientific Software-Intercomp developed the CO_2 Miscible Flood Predictive Model (CO2PM) for DOE to predict the recovery performance and economics of miscible CO_2 floods. This publicly available model was used in the 1984 NPC study and is currently used in the TORIS system.

The CO2PM is a three-dimensional (layered, five-spot) two-phase (aqueous and olefinic) three-component (oil, water, and CO_2) model that uses fractional flow theory modified for the effects of viscous fingering, areal sweep, vertical heterogeneity, and gravity segregation to predict oil, water, and CO_2 rates. Fractional flow theory (Buckley and Leverett 1942) based on a specialized version of the method of characteristics known as coherence or simple wave theory (Patton et al. 1971; Pope 1980) is applied to represent the results of first contact miscible displacement in the presence of a second immiscible phase. The model incorporates the Koval factor into the fractional flow theory to account for viscous fingering effects (Koval 1963), and an extension of the Koval approach is utilized to account for the effects of gravity segregation. The modified fractional flow theory is then corrected for areal sweep using a generalization of the method developed by Claridge (1972). A reservoir can be described in the model with up to five noncommunicating layers to account for reservoir heterogeneity, and the layer permeabilities are calculated from a reservoir-specific value for the Dykstra-Parsons coefficient.

The CO2PM generates an oil rate versus time relationship for a single five-spot pattern in a miscible flood, and the results are then scaled up to represent the performance of a reservoirwide project using a specified pattern development schedule. The after-tax cash flow for each project is then calculated, taking into account the capital costs for drilling, well conversions, CO_2 purchase, compression and recycle costs, operating costs, depreciation, royalties, and taxes. (See DOE/BC-86/12/SP and Paul et al. 1984 for details of the model methodology.)

C.3.3 Steamflood Predictive Model

Scientific Software-Intercomp developed the Steamflood Predictive Model (SFPM) for DOE to predict the recovery performance and economics of steamfloods. This publicly available model was used in the 1984 NPC Study and is currently used in the TORIS system.

The SFPM was developed using four algorithms, each of which can be used independently to predict the performance of a steam drive. These four simplified steamflood predictive algorithms are known as: (1) the Williams et al. (1980) or SUPRI (Stanford University Petroleum Research Institute) model, (2) the Jones (1981) model, (3) the Gomaa (1980) model, and (4) the Intercomp model (Aydelotte and Pope 1983). The SUPRI model provided the basic architecture for the SFPM, including the surface and wellbore heat loss calculations and the economic analysis methodology. This model uses the method developed by Marx and Langenheim (1959) for calculation of reservoir heat losses and for predicting the growth of the steam zone as continuous steam injection progresses. The original Jones model was based on the work of Van Lookeren (1977) and Myhill and Stegemeier (1978) and uses an injection rate optimization function based on a vertical conformance factor. This function was replaced in SFPM through modification of the heat balance equations to allow for variable injection rates and steam qualities. The oil recovery algorithm is based on the Marx and Langenheim equations as modified by Mandl and Volek (1969). The Gomaa model predicts steamflood performance based on empirical correlations for California reservoirs, developed from numerical simulation using the Coats et al. (1974) implicit steamflood model. Correlations were developed to predict vertical heat losses, vertical sweep, and oil recovery as a function of reservoir thickness and volume, heat injection, steam quality, and oil saturation. The Intercomp model was developed as a simplified extension of these earlier analytical heat balance models and considers fractional flow characteristics, vertical and areal sweep effects, steam injectivity, and wellbore and surface heat losses.

Using any one of these predictive algorithms, the SFPM generates an oil rate versus time relationship for a single five-spot pattern in a steamflood, and the results are then scaled up to represent the performance of a reservoirwide project using a specified pattern development schedule. The after-tax cash flow for each project is then calculated taking into account the capital costs for drilling, well conversions, steam generation costs, operating costs, depreciation, royalties, and taxes.

The four oil recovery predictive algorithms described were compared by the NPC, and the Gomaa model was found to yield the most accurate prediction of steamflood performance except when reservoir dip exceeded 10°. The NPC developed a dip correlation through a series of calibration runs, and this correlation is included in the model. The TORIS steamflood predictions use the Gomaa model. (See DOE/BC-86/6/SP and the papers cited previously for details of the model methodology.)

C.3.4 In Situ Combustion Predictive Model

Scientific Software-Intercomp developed the In Situ Combustion Predictive Model (ICPM) for DOE to predict the recovery performance and economics of in situ combustion projects. This publicly-available model was used in the 1984 NPC study and is currently used in the TORIS system.

The ICPM predicts oil recovery for in situ combustion projects based on the correlations developed by Brigham et al. (1980). These correlations relate the volumes of oil burned and produced to the volume of air injected and the reservoir volume based on the analysis of the results of 12 field pilot tests. These correlations are valid for the dry combustion process only. The NPC developed a method for predicting the performance of wet combustion processes based on laboratory slim tube test data developed by Garon and Wygal (1974) and Prats (1982). The wet combustion process correlations are applied only if the oil viscosity is above 10 cP and the reservoir permeability is above 100 mD. Various assumptions were made about the process specifics as outlined in the model documentation (DOE/BC-86/7/SP) and the NPC study.

The ICPM generates an oil rate versus time relationship for a portion of a pattern in an in situ combustion project, and the results are then scaled up to represent the performance of a reservoirwide project using a specified pattern development schedule. The after-tax cash flow for each project is then calculated, taking into account the capital costs for drilling, well conversions, process costs, operating costs, depreciation, royalties, and taxes.

C.3.5 Polymer Flood Predictive Model

Scientific Software-Intercomp developed the Polymer Flood Predictive Model (PFPM) for DOE to predict the recovery performance and economics of either polymer floods or waterflooding and to estimate the incremental performance of polymer flooding over waterflooding. This publicly available model was used in the 1984 NPC study and is currently used in the TORIS system to predict polymer flood recovery through the improvement of mobility ratio and sweep efficiency in waterfloods.

The PFPM is a three-dimensional, two-phase (water and oil) simulator that represents the waterflood performance of one-eighth of a five-spot pattern using a stream tube approach (Higgens and Leighton 1962; Leblanc and Caudle 1971) and fractional flow theory. The model uses five noncommunicating layers of equal thickness to represent some degree of reservoir heterogeneity, and the layer permeabilities are defined using the average reservoir permeability and the Dykstra-Parsons coefficient of permeability variation. The areal and vertical recovery of the waterflood is estimated using eight streamtubes in each layer and a modified version of the Buckley-Leverett fractional flow theory (Buckley and Leverett 1942) known as the method of characteristics (Patton et al. 1971; Pope 1980). The model estimates the saturation profile for each stream tube, and these calculations are used to calculate the stream tube conductivity, which determines the flow distribution between stream tubes and the change in injectivity over time.

The model takes into account the change in mobility caused by the injection of polymer and considers polymer retention, non-Newtonian effects, and other polymer properties. PFPM first estimates oil recovery using the assumption of continuous polymer injection, and then corrects the results for finite polymer slug sizes using a correlation was developed from rigorous 3D numerical simulation of polymer floods. (A Scientific Software-Intercomp finite difference polymer flood model was used to develop this correlation.) The model estimates the incremental recovery of the polymer flood by comparison of the results with a prediction of waterflood performance.

The PFPM generates an oil rate versus time relationship for an eighth of a five-spot pattern in a polymer flood project, and the results are then scaled up to represent the performance of a reservoirwide project, using a specified pattern development schedule. The after-tax cash flow for each project is then calculated taking into account the capital costs for drilling, well conversions, polymer costs, operating costs, depreciation, royalties, and taxes. (See DOE/BC-86/10/SP and the references cited above for additional details of the model methodology.)

According to the methodology devised by the NPC, the TORIS version of PFPM only assessed polymer flood feasibility in reservoirs with severe mobility problems, or where the mobility ratio was greater than 8. Subsequent to the NPC study, PFPM was modified to allow assessment of polymer floods in reservoirs where the mobility ratio was less than the value of 8. Polymer concentration schedules were developed for various mobility ratios ranging from below 2 to above 30 (ICF/BEG 1990).

C.3.6 Profile Modification Predictive Model

DOE modified the Polymer Flood Predictive Model after the NPC study to evaluate the performance of gel-polymer profile modification treatments (ICF/BEG 1990). TORIS currently uses this model to predict the recovery potential for profile modification treatments, which improve waterflood recovery through the improvement of vertical sweep efficiency.

The profile modification predictive model assumes that the gel-polymer treatment reduces the permeability contrast between the five layers in the model. The water injection rate into each of the five layers is calculated in PFPM using a radial-flow equation (Muskat 1946), thus proportioning injection by layer based on the permeability of each layer. The profile modification model assumes that the sweep efficiency in the model remains constant as the gel-polymer is injected, so the reduction in permeability in each layer is proportional to the fluid intake capacity of each layer, and the permeability in the most permeable zones is reduced the most. The injectivity into each zone is then adjusted to reflect the permeability contrast reduction. The incremental recovery and economics of the profile modification treatment are then analyzed as in PFPM.

C.3.7 Infill Drilling Predictive Model

Scientific Software-Intercomp (SSI) developed the Infill Drilling Predictive Model (IDPM) for DOE after the NPC study to predict the recovery performance and economics of infill drilling projects. TORIS currently uses this model to predict the recovery potential for infill drilling projects.

The IDPM was developed with an architecture similar to the Polymer Flood Predictive Model with more rigorous calculation methodologies. The IDPM is a three-dimensional, two-phase (water and oil) simulator that represents the waterflood performance of a portion of a five-spot or nine-spot pattern using a streamtube approach combined with finite difference solutions techniques. The model uses multiple layers (user specified, maximum of 20) for which thickness, porosity, and permeability can be varied to represent some degree of reservoir heterogeneity. For the TORIS reservoir data, the layer thicknesses are assumed to be constant, and the layer permeabilities are defined using the average reservoir permeability and the Dykstra-Parsons coefficient of permeability variation. The model uses a two-dimensional, steady state, finite difference simulation of a pattern element of symmetry to define the geometry of each streamtube within each layer. The number of streamtubes within each layer may be specified by the user. The model calculates the water-oil displacement and oil recovery within each streamtube using finite difference methods and a user-specified number of grid blocks within each streamtube. The model has the capability to account for crossflow between layers in each streamtube. The model generates a new set of streamtubes and performs the recovery calculations to predict the performance of infill drilling for drill down from five-spot to nine-spot patterns or from five-spot to smaller five-spot patterns.

To model the improvement in reservoir continuity generally realized from infill drilling, two methodologies are available in IDPM. The original methodology defined by SSI models the improvement in continuity by modifying the relative permeability endpoints to improve recovery as continuity improves. The user-specified relative permeability curve end points are assumed to be at 100% continuity and are adjusted proportionately based on the specified continuity at the original well spacing. The other method for modeling the improvement in continuity adds additional net pay in an additional layer to reflect improved continuity as reservoirs are drilled down. The user-specified net pay is assumed to be at 100% continuity and is adjusted proportionately based on the assumed continuity at the original well spacing. Either method yields reliable infill drilling project performance based on comparison with detailed simulation results (Biglarbigi et al. 1994).

The IDPM generates an oil rate versus time relationship for an eighth of a five-spot or nine-spot pattern. The results are then scaled up to represent the performance of a reservoirwide infill drilling project using a specified pattern development schedule. The after-tax cash flow for each project is then calculated taking into account the capital costs for drilling, well conversions, operating costs, depreciation, royalties, and taxes. (See Fuller et al. 1992, Biglarbigi et al. 1994, and the model documentation DOE/BC-94/4/SP for additional details of the model methodology.)

C.3.8 Predictive Models for Combination Processes

TORIS models have also been developed to evaluate infill drilling in combination with polymer flooding and profile modification treatments. These models are modified versions of the IDPM. For modeling infill drilling in combination with polymer flooding, the viscosity of the injected water was adjusted so that the mobility ratio is improved. The polymer schedules described in the PFPM were incorporated into the IDPM so that the target mobility ratio of unity or close to unity is achieved. For modeling infill drilling in combination with profile modification, IDPM was modified in the same manner as described in the previous Section C.3.7. Accordingly, the incremental economics of these two combination processes over waterflooding are estimated using the appropriate drilling costs, well conversion costs, polymer costs, operating costs, depreciation, royalties, and taxes.

C.4 Economic Considerations

The TORIS recovery models take into consideration all of the appropriate costs and variables in the economic calculations, including all process-dependent costs, all process-independent costs, and other factors such as oil price, inflation, depreciation, royalties, and taxes. Since the chemical and miscible processes involve the injection of water, the process-independent costs are defined as the typical costs associated with the installation and operation of waterflood projects. Project dependent costs are generally the incremental installation and operating costs above the base waterflood costs. The process dependent and independent costs are adjusted for product price variations, formation depth, and regional aspects according to guidelines developed by the NPC (1984). The sources for the cost information used in TORIS include Energy Information Agency publications, the American Petroleum Institute Joint Association Surveys, and vendor and operator surveys. DOE regularly updates the cost structures used in the predictive models.

C.4.1 Process-Dependent Costs

The process-dependent costs are the incremental costs associated with the installation and operation of the improved recovery projects. The process-dependent costs for chemical (polymer, profile modification, alkaline, and surfactant) processes include the costs for all injected polymer, surfactant, and alkaline agents according to formulation schedules devised by the NPC. The process-dependent costs for miscible flooding projects include the cost for installing and operating CO_2 injection and recycling plants, and the purchase price for CO_2. The CO_2 purchase price is adjusted, depending upon project location (West Texas or non-West Texas). The steamflood predictive model considers the cost to install and operate steam generators, costs associated with fuel and water treatment for steam generation, costs for drilling producers and injectors, and other process-specific facilities costs. The in situ combustion process model considers the cost for air injection equipment installation and operation, costs for drilling producers and injectors, and other process-specific facilities costs.

C.4.2 Process-Independent Costs

The process-independent costs generally include the costs for well drilling and completion, well conversion costs, normal operating costs, and associated equipment and facilities costs. The costs for drilling, completing, and converting wells are dependent on the well depth and geographic region. Operating costs on a per-well basis include normal daily expenses, surface maintenance costs, and subsurface maintenance costs. These costs are also defined based on producing depth and geographic region. The facilities costs include production and injection equipment for secondary recovery required by the drilling and conversion of wells, and costs for upgrading surface processing equipment.

C.4.3 Other Economic Considerations

Additional considerations of importance in the TORIS economic analysis methodology include the product prices, tax treatment, and economic hurdles for process viability. Crude oil prices used in the economic analyses are specified as the price for West Texas Intermediate with adjustments for oil gravity and project location. The economics also include the appropriate treatment of federal income taxes based on applicable IRS rules and include EOR tax credits when appropriate. State income and severance taxes are included in the economic calculations. The minimum acceptable rate of return, or hurdle rate, is established for each process and level of technology to determine process viability. The hurdle rates are used to reflect typical required investment efficiencies for project implementation and to account for a certain degree of project risk. In the implemented technology case, the hurdle rate for alkaline, surfactant, and in situ combustion projects is 27%, and the hurdle rate for the other processes is 16%. In the advanced technology case, the hurdle rates are reduced to 10% for all processes except in situ combustion, which is reduced to 16%. The reduced minimum acceptable rate of return in the advanced technology case reflects anticipated process improvements achieved through R&D.

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APPENDIX D
RECENT IMPROVED OIL RECOVERY (IOR) PROCESS RESEARCH

The discussion included in this appendix was originally presented in the 1994 Class 4 Department of Energy report: R*esearch Needs for Strandplain/Barrier Island Reservoirs in the United States* (Cole et al. 1994). The material has been updated in several process areas where new information has become available since publication of that report. Appendix D has been included to provide the Class 5 operator considering IOR processes with appropriate general background information and references to important recent literature. Processes and technologies discussed include infill drilling (Section D.1), conformance control technologies (Section D.2), polymers for mobility control (Section D.3), microbial processes (Section D.4), alkaline and alkaline-surfactant-polymer processes (Section D.5), surfactant process (Section D.6), steam process (Section D.7), in situ combustion process (Section D.8), and carbon dioxide processes (Section D.9).

D.1 Infill Drilling

Infill drilling has been a common practice in oil fields since the early days of the petroleum industry. It didn't take investors long to realize that more wells and faster withdrawal rates provided faster return on investment, yet the damage that overdrilling and overproduction practices often caused in terms of reduced ultimate recovery was not realized for years. The reduced productivity of wells resulting from overdrilling usually was the reason for curtailment of drilling activity in a field, as operators recognized points of diminishing returns. Many states (e.g., Texas) adopted spacing limitations to conserve the hydrocarbon resources and to prevent overdrilling and overproduction practices. As waterflooding gained in popularity, the need for controlled injection and production rates was recognized, and regular injection patterns became an important method to increase the efficiency of waterfloods. Often additional wells were drilled in waterfloods to install, align, or realign patterns in desired configurations, with adherence to spacing limitations, as required. With the development of enhanced oil recovery processes, operators drew upon the experience gained from waterflooding and began developing reservoirs on reduced spacing using defined patterns to improve process efficiency. The industry recognized early on that different reservoir conditions and process requirements resulted in different spacing requirements. It really wasn't until the 1980s that infill drilling began to be considered as a recovery process in and of itself, with significant potential for improving recovery. Since that time, numerous attempts have been made to quantify the

potential for infill drilling in the country, beginning with van Everdingen and Kriss in 1980 up through the present work of the Interstate Oil and Gas Compact Commission and Department of Energy, as discussed in this section.

Van Everdingen and Kriss (1980) suggested that infill drilling, if done properly, can be used to recover at least as much oil as the United States already has produced, or nearly 120 billion barrels. This unsubstantiated estimate was considered by many in the industry to be an overexaggeration of infill drilling potential. In 1980 Holm estimated that infill drilling in the country could add between 1 and 1.5 billion barrels of reserves per year for about 10 years and that recovery per well would be between 34,000 and 47,000 barrels of oil. Realistic analysis of infill drilling potential in west Texas carbonate fields was conducted by Driscoll (1974), Barber et al. (1983), and Ghauri (1980). This work, later compiled by Gould and Sarem (1989), indicated that recovery potential averaged about 107,000 barrels per infill well. This value is substantially higher than Holm's estimate but is specific to the heterogeneous West Texas carbonates. In 1984 the National Petroleum Council study estimated that, at $20/barrel oil price, the recovery potential for the expanded application of thermal, miscible, and chemical processes totals 7.4 billion barrels (NPC 1984). Gould and Sarem (1989) stated that "infill drilling would appear to have potential equal to or greater than EOR processes."

In 1990 DOE funded a project conducted by ICF and the Texas Bureau of Economic Geology to develop a methodology for estimating the potential for the recovery of unrecovered mobile oil (UMO) in Texas, Oklahoma, and New Mexico (ICF/BEG 1990a, 1990b, 1990c, 1990d). This study estimated the recovery potential possible through the expanded application of infill drilling, profile modification, polymer flooding, and infill drilling in combination with profile modification and polymer flooding. This work indicated that the recovery potential for infill drilling in these states at $20/barrel oil price was between 1 and 2 billion barrels (1%–2% of the original oil in place), depending upon the level of understanding of reservoir heterogeneity. This potential increases to between 1.2 and 4.5 billion barrels if infill drilling is conducted in waterfloods in combination with polymer flooding and profile modification. This work was subsequently modified and expanded by the Interstate Oil and Gas Compact Commission (DOE funded) to estimate the infill drilling potential for the country (IOGCC 1993). At $20/barrel, the infill drilling potential in the country was estimated to be between 1.3 and 1.7 billion barrels, depending on the level of technology advancement. If infill drilling is conducted in combination with polymer applications, this potential increases to between 6.3 and 10.8 billion barrels.

In 1980 Holm researched the idea of infill drilling versus tertiary oil recovery and listed the advantages and disadvantages of applying (1) infill drilling followed by a tertiary flooding process or (2) applying infill drilling and tertiary or EOR processes simultaneously.

In the first approach (infill drilling followed by EOR process), Holm cited several advantages, including: (1) expense, (2) no delays for chemical acquisition or injection plant construction, and (3) closer-spaced, paid-for patterns already in place for eventual tertiary operations. On the other hand, this approach faces several disadvantages, such as (1) the amount of oil left in patterns after the extended waterflooding will be less, thereby resulting in less oil recovered by tertiary

process, since these processes become less efficient as the oil saturation approaches the critical capillary residual-oil saturation to water flow; (2) the infill drilling program may not be designed for optimum tertiary flooding; and (3) the infill drilling projects may produce less oil than required to keep the program economical and thereby be unable to support the additional expenditures for tertiary recovery.

The second approach that Holm suggested is to conduct the infill drilling and tertiary or EOR process simultaneously. This approach could have many advantages: (1) more total oil reserves will be achieved, (2) total production or recovery elapsed time is decreased, (3) cost of the required wells can be shared, (4) early production of additional oil will occur, (5) higher oil saturation will be present in patterns at the start of the tertiary project, and (6) well patterns can be tailored to optimize both infill drilling and tertiary recovery. This approach is particularly advantageous for the chemical floods such as micellar, polymer, and surfactant because it provides new wells that can be designed to permit better distribution of injected chemicals and faster, more efficient completion of the designated water preflush required for most projects than is possible with larger spacing.

Regardless of the actual estimates of potential of infill drilling or the application of infill drilling with waterflooding or tertiary recovery projects, infill drilling is a viable process for improving recovery from many oil reservoirs in the country. The key to the success of infill drilling is understanding the reservoir heterogeneities and complexities which limit recovery potential at current well spacing and the relationship of these complexities to recovery at reduced well spacing.

D.1.1 Recent Technology Thrusts

The major thrust of research activity related to infill drilling has focused on defining and understanding the mechanisms which impact recovery from infill drilling projects. In 1974 Driscoll defined the factors controling the improved recovery of infill drilling in pattern waterfloods. These factors, in order of importance, include: (1) improved reservoir continuity, (2) improved areal sweep, (3) improved vertical sweep, (4) recovery of wedge-edge oil, and (5) improved economic limit. These factors also impact infill drilling in enhanced oil recovery projects. The development of continuity concepts and the impacts of infill drilling on areal and vertical sweep are discussed in following sections (Gould and Sarem 1989; DOE 1994).

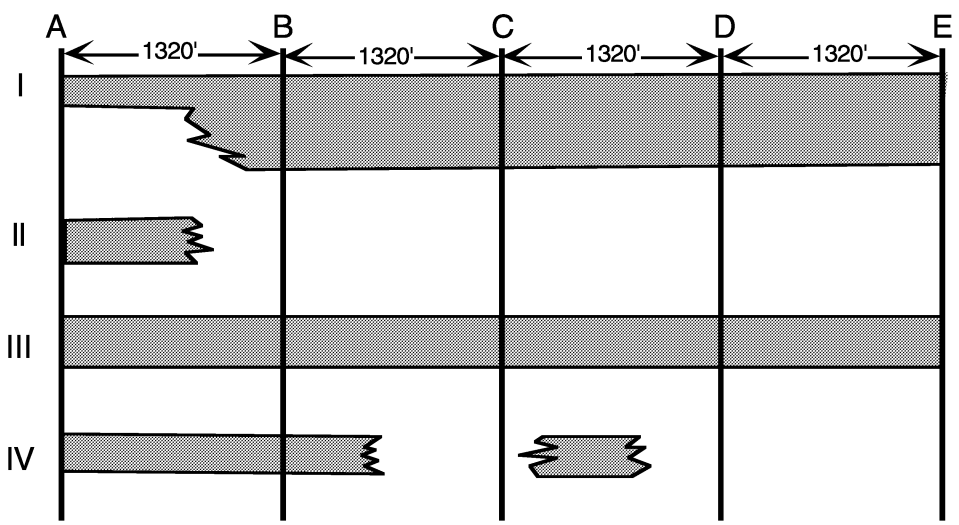
D.1.1.1 Development of Interwell Continuity Concepts

The concept of reservoir pay continuity has been developed beginning in the 1970s to define areal heterogeneities in reservoirs by defining the percentage of reservoir pay which can be contacted as well spacing or interwell distance is reduced. These continuity functions are generated through detailed well log correlation for wells at various spacings in project areas or reservoirs. The typical display of continuity is a coordinate plot of the percentage of continuous net pay versus interwell distance. As interwell distance is reduced, a higher percentage of net

pay is contacted. These relationships are not widely reported in the literature, but they have been developed primarily for highly stratified West Texas carbonate reservoirs. Realized improvement in continuity is considered to be the primary recovery improvement mechanism associated with infill drilling and has resulted in higher than expected recovery from infill wells in the projects discussed (ICF 1991).

The first published continuity relationship was generated for the Wasson Denver Unit in Texas to support Shell Oil Company allowable hearings with the Texas Railroad Commission to illustrate that reduction in well spacing could increase ultimate recovery (Driscoll 1974). Early geologic correlation work in the field revealed that the numerous definable pay stringers were not necessarily continuous over the entire field, giving rise to the concept of "continuous" and "discontinuous" pay (Ghauri et al. 1974).

The best definition of continuity was given by Stiles (1976): "Continuous pay is defined as the volume of porous rock that is connected between any two wells. The fraction of pay continuity between two wells is then the ratio of the continuous porous rock volume to the total porous rock volume." This concept is shown graphically in Figure D–1. In this work, Stiles defined continuity relationships for the Fullerton Clearfork Unit, Texas. Using this methodology, Exxon developed an innovative, computerized geologic modeling technique to draw and analyze cross sections using hundreds of wells in order to define the continuity in the Judy Creek Field, Canada (Delaney and Tsang 1982). Stiles's methodology was also used in later work in the Wentz (Clearfork) Field, Texas, to justify a marginal waterflood project (Hunter 1988).



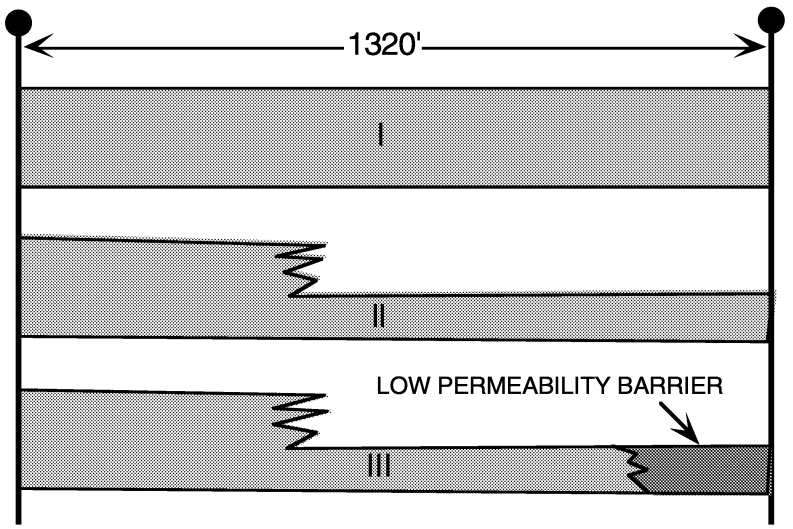
$$\% \text{ CONTINUITY} = \frac{\text{EFFECTIVE POROUS VOLUME}}{\text{TOTAL POROUS VOLUME}}$$

$$\% \text{ CONTINUITY WELL PAIR AB} = \frac{\text{BED I + III + IV}}{\text{BED I + II + III + IV}}$$

Figure D–1 Schematic Illustration—Continuity Functions (Modified from Stiles 1976)

Subsequent work by George and Stiles (1978) in the Means San Andres Unit, Texas, gave rise to the concept of floodable pay continuity. This work indicated that, although pay zones may be continuous between well pairs, the zones may not be entirely floodable due to irregularities in bed geometry, ineffective well completions, or lack of injection support. Work by Exxon in the Robertson Clearfork Unit, Texas, used geological correlations, pressure transient analysis, and numerical analysis of infill results to define both floodable and drainable continuity relationships as shown in Figure D–2 (Barbe and Schnoebelen 1986). The floodable pay continuity relationships derived for Robertson Clearfork Unit were extended by ICF and BEG (1990c) to estimate the potential for targeted and blanket infill drilling in the entire Clearfork carbonate play in the Permian Basin. ICF and BEG developed modified floodable and drainable pay continuity relationships for the Grayburg/San Andres reservoir in the Dune Field, Texas, taking into account the loss in reservoir quality between well pairs. This work was used to define the infill drilling potential for the Grayburg/San Andres play in the Permian Basin (ICF/BEG 1990b).

Recently, developments in the area of geostatistics have resulted in more advanced methods of characterizing and predicting interwell permeability and porosity trends using stochastic methods (Lucia and Fogg 1989). The use of the results from the geostatistical approaches in reservoir simulations have adequately matched infill drilling performance in highly stratified carbonate fields.



SUMMARY

BED I - 100% DRAINABLE AND FLOODABLE CONTINUITY
BED II - 100% DRAINABLE CONTINUITY; PARTIAL FLOODABLE CONTINUITY
BED III - 100% DRAINABLE CONTINUITY; 0% FLOODABLE CONTINUITY

Figure D–2 Illustration of Drainable versus Floodable Continuity (Source: Biglarbigi et al. 1994)

In work related to reservoir continuity, Texas A&M University conducted a study on the hydraulic interwell connectivity (HIC) concept based on reservoir characterization, geostatistics, production performance, and reservoir engineering (Malik et al. 1993). HIC is quantitatively defined as the ratio of observed fluid flow rate to a maximum ideal or possible flow rate between any combination of two wells in the producing unit. This approach was used as a guide for selecting infill well locations to optimize waterflood infill drilling. As a result of the simulation study, three production wells were realigned according to HIC distribution, which resulted in an additional 10% of waterflood oil recovery.

The approach outlined in the Texas A&M study is based on a geologic and engineering study of a highly stratified carbonate reservoir in the Johnson Field, Texas. The study involved the development of porosity and permeability correlations and the use of experimental semivariograms to define permeability trends between wells. A linear mathematical model was then used to calculate the HIC for each pair of wells in the study area. A three-dimensional distribution of HIC provided a better understanding of reservoir compartmentalization and interwell connectivity. It was determined that a steep HIC distribution represents a poor interwell connectivity.

D.1.1.2 Effects of Infill Drilling on Areal and Vertical Sweep Efficiency

Areal and vertical sweep efficiency improvements result from infill drilling due to the contacting of previously unswept portions of the reservoir. When patterns in a waterflood are modified through infill drilling, the original streamlines are often reversed resulting in the sweeping of unswept areas with higher oil saturations. These effects have been defined, along with the effects of oil-water viscosity ratio and permeability anisotropy, through detailed simulation studies (Gould and Munoz 1982). This work indicated that the amount of incremental recovery due to improved areal sweep depends on (1) the degree of areal heterogeneity or anisotropy, (2) the water cut at the economic limit, (3) the water cut at the time of infill drilling, and (4) the mobility ratio. Areal sweep improvements are similarly realized in enhanced oil recovery projects.

Improved vertical sweep efficiency can be realized through infill drilling projects, because new injection or production wells are added and old wells are recompleted, providing an opportunity to mechanically isolate previously swept or thief zones. The efficiency of the isolation depends upon the degree of crossflow between new zones and the isolated zones (Gould and Sarem 1989). The improved vertical sweep is usually expressed relative to the Dykstra-Parsons coefficient, V_{dp}, which is, in turn, an expression of the vertical distribution of permeability among the layers of a reservoir. Heterogeneous reservoirs (high V_{dp}) benefit the most from mechanical isolation to improve vertical sweep.

Recovery of wedge or edge oil volumes can be achieved through infill drilling by reduction of pattern size and installation of additional patterns to effectively flood unswept segments of the reservoir. Uncontacted oil volumes near the oil-water contact, on the flanks of reservoirs, or near stratigraphic features are often the target of infill drilling programs.

D.1.2 Current Research Related to Infill Drilling

Several industry cost-shared projects with the Department of Energy have focused on infill drilling to improve recovery. These projects are discussed in this section.

In 1990 DOE funded a research project to determine infill drilling potential and economic feasibility in the Frio strandplain/barrier island clastic (Class 4) oil reservoirs of South Texas (ICF/BEG 1992d). Three infill drilling scenarios were studied: (1) playwide blanket infill drilling, (2) selective reservoirwide infill drilling, and (3) strategic or geologically targeted infill drilling.

Additional reserve potential from geologically targeted infill drilling considered the facies distributions in reservoirs and facies continuity functions. Facies distributions were estimated from net sand maps, cross sections, and type logs. Facies continuity functions were based on facies continuity observed in the 41-A reservoir in West Ranch Field, a major Frio strandplain/barrier island reservoir.

Reserves from infill drilling were calculated as a function of oil price for the three drilling scenarios. In all cases, geologically targeted infill drilling recovers significantly more oil than blanket infill drilling. As oil price rises, incremental reserves from selective reservoirwide drilling approach those recovered with strategic infill drilling. However, even though incremental reserves are nearly the same, costs per barrel with geologically targeted infill drilling are about one-half those experienced with selective reservoirwide drilling.

In an effort to maximize the economic producibility of resources from the Frio fluvial-deltaic reservoirs of South Texas, DOE awarded the University of Texas Bureau of Economic Geology (BEG) a contract in 1992 with an anticipated completion date in August 1996. The objective of this effort is the implementation of advanced reservoir characterization techniques to define untapped, incompletely drained, and new-pool reservoirs for near-term recovery methods. The project will develop interwell geologic facies models of Frio fluvial-deltaic reservoirs, similar to those developed for the Frio strandplain/barrier island reservoirs by ICF/BEG, as previously discussed. The developed facies models, when combined with engineering assessments, will assist in characterizing reservoir architecture, flow unit boundaries, and the controls that these characteristics exert on the location and volume of unrecovered mobile and residual oil. The results of these studies are designed to lead directly to identification of specific opportunities for incremental recovery by recompletion and strategic infill drilling of these reservoirs.

As part of the project, two field areas were selected for the study on the basis of preliminary assessments of additional reserve growth potential and the availability of abundant geologic and production data. These areas are the western portion of the Tijerina-Canales-Blucher (TCB) Field, located in Jim Wells County and operated by Mobil, and the Rincon Field, located in Starr County and operated by Conoco. Initial reservoir characterization efforts will be tailored to geologic and engineering data analysis, leading to geologic interpretations of the reservoirs and identification of compartmentalized reservoirs in order to quantify the reserve growth potential.

Another research effort demonstrating the effectiveness of geologically targeted infill drilling is being conducted by Diversified Operating Company and funded by DOE. This Class 1 research effort will focus on infill drilling and improved reservoir management to maximize recovery from the D Sandstone reservoir of the Sooner Unit Field in Weld County, Colorado, using water injection and gas recycling as secondary methods. Phase I of the project involves well site selection and development of a reservoir operations plan. Phase II involves drilling three geologically targeted infill wells and establishing production and injection schedules. Reservoir simulation, transient well tests, and production monitoring will be used to evaluate the results. Phase II of the project involves technology transfer efforts.

A detailed geologic data analysis and interpretation of vertical seismic profiles (VSP) and three-dimensional seismic data revealed that there are several promising locations for infill drilling. Furthermore, production and pressure histories have identified a total of seven reservoir compartments. These operational or production compartments consist of one to four wells.

D.2 Conformance Control Technologies

Conformance control technologies address unrecovered mobile oil (UMO) potential. In the proper application environment, field experience indicates that the technologies are applicable at moderate oil price levels.

D.2.1 Screening, Well Selection, and Treatment Criteria

The screening criteria for the implemented and advanced technologies are summarized in Table D.1. Screening criteria primarily eliminate reservoirs. Gel polymer applications must go beyond screening criteria to candidate selection criteria, treatment design considerations, and application procedures.

In a survey of major oil companies and gel vendors, Seright and Liang (1994) found that producing water-oil ratio was usually the only criterion used to select individual wells. Through their analysis of field data and discussions with major oil companies and gel vendors, Seright and Liang developed more comprehensive candidate selection criteria for both injection and

TABLE D–1
PROFILE MODIFICATION SCREENING CRITERIA AT DIFFERENT TECHNOLOGY LEVELS

Parameter	Implemented Technology	Advanced Technology
Reservoir Temperature, °F	< 180	< 250
Brine Salinity, ppm	< 100,000	< 200,000
Permeability, mD	> 20	> 10
Oil Viscosity, cP	< 100	< 150

TABLE D–2 GEL POLYMER SELECTION CRITERIA FOR INJECTION WELLS (SOURCE: SERIGHT AND LIANG 1994)
1. Reservoir and production data indicate low sweep efficiency during waterflooding. a.Water breakthrough occurs much earlier than expected (i.e., from standard calculations or simulations or from comparison with the performance of other patterns in the field). b.Water-oil ratio (WOR) values at offset producers are much higher than expected. c.Recovery calculations indicate that considerable mobile oil remains that could be recovered more cost-effectively if a blocking agent could be realistically placed in the proper location.
2. If barriers to crossflow do not exist, then interwell tracers must show very rapid transit times (probably indicating that fractures or formation parting cause the channeling problem).
3. In unfractured wells, a.Poor injection profiles must be correlatable from well to well. b.Effective barriers to crossflow must exist (very low k_v/k_h, no flow behind pipe, no vertical fractures). c.Gel can be placed in the offending channel without damaging oil zones (e.g., using zone isolation).
4. Reduced injectivity (caused by the gel) can be tolerated.
5. The well to be treated is in good mechanical condition.

production wells (Tables D–2 and D–3). Besides producing water-oil ratio, these criteria emphasize defining the problem, defining the target mobile oil, considering injectivity and productivity, and, in the case of injection wells, evaluating the mechanical condition of the candidate wells. While industry accepts problem definition as being essential, it often receives inadequate attention in actual practice.

Having selected an appropriate candidate well, the gel polymer treatment must be matched to the well and problem. Decisions must be made whether to use near-wellbore or in-depth treatments and which of the available systems to use. Once appropriate gel system(s) are selected, the treatment must be tailored to the individual well and reservoir conditions. Treatment size, gel time, and gel strength are important variables which must be properly assessed to ensure success.

TABLE D–3 GEL POLYMER SELECTION CRITERIA FOR PRODUCTION WELLS (SOURCE: SERIGHT AND LIANG 1994)
1. Recovery calculations indicate that considerable mobile oil remains that could be recovered more cost-effectively if a blocking agent could be realistically placed in the proper location.
2. High water-oil ratio (WOR) values are observed.
3. The source of the excess water production is identified (e.g., using profiles, logs, or tracers).
4. The candidate well exhibits high productivity.
5. The gelant can be placed without damaging oil zones (e.g., using zone isolation).

Despite the importance of sizing, treatment sizing remains more art than science. Seright and Liang (1994) document the sizing guidelines used by various vendors and major oil companies for both injection and production well treatments. Their analysis suggests different sizing guidelines for different reservoir problems (individual fractures, network of fractures, high permeability strata separated from oil-productive zones by nonpermeable strata, strata with crossflow, flow behind pipe). Seright and Liang (1994) considered sizing guidelines/approaches to be an important research need.

Application practices heavily influence treatment success rates. Important application considerations include properly designed equipment, pretreatment wellbore preparation, compatibility testing with well-site fluids, and "during treatment" adjustments in concentration and rate in response to injectivity changes as the treatment proceeds (Mody 1992). Treatment adjustments as the treatment is being performed adapt planned procedures to unique well conditions.

D.2.2 Constraints

Dauben (1991) analyzed field projects to determine those parameters that limited success in field applications of gel polymers. He concluded that, like polymers, gel polymer applications are constrained by polymer degradation, instability when temperature and/or salinity limits are exceeded, and, in the case of sequentially injected polymer and crosslinking agents, polymer propagation. Additional identified constraints specific to gel polymers included (1) identifying appropriate reservoir or well candidates, (2) gel placement techniques, and (3) improved definition of design parameters affecting treatment success.

A major constraint in gel polymer applications is the uncertainty in treatment results. Mody et al. (1988) reported success rates of less than 50%. *Petroleum Engineer International* also reported technical and economic success rates less than 50% in a 1992 survey (PEI 1992). Vendors generally claim higher success rates, often in the 75%–90% range (Seright 1993). In Seright's survey (1993) of major oil companies, technical and economic success rates between the extremes were reported. Success rates reported by various companies for producing-well and injection-well treatments are summarized in Tables D–4 and D–5.

Risk or uncertainty can be controlled by (1) careful problem definition (i.e., candidate selection), (2) matching gel system to the problem, (3) designing and sizing the gel treatment, and (4) field application techniques. For injection-well treatments, tracer studies are important in identifying communication problems. Seright's survey found, that while experts felt tracers should be used in 80% of the applications, tracer studies were performed in less than half of the injection-well treatments (Seright and Liang 1994).

TABLE D–4
TECHNICAL AND ECONOMIC SUCCESS RATES (%) REPORTED BY MAJOR OIL COMPANIES FOR GEL POLYMER, PRODUCING-WELL APPLICATIONS (MODIFIED FROM: SERIGHT 1993)

	Source of Produced Water		
Company	Bottom-Water (Tech./Econ.)	Waterflood (Tech./Econ.)	Unknown Source (Tech./Econ.)
A	100/33	---	---
B	100/100	---	40/30
C	70/30	75/60	--/0
D	50/50	100/100	---
E	70/10	80/70	70/?
F	85/85	90/85	---

D.2.3 Recent Technology Thrusts

Recent technology thrusts have been process and mechanistic studies, developing of alternative systems and methods, and documenting field results leading to field application guidelines. Process and mechanistic studies have focused on modeling and simulator development. Development work associated with alternative systems focuses on expanding application environments, reducing costs, and reducing environmental hazards. Several systems under development employ mechanisms other than polymer crosslinking. Field data analysis focuses on learning from both failures and successes and on developing application guidelines.

D.2.3.1 Process and Mechanistic Studies

NIPER developed a three-phase permeability modification simulator to assist in mechanistic evaluation of the gel polymer process and to facilitate the design and assessment of potential reservoirs for permeability modification treatments. This model has been used to explore the

TABLE D–5
TECHNICAL AND ECONOMIC SUCCESS RATES REPORTED BY MAJOR OIL COMPANIES FOR GEL POLYMER, INJECTION-WELL APPLICATIONS (SOURCE: SERIGHT 1993)

Company	Technical Success Rate	Economic Success Rate
C	70	35
D	50	50
E	80	50
F	90	85

effects of various parameters including treatment timing, degree of crossflow, permeability, and permeability contrast on oil recovery in waterfloods and polymer floods (Gao and Chang 1990; Gao et al. 1990, Gao 1991a; Gao 1991b; Gao and Burchfield 1993; Gao et al. 1993).

Conclusions (Deterding et al. 1993) based on these studies include: (1) in reservoirs with low crossflow, gel treatments in both injection and production wells result in an improvement in incremental oil recovery and cash flow over that of treating only injection wells; (2) gel treatments are less effective in reservoirs with high crossflow; (3) polymer flooding initially shows a greater increase in incremental oil production than does the gel treatment, but in reservoirs with low crossflow, the gel treatment eventually produces more incremental oil; and (4) in reservoirs with low crossflow, combined near-wellbore gel treatment with a polymer flood is more effective than either a polymer flood alone, a deep gel treatment, or a deep gel treatment combined with a polymer flood.

D.2.3.2 Alternative Systems and Methods

Alternative systems and methods for conformance control include (1) higher temperature and salinity systems, (2) the Marathon process (chromium [III] carboxylate gel), (3) the Phillips process (chromium [III] propionate gel), (4) brine- and ph-initiated gels, and (5) the surfactant-alcohol system. Details of these alternative approaches are presented in the following section.

Higher Temperature and Salinity Systems

Hostile environmental conditions have been defined as temperatures greater than 167°F with brine hardness (divalent ion) levels above 2,000 ppm (Moradi-Araghi 1994). Although temperature conditions in most Class 5 reservoirs are less severe, research efforts to develop polymers (and gel polymers) with higher temperature limits can apply to the Class 5 oil resource. Polymer stability, whether in a mobility control flood or gel polymer application, can be affected by temperature, salinity, and hardness levels. Temperature limits for hydrolyzed polyacrylamides (HPAM) range from 167°F when total hardness is greater than 2,000 ppm to 200°F when total hardness is 400 ppm (Gao 1987). Ryles (1988) considered the temperature limit to be even lower, around 160°F if brines contained more than 200 ppm Ca^{+2}.

Temperature limit estimates for xanthan biopolymers range from about 160°F (Ryles 1988) to 200°F (Doe et al. 1987; Needham and Doe 1987). Xanthan temperature limits can vary significantly depending on the biopolymer source. Xanthan temperature limits are relatively insensitive to salinity or hardness variations. A different class of biopolymers, scleroglucan, exhibits higher temperature limits due to its triple-helix structure. Kalpakci et al. (1990) suggest that scleroglucan may be used at temperatures up to 220°F.

Doe et al. (1987) evaluated copolymers of vinylpyrrolidone (VP) and acrylamide (AM) and found them stable in seawater at temperatures up to 250°F. It was noted that improvements in molecular weight were needed to improve field economics. Needham and Doe (1987) noted that most advanced polymers might be of questionable utility in today's (1987) economic situation.

The Marathon Process (Chromium [III] Carboxylate Gel Technology)

Marathon developed an acrylamide polymer/chromium (III) carboxylate gel system (MARCIT system) using a chromium acetate (nontoxic) rather than toxic hexavalent chromium system. The gel system is a single-fluid system avoiding sequential slug injections used in some processes. Gel properties can be easily tailored by varying chemical concentrations (Sydansk and Moore 1992). Gels can be formulated for temperatures up to 255°F, pH values in the 4–12.5 range, and they are tolerant of high salinities and H_2S (Sydansk 1988). If required, gels can be degraded with chemicals like hydrogen peroxide or sodium hyperchlorite (Sydansk 1988). The system is primarily intended for naturally fractured reservoirs or single porosity reservoirs with vugs or high permeability channels (Southwell and Posey 1994).

The Phillips Process (Chromium [III] Propionate Gel Technology)

Because the crosslinking systems of most gel systems are incompatible or unstable in hard brines, gel polymer applications can be constrained. In the laboratory, Phillips Petroleum has evaluated a chromium [III] propionate crosslinking system for use in hard brines. This gel system, which does not require fresh water, exhibited good stability in brines with hardness levels up to 14,000 ppm (Mumallah 1988). The system is applicable for both near-well and in-depth treatments. Although chromium propionate is not available on a commercial scale, screening economics indicate roughly comparable costs with conventional gel systems. Data from field applications were not reported.

Chromium [III] Malonate Gel Technology

With conventional gel systems, in-depth treatments in high temperature reservoirs are constrained by the ability to control when gelation occurs. Lockhart and Albonico (1992) describe a chromium [III] malonate gel system which provides longer delays at high temperatures (194°F–275°F). Laboratory data indicate gelation times can be delayed more than an order of magnitude longer and that gelation times are easily controlled and predictable. Data indicate that pH has a complex influence on the gelation rate. Field applications of the system were not reported by Lockhart and Albonico.

Colloidal Dispersion Gels for In-Depth Diversion

In-depth fluid diversion treatments have historically relied upon in situ crosslinking with one approach being to sequentially inject slugs of polymer and aluminum citrate, the crosslinking agent. Alternatively, weak gels can be formed prior to injection using low polymer and

crosslinker concentrations creating a colloidal dispersion gel. Since gels are formed prior to injection, the process provides greater flexibility than in situ crosslinking. Gel stability has been proven at temperatures to 200°F (Mack and Smith 1994). Injection water salinity is limited to 30,000 ppm total dissolved solids. Identified future research needs for this system (Mack and Smith 1994) include addressing temperature and salinity limitations and forming stronger gels.

Crosslinking System for Powdered, Xanthan Biopolymer

Xanthan biopolymer crosslinking treatments typically use xanthan broth. Powdered xanthan biopolymers, which reduce transportation costs and field storage problems, are an option for reducing the cost of crosslinked polymer treatments using xanthan biopolymer. Cost reductions result from using 100% powdered xanthan biopolymer versus typical 5% broths and from easier storage and handling. French et al. (1988) investigated polymer and crosslinker (chromium [III]) concentrations for surface-prepared and in situ gels. Polymer concentrations of 1,400 to 2,000 were recommended, while recommended chromium [III] concentrations were 5–25 ppm for surface-prepared gels and 10–25 ppm for in situ gels. Injectability of surface-prepared gels was found to depend on the shear history of the gels.

Precipitation Methods

Alcohol-induced salt precipitation methods are being explored for profile modification treatments. Permeability in higher permeability, water-saturated zones is reduced by salt precipitates formed as alcohol and concentrated brine slugs mix in the reservoir. Zhu and Raible (1994) evaluated the process in laboratory corefloods. Their results indicated a 60% increase in oil recovery above that experienced with waterflooding. Permeability reductions with salt resisted subsequent water injection, with only 5%–10% of original permeability being recovered after several pore volumes of 5% NaCl injection. Potential advantages of the salt precipitation process include (1) decreased viscous crossflow effects, (2) selective placement in higher permeability thief zones, and (3) pH-independence of the precipitation process. The pH independence is of particular importance when using the gel system in CO_2 flooding applications.

A thermal precipitation method is also being evaluated for conformance control (Acock and Reis 1994). The thermal precipitation method consists of preheating the near-wellbore region with hot water or steam, injecting a hot, saturated chemical solution, and as cooling occurs, precipitation occurs due to reduced solubility. A primary, potential advantage of this system is that identified chemicals (including potassium carbonate and sodium carbonate) do not have the environmental hazards associated with conventional chromium redox gel polymer systems.

Brine-Initiated Gels

An alternative gel system, which does not rely on crosslinkers and whose formation is independent of pH, is a brine-initiated gel system. The gel forms in situ when a freshwater solution of a water soluble polymer (hydroxypropyl cellulose) and a surfactant (sodium dodecyl

sulfate) mix with brine. Whittington et al. (1994) reported 95% permeability reductions in both linear and radial corefloods using this system. Laboratory evaluation indicated that (1) the gel was resistant to subsequent brine flushing, and (2) adverse divalent ion effects could be counteracted with cosurfactants. However, Raible and Zhu (1992) evaluated the system in sandpacks and expressed concern about gel placement and long-term resistance of the formed gel to subsequent brine injection.

pH-Initiated Gels

Gels initiated by pH are being evaluated for conformance control applications. The Unocal process of using the aluminate ion as a source of aluminum consists of injecting the pregel at pH 10, then depending on alkali consumption to reduce pH below about 9.6. At that point, the aluminum is activated as a crosslinking agent (Dovan and Hutchins 1987).

The University of Kansas developed an aqueous polysaccharide polymer that can be injected in strong alkali and set by injecting alternating slugs of strong acid (Vossoughi and Buller 1989). KU's biopolymer gelation process depends on polymer solubility as a function of pH rather than crosslinking. Laboratory data in sandpacks indicate a high degree of permeability reduction can be achieved, and the gel can be remobilized by raising the pH of the injected fluid (Vossoughi and Putz 1991).

Surfactant-Alcohol System

Llave et al. (1990) are evaluating a surfactant-alcohol blend for achieving in-depth permeability modification. With this system, permeability modification results from normal chromatographic separation of the surfactant and alcohol components in the reservoir resulting in a viscous surfactant slug. Penetration depths can be controlled by varying component concentrations (Llave et al. 1990), and the slug can be remobilized by subsequent injection of alcohol slugs. Since the initial slug is relatively nonviscous, injectivity and formation damage problems during treatment are minimized.

The surfactant-alcohol system performed well in an initial pilot field test in the Stone Bluff Field, Wagoner County, Oklahoma (Llave and Dobson 1994). Waterflooding operations are characterized by poor sweep efficiency resulting from high permeability contrasts. A prior gel polymer program had been disappointing, because bottomhole samples indicated poor quality gels were formed. Shear degradation was suspected. Following extensive reservoir screening, a single injection well was treated with 500 barrels of a 2 wt% surfactant solution (one part surfactant: two parts alcohol). No injectivity problems were experienced. Posttreatment monitoring and analysis noted (1) increased oil production, (2) reduced water production, (3) reduced water injectivity, (4) improved fluid injection profiles, and (5) increased tracer breakthrough time (Llave and Dobson 1994). Costs were comparable to conventional gelled-polymer applications.

D.2.3.3 Field Results and Guidelines

Industry is directing significant effort towards improved documentation of field results with gel polymer treatments and based on field results, developing guidelines for candidate selection, treatment design, and application. This joint research and technology transfer effort improves operator confidence levels and should stimulate additional applications.

As part of their research effort in developing improved techniques for fluid diversion in oil recovery, the New Mexico Institute of Mining and Technology (Seright 1993; Seright and Liang 1994) surveyed both (1) the technical literature for injection and production well treatment results and (2) operators and vendors for their beliefs regarding various aspects of gel polymer treatments. Partial results are discussed in Sections D.2.1 and D.2.3.2. This effort represents an important step towards using field data and experience to develop more comprehensive treatment guidelines.

As part of a technology transfer grant, the University of Kansas (KU) developed a permeability modification demonstration project report (Schoeling et al. 1993). This report describes gel systems, applications technologies, and monitoring techniques in a simplified, down-to-earth manner for the independent's use. Field results with selected systems are also discussed. Additional field results from gel polymer applications in Kansas have been reported at KU's Tertiary Oil Recovery Project (TORP) conferences (Avery and Sutphen 1989; Jack et al. 1991). TORP's efforts in documenting field results represent some of the early work in the field. Subsequent documentation efforts, described below, have been more comprehensive.

Mack and Smith (1994) documented the results of 29 injection well treatments using in-depth colloidal dispersion gels in the Rocky Mountain area. Twenty-two of the projects were reported as successful. Factors involved in unsuccessful projects were: (1) starting the project too late, (2) out-of-zone injection, (3) premature shutdown of injection, (4) poor wellbore completions, (5) poor water quality, and (6) inadequate gel strength.

Southwell and Posey (1994) documented field results with the Marathon acrylamide-polymer/chromium (III) carboxylate gel system. Forty-three treatments have been performed in Wyoming's Big Horn Basin, an initial group of 17 treatments during 1985–89 and 26 treatments during 1989–92. Development costs for the two groups of treatments were reported at $0.21 and $0.99 per incremental barrel for the initial and second groups, respectively. The characteristic application was in naturally fractured waterflood reservoirs. Results from production well treatments in the Grayburg Formation in the Big Lake Field in West Texas, a fractured, natural waterdrive reservoir, were also reported (Southwell and Posey 1994). In this water shut-off application, treatments were economical based solely on lifting cost reductions. Amoco reported results of injection well conformance control treatments in their Wertz CO_2 flood in southwest Wyoming (Borling 1994). Payout times from 1.1 to 3.7 months were noted with pattern lives extended for up to two years.

Fielding et al. (1994) describe how both colloidal dispersion and Marathon gels were applied in the North Rainbow Ranch Unit, a Minnelusa reservoir in Wyoming. The reservoir is not fractured, but the Dykstra-Parsons coefficient of 0.9 indicates a highly heterogeneous reservoir. Reservoir temperature is about 200°F. Projected ultimate recovery with polymer-augmentation is 61% of the original oil in place. Problems were experienced with fines and solids production leading to shortened submersible pump life.

D.2.4 Current Research Activity

D.2.4.1 DOE Supporting Research

At the University of Kansas (KU), DOE is funding research directed toward (1) identifying and developing improved gel polymer systems, (2) determining their performance, and (3) developing better predictive methods (Green and Willhite 1994). Work in gel development is focusing on three types of gel systems: (1) an aqueous polysaccharide (developed by KU) that gels as a function of pH, (2) conventional chromium-based crosslinking systems, and (3) an aluminum citrate-polyacrylamide system. The aluminum citrate-polyacrylamide system was determined to be less toxic than several organic crosslinkers which were evaluated. Laboratory work is focusing on chemical reaction kinetics with the goal of developing mathematical models for predicting performance.

At the University of Michigan, research completed in 1993 examined a variety of new fluid diversion or profile modification techniques (Fogler 1994). Among others, strategies investigated included a particulate system, a foamed gel for injection wells, and a water-reactive gel for water shutoff at production wells.

At the Petroleum Recovery Research Center in New Mexico, DOE is funding research directed toward (1) comparing the effectiveness of gels with other fluid diversion techniques (foams, emulsions, particulates) and (2) identifying the mechanisms by which gels selectively reduce water permeability more than oil permeability. Early work is focusing on documenting field applications, operator and vendor experience, and application guidelines (Seright and Liang 1994; Seright 1993). Significantly, their work is considering production as well as injection well treatments. Survey information indicates that in the early 1980s, injection well treatments were most common. Since 1990 over 80% of gel treatments have been in production wells, with the majority of those being in wells in fractured bottom-waterdrive reservoirs rather than injection well treatments in waterfloods (Seright and Liang 1994). Seright and Liang contend that the difficulty and delay in measuring technical and economic performance of injection well treatments is partially responsible for the trend toward production well treatments.

At NIPER, research focuses on developing alternative conformance control systems without the environmental hazards of the chromium redox system. An initial task in the research effort is developing a sweep improvement literature database covering gel polymers and other systems. Alternative technologies being evaluated include a surfactant-alcohol system and biopolymer-

based systems (NIPER/BDM 1994). The surfactant-alcohol system relies on chromatographic separation in the reservoir, leaving a viscous surfactant gel blocking pore throats in high-permeability zones. Laboratory research is focusing on the salinity and temperature conditions where the surfactant and alcohol system is effective.

D.2.4.2 DOE Cost-Shared Field Demonstration Program

DOE has initiated cost-shared field demonstration projects with operators in Class 1 fluvial-dominated deltaic, Class 2 shallow-shelf carbonate, and Class 3 slope-basin and basin clastic reservoirs. Two Class 1 projects specifically note profile modification applications, one using gel polymer and one using indigenous microorganisms. One Class 2 project incorporates gel polymer technology. One of the Class 3 projects incorporates gel polymer technologies.

The Class 1 project led by the University of Kansas's Center for Research incorporates gel polymers, polymer flooding, and reservoir management technologies in fields in southeast Kansas. Production problems being addressed include (1) poor volumetric sweep, (2) plugging of injection wells, and (3) lack of production optimization through simulation and management.

The Class 2 project by Sensor, previously Beard Oil, proposes to systematically evaluate fluorescent, ionic, and radioactive tracers as tools to design and apply crosslinked polymer gel treatments. Tracer data will be integrated with reservoir and production data.

The Class 3 project by the City of Long Beach proposes the use of chemical methods of profile modification to improve waterflooding sweep efficiency.

D.3 Polymers for Mobility Control

The polymer process is an economical process, when applied in the proper environment, for recovering additional unrecovered mobile oil (UMO). Increased oil recovery from polymer flooding can result from one or more of three different mechanisms: fractional flow effects, mobility ratio effects, and fluid diversion effects (Needham and Doe 1987). Fractional flow and mobility ratio effects favor starting polymer floods early. Fluid diversion effects are more significant for tertiary polymer floods.

D.3.1 Screening Criteria

The screening criteria used by the NPC (1984) for implemented and advanced technology levels are summarized in Table D–6. For the advanced technology level, advances in polymer chemistry expand the temperature and salinity limits for the polymer process.

TABLE D–6 NPC POLYMER SCREENING CRITERIA AT DIFFERENT TECHNOLOGY LEVELS (SOURCE: NPC 1984)		
Parameter	**Implemented Technology**	**Advanced Technology**
Reservoir Temperature, °F	< 200	< 250
Brine Salinity, ppm	< 100,000	< 200,000
Permeability, mD	> 20	> 10
Oil Viscosity, cP	< 100	< 150

D.3.2 Constraints

Dauben (1991) analyzed field projects to determine those parameters which limited success in polymer floods. He concluded that polymer floods were constrained by three factors: (1) inadequate polymer propagation, (2) polymer degradation, and (3) polymer stability in high temperature, high-salinity environments. Poor propagation often results from formation plugging. Degradation can result from mechanical, microbial, or chemical causes. Each type of polymer has certain temperature and salinity restrictions, and efforts continue to develop polymers suitable for harsher environments.

Inadequate polymer propagation leads to formation plugging which leads to reduced injectivity which, in turn, often leads to injecting at pressures above the formation parting pressure. Injection at pressures above the parting pressure was noted in the Big Muddy (Cole 1988), North Burbank (Tracy and Dauben 1981), Manvel (Hamaker and Frazier 1982; Widmeyer and Pindell 1981), Robinson M-1 (Cole and Dauben 1987), and West Burkburnett (Talash and Strange 1981) projects. When formation parting occurs, sweep efficiency is reduced resulting in reduced recovery.

D.3.3 Recent Technology Thrusts

Recent polymer technology development efforts have focused in the following areas: (1) developing polymers for harsher environments, (2) applying polymers in the secondary rather than tertiary stage, (3) polymer propagation and retention, (4) mechanical degradation, and (5) polymer injectivity. Since temperature and salinity of most Class 5 reservoirs are within environmental stability limits for existing polymers, the other technology thrusts will impact Class 5 polymer potential more significantly.

D.3.3.1 Polymers for Harsher Environments

Polymer stability can be affected by temperature, salinity, hardness, pH, and mechanical shear. Existing hydrolyzed polyacrylamide (HPAM) polymers exhibit temperature limits ranging from 167°F when total hardness is greater than 2,000 ppm to 200°F when total hardness is 400 ppm (Gao 1987). Ryles (1988) considered the temperature limit to be even lower, around 160°F if brines contain more than 200 ppm Ca^{+2}. Xanthan biopolymers have a useful temperature limit of about 160°F (Ryles 1988), although some sources (Doe et al. 1987; Needham and Doe 1987) state a useful temperature limit of 200°F. Different levels of substitution with pyruvate and acetate in different xanthan biopolymers cause the thermal stability limits to vary (Gall 1993). Xanthan stability is less affected by divalent ions than HPAM polymers (Ryles 1988). Alternative polymers are being evaluated to extend the useful temperature and salinity limits of polymer applications.

A different class of biopolymers, scleroglucan, exhibits higher temperature limits due to its triple-helix structure (Gall 1993). Scleroglucan also exhibits relatively high salinity and divalent ion limits. Kalpakci et al. (1990) suggest that scleroglucan may be used at temperatures up to 220°F. Although early scleroglucan applications experienced plugging problems, modifications in the biosynthesis process and in posttreatment have led to enhanced filterability (Rivenq et al. 1989).

Doe et al. (1987) evaluated copolymers of vinylpyrrolidone (VP) and acrylamide (AM) and found them stable in seawater at temperatures up to 250°F. It was noted that improvements in molecular weight were needed to improve field economics. Needham and Doe (1987) noted that advanced polymers might be too expensive for the economic conditions prevailing in 1987.

Sohn et al. (1990) address polymer salinity limitations through the concept of preconditioning. Preconditioning recognizes the economic benefits of using less expensive hydrolyzed polyacrylamides. Rather than using freshwater preflushes to protect the polyacrylamides from saline waters, a small slug of a more salt-tolerant polymer is injected first. This slug represents only 10%–15% of the total polymer slug (Sohn et al. 1990). When compared to freshwater preflush, this process shortens both preconditioning time and project life. Sohn et al. documented two applications in Germany where preconditioning was successful. Injection protocol or strategy, of which preconditioning is just one example, has been identified as a research need (Lorenz 1991; Gall 1993).

Polymers can be affected by the pH of the injected fluids. Hydrolyzed polyacrylamides are quite stable in the high pH environment of an alkaline flood. Xanthans, however, can be degraded at temperatures below 130°F in alkaline floods (Rivenq et al. 1989). The biopolymer used in KU's pH-initiated gel system (see Section D.2.3.2) has advantages for alkaline flooding since it is soluble and stable in higher pH environments (Vossoughi and Putz 1991). Polymer stability under alkaline conditions and polymer effects on interfacial tension reductions with the alkaline-surfactant-polymer (ASP) process (see Section D.5.3.3) should be considered when designing alkaline floods.

D.3.3.2 Secondary Rather Than Tertiary

Higher oil recovery can be experienced when polymer floods are started earlier in waterflood life; i.e., as secondary rather than tertiary floods. Fractional flow and mobility ratio effects favor starting polymer floods earlier. In Germany, where projects are started earlier, polymer flood recoveries are significantly higher than experienced in typical U.S. floods (Lorenz 1991). By eliminating freshwater preflushes, Sohn et al.'s (1990) preconditioning concept takes advantage of early polymer injection. Based on their analysis of 27 polymer floods, Needham and Doe (1987) determined that potential was four times higher in secondary floods and significantly less polymer was required. In Wyoming's Minnelusa reservoir, early polymer floods are recognized as the state-of-the-art technology (Hochanadel 1990). The economic and recovery benefits of starting polymer floods earlier in life has been clearly demonstrated.

D.3.3.3 Propagation and Retention

Although some polymer retention is beneficial, excess polymer retention or degradation reduces polymer concentration and mobility control and ultimately results in reduced oil recovery. Polymer degradation by bacteria or oxygen can be controlled by biocide treatment and system design. Polymer retention includes both adsorption and mechanical entrapment effects. Hydrolyzed polyacrylamides are known to adsorb more than biopolymers. Gao (1987) stated that inaccessible pore volume must be considered when evaluating polymer retention. Screening tests for polymer retention are recommended. The API standard (1990) recommends performing dynamic corefloods in native reservoir cores at reservoir conditions. Huh et al. (1990) found the amount of entrapment to be a function of polymer flux (i.e., retention is maximized at high concentrations and rates). Gao (1992) found that laminations in the reservoir and their angles affect polymer retention and recommended determining lamination angle as part of the polymer screening process.

D.3.3.4 Mechanical Degradation

Polymers exhibit varying susceptibility to mechanical degradation. Biopolymers are less susceptible to mechanical degradation than hydrolyzed polyacrylamides. With hydrolyzed polyacrylamides, susceptibility to mechanical degradation increases as the molecular weight and, accordingly, viscosity increases. Equipment design and preshearing are conventional approaches to reducing mechanical degradation effects.

Gao (1991a,b) approached the shear degradation issue with crosslinked, low-molecular-weight polyacrylamides. Because of the characteristics of crosslinked polymers, low-crosslinking-density gelled polymers under high shear conditions, like those near a wellbore, should exhibit improved injectivity. Since they reheal at low shear conditions, like those away from the wellbore, these gelled polymer systems should be less sensitive to shear degradation. Gao's laboratory work (Gao 1991a,b) verified improved injectivity and rehealing under low shear conditions.

Taber and Seright (1992) described advantages of horizontal wells in polymer floods. For a given injection pressure, fluid velocity at the sandface is lower than with vertical wells, decreasing the potential for shear degradation. Higher injection rates, which could be achieved with horizontal injection wells, would also decrease polymer residence time, thereby reducing the long-term stability requirements for the polymer.

D.3.3.5 Injectivity

Injectivity and mechanical degradation issues are often interrelated, as is evident in Gao's work with crosslinked low-molecular-weight polyacrylamides. Field projects often experience reduced injectivity that can delay oil recovery and/or lead to injection overpressuring and formation parting. Polymer plugging can result from polymer solution properties, reservoir properties, or surface mixing and wellbore problems. Fletcher et al.'s work (1992) indicated that fractures, whether natural or hydraulically created, greatly influence polymer injectivity. In unfractured wells, their work indicated that injectivity reductions result from face plugging and are a function of cumulative polymer flux. In fractured wells, Fletcher et al. (1992) found that filtered polyacrylamide and unfiltered Xanthan could be injected without significant injectivity loss or fracture growth.

Treiber and Yang (1986) investigated polymer plugging in corefloods and found plugging to be a function of four factors: (1) cumulative polymer volume per cross sectional area, (2) core permeability, (3) hydrodynamic size of the polymer, and (4) core mineralogy, particularly clays. Their work indicated that core composition and polymer-rock interactions significantly influence polymer plugging. Treating the wellbore with organic cations prior to polymer injection reduced subsequent polymer plugging.

D.3.4 Current Research Activity

D.3.4.1 DOE Supporting Research

At the University of Southern Mississippi (McCormick and Hester 1994), research is focusing on water-soluble copolymers for mobility and conformance control applications. Copolymer synthesis represents a major part of the effort. Research activity at NIPER (NIPER/BDM 1994) continues to focus on developing polymer systems for harsher environments and on polymer retention. Stability of a low-anionic polyacrylamide polymer reported to be stable in higher salinity environments is being evaluated. Lamination angle effects on polymer retention in cores at residual oil saturation are being further explored. Some effort is also directed toward modeling using the UTCHEM simulator.

D.3.4.2 DOE Cost-Shared Field Demonstration Program

DOE has initiated cost-shared field demonstration projects with operators in Class 1 fluvial-dominated deltaic, Class 2 shallow-shelf carbonate, and Class 3 slope-basin and basin clastic reservoirs. The University of Kansas's Class 1 project (see Section D.2.4.2) incorporates polymers along with gel polymers and reservoir management. No Class 2 projects specifically note polymer flood applications. One of the Class 3 projects proposed by the University of Texas at Austin-BEG will consider polymer for its enhanced oil recovery pilot tests.

D.4 Microbial Processes

Microbial enhanced oil recovery (MEOR) technologies have evolved significantly in recent years. MEOR technologies recover oil through several different mechanisms including surfactant generation, wettability alterations, gaseous byproducts, and plugging. MEOR processes can be used for wellbore stimulation or cleanup, permeability modification, microbially enhanced waterflooding, polymer flooding, and coning mitigation. While high recovery efficiencies like those achievable with miscible processes (CO_2 or surfactant) may not be experienced, MEOR technologies, like conformance control technologies, can be economical at moderate oil prices.

D.4.1 Screening Criteria and Procedures

Bryant (1990, 1991) published both screening criteria and screening procedures for MEOR processes. MEOR applications must first pass screening criteria (see Table D–7); then the process must be tailored to the application. As in most IOR processes, defining the reservoir and well characteristics is essential. Having defined the reservoir and well characteristics, the type of microorganisms must be matched to the problem, and the laboratory screening procedures performed (see Table D–8). In many aspects, MEOR technologies resemble gel polymer technologies in that tailoring to individual applications is required.

D.4.2 Constraints

MEOR applications are constrained by the lack of widespread industry experience and confidence in their success in proper applications. Prior DOE-sponsored projects have demonstrated that MEOR technology has potential, but predictability of MEOR technology has not been demonstrated and documented (Bryant 1993). Additionally, successful applications in projects with higher target oil saturations need to be demonstrated.

TABLE D–7 MEOR SCREENING CRITERIA (SOURCE: BRYANT 1991)	
Parameter	**Recommended Range**
Salinity	<15% sodium chloride; total TDS may be higher
Temperature/depth	<170°F; <8,000 ft
Trace minerals	<10–15 ppm of arsenic, mercury, nickel, selenium
Reservoir rock permeability	>50 millidarcies, unless highly fractured
Indigenous microorganisms	Compatible with injected microorganisms in selected MEOR process
Crude oil type	>15° API; not enough information available yet for heavier crude oils
Residual oil saturation	>25%; may be some exceptions
Well spacing	<40 acres; a response can generally be seen sooner on closer well spacing

D.4.3 Recent Technology Thrusts

Potential applications of MEOR technologies have widened significantly as a result of focused research and technology transfer efforts, much of which has been performed by NIPER. NIPER's efforts have focused in the areas of database development, culture banking, mechanistic understanding, modeling and simulation development, microbially enhanced waterflooding, and plugging or permeability modification technologies (Bryant 1993).

TABLE D–8 MEOR SCREENING PROCEDURES (SOURCE: BRYANT 1991)	
Parameter	**Screening Procedure**
Microorganism used	Determine potential mechanisms for increasing oil production.
Salinity	Use compatibility testing to assay for microbial growth and metabolism.
Temperature/depth	Use compatibility testing to assay for microbial growth and metabolism under reservoir conditions.
Trace minerals	Use compatibility testing to determine.
Reservoir rock permeability	If multiwell process, conduct a single-well injectivity test and coreflooding studies.
Indigenous microorganisms	Use compatibility testing to assay for microbial growth and metabolism under reservoir conditions.

NIPER developed a MEOR Field Project database documenting reservoir characteristics where MEOR technologies have been applied (Bryant 1991). Trends evident from the project data were used to develop and revise published MEOR screening criteria. As of late 1993, the database contained data on 69 different field projects with additional entries planned in the near future (Bryant 1993). In a somewhat correlative effort, NIPER has also developed a culture bank of microorganisms capable of improving oil mobilization under a wide variety of conditions.

Laboratory development work, as reported by Bryant (1993), has demonstrated that (1) microbial compatibility tests between injected and indigenous mechanisms are essential, (2) microbial cells are important to oil mobilization and recovery, (3) combinations of *Bacillus* and *Clostridium* species perform more effectively than either species alone, (4) reservoir wettability can be altered by microbial action, and (5) low concentrations of certain additives improve microbial performance. MEOR process research has focused on microbial well stimulations, microbially enhanced waterflooding, microbial permeability modification, and microbial wellbore cleanup technologies.

In conjunction with laboratory development work, NIPER has developed a microbial simulation model (Chang et al. 1991). The model incorporates microbial growth and decay, microbial deposition, chemotaxis, diffusion, convective dispersion, tumbling, and nutrient consumption effects (Bryant 1993). Laboratory results are being considered in the simulator development effort. At present, the model does not incorporate or predict enhanced oil recovery effects which reduce residual oil saturation.

NIPER has conducted field demonstrations of microbially enhanced waterflooding in the Delaware-Childers and Chelsea-Alluwe fields in northeast Oklahoma. The initial 20-acre MEOR pilot in the Mink Unit, Delaware-Childers Field led to a larger 380-acre, field-scale pilot in the nearby Phoenix lease in the Chelsea-Alluwe Field. Production rate increases for the Mink Unit and Phoenix projects were 13% and 19.6%, respectively (Bryant et al. 1994). Nutrient costs, the primary cost in an MEOR process, for the Mink Unit and Phoenix projects were $3.24 and $2.33 per incremental barrel of oil, respectively. Significantly, no operating problems were encountered before or during either project.

Bryant (1994) discusses potential microbial applications for North Sea production. North Sea challenges include (1) the necessity of operating from platforms with limited storage capacity, (2) the wide spacing of wells, (3) highly faulted reservoirs, (4) higher than typical temperatures, (5) in some cases, high clay content, and (6) brines with fairly high salinity and hardness. Potential conformance control applications were noted. Bryant's article succinctly summarizes the multiple facets of microbial EOR.

D.4.4 Current Research Activity

D.4.4.1 DOE Supporting Research

In the recent past, two national laboratories have participated in MEOR research. At Idaho National Engineering Laboratory, research was directed towards developing MEOR systems for reservoirs containing medium to heavy oils and towards evaluating wettability effects on oil recovery (McCoy 1994). At Brookhaven National Laboratory, research was directed towards MEOR applications in higher temperature and pressure applications (Premuzic and Lin 1994). Biochemical interactions with Alabama Smackover crudes were being evaluated.

At NIPER, research is focusing on performing (1) microbial single-well stimulation field tests, (2) further developing coreflooding experimental procedures, (3) determining microbial retention and adsorption effects in porous media, and (4) incorporating laboratory and field data into the MEOR process simulation package (NIPER/BDM 1994).

D.4.4.2 DOE Cost-Shared Field Demonstration Program

DOE has initiated cost-shared field demonstration projects with operators in Class 1 fluvial-dominated deltaic, Class 2 shallow-shelf carbonate, and Class 3 slope-basin and basin clastic reservoirs. One Class 1 project incorporates MEOR technology. Hughes Eastern proposes to stimulate indigenous microorganisms in the Carter Sandstone, North Blowhorn Field, Alabama, using inorganic (fertilizer) nutrients. The intent is to expand the biomass to preferentially plug the more porous zones of previously waterswept areas, thus forcing injection water through less permeable zones. No Class 2 or Class 3 projects incorporate MEOR technologies.

D.5 Alkaline and Alkaline-Surfactant-Polymer (ASP) Processes

Alkaline projects using strong alkalis have limited potential considering the alkaline consumption and operations problems experienced in historical projects (Dauben 1991). Weak alkalis reduce these problems, but by themselves do not generate high enough pH values to lower interfacial tension (IFT) and mobilize oil. While conventional surfactant floods generate low IFT and mobilize significant oil, costs are too high with concentrations typically used. However, weak alkalis and low concentrations of surfactant can exhibit synergistic effects which lower IFT and mobilize oil at costs low enough to be feasible at moderate oil prices (French et al. 1988). The process employing weak alkalis, a low concentration of surfactant, and polymer for mobility control is known as the ASP process. Current trends are to use the alkali in combination with surfactants and polymers (Lorenz 1988; Krumrine and Falcone 1987).

D.5.1 Screening Criteria

The screening criteria used by the NPC (1984) for the implemented and advanced technology levels are summarized in Table D–9. Since the advantages of the ASP process had not yet been defined, the NPC screening criteria primarily apply to conventional alkaline flooding.

Screening criteria for the ASP (or surfactant-enhanced alkaline) process were developed by NIPER (see Table D–10; Lorenz and Peru 1989; Gall 1993). French and Burchfield (1990) provide a detailed discussion of these screening criteria. Note that the screening criteria specify parameters not typically available without laboratory evaluation. To be a candidate for surfactant-enhanced alkaline flooding, a reservoir should: (1) contain little or no gypsum, (2) exhibit a divalent ion exchange capacity less than 5 milliequivalents per kilogram, and (3) have an in situ pH greater than 6.5. Although crude oils having high acid numbers are desirable, high-acid-number crude oils are not essential for the process (Lorenz 1988).

Gall (1993) summarized the laboratory procedures required to evaluate ASP process potential for a given reservoir:

- Determine the reservoir mineral, brine, and oil properties and compare with screening criteria to determine feasibility.
- Determine whether the oil is interfacially reactive with alkalis and alkali and surfactant mixtures. Interfacial tension experiments are typically performed. A crude oil rating system developed by Smith (1993) for estimating alkaline reactivity without specific IFT testing is one alternative for rapid screening of candidate crude oils.
- Quantify the extent of alkali-mineral reactions
- Quantify the extent of surfactant losses
- Measure mobilized oil in coreflooding experiments

Once these laboratory data are available, a reservoir-specific economic evaluation must be performed.

TABLE D–9
NPC ALKALINE SCREENING CRITERIA AT DIFFERENT TECHNOLOGY LEVELS
(SOURCE: NPC 1984)

Parameter	Implemented Technology	Advanced Technology
Reservoir Temperature, °F	<200	<200
Brine Salinity, ppm	<100,000	<200,000
Permeability, mD	>20	>10
Oil Gravity, °API	<30	<30
Oil Viscosity, cP	<90	<100
Rock Type	Sandstone	Sandstone

D.5.2 Constraints

Dauben (1991) analyzed field projects to determine constraints to field applications of the alkaline process. Strong alkali floods are constrained by excessive consumption and operational problems. These constraints fostered research with weak alkalis and the ASP processes. Although incremental recovery using the ASP process was excellent in the White Castle and West Kiehl Field projects, the ASP process has not yet been widely applied. Although research and limited field projects indicate significant potential for this process, field applications of the ASP process are still constrained by the lack of well-documented field data. To some extent, the ASP process may be constrained by association with the many failures experienced with past alkaline floods using strong alkalis.

D.5.3 Recent Technology Thrusts

Recent research and technology thrusts have focused on the ASP process, because it avoids the alkaline consumption and operations problems of the strong alkali process, reaps benefits from synergism between the alkaline and surfactant agents, and is potentially applicable to light as well as heavy oils. The research and development effort is directed toward defining the parameters controlling effectiveness of the process and demonstrating the technology in field applications.

TABLE D–10
SCREENING CRITERIA FOR SURFACTANT-ENHANCED ALKALINE FLOODING
(SOURCES: LORENZ AND PERU 1989, GALL 1993)

Parameter	Criteria
Oil Viscosity, cP	<100
Permeability, mD	>10
Brine Salinity, ppm	<200,000
Temperature, °F	<200 (≈9,000 ft depth)
Acid Number, mg KOH/g oil	>0.3 desirable (not essential)
Clay Content	Moderate, dependent upon type
Gypsum	<0.1% (<10,000 ppm sulfate)
Divalent Ion Exchange Capacity, meq/Kg	<5 (<1% montmorillonite or <.005 equivalent fraction divalent ions in brine)
pH	>6.5 (<.01 mole fraction CO_2 in gas)

Recent technology thrusts have focused on (1) interfacial tension (IFT) lowering, (2) injection strategy, (3) polymer and alkaline-surfactant interactions, and (4) field tests. The following section discusses these areas including successful field tests in a Wyoming Minnelusa (non-Class 5) reservoir and an onshore Louisiana project (non-Class 5 reservoir).

D.5.3.1 Interfacial Tension (IFT) Lowering

Historically, alkaline projects have been considered only in reservoirs where crude oils exhibit high acid numbers, with higher acid numbers generally being associated with lower gravity crudes (Lorenz and Peru 1989). Laboratory results (French et al. 1990; French and Burchfield 1990) indicate that with certain crudes, significant IFT lowering can occur in low-acid-number crude oils using the ASP system. However, each oil behaves differently, so synergism and IFT lowering must be determined at reservoir conditions for each oil (French et al. 1990). With acidic crudes, ASP systems typically cause a rapid lowering of IFT from alkali reactions with the crude while sustained low IFT results from the synthetic surfactant (French et al. 1988). With nonacidic crudes, IFT lowering results from synergism and may occur rapidly or slowly depending upon the crude oil (French et al. 1990).

D.5.3.2 Injection Strategy

ASP process effectiveness varies with the injection strategy used. French and Josephson (1991) compared oil recovery in Berea Sandstone cores using different injection strategies using crude oil from the Hepler Field (Kansas). Their work confirmed the benefit of alkaline preflushes for controlling surfactant consumption and adsorption. Although highest recovery was observed when an alkaline surfactant slug was followed by polymer, recovery with a single slug (after the preflush) containing alkali-surfactant-polymer was nearly as high, and oil recovery occurred more quickly. This strategy was recommended for the Hepler Field project (see Section D.5.4.1).

D.5.3.3 Polymer and Alkaline-Surfactant Interactions

Research has confirmed that polymer-surfactant interactions affect the properties of a developed ASP system. Corefloods associated with the Hepler Field project (Section D.5.4.1) exhibited polymer-surfactant interactions (French and Josephson 1991). French and Josephson (1993) established that polymer-surfactant interaction was affected by pH, ionic strength, crude oil composition, and the properties of the polymers and surfactants. Interactions included phase separation, precipitation, and viscosity loss. Adverse effects on polymer rheology were lessened when oil was present and pH values were higher. Pitts (1994a) found that at higher surfactant concentrations, IFT increases following polymer addition were lessened. Research regarding polymer interactions is intertwined with injection strategy research.

D.5.3.4 Field Tests of the ASP Process

West Kiehl Field, Wyoming

The West Kiehl Field in Wyoming produces from a Minnelusa reservoir. Production from the solution-gas drive reservoir decreased rapidly after discovery in 1985. Ultimate primary recovery efficiency was estimated at 11% of the OOIP (Clark et al. 1988). Reservoir permeability is 350 mD. The operator evaluated waterflooding, polymer flooding, alkaline-polymer waterflooding, and alkaline-surfactant-polymer (ASP) flooding. Based on analyses that indicated the ASP process would ultimately recover 56% of the OOIP versus 40% with the other processes, the operator implemented the ASP process in 1987, only two years after initial discovery (Clark et al. 1988).

The West Kiehl Unit injection strategy involved several steps: (1) initial water injection to establish base injectivity, (2) then sodium carbonate, (3) then sodium carbonate and surfactant, (4) then sodium carbonate, surfactant, and polymer. Once the desired chemical slug volume had been injected, a tapered polymer slug was injected. A 0.37 pore volume ASP solution was injected, followed by a tapered polymer slug beginning in 1991 (Meyers et al. 1992). Although injection pressures were allowed to exceed the formation parting pressure, no adverse effects on recovery have been noted. More than a tenfold increase in daily oil production was observed within months of starting injection. Through November 1991 the ASP project had produced about 100,000 barrels of incremental oil at a cost (incremental cost over waterflood) of $3.94 per incremental barrel (Meyers et al. 1992). Estimated ultimate recovery efficiency is 60.6% of the OOIP, higher than originally estimated, which would reduce incremental costs to $2.13 per incremental barrel.

DOE is funding a detailed evaluation of the project (Pitts 1994b) (1) to further quantify incremental oil recovery, (2) to quantify the effects of chemical slug volume, and (3) to determine the economic ramifications of the ASP technology.

White Castle Field, Louisiana

Shell tested cosurfactant-enhanced alkaline flooding in a steeply dipping sand in the White Castle Field in onshore Louisiana. Although reservoir dip (45°) is much steeper than the 0°–5° range in the offshore Gulf of Mexico reservoirs (Shell's ultimate target for the process), reservoir and fluid characteristics are similar, and gravity effects can be accounted for during simulation (Falls et al. 1992). To define the affected pore volume and flow patterns and to separate formation brine from the alkaline slug, the reservoir was preflooded with NaCl brine to residual oil saturation (Falls et al. 1992). Sodium carbonate was used in the chemical slug after initial injection indicated significant injectivity reductions with a sodium silicate slug. Chemical slug volume was 0.27 pore volume, followed by a 1.85 pore volume 1% NaCl chaser slug. Analysis indicated the process recovered 38% of the waterflood residual oil, and the chemical slug propagated through the reservoir with predictable losses (Falls et al. 1992).

Shell evaluated the effect of dip angle on oil recovery in sandpack floods and found oil recovery to be consistent with theory (Nelson 1993). As a result of the White Castle test and laboratory investigations, Shell developed a "surfactant-induced drainage" process where surfactants are injected into watered-out producers near the top of steeply dipping reservoirs (Nelson 1993). Mobilized oil is produced by gravity effects and polymer is not required.

D.5.4 Current Research Activity

D.5.4.1 DOE Supporting Research

Surtek is performing a detailed evaluation of the ASP process in the West Kiehl Field, Minnelusa reservoir project in Wyoming. Results of this project are quite favorable (see Section D.5.3.4). Detailed evaluation of the West Kiehl ASP project will provide operators with improved information to evaluate potential applicability of the ASP process to their reservoirs (Pitts 1994b).

DOE is funding mechanistic research on the ASP process. Surtek's research is directed toward defining interactions of an alkaline agent, a surfactant, and a polymer on a fluid-fluid and a fluid-rock basis. Initial work indicates that surfactant-alkali IFT reduction synergism is reduced by the presence of polymer (Pitts 1994a). Surtek is also researching how to improve the economics of the ASP process. At the Illinois Institute of Technology (IIT), research is focused on pH buffering with mixed alkali systems as a means of improving ASP costs and effectiveness (Wasan 1994; Rudin and Wasan 1993).

At NIPER, research is focusing on weak alkalis and the ASP process. Current research is investigating (1) polymer-surfactant interactions, (2) the effect of wettability on oil recovery, and (3) relative oil recoveries with different ASP formulations in heterogeneous field cores (NIPER/BDM 1994). The research is interconnected with evaluation of the ASP process in the Hepler Field in Kansas (see next paragraph). Light-scattering is being evaluated as an experimental technique for evaluating polymer-surfactant interactions. Wettability effects are being evaluated in Berea Sandstone cores using crude oil from the Hepler oil field. Preliminary coreflooding results with heterogeneous field core indicate that mobility control affects oil recovery more than size of the chemical slug (NIPER/BDM 1994).

NIPER and Russell Petroleum evaluated a potential application of the ASP process in the fluvial-deltaic Tucker Sand, a local equivalent of the Bartlesville Sand, in the Hepler Field in Kansas. Initial laboratory work developed an effective ASP formulation (French et al. 1990). Advanced analytical techniques like X-ray computer tomography, petrographic image analysis, and a minipermeameter indicated that compartmentalization and lamination extend to the microscale (French 1994a). Field tracer tests were also performed. The high degree of heterogeneity found in field cores and less than anticipated oil recovery in corefloods led to a recommendation to not implement the ASP process in the Hepler Field (French 1994b). If the operator conducts a polymer flood and establishes that good field sweep efficiency could be obtained, the ASP process will be reconsidered at a later date.

D.5.4.2 DOE Cost-Shared Field Demonstration Program

DOE has initiated cost-shared field demonstration projects with operators in Class 1 fluvial-dominated deltaic, Class 2 shallow-shelf carbonate, Class 3 slope-basin and basin clastic reservoirs. No Class 1, 2, or 3 projects specifically note alkaline or ASP processes.

D.6 Surfactant Processes

Being a miscible process, the surfactant process can recover significant oil. However, field results with surfactants have been unpredictable, costs are front-end loaded, and current chemical systems are uneconomic at moderate oil prices (Pope 1993). Field projects have also exhibited high sensitivity to reservoir heterogeneities. As a result, industry perceptions of the process are somewhat negative, and research in surfactant development has diminished. However, the process can be highly efficient and, if improvements are made, applicable to a large number of reservoirs, including those in Class 5.

D.6.1 Screening Criteria

The screening criteria used by the NPC (1984) for the implemented and advanced technology cases are summarized in Table D–11.

In the advanced technology case, the process becomes applicable to either sandstone or carbonate reservoirs. Temperature, salinity, permeability, and viscosity limits are also extended. Although salinity-temperature levels in Class 5 reservoirs do not generally restrict surfactant applications, surfactant applications are constrained by process economics. Chemical and/or process changes that result in more cost-effective systems will expand surfactant recovery potential in the Class 5 oil resource.

TABLE D–11
SURFACTANT PROCESS
NPC SCREENING CRITERIA AT DIFFERENT TECHNOLOGY LEVELS
(SOURCE: NPC 1984)

Parameter	Implemented Technology	Advanced Technology
Reservoir Temperature, °F	< 200	< 250
Brine Salinity, ppm	< 100,000	< 200,000
Permeability, mD	> 40	> 10
Oil Viscosity, cP	< 40	< 100
Rock Type	Sandstone	Sandstone or carbonate

D.6.2 Constraints

Dauben (1991) analyzed field projects to determine constraints to field applications of the surfactant process. Surfactant floods were found to be constrained by excessive chemical loss, polymer limitations (see Section D.3), process design and operations, and an inherent design weakness. The inherent design weakness refers to the need for two dissimilar fluid slugs to travel in sequence and remain intact as they travel through the reservoir.

Field experience indicates that (1) preflushes to protect surfactant slugs from excessive salinity and hardness have been ineffective and (2) chemical systems must be effective in the presence of both injection brine and formation water (Kalpakci et al. 1990). Since surfactants encounter a variety of salinity and hardness environments as they move through a reservoir, chemical systems that maintain their effectiveness in a wide range of environments are desirable. Although technology advances have been made in this area, more broadly applicable chemical systems are still needed. From a cost-effectiveness standpoint, these chemical systems should also incorporate industrial-grade rather than laboratory-grade surfactants.

D.6.3 Recent Technology Thrusts

Surfactant research has focused on developing improved chemical systems that tolerate more salinity, are more effective in varying salinity environments in reservoirs, and do not separate as the chemical slug moves through the reservoir. Recent technology thrusts discussed in this section include (1) more cost-effective mixed surfactant systems, (2) surfactants effective in higher temperature and salinity environments, (3) research tool development (chemical EOR database and laboratory screening procedures), and (4) more cost-effective surfactant flooding approaches.

D.6.3.1 Mixed Surfactant Systems

Mixed surfactant systems are mixtures of surfactants rather than surfactant-alcohol mixtures encountered in conventional surfactant systems. Mixed surfactant systems are (1) more cost-effective than conventional systems, (2) adaptable to a broader range of reservoir conditions, (3) more tolerant of widely varying conditions in the reservoir, and (4) not as susceptible to chromatographic separation as the chemicals move through the reservoir (Llave et al. 1991). Synergistic effects in properly formulated mixtures of two to three surfactants yield solutions that exhibit properties better than that of any of the surfactants individually.

NIPER has been investigating how surfactant structure and combinations of surfactant affect the performance of mixed surfactant systems. Research and findings are summarized here.

- Llave et al. (1991) studied the effects of component substitution, salinity, ratio of components, total surfactant concentration, and surfactant type on the behavior of mixed surfactant systems. Results indicate the following:

- The molecular weight and branching structure of the primary sulfonate-type surfactant affect phase behavior. For mixed systems, longer chain lengths favor good solubilization and low IFT values. The combined effect of chain length and branching in the primary surfactant can alter the system requirement for secondary salinity-tolerant surfactant.
- Ethoxylated secondary surfactants affect salinity tolerance of the mixture with the effect varying with molecular weight and branching-structure of the ethoxylated surfactant. Shorter hydrocarbon chain lengths and branching in the secondary ethoxylated surfactants improve solubility and salinity tolerance.
- Ethoxylated sulfates improve salinity tolerance more than ethoxylated sulfonates when the primary surfactant is a sulfonate-type surfactant.
- The proportion of primary and secondary (salinity-tolerant) surfactants affects the favorable salinity range of the mixed surfactant system.
- The range of salinity tolerance is affected by the total surfactant concentration in the mixed system.

• Llave et al. (1993) investigated the performance of mixtures of a well-studied anionic primary surfactant with ethoxylated anionic/nonionic surfactants. Results indicate the following:

- Ethoxylated surfactants can improve solution behavior of the overall system.
- Ethoxylated nonionic surfactants yield higher salinities compared to ethoxylated anionic surfactants.
- The proportion of surfactant component in solution is critical to balancing solubilization capacity and enhanced salinity tolerance.

This basic research regarding the effects of surfactant structure(s) on oil recovery, when interrelated with information contained in the chemical EOR database, provides the foundation for continuing development of more cost-effective surfactant systems.

D.6.3.2 High-Temperature, High-Salinity Surfactants

NIPER has investigated three potential surfactant systems for high-temperature and high-salinity environments: (1) ethoxylated sulfonates, (2) ethoxylated carboxylates, and (3) amine oxides (Gall 1993). Amine oxide surfactants exhibit improved salinity tolerance and reduced alcohol requirements (Olsen 1989). However, field applications are constrained by the large volumes of chemicals required. Carboxymethylated ethoxylated (CME) surfactants are adaptable for application in harsh environments (Olsen and Josephson 1987; Strycker 1989), but surfactant losses are too high. Sacrificial agents to reduce surfactant loss are not effective at optimum reservoir conditions (Gall 1989). Work on ethoxylated sulfonate systems has largely been in conjunction with mixed surfactant systems.

D.6.3.3 Chemical EOR Database and Expert System

Considering the wide range of prior research and surfactant possibilities, a chemical EOR database has been developed to organize laboratory and field information (Llave 1992). The database includes both a literature reference section and a surfactant information section cross-referencing and identifying data on specific surfactants and chemicals. Long-range, the database may evolve into some level of expert system to assist formulators in developing chemical systems for specific reservoirs.

D.6.3.4 Laboratory Screening Procedures

In developing surfactant systems, the performance of myriad combinations of surfactants must be evaluated. Conventional phase behavior measurements using salinity scans are time consuming. Llave and Olsen (1988) established that phase inversion temperature (PIT) could be used as a more rapid, preliminary screening measurement. Phase inversion temperature is that temperature at which a water-in-oil emulsion reverts to an oil-in-water emulsion or vice versa. NIPER developed semiautomated, computer-monitored equipment for measuring the phase inversion temperature. Results from PIT measurements are used to determine appropriate salinity ranges, then the time-consuming salinity scans are performed in only those selected ranges.

X-ray imaging methods and visualization have become integral to surfactant development studies. Imaging of fluid saturations during corefloods provides insight regarding the effectiveness of surfactant and polymer systems at mobilizing oil and regarding the effects of rock properties and reservoir heterogeneities on fluid movements (Gall 1993).

D.6.3.5 Cost-Recovery Balance

Kalpakci et al. (1990) describe a low-tension polymer flood approach for cost-effective chemical flooding. The process involves coinjection of polymer and low concentration surfactant followed by a polymer mobility control slug. Although recovery efficiency is not as great as conventional surfactant processes, recovery does increase, chemical costs are lower, and chemical costs are not all incurred on the front end. Although Nelson (1989) was critical of low concentration surfactant flooding, his discussion did not consider added polymer.

Low-tension polymer flooding sacrifices oil recovery in return for lower chemical cost. The premise highlights that chemical flooding must optimize economic recovery, not oil recovery. In simulation work for North Sea surfactant floods, Jacobsen and Hovland (1994) evaluated economy, defined as maximum discounted net cash, and found that optimum economy was achieved when typically less than 50% of the technical potential, or maximum incremental oil recovery, was recovered. This concept of optimum cash recovery rather than optimum oil recovery must be kept at the forefront as development work for improved surfactant systems continues.

D.6.4 Current Research Activity

D.6.4.1 DOE Supporting Research

At the University of Texas, research effort is focusing on improving the economics of the surfactant process through simulation studies of alternative design strategies (Pope and Sepehrnoori 1994). The outlined research includes improvements in simulator capability, then optimization of the surfactant process using the simulator.

At Columbia University, research effort is focusing on the mechanisms underlying surfactant adsorption and precipitation on reservoir minerals (Somasundaran 1994). The end objective is to better understand and control surfactant losses.

At NIPER, research is continuing on mixed surfactant systems (NIPER/BDM 1994). Phase behavior evaluations are directed toward identifying optimal salinity conditions for different chemical systems. NIPER's Automated Phase Inversion Temperature (PIT) apparatus, salinity, and alkane scans are being used to determine the range of application conditions. Current work is investigating the effect of anionic-nonionic components of the mixture on optimal conditions. As optimal conditions are identified, oil recovery with different injection strategies is being evaluated in coreflooding experiments.

D.6.4.2 DOE Cost-Shared Field Demonstration Program

DOE has initiated cost-shared field demonstration projects with operators in Class 1 fluvial-dominated deltaic, Class 2 shallow shelf carbonate, and Class 3 slope-basin and basin clastic reservoirs. No Class 1, Class 2, or Class 3 projects specifically incorporate surfactant flooding technology. The low level of interest in field projects reflects adverse economics at present and concern with costs and oil prices perceived in the near future.

D.7 Steam Processes

Steam projects in Class 5 reservoirs have historically been focused in California. Existing steam projects are particularly influenced by economics and environmental regulations. Technology advances will play a role in improving economics and complying with environmental regulations. Outside California, new steam projects face typical technical constraints plus the lack of a thermal infrastructure.

D.7.1 Screening Criteria

The screening criteria used by the NPC (1984) for the implemented and advanced technology cases are summarized in Table D–12.

The depth and net pay thickness criteria recognize heat loss effects. As technology improves from the implemented to the advanced technology level, the depth criterion increases from 3,000 to 5,000 feet while minimum net pay thickness decreases from 20 to 15 feet. The minimum permeability criterion also decreases significantly, from 250 mD down to ≥ 10 mD.

D.7.2 Constraints

Dauben (1991) analyzed steamdrive field projects to determine constraints to field applications considering steam cycling operations on individual wells as part of the steamdrive process. Steam operations were found to be constrained by gravity override, reservoir heterogeneity, downhole completions, and steam generation costs. Gravity segregation represents the primary performance constraint while environmental regulations greatly influence steam generating costs. Steam's high mobility accentuates reservoir heterogeneity's effect. Downhole completion constraints recognize that prudent design and operations practices are not always followed.

Sarathi (1993) outlined technical difficulties (i.e., constraints) for steam injection processes. These difficulties include: (1) reservoir definition, (2) poor conformance and capture efficiency, (3) low injection/production ratio, (4) excessive heat losses or poor net energy ratio, (5) sand control, (6) wellbore damage, (7) emulsion production, and (8) boiler feedwater and low-grade fuel options. Sarathi (1993) specifically noted steam quality measurement and high-temperature instruments and materials as operations constraints.

TABLE D–12
STEAM PROCESS
NPC SCREENING CRITERIA AT DIFFERENT TECHNOLOGY LEVELS
(SOURCE: NPC 1984)

Parameter	Implemented Technology	Advanced Technology
Oil Gravity, °API	10–34	------
In Situ Oil Viscosity, cP	≤ 15,000	------
Depth, feet	≤3,000	≤ 5,000
Pay Zone Thickness, feet	≥20	≥15
Porosity, fraction*	≥ 0.20	≥ 0.15
Permeability, mD	250	≥10
Transmissibility, kh/μ	≥ 5	------
Reservoir Pressure, psi	≤1,500	≤2,000
Minimum Oil Content at Start, fraction	≥0.10	≥ 0.08

* Ignored if minimum oil content criterion satisfied.

Air quality regulations constrain both existing and new steam operations, particularly in California where the bulk of steam operations are currently located. Outside California, steam operations are constrained by the lack of thermal infrastructure (vendors, equipment, experience, etc.).

D.7.3 Recent Technology Thrusts

Although steamflood technology has made significant advances during the past three decades, the technology is far from mature, and ample room exists to improve the process and the ultimate recovery in both ongoing and future projects. During the early 1980s, although the need for efficiency was recognized, very little attention was paid to improving the operation since oil prices were high. The focus of research during the early 1980s was to extend the application of steam to different reservoir settings and explore the use of chemical additives to improve the sweep efficiency. During this time period, research was also directed towards combining other EOR processes, such as gas or caustic flood processes, with steam to enhance recovery. The oil price collapse of the mid-1980s forced the steamflood operators to move away from research directed at improving the process to research that contributed to lowering the recovery cost. The current trends are to develop technology and practices that improve the efficiency of field operation.

During the past 10 years, noticeable advances in steamflood practices have been made that enable operators to manage the injected heat more efficiently and improve profitability. Topics covered in this section include advances in steam distribution practices, subsurface equipment and methods, process improvements directed towards enhancing steamflood recovery, advances in reservoir management practices, and simulation.

D.7.3.1 Advances in Steam Distribution Practices

In a steamflood the wet (two-phase) steam leaving the steam generator is injected into the reservoir through a network of pipelines called the steam distribution system. Up until the late 1970s, it was commonly assumed that the two-phase steam would divide evenly at various branching points (such as the tees and wyes) in the network and arrive at the wellhead with approximately the same quality as the generator output, or proportionately less after adjustment for heat losses in the lines. Research by Chevron, however, showed that widely different steam qualities can arrive at the wellheads (Hong 1978). As a result of further research into the problems of phase splitting, the use of tees in the dead-end configuration was adopted by the industry to achieve uniform steam quality distribution (Sarathi and Olsen 1992). However, recent wellhead flow rate and quality measurements indicate that uneven quality splits commonly occur whenever the ratio of split volumes at dead-end tees deviates considerably from 1:1 (Peake 1992; Jones and Williams 1991). The range of steamflow conditions that produce

acceptable quality splits has been determined (Chien and Schrodt 1992). Insertion of nozzles directly downstream of impacting tees or use of large diameter tees in the network can increase the range of flow conditions for which acceptable quality split occurs (Hong and Griston 1994).

D.7.3.2 Steam Flow and Steam Quality Measurement and Control

Proper evaluation and management of a steamflood require an accurate determination of energy entering the formation. The enthalpy or total heat entering the formation depends strongly upon the steam quality and rate of steam injection. Currently, orifice plates are used to measure the rate, and fixed or variable chokes operating at critical flow conditions are used to control the well injection rate (Redus et al. 1988 ; Griston 1989; Chien and Schrodt 1992). Recent advances in this area have been limited to improving the accuracy of correlations used for converting orifice or choke readings into rates (Surbey et al. 1988; Chien et al. 1992; Chien 1993).

Steam quality, which enters into the calculation of steam generator efficiency and wellhead injection rate using devices such as the critical choke, is even more difficult to measure. Sarathi and Olsen (1992), discussed in detail the various oilfield steam quality measurement practices and their limitations. Recent advances in surface online steam quality measurement techniques include the neutron densitometer technique (Wan 1990) and development of improved correlations to estimate steam quality from orifice plate data (Chien and Schrodt 1992; Blacker and Bellaci 1994). A satisfactory technique does not yet exist to measure downhole steam quality.

D.7.3.3 Subsurface Equipment and Methods

Since the mid-1980s, major emphases have been placed on measuring downhole parameters and altering operations on the basis of specific in situ data. This led to the improvement or development of new subsurface equipment and methods in the past decade to inject steam simultaneously into multiple zones and exercise control over steam injection profiles.

Parallel tubing methods developed in the mid-1980s (Hong 1987; Anderson and Hutchinson 1983) to inject steam simultaneously into two or more independent sands using a common wellbore are now extensively being used in U.S. and overseas steamflood operations.

Some control of where the steam enters the reservoir can be accomplished using limited entry perforation schemes. The scheme, patented in the mid-1980s (Hong et al. 1987), is used to inject constant quality steam between two or more targeted intervals through limited entry outlets. Downhole critical velocity chokes (Webb 1988) are employed to achieve the limited entry outlets. A theoretical framework for limited entry perforation has been developed (Chiou and Owens 1992).

D.7.3.4 Injection Profiling

Measurement of steam injection profiles is important so that adjustments may be made to assure that steam is contacting the oil-bearing formation. Since the mid-1980s, industry has expended considerable effort to increase the reliability of profile survey data. Radioactive tracer measurement of steam injection profiles using gamma ray logging tools is one such innovation (Nguyen and Stevens 1988); however, data interpretation is difficult due to lack of knowledge of the flow stream lines in the injection wells. Current efforts are directed at improving data analysis methods so that injection profiles may be determined more reliably (Griston 1990).

D.7.3.5 Process Improvements

During the past decade, considerable efforts have been expended to improve recovery, reduce gravity override, and manage the injected heat more efficiently. These practices have improved steamflood economics, as discussed below.

Infill Drilling

A relatively new practice in steamflood projects, infill drilling is directed at improving steamflood recovery in projects with a five-spot configuration, such as the Kern River Field, California. The infill drilling involves converting the normal 2.5-acre five-spot patterns to inverted nine-spot patterns by drilling infill producers at the midpoints of pattern boundaries. The objective of infill drilling is to recover the oil that would otherwise be bypassed by the injected steam. Texaco was the first operator to practice infill drilling in a steamflood (Restine et al. 1987). Although infill drilling accelerated production and recovered oil from the so-called blind spots (pockets of bypassed oil), some steam injection practitioners think it does not increase the ultimate recovery. Decisions to drill infill wells have historically been based on accelerated economics, not on incremental recovery (Blevins 1990).

Slimhole Wells

Like infill drilling, this is a new practice in steamflood projects and was designed to reduce drilling and completion costs. A slimhole is different from a conventional well in that no downhole equipment such as packers and tubing is used, lowering drilling and completion costs. Slimholes allow the dedication of injectors to individual sandbodies to improve sweep efficiency and production. The low cost of slimhole drilling allowed Chevron to drill 38 slimhole producers and 10 observation wells for about the same investment required to drill seven conventional dual-string wells (Dennis et al. 1994). This project, implemented in a Midway-Sunset California property, increased the daily oil production from 1,800 barrels to 2,600 barrels (Dennis et al. 1994).

Horizontal Wells

The use of horizontal wells in a steamflood to recover oil from blind spots is an emerging technology (Spiers and Warren 1994; Jespersen and Fontaine 1993; Buller 1992; Carpenter and Dazet 1992; Dickinson et al. 1992; Sahuquet et al. 1990; Huang and Hight 1989; Dietrich 1987). By placing horizontal producers at or near the bottom of a steamflood interval along the pattern boundary, oil in the steam gravity override zone which is bypassed by steam can be captured. UNOCAL has used a horizontal injector to efficiently heat a previously bypassed portion of the reservoir and successfully recovered incremental oil (Buller 1992). Shell's horizontal well steamflood experience in California indicates that horizontal thermal wells are prolific oil producers. Production rates from horizontal wells average 2.6–6 times those of vertical wells (Carpenter and Dazet 1992). Use of horizontal wells in steamflood operations improved the sweep efficiency, oil-steam ratio, and project profitability (Spiers and Warren 1994).

Mobility Control Techniques

Mobility control techniques are processes that attempt to improve the displacement efficiency and vertical sweep efficiency of the steamdrive. These techniques include waterflood after steamflood (Hong 1987; Ault et al. 1985), steamfoam (Patzek and Koinis 1990; Mohammadi et al. 1989), and water-alternating-steam processes (Hong and Stevens 1992; Bautista and Friedmann 1994). Chevron and Texaco implemented the waterflooding after steamflood process in California in the early 1980s, but discontinued the practice due to adverse production problems and questionable benefits (Sarathi 1991). Although the steamfoam process for sweep efficiency improvement proved to be effective in field applications, the process has not generated much enthusiasm among operators due to questionable economics with oil prices less than $20/bbl (Sarathi and Olsen 1993). The water-alternating-steam process (WASP) is akin to the water-alternating-gas injection process, a proven mobility control technique in the gas injection process. One major benefit of WASP is the reduction or elimination of steam breakthrough (Blevins 1990). Chevron has implemented this mobility control technique at the West Coalinga and Cymric Fields, California, and claims to have succeeded in eliminating steam breakthrough problems and in improving sweep and recovery efficiency (Hong and Stevens 1992; Bautista and Friedmann 1994). In addition, cost-effective high temperature polymer gels have been developed and successfully applied in California steamflood projects to mitigate steam channeling and premature steam breakthrough (Hunter et al. 1992; Littlefield et al. 1992).

D.7.3.6 Reservoir Management

Since the price collapse of the mid-1980s, increased emphasis has been placed by steamflood operators on improving steamflood reservoir management practices. Industry now recognizes that improvements in steamflood reservoir management are the only way to increase performance and keep production costs down (Schmidt 1990). Blevins (1990) defines steamflood

reservoir management as those practices which include reservoir monitoring, heat management, water management, and conducting the operation in compliance with applicable environmental regulations.

Reservoir monitoring includes surveys conducted during the course of a steamflood project to gather information necessary for developing and updating the reservoir description. These surveys are conducted in injection, production, and observation wells. Recent advances in steamflood monitoring techniques include the use of cased-hole pulsed neutron capture logs to quantitatively predict the in situ steam distribution and steam breakthrough time (Guo et al. 1993; Guo 1991; Masse et al. 1991), pressure survey in observation wells, cross-hole seismic profiles (Paulson et al. 1992) and use of surface deformation measurement tools to map areal migration of steam (Bruno and Bilak 1994). Since typical steamflood fuel costs over the life of a project are on the order of five to ten times the initial investment, effective heat management practices are being emphasized by operators (Ziegler et al. 1993). Recent advances in monitoring tools and interpretation techniques have greatly enhanced an operator's ability to implement sound, economical heat management practices.

D.7.3.7 Simulation and Performance Prediction

Advances in computer hardware and numerical solution techniques in the past 15 years have made it possible to develop complex thermal simulators and conduct fieldwide simulations (Hong et al. 1992; Blunschi 1987). Advances in thermal simulation techniques have contributed to the development of advanced steamflood implementation techniques and operational practices (Kumar 1990; Hong 1988; Hong 1991; Chu 1993a; Chu 1993b; Hong 1993). Newer and more reliable steamflood performance prediction models are being developed using historical production data (Torabzadeh et al. 1990; Harrigal and Wilcox 1992).

D.7.4 Current Research Activity

The technical challenges facing steamflood operators in this low oil price environment are related to finding the most cost-effective ways of applying known technologies to maximize production and minimize operating costs. The current industry research effort is focused on developing better heat management and reservoir description techniques to reduce operational cost and improve the bottom line profit. Some of these issues were discussed in the previous section.

D.7.4.1 DOE Supporting Research

At NIPER, research is focused on improving the understanding of light and heavy oil production using steam and on using this understanding to accelerate the development and expansion of the domestic resource base. Towards this end, NIPER is establishing a high-temperature, high-

pressure steamflood laboratory that will allow steamflood experiments to be conducted at field conditions. Initial research will focus on developing steamflood operational parameters to recover high pour point crude oil from sucrosic dolomite reservoirs.

NIPER is working with the Naval Petroleum Reserve No. 3 (NPR-3) to develop ways to improve recovery efficiency and economics of the NPR-3 light oil steamflood project. Simulation studies are also being conducted at NIPER to assess steamflood potential of Gulf Coast heavy oil reservoirs (Sarkar and Sarathi 1993a,b).

DOE is funding steamflood mechanistic research at Stanford University and the University of Southern California (USC). Stanford is working on several areas: (1) studies directed toward understanding the effects of steamflood conditions on flow properties, such as the relative permeability and steam flow behavior in fractured reservoirs, (2) improvement of well-testing methodologies for steamflood injection and production wells, and (3) development of improved steamflood performance prediction models. Research at USC is directed towards understanding rock-fluid interaction mechanisms in steamflood reservoirs and the influence of micro- and macro-scale heterogeneities on steamflood performance. In addition, DOE is sponsoring a project at Lawrence Livermore National Laboratory (LLNL) to apply borehole electromagnetic methods to monitor in situ changes in electrical conductivity during steamflood. The goal of this project is to develop practical tools to locate the steamfront and tools to map oilfield structure.

D.7.4.2 DOE Cost-Shared Field Demonstration Program

DOE has awarded contracts for cost-shared field demonstration projects in Class 1 fluvial-dominated deltaic and Class 2 shallow-shelf carbonate reservoirs. Steam processes were not involved in any of the projects awarded.

In Class 3 slope-basin and basin clastic reservoirs, which includes a portion of California's thermal operations, DOE awarded contracts for two thermal projects, one in the Midway-Sunset Field, CA, and the second in the Wilmington Field, CA. Diverse technologies covering a range of reservoir characterization, steam processes, operations, and economic issues are incorporated in these projects.

D.8 In Situ Combustion Processes

The in situ combustion process is applicable to and has potential in selected Class 5 reservoirs, such as the California heavy oil reservoirs where in situ combustion has been tested.

D.8.1 Screening Criteria

The screening criteria used by the NPC (1984) for the implemented and advanced technology cases are summarized in Table D–13.

With implemented technology, in situ combustion can be applied in reservoirs up to 11,500 feet depth versus 3,000 feet for steam. Although viscosity limits are more restrictive, 5,000 cP versus 15,000 cP for steam, the permeability limit falls to 35 mD from 250 mD for steam. With implemented technology, reservoir pressure is limited to 2,000 psi. The most significant changes with the advanced technology case are the reservoir pressure criterion increasing from 2,000 to 4,000 psi and the minimum net pay criterion decreasing from 20 to 10 feet.

D.8.2 Constraints

Dauben (1991) analyzed in situ combustion field projects to determine constraints to field applications. In situ combustion projects were found to be constrained by (1) poor sweep efficiency with the large volumes of noncombustible gases (assuming air injection) flowing through the reservoir, (2) erosion/corrosion in equipment, and (3) oil treating. Many problems experienced in early in situ combustion projects were related to inadequate reservoir characterization.

Improvements in technology and operating practices addressing these constraints have been made, but there is a shortage of current, well-documented field tests demonstrating the success of these improvements and the current economic potential of the process. New project starts are being constrained by operator perceptions from past projects, lack of demonstrated success with new technologies, and a shortage of current industry personnel with direct in situ combustion experience.

TABLE D–13
IN SITU COMBUSTION PROCESS
NPC SCREENING CRITERIA AT DIFFERENT TECHNOLOGY LEVELS
(SOURCE: NPC 1984)

Parameter	Implemented Technology	Advanced Technology
Oil Gravity, °API	10 to 35	------
In Situ Oil Viscosity, cP	≤ 5,000	≤ 5,000
Depth, feet	≤11,500	------
Pay Zone Thickness, feet	≥20	≥ 10
Porosity, fraction*	≥ 0.20	≥ 0.15
Permeability, mD	35	≥ 10
Transmissibility, kh/μ	≥ 5	------
Reservoir Pressure, psi	≤2,000	≤ 4,000
Minimum Oil Content at Start, fraction	≥0.08	≥ 0.08

* Ignored if minimum oil content criterion satisfied.

Technology thrusts discussed in this section include: (1) use of ISC process in carbonate reservoirs, (2) the double displacement process, (3) the horizontal well ISC process, (4) the pressure up-blowdown process, (5) the combustion override split-production horizontal well process, (6) the use of foam, and (7) hydrogen peroxide injection as an alternative to air or oxygen injection.

D.8.3 Recent Technology Thrusts

Despite the poor track record of in situ combustion (ISC) in the field and its reputation as the problem-prone EOR technology, industry interest in the process remains high due to the success of several field projects (notably in Canada) in very diversified reservoirs. Even in the United States, interest in the process has been revived because of Koch's success in implementing this technology in deep carbonate reservoirs. Notable advances have been made during the past 15 years in applying ISC to many reservoir settings. The main thrust in the United States has been to use the ISC technique as a means to repressurize and recover oil from deep, light-oil reservoirs. These and other advances are discussed in the following sections.

D.8.3.1 Use of ISC in Carbonate Reservoirs

Until 1984 ISC was considered applicable only to sandstone reservoirs because of their more favorable reservoir parameters. In 1985 Koch challenged this notion for the first time and implemented in situ combustion projects in the deep, thin, low-permeability carbonate reservoirs of the Williston Basin in North and South Dakota. Because of the uniqueness and proprietary nature of the projects, project details were not made public until 1994 (Kumar et al. 1994; Miller 1994). Koch's projects involve injection of air into deep carbonate reservoirs to pressurize and ignite the formation and displace the oil. The noteworthy aspect of these projects is that they violated many of the published screening criteria and yet proved to be commercially successful. The reservoir properties for these projects are compared to published screening guides in Table D–14. The combined daily oil production from Koch's ISC projects in early 1994 was 4,900 barrels, which essentially doubled the reported 1992 U.S. daily oil production of 5,200 barrels from eight active ISC projects (Moritis 1992).

D.8.3.2 Double Displacement Process

In 1994 Amoco Production Company, in partnership with DOE, initiated a unique in situ combustion project to recover oil from a deep, watered-out light oil reservoir in the West Hackberry Field in Cameron Parish, Louisiana. The goal of this Amoco/DOE Class 1 mid-term program is to use ISC to create a gas cap to push the encroached water column downward towards the original-water-oil contact and allow oil to drain by gravity (Fassihi and Gillham 1993). The process of displacing a water-invaded oil column by an expanding gas cap is called the double displacement process (Carlson 1988).

D.8.3.3 Horizontal Well ISC Process

The use of horizontal wells as producers in ISC projects is becoming increasingly popular with Canadian operators due to increased production performance and substantial reduction in operating problems, such as sand production and low gas-oil ratios (Morgan 1993; Ames et al. 1994). The reduced operating problems were attributed to the extremely low drawdown during oil flow toward the producers. Canadian experience indicates that, in bottomwater drive reservoirs, recovery by ISC can be enhanced by placing horizontal wells between the overlying combustion gas cap and the underlying acquifer (Ames et al. 1994). In the United States, horizontal wells were used in a Southeast Kansas in situ combustion project, but the results were disappointing (Satchwell et al. 1994).

D.8.3.4 Pressure Up-Blowdown Combustion Process

This relatively new variation of the conventional combustion process (patented by BP Resources, Canada) minimizes channeling and improves recovery in highly viscous crude oil reservoirs (Hallam and Donnelly 1988; McGee et al. 1988). The process, developed as a follow-up to cyclic steam stimulation, is designed to exploit a highly viscous crude oil reservoir with high mobility contrast. As the initial step, a heat link is established between the injector and producer by

TABLE D–14
KOCH'S IN SITU COMBUSTION PROJECTS
RESERVOIR PROPERTIES VERSUS PUBLISHED SCREENING GUIDES

Properties	Iyoho (1978)	Chu (1982)	NPC (1984) Advanced Technology	MPHU* (Miller 1994)	Buffalo (Miller 1994)	Capa Madison (Miller 1994)
Oil Gravity, °API	10–40	<40	--	39	31	43
In Situ Oil Viscosity, cP	≤1,000	--	≤5,000	0.48	2.1	0.28
Depth, ft	--	<12,000	--	9,500	8,450	8,400
Payzone Thickness, ft	5–50	--	≥10	18	10	20
Porosity, % (≈)	>20	>16	>15	17	20	10
Permeability, mD	>300	>100	≥10	5	10	1
Initial Oil Saturation, S_o	>50	>35	>53	57	55	58
Reservoir Pressure, psi	<4,000	--	≤4,000	4,500	4,200	4,200
Residual Oil Saturation ≈S_o	>0.077	>0.1	>0.08	0.1	0.11	0.06

*Medicine Pole Hill Unit

injecting steam into the reservoir. The reservoir is then alternatively pressurized and depressurized to advance the combustion front and produce the mobilized oil. The process, field tested in Canada in the mid-1980s, proved to be very effective in recovering immobile oil. It may find application in some California Class 5 reservoirs. The earlier DOE cost-shared in situ combustion projects in these fields (Shipley et al. 1980; Stair 1980) failed because of poor oil mobility.

Another variation of this process, which is currently being field tested in Canada, is the "pressure cycling in situ combustion process" (Marjerrison and Fassihi 1994). This process is a cyclic in situ combustion process that involves periods of high-rate air injection followed by zero injection.

D.8.3.5 The Combustion Override Split-Production Horizontal Well (COSH) Process

This process is a new approach to combustion processes (patented by Alberta Oil Sands Technology and Research Authority (AOSTRA), Alberta, Canada) that combines the high recovery potential of a gravity drainage mechanism with the energy efficiency of the combustion process to improve oil recovery while minimizing the negative aspects of the combustion process (Kisman and Lau 1994). The process is essentially a gravity drainage process and, as such, its applicability is limited to thick, dipping reservoirs with good vertical permeability, such as the Potter Sand of Midway-Sunset Field, California.

D.8.3.6 Use of Foam in ISC Process

The use of foam to improve sweep efficiency is a relatively new concept in ISC projects. The concept, field tested in Russia, appeared to be a technical success and holds promise for reducing gas channels and improving production (Abasov and Kismetov 1991; Mamedov and Bocserman 1992). In the reported projects, 24,000 barrels of foam-forming surfactant solution (2% active), stabilized with 0.1% high-temperature polymer solution, was injected into three combustion wells over a five-month period. Injection of the foaming solution resulted in 55,000 barrels of incremental oil.

D.8.3.7 Hydrogen Peroxide In Situ Combustion Project

Recently, a U.S. patent was issued for the use of hydrogen peroxide instead of air as the fluid to initiate and sustain combustion (Bayless and Williams 1989). Laboratory combustion tube runs indicate that the process can recover substantial amounts of oil, while overcoming the drawbacks of conventional steam or ISC thermal processes (Moss and Moss 1994).

D.8.4 Current Research Activity

Amoco is the only U.S. operator currently conducting in situ combustion-related research in the United States. In 1990 Amoco formed an industry consortium to evaluate the air injection, in situ combustion process in deep, high-pressure, light-oil reservoirs. DOE, through BDM-Oklahoma, is participating in the Amoco in situ combustion research consortium to encourage further advancement of ISC technology. The aim of this research is to experimentally identify and quantify effects of pressure on the process and the effects of the combustion products on crude oil recovery.

D.8.4.1 DOE Supporting Research

DOE is funding in situ combustion kinetic research at Stanford University. The aim of this research is to evaluate the effects of different reservoir parameters on the in situ combustion process. The project is primarily investigating the effects of various heavy metals found in the rock and crude on process behavior.

At NIPER the thermal research group is currently compiling an in situ combustion handbook for independent operators. The purpose of this compendium project is to document the valuable experience of past in situ combustion experts and to encourage operators to consider implementing field projects.

D.8.4.2 DOE Cost-Shared Field Demonstration Program

DOE has awarded a contract to Amoco for a cost-shared field demonstration project in a Class 1 fluvial-dominated deltaic reservoir that uses combustion technology to mobilize and recover light oil from a deep, watered-out reservoir. The project is to be implemented in the West Hackberry Field located in Cameron Parish, Louisiana, near Lake Charles (Fassihi and Gillham 1993).

D.9 Carbon Dioxide (CO_2) Processes

Carbon dioxide recovery processes, primarily miscible flooding, contribute a significant portion of the enhanced oil recovery production in the United States. Most miscible flooding projects are located in geographic areas having access to a CO_2 pipeline infrastructure. For Class 5 reservoirs the northern Rocky Mountain region is the only area having potential access to an existing CO_2 pipeline structure. Other Class 5 areas will incur higher CO_2 costs because of their lack of access to the supply infrastructure. Although recovery efficiencies with cyclic CO_2 stimulation treatments may be lower than with miscible floods, cyclic treatments can be economic under certain reservoir and economic conditions. The TORIS estimates of recovery potential from CO_2 do not include any potential contribution from immiscible or cyclic CO_2 stimulation treatments.

D.9.1 Screening Criteria

Since the NPC (1984) screening criteria only address CO_2 miscible flooding, only two criteria are specified: (1) reservoir pressure should be sufficient to reach miscibility, and (2) crude gravity ≥ 25° API. Screening criteria remain the same at the advanced technology level, but the advanced technology case allows higher recovery through using larger CO_2 slugs and mobility control agents (see Appendix C). The pressure criterion effectively limits miscible operations to reservoirs more than 2,000 feet deep (Taber and Martin 1983). Klins' (1984) screening criteria recognized API gravity, pressure, depth, and temperature limits, but also added a viscosity criterion of 12 cP or less.

Like other IOR processes, CO_2 miscible screening criteria identify reservoirs where the process won't work, but additional screening concepts must be used to determine candidate reservoirs. Flanders et al. (1993) used economic screening concepts to evaluate the economic viability of CO_2 floods in small- to medium-size fields. Sensitivities to CO_2 cost, tax incentives, depth, pore volume, operating costs, and startup costs were evaluated. Economic viability was found to be very field-specific, with a primary variable being startup costs. Startup costs include things like tubular condition, wellbore integrity, completion type, conversion of wells to CO_2 injection, workovers in production and injection wells, facility modifications, CO_2 compression recycling plant, corrosion prevention measures, etc. Startup costs and operating costs are depth dependent. The single biggest factor affecting economic viability is the CO_2 supply and delivery infrastructure (NIPER and K&A 1991).

Rivas et al. (1992) performed a parametric study using a numerical simulator to determine optimum reservoir candidates among reservoirs passing the basic screening criteria. Reservoir parameters examined included temperature, pressure, porosity, permeability, dip, API gravity, oil saturation, net oil sand thickness, minimum miscibility pressure, saturation pressure, remaining oil in place, and reservoir depth. Parameters that influenced CO_2 flood performance the most were API gravity, oil saturation, and reservoir pressure. Optimum conditions for these parameters were 36° API, 60% oil saturation, and pressure at the time of injection of about 200 psi over minimum miscibility pressure.

The NPC screening criteria do not address well selection criteria for cyclic CO_2 stimulation. Thomas and Monger-McClure (1991) evaluated performance trends for light-oil cyclic CO_2 stimulation treatments and suggested the following well selection guidelines:

- Desirable reservoir characteristics include shallower reservoirs, operating below the minimum miscibility pressure, a thick pay interval, a mobile-water or free-gas saturation, and an adequate drive mechanism.
- Treatments are well suited to high water-cut wells since high oil saturations are not required.
- Wells should exhibit mechanical integrity.
- Baseline production data should be available.

In evaluating experience with cyclic CO_2 treatments in Wyoming, Carlisle (1992) confirmed the importance of mechanical integrity and added two additional caveats:

- Wells with thief zones or extensive fractures are not good treatment candidates.
- Wells with good initial (not current) oil production rates are preferred.

In their cyclic CO_2 stimulation program in southwest Wyoming, Amoco found containment (i.e., no thief zones or extensive fracturing) was critical to success (Passmore 1991). In one reservoir, their well selection criteria considered prior waterflood response rather than Carlisle's primary production.

D.9.2 Constraints

Dauben (1991) analyzed field projects to determine constraints to field applications of the CO_2 processes. He listed four constraints: (1) reservoir heterogeneity, (2) mobility control, (3) injectivity, and (4) operations. Of these constraints, mobility control is the primary constraint. Reservoir heterogeneity constraints can be addressed through reservoir characterization. Injectivity constraints can be addressed through project design. Although costs are higher than with waterflooding, operations-related constraints can be addressed through equipment selection and operating practices. Mobility control affects flooding operations, whether miscible or immiscible. With cyclic CO_2 stimulation operations, containment problems replace mobility control as a primary constraint.

For any CO_2 project, CO_2 supply and cost constrain field applications. Natural CO_2 sources with the corresponding supply infrastructure are shown in Figure D–3. Except for a portion of the Class 5 resource in the northern Rocky Mountains, other Class 5 locations must depend on high purity manmade sources such as fertilizer plants, flue gas absorption and cleanup, or commercial CO_2 (truck) delivery. In most cases, commercial CO_2 (truck) sales represent the only viable source, especially for cyclic CO_2 treatments. In 1992 the cost differential between pipeline and truck costs in the northern Rocky Mountain area was more than threefold (Branting and Whitman 1992). This cost differential effectively prohibits large-scale flooding and discourages less efficient cyclic treatments. However, Amoco found the results of cyclic CO_2 treatments using trucked CO_2 in the Salt Creek Field sufficiently encouraging to plan additional treatments (Passmore 1991).

D.9.3 Recent Technology Thrusts

Mobility control and predictability are two areas of technology activity in CO_2 flooding. For selected medium- to low-gravity crudes in the Class 5 resource, immiscible CO_2 flooding may be an option. Since a large portion of the Class 5 oil resource is distant from existing CO_2 infrastructure, cyclic CO_2 treatments have potential application. This section reviews technology thrusts in mobility control, predictability, immiscible CO_2 flooding, and cyclic CO_2 stimulation treatments.

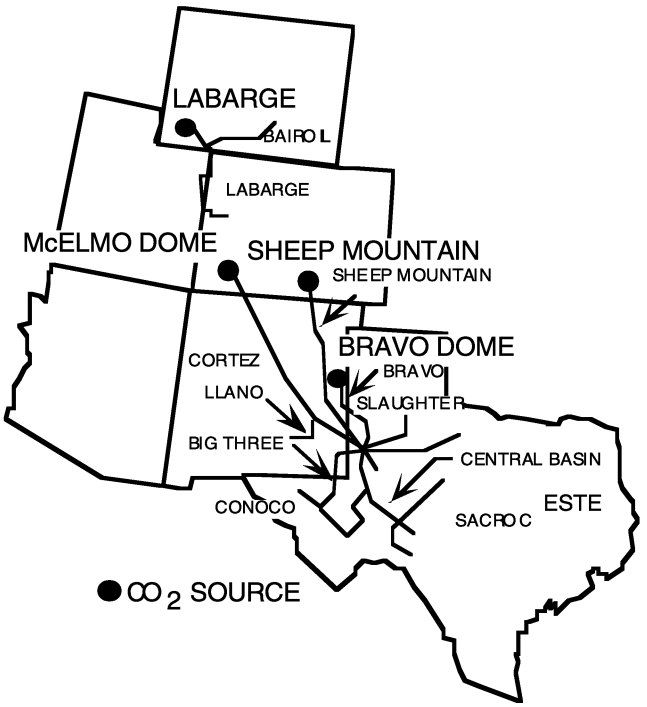


Figure D–3 Major CO_2 Pipelines Servicing the Permian Basin and the Rocky Mountain States (Source: DOE 1993)

D.9.3.1 Mobility Control

Methods which are being investigated for mobility control in CO_2 floods include foams, polymer gels, gas viscosifiers, and, most recently, precipitation methods. Both foams and gel polymers, which have been applied in field tests, receive the most industry attention.

Foam positively affects gas mobility by replacing the gas relative permeability and viscosity with a lower relative permeability and higher gas-foam viscosity. Both effective gas permeability and apparent viscosity of the foam depend on foam quality and texture. Foam apparent viscosity or rheology depends on both foam quality and foam texture. Experimental results show that foam apparent viscosity (1) increases sharply as foam quality, the ratio of gas volume to total foam volume, becomes greater than 90% and (2) may either increase or decrease with increasing shear rate (Chung 1993; Yang and Reed 1989).

Foam effectiveness depends on foam generation, foam transport, and foam stability. The major controlling factors in foam generation are gas flow rate, liquid volume fraction, and surfactant concentration (Chung 1993). Oil saturation, pore structure, system pressure, and surfactant type also affect foam generation (Friedmann and Jensen 1986). Surfactant losses through adsorption and precipitation influence foam generation and foam transport. Oil is known to adversely affect foam stability.

Three choices exist for foam emplacement in a CO_2 flood (Jonas et al. 1990): (1) CO_2 displacing a single slug of surfactant, (2) alternate injection of surfactant in brine and CO_2 (SAG), and (3) simultaneous injection of CO_2 and surfactant. From a reservoir standpoint, rapid alternate injection approximates simultaneous injection. Operations considerations exert a large influence on simultaneous injection versus SAG injection, and with SAG injection, the length of the cycles.

In field projects potential foam benefits include: (1) improved CO_2 utilization, (2) reduced gas production and associated recycling costs, and (3) increased oil production (Hoefner et al. 1994). Operating at higher bottomhole pressures with foam can result in accelerated production, improved sweep efficiency, and (if operations are limited by gas-processing capabilities) less shut-in production.

Foam behavior in porous media is a complex phenomenon with much remaining to be learned. Field applications add even more complexity for understanding and applying foams. Field test approaches range from one-well tests, such as Chevron's Rangely Weber Sand Unit in Colorado, (Jonas et al. 1990), to extensive research-oriented tests, such as Phillips' DOE test in New Mexico's East Vacuum Grayburg San Andres Unit (Stevens and Martin 1994), to commercialization programs like that conducted by Mobil (Hoefner et al. 1994).

Mobil's commercialization program had a specific objective of defining economic potential of foam treatments in a variety of reservoir conditions. Four field tests were conducted in two different reservoirs. Mobil focused on "learning by doing" in the field (Hoefner et al. 1994), recognizing that research and laboratory work can only go so far, especially considering the complexities of the foam process. Although Mobil did not report specific economic performance, additional field tests are planned.

Polymer Gels

The CO_2 flood environment places special requirements on gel polymer treatments. Gels for CO_2 floods must form and then be stable in the low pH, carbonated brine environment. Gels created by the conventional chromium redox process are known to be unstable in such an environment. As with gel polymers for other applications (see Section D.2), well selection and treatment guidelines heavily influence treatment success rates. Two field projects illustrate gel polymer applications in CO_2 floods.

In their Lick Creek Meakin Sand Unit immiscible CO_2 project in Arkansas, Phillips Petroleum Company tested foam, aluminum citrate gels, chromium redox gels, and Halliburton's K-Trol™ VC process, in that order (Moffitt and Zornes 1992). The Halliburton K-Trol™ VC process involves the injection of a low-viscosity acrylamide monomer which undergoes in situ polymerization and simultaneous crosslinking with an organic crosslinking agent. The created gels are strong, rigid, and stable in a low pH environment. In this project the foam and aluminum citrate gels did not have sufficient strength for the high permeability channels. Four

chromium redox and 10 K-Trol™ treatments were performed. Although more costly, the K-Trol™ treatments exhibited more positive production response in offset producers. K-Trol™ treatment costs were $3.73 per incremental barrel of oil.

Amoco used acrylamide-polymer/chromium (III) carboxylate gels in their Wertz CO_2 flood in southwest Wyoming (Borling 1994). CO_2 flooding was started in the fractured Tensleep reservoir in 1986. Major CO_2 breakthrough occurred and conformance problems were evident, as well as significant declines in production. Foam treatments using surfactant were attempted first, but only short-term conformance control resulted, particularly when natural fractures were present. Amoco conducted gel polymer treatments in ten injection wells. Criteria, in order of priority, for selecting candidate wells were:

- Pattern reserves
- Historic fluid injection conformance
- Offset production well performance
- Injection fluid cycle time
- Well history information

Posttreatment analysis indicated pattern lives were extended by nearly two years with incremental reserves per pattern ranging from 35,000 to 140,000 barrels. Individual treatment payout times ranged from 1.1 to 3.7 months.

Gas Viscosifiers

Several approaches have been explored for increasing viscosity of the CO_2 gas, thereby improving mobility control:

- Viscosifying the carbon-dioxide-rich phase by adding polymers as direct thickeners (Dandge and Heller 1987)
- In situ polymerization of soluble monomers in supercritical carbon dioxide (Terry et al. 1987)
- Viscosifying the carbon-dioxide-rich phase by adding entrainers (Llave et al. 1990)

Dandge and Heller (1987) at New Mexico's Petroleum Recovery Research Center (PRRC) found that the CO_2 solubility of presently available polymers was limited. PRRC's work with synthesized ionomers was discouraging and research was discontinued (Chung 1993). Bae and Irani (1990) at Chevron found that commercially available polysiloxanes are effective viscosifying agents for CO_2 when used in combination with cosolvents. The viscosity of CO_2 was increased by two orders of magnitude. Terry et al. (1987) found that, while monomers could be polymerized in situ, no increases in apparent viscosity were observed.

NIPER (Llave et al. 1990; Strycker and Llave 1991; Raible 1992) has investigated entrainers (or cosolvents) for CO_2 mobility control. Cosolvents can increase the viscosity and density of the CO_2 gas and enhance the extraction of oil compounds into the CO_2 rich phase. Raible (1992) found that:

- If reservoir conditions are sufficient to achieve miscibility, reservoirs are not candidates for entrainers, since the gas phase at miscible conditions will already be saturated with crude oil.
- Only a limited number of cosolvents are potential additives. Cosolvents must be miscible with the gas phase at reservoir conditions, must have limited solubility in the oil phase, and must exhibit limited brine solubility.
- Higher molecular weight cosolvents such as isooctane are not as effective as lower molecular weight cosolvents such as propane. Although oil recovery in corefloods using propane as a cosolvent was higher, only small increases in gas viscosity were noted.

Although potential may exist with the different gas viscosifying methods, industry interest and activity appears focused in the foam and gel polymer areas.

Precipitation Methods

Alcohol-induced salt precipitation is one profile modification method that is being studied (Zhu and Tiab 1992; Zhu and Raible 1994; Chung 1993). This method is based on a salt precipitation process resulting from the injection of concentrated brine and alcohol slugs. Mixing of the alcohol and concentrated brine cause a reduction in salt solubility and precipitation of solid salt. Since brine and alcohol have a higher relative permeability in watered-out zones, this method selectively plugs the more permeable flow paths. Claimed advantages include (1) less crossflow effect with lower viscosity fluids, (2) miscibility with connate waters, (3) relative independence from adsorption, temperature, and fluid pH effects, and (4) precipitated salts are relatively stable in high salinity, low pH environments of CO_2 floods (Zhu and Raible 1994; Chung 1993).

Laboratory results (Zhu and Raible 1994) indicate:

- Higher salt concentrations form larger salt crystals which grow with time.
- Ethanol is more effective than methanol.
- Cores with permeabilities modified by salt precipitation are resistant to salt dissolution by subsequent waterfloods with low-salinity brines.
- Salt precipitation increased oil recovery in CO_2 corefloods.

D.9.3.2 Predictability Issues

Chung (1993) identified four problems associated with predicting performance of gas displacement operations. These problems are:

- Inadequate representation of fluid phase behavior
- Incomplete mixing of injection gas and reservoir oil
- Reservoir heterogeneities, particularly those related to permeability; i.e., permeability distribution, fracture configuration, location of faults
- Simulation and modeling techniques

Current NIPER work regarding performance prediction improvements is summarized in Section D.9.4.1 under DOE Supporting Research.

D.9.3.3 Immiscible CO_2 Displacement

Immiscible CO_2 flooding is an alternate IOR method for heavy oil recovery, particularly for reservoirs deeper than 4,000 feet or less than 20 feet thick. Recovery mechanisms include oil viscosity reduction, oil swelling, solution gas drive, and hydrocarbon extraction. NIPER (Chung 1993; Chung and Burchfield 1987) has been actively involved in developing physical property measurements of CO_2–heavy oil mixtures, coreflooding tests, and mobility control improvements. NIPER-developed CO_2–heavy oil correlations are now used as references for heavy oil properties (Chung 1993). Coreflooding tests indicate that recovery with immiscible, high pressure CO_2 flooding can be as high as observed with miscible flooding. Mobility control methods which have been examined include the surfactant-enhanced WAG process and the entrainer (cosolvent) process.

D.9.3.4 Cyclic CO_2 Treatments (Huff and Puff)

Several field tests have evaluated efficiency of cyclic CO_2 treatments in both heavy and light oils. These field tests illustrated that, while simulation may help design treatments for a given application, field treatment data best determine the optimum economic design for a given reservoir and field. Under the right circumstances, cyclic CO_2 treatments have been proven to be economical, although recovery is admittedly lower than with flooding processes.

Big Sinking Field, Kentucky

IFP documented the results of a field-scale cyclic CO_2 program in the Big Sinking Field in Kentucky (Miller et al. 1994). Reservoir depth is 1,300 feet, pressure is 150 psi, and oil gravity is 36° API. From 1985–1994, 390 treatments were performed in 240 wells. Treating procedures are as follows: CO_2 is trucked in and injected down the annulus, the well is shut in for about 10 days

and then placed back on pump. Treatment sizes ranged from 20 to 120 tons per well. Observed CO_2 efficiencies were in the 0.87–1.41 McF/bbl range. From an economic standpoint, the smaller 20-ton treatments yielded the highest CO_2 efficiency.

Wyoming Experience (Wyoming Carbonics, Inc.)

Wyoming Carbonics performed 29 cyclic CO_2 treatments during 1990–91 (Carlisle 1992). Well selection and treatment guidelines were developed from the experience gained with these treatments. Wells with thief zones or extensive fractures do not make good candidates for treatment. Good initial production potential is more important than current production rate. Other guidelines for equipment, operating practices, and CO_2 soak time as a function of reservoir pressure were developed. For low-pressure (< 400 psi) reservoirs, shut-in times of only 5–8 days are recommended. For moderate-pressure (400 to 1,000 psi) reservoirs, shut-in times of 10–14 days are recommended. For high-energy (1,000 to 2,400 psi) reservoirs, shut-in times of 15–30 days are recommended.

Wyoming Experience (Amoco)

During 1990 Amoco conducted 13 cyclic CO_2 treatments in Wyoming in five different oil fields (Passmore 1991). Design criteria included creating a 50% CO_2 saturation 150 feet from the wellbore. CO_2 was injected over a one- to two-week period, followed by a soak period averaging 35 days. In the Lost Soldier and Wertz Fields, where treatments were conducted at pressures above the minimum miscibility pressure, four of seven treatments were considered economically successful. In the Salt Creek Field, treatments were conducted at pressures below minimum miscibility pressure. In Salt Creek two of three treatments exhibited poor containment. Among other things, Amoco concluded: (1) containment was critical, (2) injecting CO_2 down the tubing-casing annulus was preferable, and (3) treatments needed to be optimized to smaller volumes and shorter soak times (Passmore 1991).

Texas Gulf Coast (Texaco)

Haskin and Alston (1989) outlined overall results from 28 well treatments in Texas Gulf Coast Miocene reservoirs. Gravities ranged from 23° to 30° API and viscosities ranged from 2 to 33 cP. They concluded: (1) viscosity reduction and oil swelling were the primary recovery mechanisms, (2) soak times of two to three weeks were better than either shorter or longer times, and (3) oil-cut response from the initial treatment can guide selection of wells for multiple cycles of CO_2 treatments.

D.9.4 Current Research Activity

D.9.4.1 DOE Supporting Research

The Petroleum Recovery Research Center in New Mexico is conducting a joint industry, university, and government project evaluating the use of foam for mobility control and fluid diversion in a CO_2 flood. The field site is in the East Vacuum Grayburg San Andres Unit in southeast New Mexico. Favorable production response was obtained from the initial foam test (Martin et al. 1994). Additional foam tests are being conducted, and alternative foam generation schemes are being investigated.

At Stanford, research is exploring viscous and gravity effects in two-dimensional and three-dimensional flow experiments (Orr 1994). After the relationships between process mechanisms are qualified, displacement processes which take advantage of crossflow in heterogeneous media can be designed. At Morgantown, research is focusing on (1) scaling thermodynamics, (2) models of fluid flow and miscible fingering that conform to current scaling theory, and (3) experiments and modeling for the development of surfactant-based mobility control on the basis of either leave-behind lamellae or fluid dispersions (Smith 1994).

At NIPER, research is continuing on improving gas flood performance prediction ability and on mobility control methods (NIPER/BDM 1994). Performance prediction research is focusing on interfacial tension behavior of oil-water phases with CO_2 dissolution and on developing a more accurate compositional prediction method for CO_2-water-hydrocarbon systems. Alternatives to the Peng-Robinson equation of state are being evaluated. Mobility control research is evaluating selective placement of polymer gels and the precipitation of salts and chemicals. Napthalene precipitation as a profile modification technique is currently being evaluated. Polynuclear aromatic compounds such as napthalene are highly soluble in a ketone solvent, but precipitate when mixed with water. The theory behind this method is that injection of an aromatic solution into a water zone or channel would cause precipitation of the napthalene, thus blocking the water zone. Cosolvent and NaCl effects on precipitation and phase behavior are being determined in phase behavior studies.

D.9.4.2 DOE Cost-Shared Field Demonstration Program

DOE has initiated cost-shared field demonstration projects with operators in Class 1 fluvial-dominated deltaic, Class 2 shallow-shelf carbonate, Class 3 slope-basin and basin clastic reservoirs.

Under Class 1 projects, Texaco is evaluating CO_2 miscible displacement in a watered-out reservoir in Port Neches Field in the inland waters of southeast Texas. This project incorporates a horizontal CO_2 injection well located along the original oil-water contact. Reservoir pressure will be raised above the minimum miscibility pressure by injecting salt water.

Due to the local availability of CO_2 in Colorado and New Mexico four of 11 Class 2 projects incorporate some aspect of CO_2 technology. Texaco is evaluating the CO_2 huff 'n' puff process in the Central Vacuum Unit in southeast New Mexico. The Utah Geological Survey plans to evaluate secondary/tertiary recovery potential in five fields in the Paradox Basin of Utah, then conduct a small CO_2 flood in one of the fields. Oxy USA is combining several technologies (cross-wellbore tomography, 3-D seismic, horizontal flood fronts created by hydraulic fracturing, cyclic CO_2 stimulation treatments) in Texas San Andres reservoirs. Phillips is combining horizontal injection wells drilled from a centralized location with CO_2 flooding in a Texas San Andres reservoir.

Two of the Class 3 projects incorporate CO_2 technology (OGJ 1994). Chevron will initiate immiscible CO_2 flooding in the Miocene Antelope/Monterey Shale in Buena Vista, California. Parker and Parsley will initiate a CO_2 gravity drainage pilot in the fractured Spraberry reservoir in West Texas.

Industry interest in CO_2 processes is reflected by the number of cost-shared field demonstration projects incorporating the technology, often in combination with other improved oil recovery technologies.

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APPENDIX E
RECENT NUMERICAL SIMULATION AND MODELING RESEARCH

The discussion included in this appendix was originally presented in the 1994 Class 4 Department of Energy Report: *Research Needs for Strandplain/Barrier Island Reservoirs in the United States* (Cole et al. 1994). Appendix E has been included here to provide operators of Class 5 reservoirs with quick access to pertinent information on current reservoir simulator types and their availability.

Computer reservoir simulation techniques have advanced significantly over the years. State-of-the-art desktop simulators are now available to perform both history matching and predictive numerical modeling of virtually every improved oil recovery process. Computer reservoir modeling has evolved due to the efforts of both the federal government and the petroleum industry. Although many of the commercially available reservoir simulators are state-of-the-art PC-based models, most are very expensive to purchase and require experienced staff to perform simulation studies.

The main objective of this chapter is to summarize the various features of the publicly available simulators developed by DOE. Such simulators can be used by independent operators and others as reservoir management tools to define reservoir constraints on production and to design processes for improved oil recovery (IOR). The advantages of using publicly available simulators are numerous. First, the expense incurred in purchasing them is insignificant when compared to similar commercially available simulators. Second, most publicly available simulators are relatively user-friendly and require low-cost hardware for operation.

From a reservoir management point of view, reservoir simulators are critical for the proper selection and design of improved oil recovery processes for field application. Reservoir simulators are valuable tools for determining the sensitive parameters that affect particular IOR processes and for determining the most efficient design for project implementation or modification. Simulators can be used to optimize overall recovery process design, assess the risk in applying the process, and quantify the economic viability of recovery processes. Commercial reservoir simulators are available from many vendors and consulting firms, and many major oil companies have developed sophisticated in-house simulators to fit specific simulation needs. Detailed reservoir simulation studies are probably more critical and beneficial to independent operators who are faced with limited budgets and technical expertise. Hence, publicly available simulators become a very important tool for selecting and designing the appropriate IOR process. Therefore, continued development and improvement of these publicly available simulators becomes a significant research need for the industry.

E.1 Public Domain Reservoir Simulators

DOE has funded the development of numerous publicly available numerical reservoir simulators in the last decade, including a black oil simulator (BOAST), a pseudo-miscible simulator (MASTER), and various modified versions of these two basic simulators. The purpose of this section is to describe the applications, features, and computer requirements of the reservoir simulators which have been developed by DOE, as summarized in Table E–1. These simulators have a wide range of applicability, including simulating primary recovery, secondary recovery, and improved oil recovery processes.

The widely used BOAST and the lesser used MASTER simulators were initially developed to run on mainframe computer systems and were written in FORTRAN. With the expanded use of personal computers (PCs), the BOAST model and subsequently the MASTER model were modified and compiled to run in a PC environment. Initially, the movement to the PC environment resulted in the loss of some computational capabilities. For example, the capability and power of the PC hardware determined the maximum possible number of grid blocks, the maximum number of iterations, and the maximum number of time steps, which limited the accuracy of the simulations. Today, with the advancement in computer hardware capabilities, the PC-based simulators are capable of performing a wide range of large-scale history matching and performance prediction simulations. On the other hand, some of the more recent advances in reservoir simulation techniques, such as finite element methods and fractal modeling, which require high speed and large storage computing capabilities, are currently available only with commercial mainframe-based reservoir simulators.

E.1.1 Black Oil Applied Simulation Tool (BOAST, BOAST II)

The Black Oil Applied Simulation Tool (BOAST) simulator was developed by DOE and was originally released to the public in 1982 (Fanchi et al. 1982). BOAST was developed as a simplified reservoir model for simulating primary depletion, pressure maintenance by water or gas injection, and secondary recovery operations. BOAST is a three-dimensional, three-phase black oil reservoir simulator that models the multiphase flow of oil, water, and gas in porous media. BOAST uses the implicit pressure/explicit saturation (IMPES) formulation for solving finite-difference equations and incorporates line-successive overrelaxation (LSOR) or direct elimination solution options for solving the pressure equations. This model has been widely used by the industry, academia, and research institutions and was found to provide reasonably accurate predictions of reservoir performance under most circumstances.

Defined operational limitations of BOAST, however, resulted in the release of a modified version of the model, called BOAST II, in 1987 and the subsequent release of a PC version of the model in 1989. The modifications included in the BOAST II model included the addition of numerous

Table E–1
Publicly Available Reservoir Simulators

Name of Simulator	Applications	Features	Computer Requirements
BOAST II	Primary depletion Secondary recovery Waterflooding Pressure maintenance by water or gas injection	Restart option Multiple PVT regions Multiple rock regions Different aquifer models	80386 and up 4 megabyte memory
BOAST 3-PC	Primary depletion Secondary recovery Waterflooding Pressure maintenance by water or gas injection Steeply dipping reservoirs	Multiple PVT regions Multiple rock regions Different aquifer models Postprocessor for 2D visualization 3D, 3-phase simulator	80386 and up 4 megabyte memory Math coprocessor
BOAST-VHS	Primary depletion Secondary recovery Waterflooding	3D, 3-phase simulator Horizontal, slanted, and vertical wells Dynamic redimensioning	640 KB RAM minimum Math coprocessor 386 or 486 processor preferred EGA or VGA support
MASTER "MISC4" a newly developed PC-version	Miscible or immiscible gas flooding	3D, 3-phase simulator Multicomponent, pseudo miscible Tracks oil, gas, water, up to 4 solvent species, and a surfactant. Multiple PVT regions (10)	Mainframe computer, or 80386 and up 4 megabyte memory
MTS	Microbial and nutrient transport Permeability reduction caused by cell clogging	3D, 3-phase simulator Multicomponent Porosity change and perm reduction No microbial oil recovery mechanisms	Mainframe computer
PC-GEL or "BEST GEL"-mainframe	Polymer flooding Polymer gel treatment Tracer test simulation Primary depletion Waterflooding Secondary recovery	3D, 3-phase simulator Multicomponent Transport of up to 5 chemical species Gelation kinetics Polymer and gel rheology Adsorption of each chemical species	PC-version, 640 KB RAM minimum Math coprocessor 386 or 486 processor EGA or VGA support

features to improve the versatility of the model for use in full field simulations (Fanchi et al. 1987). The improvements to BOAST included in BOAST II were primarily the addition of the following:

- Numerous user-friendly enhancements, such as data input and output improvements, restart capabilities, and initialization data checks
- Reservoir engineering features, such as an optional three-phase relative permeability algorithm, multiple rock and PVT regions, and additional acquifer models
- Well model features, such as individual well GOR and WOR constraints, minimum oil/water production constraints, and multiple wells per grid block
- Numerical features, such as iterative matrix solution methods, inactive grid block capability, and options for reducing numerical dispersion.

These improvements greatly improved the accuracy of the model predictions and improved the program run time. The improved BOAST II model was released by DOE in 1989 in a PC version which was found to compare reasonably well with commercial reservoir simulators (Stapp and Allison 1989).

Further improvements were made to the PC version of BOAST II by BDM Federal as part of a study conducted by Louisiana State University to "Assist in the Recovery of Bypassed Oil in the Gulf of Mexico," DOE Contract DE-AC22-92BC14831 (Mathematical and Computer Services, Inc. 1993a). The resulting BOAST 3-PC model includes numerous enhancements that have increased the applicability and efficiency of the BOAST II model. One of the main features added was a gravity drainage or dipping reservoir option to allow the simulator to accurately model recovery in steeply dipping reservoirs, such as those flanking Gulf of Mexico salt domes. The code was also modified to improve the subroutines for handling three-phase relative permeability and to improve the overall simulator execution speed. The streamlining of the code and recompilation using a 32-bit processor has resulted in a 386/486 PC-based model which runs approximately 3.7 times faster than the original PC version of BOAST. In addition, two postprocessors were added to BOAST 3-PC to generate plots of oil, water, and

gas production rates, GOR, cumulative production, and other output parameters versus time and to generate color areal or cross-sectional displays of model output parameters (saturation, pressure, rates, GOR, etc.) at various time steps (Young et al. 1993; Mathematical & Computer Services, Inc. 1993b).

E.1.2 Miscible Applied Simulation Techniques for Energy Recovery (MASTER)

The Miscible Applied Simulation Techniques for Energy Recovery reservoir simulator, MASTER, was developed by DOE as a simplified model for simulating miscible and immiscible gas flooding projects (Ammer and Brummert 1991). MASTER is a four-component (oil, water, gas, and solvent), three-dimensional, three-phase flow model based on the original BOAST simulator code. The model allows simulation of injecting up to four solvent slugs or species and a

surfactant. The solvent phase can be defined as any of the typical injected gases, carbon dioxide, nitrogen, hydrocarbon gas, or flue gas. The miscibility of the solvent phase with the hydrocarbon gas, oil, and water phases is accounted for in the simulator. Miscibility is simulated by the mixing parameter approach to calculate effective fluid densities and viscosities (Todd and Longstaff 1972; Watkins 1982). Mobility control can be simulated in MASTER as a function of local surfactant concentration to reduce the mobility of the solvent phase. The model also accounts for the precipitation of asphaltenes and the associated permeability reduction. The miscible features in MASTER can be easily bypassed in the model to simulate immiscible injection processes, although projections are known to be less accurate in the immiscible mode due to problems with the bubble point pressure-tracking scheme when solvent injection occurs below the minimum miscibility pressure. The model can also be operated as a standard black oil simulator to simulate primary and secondary recovery processes.

Under the Louisiana State University project (Assist in the Recovery of Bypassed Oil in the Gulf of Mexico; DOE Contract DE-AC22-92BC14831), the MASTER code was modified to allow the simulator to be run efficiently in the 386/486 PC environment (Mathematical & Computer Services, Inc. 1993a). The code modifications incorporated into this model, called MISC4, include removing the option to allow injection of up to four different solvent slugs, instead allowing the injection of only one solvent. This greatly reduced the memory requirements for the simulator, allowing it to run more efficiently on a PC. The two postprocessors which were added to BOAST 3-PC were also added to MISC4 to facilitate the display of output data.

E.1.3 Black Oil Applied Simulation Tool for Vertical/Horizontal/Slant Wells (BOAST-VHS)

A PC-based simulator was developed in 1992 by NIPER for simulating the performance of horizontal and slanted wells in oil reservoirs. The Black Oil Applied Simulation Tool for Vertical/Horizontal/Slant Wells, BOAST-VHS, is a three-dimensional, three-phase, finite difference black-oil simulator based on the original BOAST code. Many of the features included in the revision of BOAST to BOAST II were not included in this model due to operating system memory constraints. The model can be used to accurately simulate primary depletion, pressure maintenance, and basic secondary recovery operations using any combination of vertical, horizontal, and slanted wells. The various features and the operating aspects of BOAST-VHS are described in detail in the model user's guide, which is available from DOE (Chang et al. 1992).

E.1.4 Polymer Applications Simulator (PC-GEL)

In 1990 NIPER developed a PC-based simulator for predicting the performance of gel polymer applications in oil reservoirs (Gao and Chang 1990). PC-GEL is a three-dimensional, three-phase permeability modification simulator developed by incorporating an in situ gelation model into the BOAST black oil simulator. The features included in the simulator are:

- Transport of up to five chemical species

- Gelation reaction kinetics of the polymer with crosslinking agents
- Rheology of the polymer and gel
- Inaccessible pore volume to macromolecules
- Adsorption of chemical species on rock surfaces
- Permeability reduction caused by adsorption of polymer and gel.

The PC-GEL simulator is useful for simulating and optimizing any combination of primary production, waterflooding, polymer flooding, and permeability modification treatments. A detailed description of the model features and operations is contained in the PC-GEL user's guide and documentation manual, which are available from DOE (Chang and Gao 1993).

E.1.5 Microbial Transport Simulator (MTS)

The Department of Energy and NIPER are currently developing a public domain reservoir simulator for simulating and modeling microbial and nutrient transport in porous media (Chang et al. 1991). The Microbial Transport Simulator, MTS, is a three-dimensional, three-phase, multi-component simulator that was developed by incorporating microbial growth and transport algorithms into the BOAST black oil simulator. Specific algorithms in the simulator account for microbial growth and transport, nutrient transport and consumption, and porosity and permeability changes resulting from clogged pores due to microbial growth and transport. This simulator can accurately predict the propagation of microbes and nutrients in porous media for designing laboratory coreflood experiments and for predicting improved oil recovery from injection profile modification using microbial processes. Additional research is being conducted at NIPER to examine improved oil recovery mechanisms resulting from microbial injection processes, including the impacts that microbial processes have on the relative permeability relationships and hydrocarbon saturation in oil reservoirs. This research focuses on defining the combined oil recovery effects of microbial transport systems, including impacts of the byproducts of microbial growth (surfactants, acids, alcohols, and various gases). With the incorporation of these oil recovery aspects into MTS, this simulator will be a valuable tool for predicting the performance of microbially enhanced oil recovery (MEOR) processes and perhaps for modeling bioremediation processes for underground contamination involving hydrocarbon products or other inorganic and organic compounds.

E.2 Commercial Reservoir Simulators

Although this chapter mainly focuses on reservoir simulators developed under DOE contracts, it is important to mention that advanced simulators are commercially available with state-of-the-art capabilities, such as user-friendly input data systems, geologic data mapping packages, and postprocessor 3D visualization packages. These integrated systems offer researchers and operators state-of-the-art technologies which can enhance their capabilities in terms of reservoir

management, reservoir development, and process prediction studies. It is well beyond the scope of this report to discuss the specific capabilities of the multitude of simulators which are commercially available to oil and gas operators. This section focuses on some of the advanced computational techniques being developed to more accurately and cost-effectively simulate petroleum reservoirs.

Recent advancements in numerical simulation capabilities are primarily being achieved by exploiting the rapidly expanding computational and memory capabilities of computer software and hardware systems. Some recent advancements in petroleum industry numerical simulators include: (1) improvements in recovery process simulation capabilities, (2) development of advanced computational algorithms, (3) the use of artificial intelligence, (4) the use of geostatistical methods and automatic gridding capabilities to define geologically complex reservoirs, and (5) the incorporation of advanced image processing techniques in postprocessors.

E.2.1 Recovery Process Simulation Capabilities

The evolution of oil and gas recovery methods has directly resulted in greater ability to numerically simulate these processes, especially with the expanded memory and computational capabilities of computer systems. Vast improvements have been made in the last decade in the three-dimensional simulation of two-phase (oil-water, gas-water) and three-phase flow in porous media. Advanced simulators are being developed to simulate virtually all recovery processes, including: thermal processes (steamflooding and in situ combustion), chemical processes (surfactant, polymer, alkaline, and alkaline-surfactant-polymer), gel polymer applications, miscible and immiscible gas injection processes (CO_2, nitrogen, flue gas, and hydrocarbon gas), and microbial processes. For accurately simulating compositional change through various phases, compositional simulators and algorithms are being developed for gas (e.g., CO_2) and thermal injection processes using an equation-of-state approach. Simulators are also being developed to model complex recovery problems such as production from tight gas sands, production of coal bed methane, recovery of oil and gas from naturally fractured reservoirs (dual porosity/permeability simulators), and to study formation damage mechanisms. Advanced models are being developed to simulate the propagation of induced fractures in oil and gas reservoirs including the development of capabilities to predict fracture orientation. Advanced numerical well models are also being integrated into numerical reservoir simulators to account for wellbore hydraulics in complex situations, such as horizontal wells. Optimization software is being developed and incorporated into numerical simulators to optimize recovery processes, wellbore hydraulics, and even production or injection facilities.

E.2.2 Computational Algorithms

The increased calculation speed and memory capabilities of computer systems have facilitated the incorporation of advanced computational algorithms into reservoir simulators. The accuracy of reservoir simulation is being improved dramatically through finite element formulations and

fully implicit solution formulations. New numerical solvers are also being developed, including iterative and parallel solvers and preconditioners for iterative numerical schemes. Parallel calculation algorithms are being developed to exploit parallel and massively parallel computing capabilities. Local and adaptive grid refinement capabilities are being developed to more accurately simulate complex fluid-flow problems, such as coning, frontal advance, and near-wellbore phenomena.

E.2.3 Artificial Intelligence

Artificial intelligence methods are being successfully developed for numerical reservoir simulation. Expert systems are being considered to provide solutions to complex problems, such as:

- Predicting input variables where data are missing or questionable
- Selecting optimum recovery processes based on reservoir parameters and performance
- Identifying sensitive variables affecting specific recovery process efficiency
- Selecting optimum injectant composition (e.g., gel polymer formulations) based on reservoir parameters
- Selecting the optimum simulator for use in history matching and predicting reservoir performance

An index is developed during simulation to determine local areal needs for grid refinement and implicit formulation. Artificial intelligence is also being considered to automatically perform complex, time intensive operations, such as reservoir performance history matching or the construction of input datasets.

E.2.4 Modeling Geologically Complex Reservoirs

Advanced computational capabilities can successfully be applied to the modeling of geologically complex reservoirs. Geostatistical methodologies are being incorporated into numerical simulators to predict values for reservoir parameters, such as porosity and permeability between known data points in heterogeneous reservoirs. These reservoir complexities are being estimated using sophisticated numerical techniques, such as kriging, conditional simulation, simulated annealing, and fractal simulation. Also, complex numerical methods are being devised to automatically generate the optimum three-dimensional grid scheme for use in simulating process performance in geologically complex reservoirs.

E.2.5 Image Processing

Another area benefiting significantly from advanced computational capabilities is the interpretation of simulator output data. Image processing techniques are being developed and used for rapidly visualizing simulator output data, which greatly reduces the time required to interpret simulator results by virtually eliminating the need to review reams of hardcopy output data matrices at numerous time steps. The use of three-dimensional visualization software, graphical displays, animation, and even virtual reality can make a once cumbersome task enjoyable for simulation experts and nonexperts alike.

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APPENDIX F
ENVIRONMENTAL REGULATORY COMPLIANCE ISSUES RELATED TO PRODUCTION OPERATIONS

Environmental issues that face oil production operations targeted at Class 5 reservoirs are not different from activities targeted at other reservoir types. Rather, environmental issues are tied to the location of the project (i.e., relationship of the project with existing oil production activities, surface and groundwater, urban areas, sensitive areas such as wetlands, floodplains, tundra, and coastal areas, the presence of listed endangered species or habitats, and the presence of historical, archeological, or paleontological sites) and the activities that occur during the project (i.e., construction of surface facilities, such as pipelines, fences, roads, pads, and buildings, and recovery processes that may use fresh water and produce wastewater, air emissions, solid waste, or noise). Activities conducted as part of DOE's program of field demonstrations in high-priority reservoir classes must have and comply with the usual and appropriate federal, state, and local environmental permits required of all similar oil production operations.

Production operations targeting Class 5 reservoirs do not entail any special environmental issues; factors that determine the nature and magnitude of potential environment impacts are site- and project-specific, such as:

- Environmental setting of the project, including factors such as surface water, groundwater, land use, historic sites, wetlands, endangered species, socioeconomic factors, etc.
- Recovery operations involving facilities construction, water discharge, air emissions, waste generation, etc.
- Local, state, and federal regulatory requirements

A complete discussion of environmental issues related to production operations would be too lengthy for this report and would be made obsolete by new legislation or regulations. Information can be obtained from a variety of sources, including local, state, and federal government agencies; industry associations; libraries; historical societies; and consultants. A report is available from DOE that summarizes environmental regulatory requirements of the various states and provides points of contact for additional guidance (Madden et al. 1991). The Interstate Oil and Gas Compact Commission (IOGCC) in Oklahoma City, Oklahoma, can provide considerable information.

F.1 National Environmental Policy Act

Compliance with NEPA is a specific requirement for conducting work with the federal government. Basically, NEPA requires that potential environmental impacts and mitigating factors be considered in planning any federal action, i.e., before making a decision to expend federal funds, environmental consequences of the proposed action and alternative actions must be considered.

Making a sound decision requires adequate information about environmental conditions that might be affected by the proposed activity. The types and possible sources of information that are useful in assessing environmental impacts are presented in Table F–1. Since collecting all pertinent data can be time consuming, only those organizations selected to participate in demonstration projects will be required to collect complete information. Activities that will be part of a project are also considered for NEPA assessment. Questions that must be addressed include the following:

- Will new wells be drilled and, if so, will they be infill wells?
- Is the project site in an area in which oil production activities have occurred previously?
- Will surface construction, such as roads, buildings, pads, pipelines, be required?
- Will water discharges or air emissions occur?
- Will hazardous waste be generated?

In the event that the proposed project likely will have an adverse environmental impact, measures proposed to mitigate the impact are an important part of the NEPA decision process. Examples of environmental concerns related to specific recovery processes are presented in Table F–2.

In case the nature and magnitude of the potential environmental impacts are uncertain, NEPA requires that an Environmental Assessment (EA) be performed. The two possible outcomes of an EA are: (1) a determination that significant impacts may result from the action, in which case an Environmental Impact Statement (EIS) must be prepared, or (2) a determination that significant impacts are unlikely to occur in which case a Finding of No Significant Impact (FONSI) will be prepared, and an EIS will not be required. If a specific proposed action is similar to actions for which EAs have always resulted in FONSIs, then it is possible that the proposed action can be declared Categorically Excluded (CX) from further NEPA assessment, i.e., neither an EA nor an EIS will be required.

Table F–1 Types And Possible Sources Of Environmental Data	
Air Quality	National Oceanic and Atmospheric Administration (NOAA) State, Regional, and Local Air Pollution Control Agencies U.S. Environmental Protection Agency State and Local Public Health Agencies
Surface Water Quality	U.S. Geological Survey U.S. Environmental Protection Agency State and Local Water Regulatory Agencies
Groundwater	U.S. Geological Survey State Geological Surveys State Water Resources Agencies State and Local Public Health Agencies U.S. Environmental Protection Agency
Historic and Cultural Resources	National Historic Trust Advisory Council on Historic Preservation State Historic Preservation Officers State and Local Historical and Archeological Societies
Threatened and Endangered Species	U.S. Fish and Wildlife Service U.S. Environmental Protection Agency State Fish and Wildlife Agencies State Forestry Commissions
Floodplains	Federal Emergency Management Agency (FEMA) U.S. Geological Survey U.S. Army Corps of Engineers State and Local Water Resources Agencies Water Management Districts
Wetlands	U.S. Army Corps of Engineers U.S. Environmental Protection Agency U.S. Fish and Wildlife Service Soil Conservation Service Water Management Districts
Soil Data	Soil Conservation Service U.S. Geological Survey State Geological Surveys State Agriculture Agencies
Climatology	National Oceanic and Atmospheric Administration (NOAA) Local Airports State and Local Air Pollution Control Agencies Regional Planning Agencies
Coastal Zones	National Oceanic and Atmospheric Administration (NOAA) U.S. Environmental Protection Agency
Topography	U.S. Geological Survey
Noise	U.S. Environmental Protection Agency
Transportation	U.S. Department of Transportation State Departments of Transportation
Demographics	U.S. Bureau of the Census
Economic Data	State and Local Employment Commissions Chambers of Commerce Local Councils of Governments U.S. Bureau of the Census U.S. Department of Labor U.S. Department of Commerce
Chemical Toxicity	U.S. Environmental Protection Agency Manufacturer's Material Safety Data Sheets (MSDS)

Table F–2
Environmental Concerns Related to Recovery Processes
(Source: Madden et al. 1991)

Issue	Steam Injection	In Situ Combustion	Chemical Flooding	CO_2 Injection
Air	*SO_2, NO_x, and PM_{10} emissions from steam generators* Wellhead emissions of HC	HC and CO emissions from wells SO_2, NO_x, and TSP emissions from air compressors	Fugitive emissions from on-site manufacture of chemicals	Leaks of CO_2 in process use or transport H_2S emissions from wells
Water Use	*Significant water demand*	Moderate water demand in wet combustion processes	*Significant water demand*	*Significant water demand*
Water Effluent	*Disposal of produced water*	*Disposal of produced water* Aquifer contamination from low pH water with trace metals resulting from corrosion of well casings	*Aquifer contamination from injected chemicals* *Disposal of produced water* Spills or leaks of chemicals to surface waters	Disposal of produced water Aquifer contamination from low pH water and corrosion of well casings
Solid Waste	Disposal of scrubber sludges Disposal of water treatment wastes	Disposal of wastes from wellhead gas cleaning Disposal of water treatment wastes	Disposal of wastes from on-site chemical manufacture Disposal of water treatment wastes	Disposal of water treatment wastes

Key: Italicized entries are of major environmental concern; SO_2 = sulfur dioxide, NO_X = nitrogen oxides, PM_{10} = particulate matter ≤ 10μ in diameter, HC = hydrocarbons, CO = carbon monoxide, TSP = total suspended particulates, CO_2 = carbon dioxide, H_2S = hydrogen sulfide

F.2 Other Federal Regulations

In addition to considering environmental factors in the planning process, the conduct of all demonstration projects must comply with applicable federal, state, and local regulations and have the appropriate permits. As stated before, a complete summary here of all applicable regulations is not possible. A relatively complete summary of applicable regulations and agency points of contact can be found in the *Environmental Regulations Handbook for Enhanced Oil Recovery* (Madden et al. 1991). The American Petroleum Institute (API) has published guidelines for the management of solid waste in exploration and production operations (API 1989).

Principal federal regulations that will be applicable to most oil production operations include, but are not limited to, the following:

- Resource Conservation and Recovery Act (RCRA) — The goals of RCRA are to protect human health and the environment, reduce or eliminate the generation of hazardous waste, and conserve energy and natural resources by regulating the management of active facilities (Oak Ridge National Laboratory 1992a). Anyone who generates, transports, treats, stores, or disposes of hazardous waste must notify EPA of these activities and comply with RCRA. Drilling fluids, produced water, and other wastes associated with exploration, development, or production of crude oil are exempt from regulation under RCRA (42 USC 6921 §3001(b)(2)(A); also 40 CFR 261.4(b)(5); Arbuckle et al. 1991); however, they are regulated under regional or state solid waste disposal programs. States have jurisdiction to decide if wastes exempt from federal RCRA requirements are also exempt from state regulation as hazardous waste. Requirements vary from state to state.
- Safe Drinking Water Act (SDWA) — As it applies to oil and gas production operations, the SDWA is directed toward the prevention of contamination of underground sources of drinking water (USDW) by regulating underground injection and Underground Injection Control (UIC) programs (primarily 40 CFR 144, 145, 146, 147, and 148; Oak Ridge National Laboratory, 1992b). Wells related to oil and gas production that are used to inject fluids, either for improved recovery or fluid disposal, are called Class II injection wells. Regulations to implement the SDWA may not interfere with or impede the underground injection of brine or other fluids which are brought to the surface in connection with oil or natural gas production, or any underground injection for the secondary or tertiary recovery of oil or natural gas unless such requirements are essential to assure that underground sources of drinking water will not be endangered by such injection (42 USC 300h §1421(b)(2)). Reporting, well construction, mechanical integrity testing, and area of review requirements vary from state to state. An organization that has considerable information regarding the requirements related to the SDWA is the Groundwater Protection Council (formerly the Underground Injection Practices Council) in Oklahoma City, OK.
- Clean Water Act (CWA) — The objective of the CWA is to restore and maintain the chemical, physical, and biological integrity of the nation's waters (Oak Ridge National Laboratory 1993). Discharges from point sources into surface water are regulated and require permits under the National Pollution Discharge Elimination System (NPDES), §402 of the act. Such discharges must meet certain quality and monitoring requirements that vary from state to state and depend on the ambient quality and public use of the surface water. Specific implementing regulations that could apply to oil and gas production operations include those directed toward discharge of oil (40 CFR 110), oil pollution prevention related to nontransportation sources both onshore and offshore, and the preparation of Spill Prevention Control and Countermeasures plans (40 CFR 112), designation of hazardous substances (40 CFR 125), water quality

standards (40 CFR 131), guidelines establishing test procedures for the analysis of pollutants (40 CFR 136), and effluent guidelines and standards for various point source categories (40 CFR Subchapter N).

- Clean Air Act (CAA) — The CAA is directed toward protecting and enhancing air quality. The CAA contains provisions for air pollution prevention and control, air quality and emission limitations, prevention of significant deterioration of air quality, requirements for nonattainment areas, emission standards for moving sources, acid deposition control, permits, and stratospheric ozone protection (Oak Ridge National Laboratory 1991). Requirements vary from state to state and often vary between locations within a state.
- Endangered Species Act (ESA) and the related Fish and Wildlife Coordination Act (FWCA) — These acts are designed to protect plant and animal resources from adverse effects due to development projects. Both acts require consultation with wildlife authorities prior to committing resources to certain types of projects (Oak Ridge National Laboratory 1989). An endangered species is one that is in danger of becoming extinct throughout all or a significant portion of its range. A threatened species is one that is likely to become endangered in the foreseeable future. The ESA makes it illegal to kill, collect, remove, harass, import, or export an endangered or threatened species without a permit from the Secretary of the Interior. The act mandates coordination between the federal government and state and foreign governments. The purpose of the FWCA is to assure that fish and wildlife resources receive equal consideration with other values during the planning of development projects that affect water resources.

Other statutes that could affect oil production operations, but which will not be discussed here, include the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA); the Superfund Amendments and Reauthorization Act (SARA); the Oil Pollution Act; and the Toxic Substances Control Act (TSCA). To ensure that a specific oil production operation is conducted in compliance with all applicable environmental regulations, the operator should contact the appropriate local, state, and federal regulatory agencies.

According to a study conducted by the American Petroleum Institute (Perkins 1993), the petroleum industry spends more than $8 billion per year on environmental quality protection. The study projects that new and potential environmental costs to the industry likely will range between $17 billion and $25 billion per year by the end of the 1990s. The abandonment of U.S. crude oil resources could be accelerated and the recovery potential decreased as a result of the cost of compliance with future regulatory requirements (ICF 1990). One of the goals of the Domestic Natural Gas and Oil Initiative is to increase domestic natural gas and oil production and environmental protection by advancing and disseminating new exploration, production, and refining technologies (U.S. Department of Energy 1993). Developing and using recovery methods that are more cost-effective and environmentally sound will help mitigate the adverse impacts on production due to environmental regulations.

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APPENDIX G
CLASS 5 BIBLIOGRAPHY

An expanded bibliography of references is provided for Chapters 2 and 3. This bibliography includes references on fluvial/alluvial processes and geological and engineering analysis of the regions, states, and specific oil fields which have Class 5 production. There are two major divisions of the bibliography. G.1 is organized by process or type of depositional system, and G.2 is organized by state.

Within G.1, sections list references to specific processes or categories of Class 5 fluvial/alluvial systems. Section G.1.1 references include a number of major papers and textbooks which cover a broad spectrum of topics on alluvial and fluvial deposition. Section G.1.2 (alluvial fans), Section G.1.3 (braided streams), and Section G.1.4 (meandering streams) contain references on the three end members of the fluvial/alluvial system. Section G.1.5 has references to specific fields or regions which may cover one or more depositional systems. Section G.1.6 (heterogeneity) and Section G.1.7 (simulation) have references which deal with means of interpretation of processes in fluvial/alluvial systems.

Section G.2 is organized alphabetically by the 17 states where TORIS Class 5 production has been identified. Within each state section, subsections include references on engineering and geology. For most states these are separate subsections. In some cases (i.e., New Mexico), only one type of information was found. In a few cases, either where few references were found (i.e., Arkansas) or where engineering and geologic topics are covered in the same papers (i.e., North Dakota), only one section per state is included.

G.1 BIBLIOGRAPHY (By Process)

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