A Review of Slope-Basin & Basin Clastic Reservoirs in the United States

Work Performed Under Contract DE-AC22-93BC14964
and Cooperative Agreement DE-FC22-83FE60149

For:

U.S. Department of Energy
Assistant Secretary for Fossil Energy

Bartlesville Project Office
U.S. Department of Energy
Bartlesville, Oklahoma

December 1993

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A Review of Slope-Basin & Basin Clastic Reservoirs in the United States (Class III)

By
Richard A. Schatzinger, Viola Rawn-Schatzinger, Ming-Ming Chang, and Susan R. Jackson

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Robert E. Lemmon, Project manager
Bartlesville Project Office
U. S. Department of Energy

For
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By
IIT Research Institute
National Institute for petroleum and Energy Research
Bartlesville, OK 74005

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TECHNICAL SUMMARY

The U.S. Department of Energy (DOE) is preparing to announce that Slope-Basin & Basin clastic reservoirs have been selected as third in a series of reservoir classes on which to target its government funded, cost-share Research, Development, and Demonstration (RD&D) activities in a continuation of its effort to maximize the economic producibility of domestic oil resources. This report provides background information regarding the DOE's understanding of the reservoir and geologic characteristics of the Slope-Basin & Basin clastic reservoirs and the principal impediments to increased production.

Major conclusions of the report include the following:

- Identified (i.e., included in the TORIS database) Slope-Basin & Basin clastic reservoirs collectively account for 60 billion barrels of light and heavy (< 20° API) original oil-in-place (OOIP) in the United States. Ultimate recovery from these reservoirs under current conditions is estimated at 17.3 billion barrels (conventional primary and secondary and existing tertiary recovery); of this, 15.7 billion barrels has already been produced.

- Identified Slope-Basin & Basin clastic reservoirs are distributed over eight states, but the largest concentration of these reservoirs is in California. Over 90% of the OOIP in this class of reservoirs is located in the San Joaquin, Santa Maria, Santa Barbara-Ventura, and Los Angeles Basins. Other important concentrations are in Texas, New Mexico, Illinois, Louisiana, Mississippi, and the Appalachian states. Slope-Basin & Basin clastic reservoirs in the Federal OCS area of the Gulf of Mexico are not represented in the database used in this analysis.

- A large percentage of the fields containing Slope-Basin & Basin clastic reservoirs have historically been operated by major oil companies. In 1991, about 167 million barrels of oil were produced from identified Class III reservoirs, nearly 60% by majors, 38% by small independents, 2% by large independents, and the remaining 0.7% by mid-sized independents.

- Analysis of reservoir and production data of California and Texas Slope-Basin reservoirs listed in the TORIS database indicate that the four slope-basin reservoirs in California have similar porosity, net pay, and oil gravity compared to the three plays in Texas, implying that regional similarities exist among reservoirs in this class.

- The dominant depositional process in the slope-basin environment (depths of 45 m to 4,000 m below sea level) is the downslope movement of suspended sediments in gravity-driven turbidity currents. Turbidites, deposits that result from turbidity currents, are the "basic building blocks" of many submarine fans.

- Submarine fans tend to form on two types of continental margins that have strong implications about the fan size, geometry, seafloor gradient, and sand/shale ratio. The first type are tectonically active margins, where the fans tend to be thicker and more sand-rich. Many of the turbidite reservoirs in California were deposited in this type of setting. The second type are tectonically passive margins, where fans are generally thinner, and have lower sand to shale ratios. The turbidite reservoirs of Texas were formed in a setting closer to this type of margin.

- The submarine fan and turbidite system is highly complex and variable, therefore a clear understanding of lithofacies distribution, sand-body geometry, and reservoir quality is essential for effective reservoir management. Braided suprafan lobes are characterized by stacked channel sandstones with good lateral and vertical communication, constituting excellent reservoir facies. Depositional lobes form sheet-like sand bodies with good lateral communication, moderate vertical communication and constitute good reservoir facies. Fan lobes are highly sinuous channel and associated levee systems that are characterized by poor lateral and vertical communication, but have the potential to be moderately good reservoir facies. Ponded lobes are mud-rich and comprise poor reservoir facies.

- Dimensions of both modern and ancient submarine fan and fan channel systems can vary by three orders of magnitude. Fan dimensions and geometry are controlled by tectonics (including faulting, flexing, subsidence rates, and active versus passive margins); paleogeography of the basin; amount and type of sediment available including sand/shale ratio; frequency of channel avulsion; slope and fan gradient; and channel sinuosity.

- The majority of existing EOR projects in Class III reservoirs are steam drive and cyclic steam injection in California (primarily in the Midway-Sunset Field). Many of these projects were initiated in the late 1970s and early 1980s and are currently reported as technical and economic successes.

- The application of additional recovery technologies in these reservoirs could yield nearly 5.4 billion barrels of new reserves. However, 1.4 billion barrels of this oil is at risk of abandonment by the year 2000.

- Using a range of oil prices ($20 to $32/B) under both existing and advanced technology scenarios, the DOE model shows that additional heavy oil recovery by thermal methods would have the largest impact on increasing the recoverable reserves from Class III reservoirs. Nearly 55% of the recovery potential is attributable to thermal methods (steam flooding and in-situ combustion), 30% to chemical flooding, and the remaining 15% to advanced secondary recovery methods (i.e., infill drilling, polymer flooding, and profile modification).

- Due to the stratigraphically complex nature of Slope-Basin & Basin clastic reservoirs, these fields often require the development and implementation of dynamic, integrated reservoir management strategies in order to optimize recovery. Proper reservoir characterization is essential in order to plan, implement, and optimize infill drilling and enhanced oil recovery projects in highly stratified Class III reservoirs.

- There are a number of environmental constraints associated with operations in Slope-Basin & Basin clastic reservoirs. Each of these constraints, ranging from Federal environmental statutes to regional or local environmental regulations, can cause an exploration or production operation to be delayed, abbreviated, or abandoned. This may result in a reduction in future oil recovery.

- As a majority of incremental resource recovery is expected through thermal recovery processes, Federal and state air quality regulations could have the greatest impact on future recovery from Class III reservoirs. The Federal Clean Air Act could impact thermal recovery operations in a number of ways. Existing projects in certain areas (mainly California) would incur high equipment costs to reduce the emission of pollutants, such as carbon monoxide and sulfur dioxide. Permitting requirements under the Clean Air Act Amendments can place a substantial financial and administrative burden on Class III operations.

The amount of potentially recoverable oil resource endangered by abandonment establishes an urgency in ensuring the application of current technologies to as many Slope-Basin & Basin clastic reservoirs as possible. Potential recovery attributable to advanced technology likewise establishes a substantial target for RD&D. Promoting the development and application of technologies designed to improve recovery from Class III reservoirs is an important part of the ongoing effort to protect and expand the nation's resource base.

CHAPTER I

BACKGROUND AND OBJECTIVES

The Mission

In 1988, responding to increasing evidence of U.S. dependence on foreign oil, the U.S. Congress directed the Department of Energy's (DOE) Office of Fossil Energy to create a plan that would refocus oil research programs with the specific goal of increasing domestic oil production as part of a Hydrocarbon Geoscience Research Strategy. This direction was based in part on the recommendations in a report by the Solid Earth Sciences panel of the Energy Research Advisory Board entitled "Geoscience Research for Energy Security." In 1990, after holding a series of public meetings and gathering thousands of pages of testimony, the DOE published the National Energy Strategy: a plan seeking to strike a balance between competing resources and national priorities in order to arrive at a sensible, cohesive approach to our nation's energy policy.

Other concurrent studies emphasized additional facets of the energy security situation. Analysis by the DOE's Tertiary Oil Recovery Information System (TORIS), an extensive compilation of petroleum-related information, disclosed the urgency of the situation as a result of the increasing rate of well abandonment. The Hydrocarbon Geoscience Research Coordinating Committee, in cooperation with the Geoscience Institute for Oil and Gas Recovery Research, published a strategy document which urged a balance of near-, mid-, and long-term research and stressed the need to increase our understanding of reservoir complexities.

In response to these studies, the DOE announced its new Oil Research Program Implementation Plan on January 31, 1990.[1] This plan recommended a program of field-based research on prioritized geologic classes of reservoirs, aimed at rapidly developing and demonstrating cost-effective advanced recovery technology. Under this new plan, a balance of near-, mid-, and long-term research would pursue the primary goal of improving the economic producibility of domestic oil and preserving access to those reservoirs containing the largest volumes of oil that are under the greatest risk of being abandoned. The critical need to accelerate this effort was recognized by Congress in the Energy Policy Act of 1992. In addition, the Domestic Natural Gas and Oil Initiative of 1993 includes field-based research as an important aspect of efforts to strengthen national energy security and improve recovery of the nation's oil resource.

Building upon preceding efforts, the oil plan establishes a program of highly targeted research, development, and demonstration activities in collaboration with state governments, the industrial sector, and the academic community. It focuses on the reduction of technical and economic constraints on producibility in order to realize the enormous potential of recovery from the resource remaining in known domestic reservoirs. The program sets three time-specific goals:

- In the near-term, to extend the producing life of reservoirs, with a high recovery potential that are rapidly approaching their economic limits and are therefore in danger of being abandoned, through improved utilization of reservoir characterization techniques, production technologies, and environmental practices.

- In the mid-term, to develop, test, and transfer the best, currently defined advanced technologies to operators of reservoirs with the greatest potential for incremental recovery.

- In the long-term, to develop a sufficient fundamental understanding of new recovery techniques for the oil left after the application of the most advanced, currently employed, mid-term processes. The effort would focus on major classes of reservoirs for which no advanced technologies are anticipated to be available.

Strategic Approach

A major constraint to maximizing production in U.S. reservoirs has been the reservoirs' internal heterogeneity -- variations in permeability and porosity that control the flow of fluids -- especially at the interwell scale. Such heterogeneities are the result of the geological processes of deposition, diagenesis, and structural deformation. The DOE hypothesized that grouping reservoirs into classes with common geologic properties could help isolate the distinctive types of heterogeneities that recovery process designs must overcome to become effective. To implement this approach, the DOE commissioned an effort to develop a classification system based on geologic processes and apply it to a nationwide sample of reservoirs for analysis and prioritization.

The DOE requested the Interstate Oil and Gas Compact Commission (IOGCC) to assist in the classification of U.S. reservoirs as part of an ongoing effort to estimate the domestic oil recovery potential. The IOGCC, in turn, enlisted the assistance of the Geoscience Institute for Oil and Gas Recovery Research. A general classification scheme, or "classifier," developed by the Institute, was expanded into application procedures by a team of senior geologists with extensive experience in major U.S. oil-producing regions.[2] In all, 2,816 different geologic descriptions were determined through various combinations of lithology, deposition, diagenesis, and structural deformation.

The reservoirs contained in the DOE's Tertiary Oil Recovery Information System (TORIS) were used as a nationwide sample for the project. TORIS contains detailed descriptions of more than 2,500 generally large reservoirs in 23 states that collectively account for over 348 billion barrels (nearly 65%) of the nation's original oil-in-place. These reservoirs were grouped into classes and subclasses using the classifier. Twenty-two geologic classes (16 clastic and 6 carbonate) with structural subclasses for clastics and diagenetic subclasses for carbonates were defined[3].

Clastic Reservoirs

Sixteen clastic classes (Figure I-1) were derived from 28 clastic depositional systems described in the classifier. These classes contain siliciclastic rocks which were deposited in the paleoenvironmental settings indicated by their names. While some are fairly uniform depositional environments, such as those of the eolian class, others are complex, as in the various deltaic classes. For most reservoirs, a relatively refined description of the depositional processes was possible (e.g., Fluvial-Dominated Deltas), but for others, the unavailability of data or the complexity of the depositional processes necessitated the use of broader, undifferentiated classes (e.g., Fluvial, Strandplain, Delta).

Carbonate Reservoirs

Six carbonate classes (Figure I-2) were derived from 20 individually described carbonate depositional systems defined in the classifier. The carbonate reservoirs classified were deposited in marine or near-marine settings. The class names are descriptive of the location or conditions under which deposition occurred. However, the Shallow Shelf/Restricted carbonate class contains reservoir rock deposited in the nearshore subtidal, as well as the shallow shelf, environment.

The grouping of the reservoirs into "classes" creates a smaller number of research targets, while preserving distinctness of the reservoirs. The results of the classification effort help in focusing further studies. Reservoirs within these classes are expected to manifest distinct types of reservoir heterogeneities as a consequence of their similar lithologies and depositional histories.

Figure I-1

Classification of Clastic Reservoirs

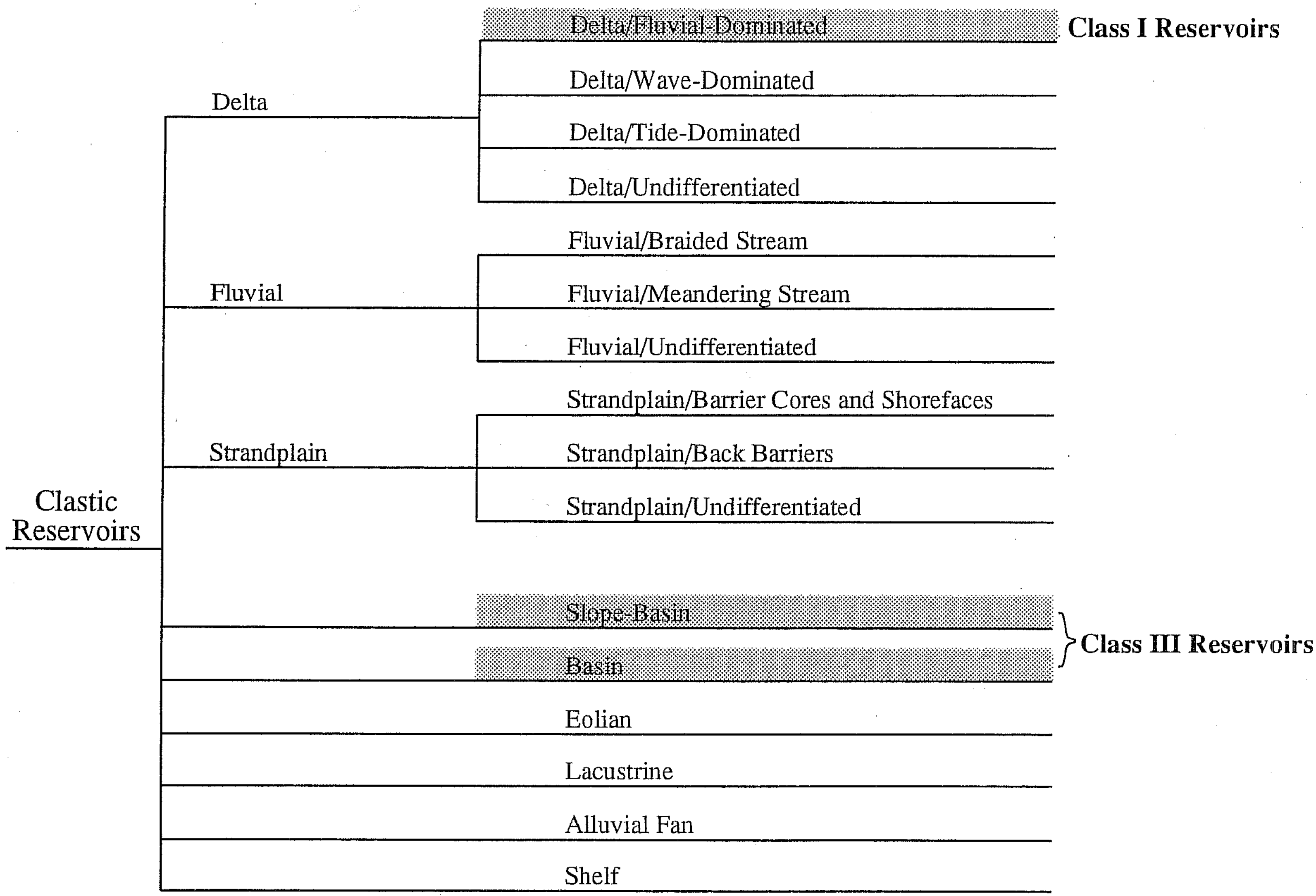
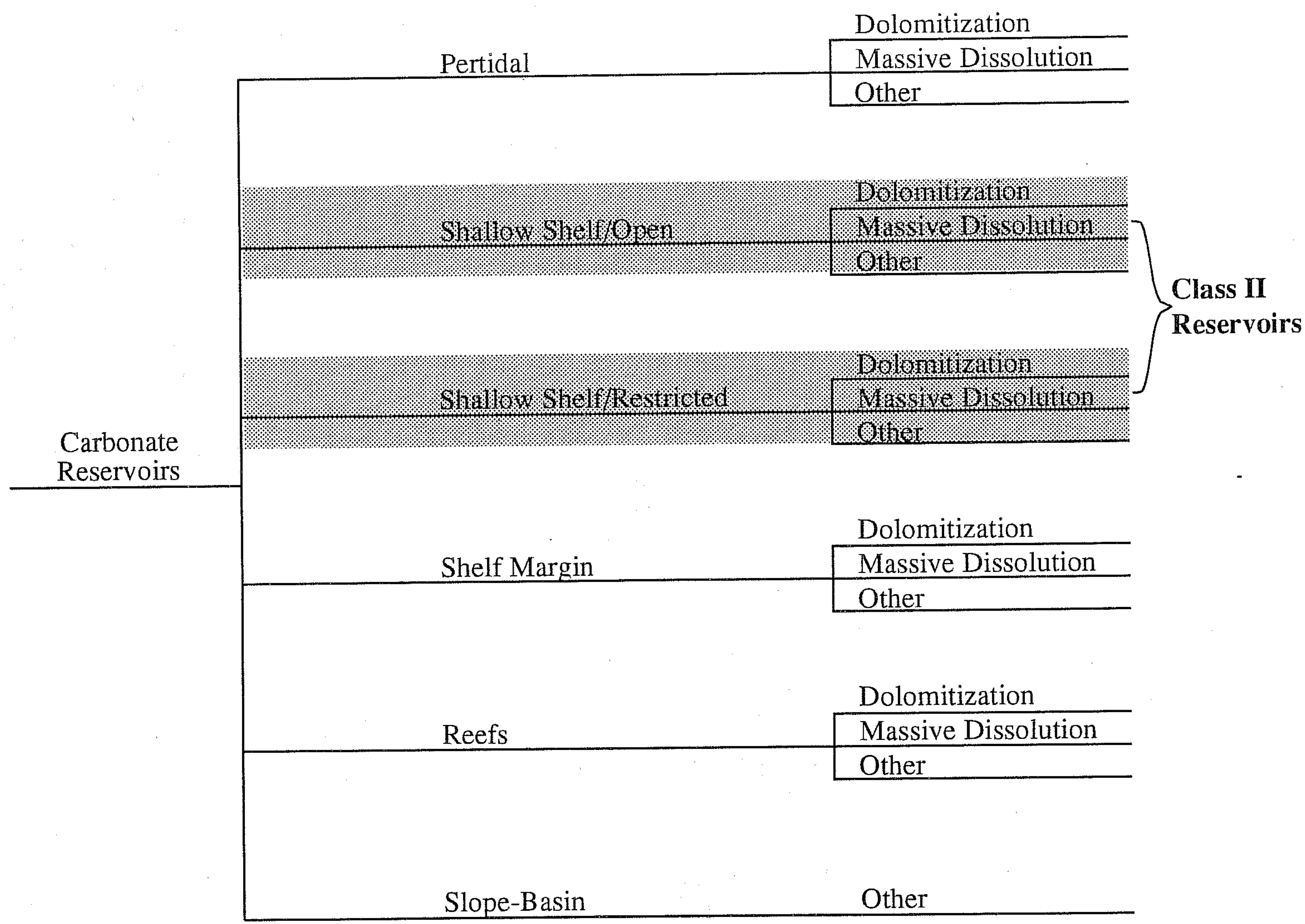


Figure I-2

Classification of Carbonate Reservoirs



Distribution of the Oil Resource

The reservoir classes were ranked by total original oil-in-place (OOIP) to determine the relative volumes of oil associated with the classes in the sample analyzed (Figure I-3). The Slope-Basin clastic geologic class contains nearly 53 billion barrels of oil. This represents over 15% of the total oil in the sample, making it the largest geologic class. The Spraberry Formation of Texas and the Stevens Formation of California are two examples of Slope-Basin clastic reservoirs. The Delta/Fluvial-Dominated reservoirs comprise the second largest class and contain over 45 billion barrels of OOIP, or approximately 13% of the oil in the sample. This class includes, among others, the deltaic sands of West Hackberry field in South Louisiana and several Bartlesville sands in northern Oklahoma and southern Kansas. The remaining classes in the top five (ranked by OOIP) include Carbonate Shallow Shelf/Open reservoirs, such as the Meramec in the Sooner Trend of Oklahoma and many Grayburg-San Andres reservoirs of the Permian Basin in Texas and New Mexico; Fluvial/Braided Stream reservoirs, like the Sadlerochit sand in Prudhoe Bay or the Cut Bank sand of Montana; and Delta/Wave-Dominated reservoirs, such as the Woodbine field or the Big Wells (San Miguel) field of Texas. These three classes represent 43 billion, 28 billion, and 25 billion barrels of OOIP, respectively. In all, the top five geologic classes represent 194 billion barrels of OOIP, accounting for 56% of the resource in the database. The top ten classes, which also include Shallow Shelf/Restricted, Clastic Shelf, Strandplain/Barrier Core and Shoreface, and the Carbonate Reef and Alluvial Fan classes, contain 83% of the studied resource.

An analysis of the oil remaining after conventional production suggests a similar concentration of the oil resource in the top five classes (Figure I-4). The Slope-Basin clastic and Delta/Fluvial-Dominated classes continue to be the top two classes, with remaining oil-in-place (ROIP) estimated at 37 billion and 30 billion barrels, respectively. The Shallow Shelf/Open class is ranked third with nearly 30 billion barrels of ROIP. The Fluvial/Braided Stream class contains 16 billion barrels and the Shallow Shelf/Restricted class contains over 15 billion barrels of ROIP. Collectively, the top five geologic classes represent nearly 58% of the estimated 194 billion barrels of ROIP in the sample reservoirs. The top ten classes based on ROIP contain a total of 83% of the remaining oil resource in the studied database.

In implementing its oil research program plan, the DOE has used information available in the TORIS database to identify reservoirs that have significant production potential over the near- and mid-term. Rankings of geologic classes were developed based on the largest recovery potential and the greatest threat of abandonment. The rankings were used to prioritize and focus the government's RD&D efforts on areas where it was needed most.

To date three classes have been identified for further action. These are:

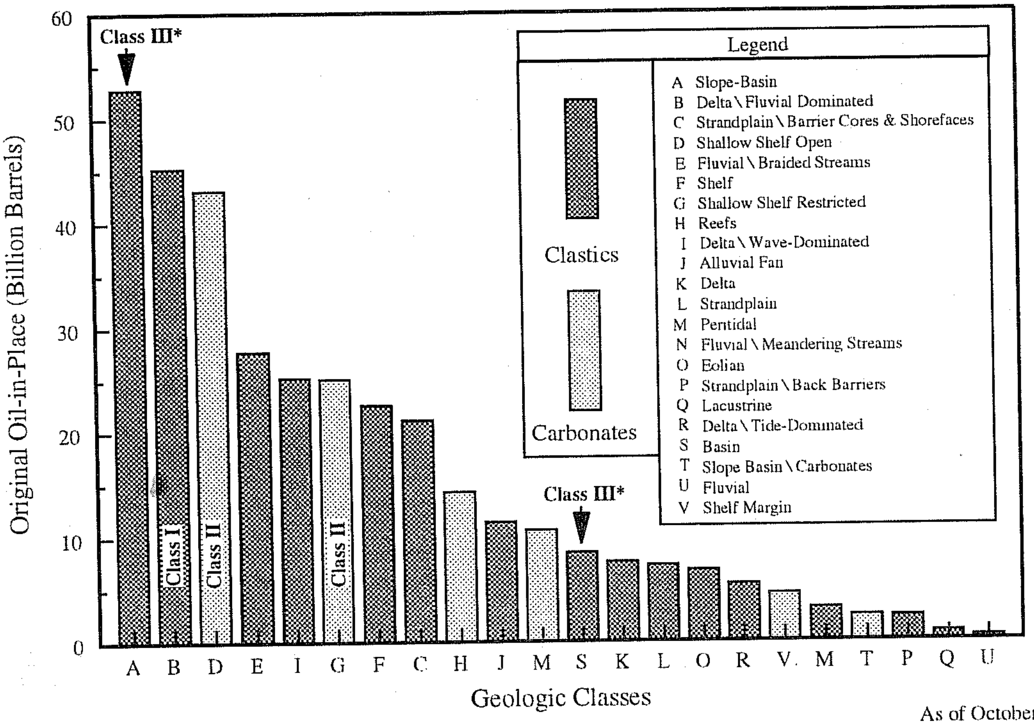
- **Class I - Fluvial Dominated Deltaic Reservoirs** -- In April 1992, the DOE awarded funds for 14 cost-sharing field research projects to industry. Five projects had near-term objectives while the remaining nine had mid-term goals.

- **Class II - Shallow-Shelf (Open & Restricted) Carbonate Reservoirs** -- In April 1993, the DOE awarded funds for 11 cost sharing projects (eight near-term and three mid-term) to the industry.

- **Class III - Slope-Basin & Basin Clastic Reservoirs** -- The DOE is currently in the process of announcing a competitive solicitation for funded cost sharing projects for Class III reservoirs.

Figure I-3

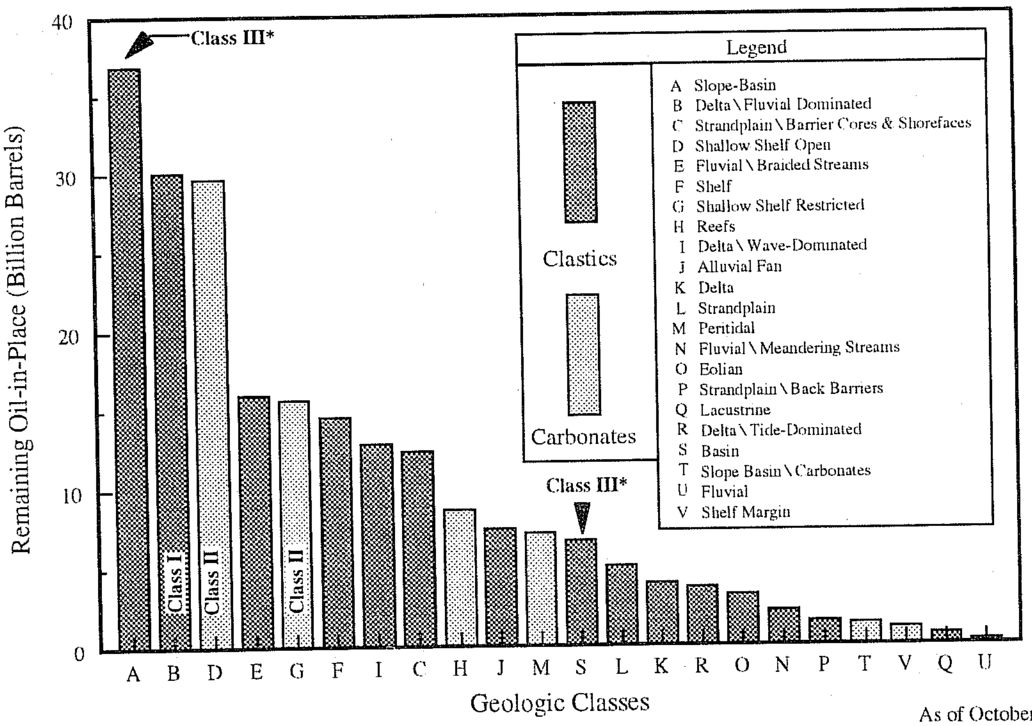
Original Oil-in-Place for 22 Geologic Groupings (Light and Heavy Oil)



* Slope Basin & Basin classes have been combined into one class (Class III)

Figure I-4

Remaining Oil-in-Place for 22 Geologic Groupings (Light and Heavy Oil)



* Slope Basin & Basin classes have been combined into one class (Class III)

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Objectives of the Report

This report provides background information to the industry at large, regarding the DOE's current understanding of the reservoir and geologic characteristics of the class. It also defines the principal impediments to increased production from Slope-Basin & Basin clastic reservoirs. The report covers the following topics:

- The development history of Slope-Basin & Basin clastic reservoir fields and an operator profile of these reservoirs based on current production percentages (i.e., Majors, Large Independents, and Small Independents);
- The geologic characterization of Slope-Basin & Basin clastic reservoirs;
- The status of existing EOR projects and processes;
- A review of current literature pertaining to the technical and operational constraints of Slope-Basin & Basin clastic reservoirs;
- A presentation of the nationwide and statewide distribution of Slope-Basin & Basin clastic reservoirs and their recovery potential through improved techniques (i.e., tertiary and advanced secondary recovery);
- An assessment of resource abandonment risk and the related urgency of resource development in the near- and mid-term; and
- A review of the environmental constraints on the further development of Slope-Basin & Basin clastic reservoirs.

This report provides a listing of the Slope-Basin & Basin clastic reservoirs as contained in TORIS. Additional Slope-Basin & Basin clastic reservoirs (both onshore and offshore), not currently listed in the TORIS database, will be considered in the DOE's competitive solicitation.

REFERENCES CITED

1. U.S. Department of Energy, 1990, *Oil Research Program Implementation Plan.*

2. 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 for U.S. Department of Energy/Office of Fossil Energy, Bartlesville Project Office. 1990.

3. Ray, M.R., Brashear, J.P., and Biglarbigi, K., 1991, Classification System Targets Unrecovered U.S. Oil Reserves, *Oil and Gas Journal* V. 89 No. 39 p. 89.

CHAPTER II

DESCRIPTION OF THE SLOPE-BASIN & BASIN CLASTIC RESOURCE

Clastic reservoirs are vitally important reservoirs in the production of oil and gas in North America. It is estimated that approximately two-thirds of the major oil and gas fields are producing from clastic reservoirs. This estimate is confirmed by the DOE database available in the Tertiary Oil Recovery Information System (TORIS), which shows that approximately 67% of total light and heavy oil resources are found in clastic reservoirs. Of the clastic reservoirs represented in the TORIS database, the most significant are those deposited in the Slope-Basin & Basin environment (Figure II-1). Slope-Basin & Basin clastic reservoirs contain a significant portion of the oil resource in the United States and make up a dominant portion of the California resource. The identified reservoirs account for approximately 60 billion barrels of the total light and heavy oil resource represented in the TORIS database.

The Slope-Basin depositional environment is the dominant resource class among all lithologies and environments, with nearly 53 billion barrels of original oil-in-place (OOIP) as shown in Figure II-2. The Basin depositional environment is the twelfth largest class in terms of OOIP (7 billion barrels). For procurement purposes, the DOE has grouped both the Slope-Basin and Basin clastic depositional sittings into a single class (Class III). The reservoirs in Class III represent a continuum of marine depositional environments, deposited along continental margins and in relatively deep water -- usually in a "fining up" sequence (Figure II-3). The geographic and geologic description of the Class III reservoirs, along with reservoir characteristics, are discussed in the following sections of this chapter.

The Target Resource

The TORIS database contains geologic and engineering information on reservoirs accounting for nearly two-thirds of the total known onshore original oil-in-place (OOIP) in the United States. Of the 348 billion barrels of light and heavy OOIP represented in TORIS, about 60 billion barrels (17%) are contained in over 200 Slope-Basin & Basin clastic reservoirs.

Nearly 15.7 billion barrels, representing 26% of the OOIP in Slope-Basin & Basin clastic reservoirs, has been produced as of December 1991 (Figure II-4). An additional 1.6 billion barrels (2.7%) of OOIP are proved reserves. Of the remaining 42.7 billion barrels of OOIP, an estimated 14.7 billion barrels is unrecovered mobile oil (UMO) which remains in the reservoirs due to macroscopic heterogeneities and unfavorable fluid characteristics. This is the target for advanced secondary recovery (ASR) techniques, including infill drilling, horizontal drilling, polymer flooding, and permeability profile modification. The remaining 28.0 billion barrels of oil are trapped within the reservoirs by surface tension and capillary forces. The latter immobile oil resource is the target for enhanced (tertiary) oil recovery (EOR) processes.

Table II-1 shows the distribution of OOIP among light and heavy oil resources for the Slope-Basin & Basin clastic reservoirs in the U.S. Light oil reservoirs comprise 36.8 billion barrels (61%) of the OOIP in Class III reservoirs, with the remaining 23.2 billion barrels (39%) located in heavy oil reservoirs.

Locations of the Slope-Basin & Basin Clastic Reservoirs

Slope-Basin & Basin clastic reservoirs in TORIS are found in eight states (Figure II-5). California basins (Los Angeles, San Joaquin, Santa Barbara-Ventura, and Santa Maria) account for over 85% of OOIP (Figure II-6) and about two-thirds of the 206 Class III reservoirs. Texas basins (Midland, Delaware,

Figure II-1

Distribution of Original Oil-in-Place in TORIS (Light and Heavy Oil)

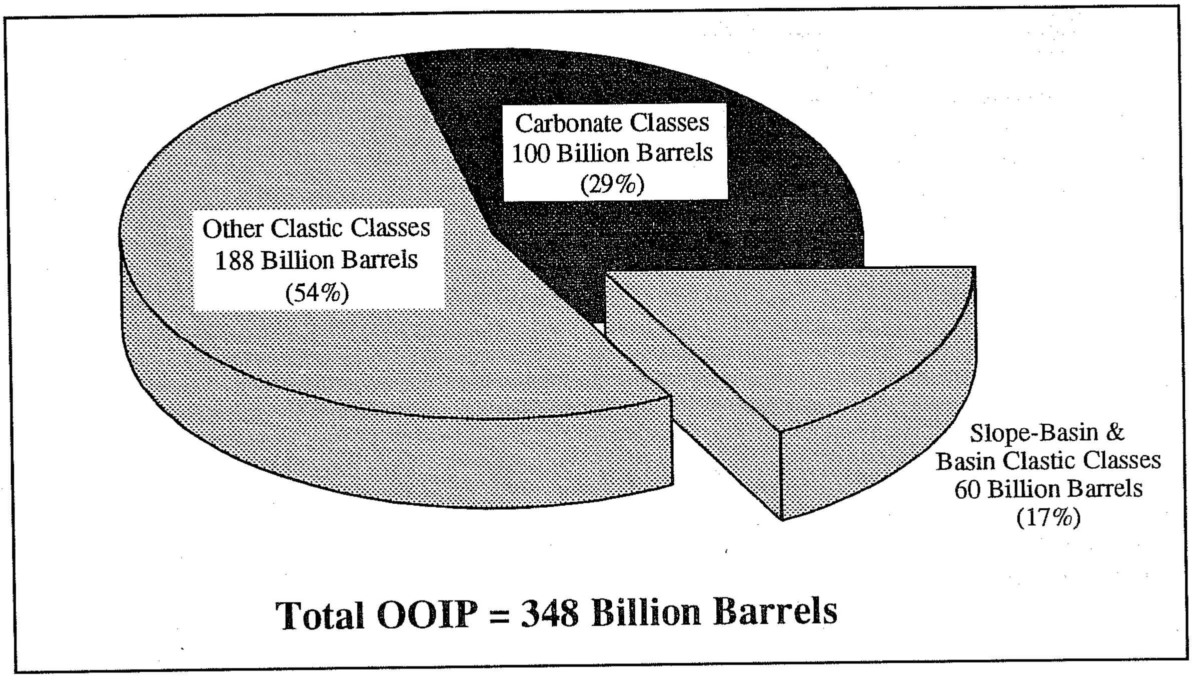
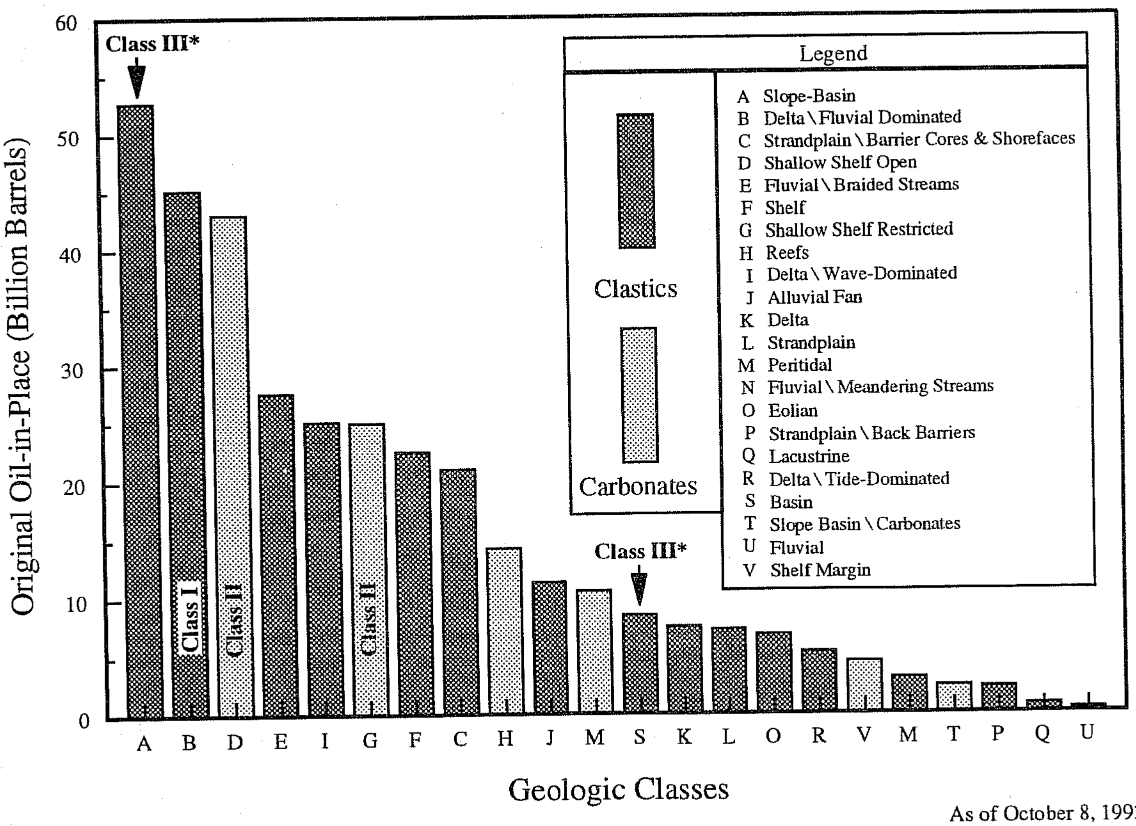


Figure II-2

Original Oil-in-Place for 22 Geologic Classes (Light and Heavy Oil)



As of October 8, 1993

* Slope Basin & Basin classes have been combined into one class (Class III)

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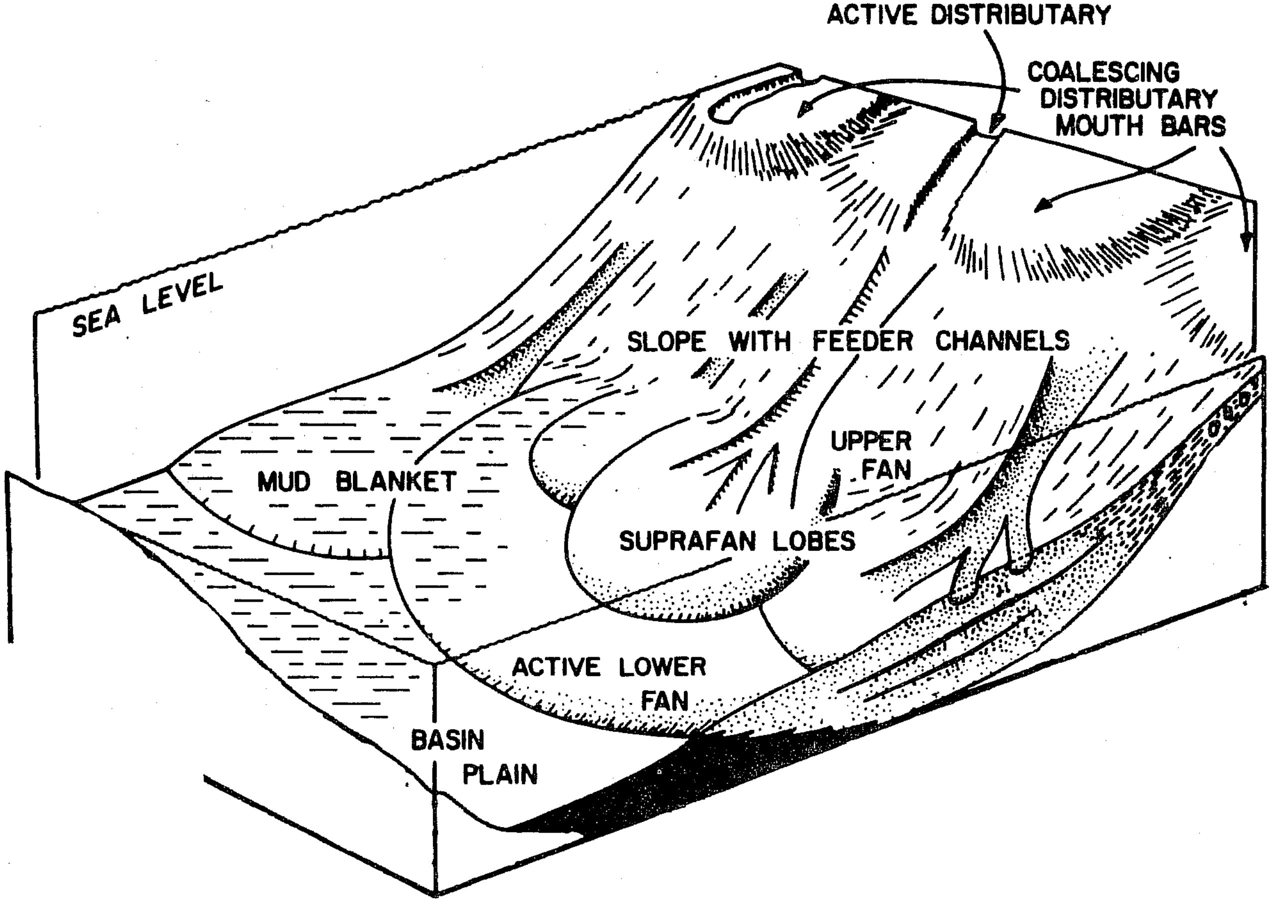
Figure II-3

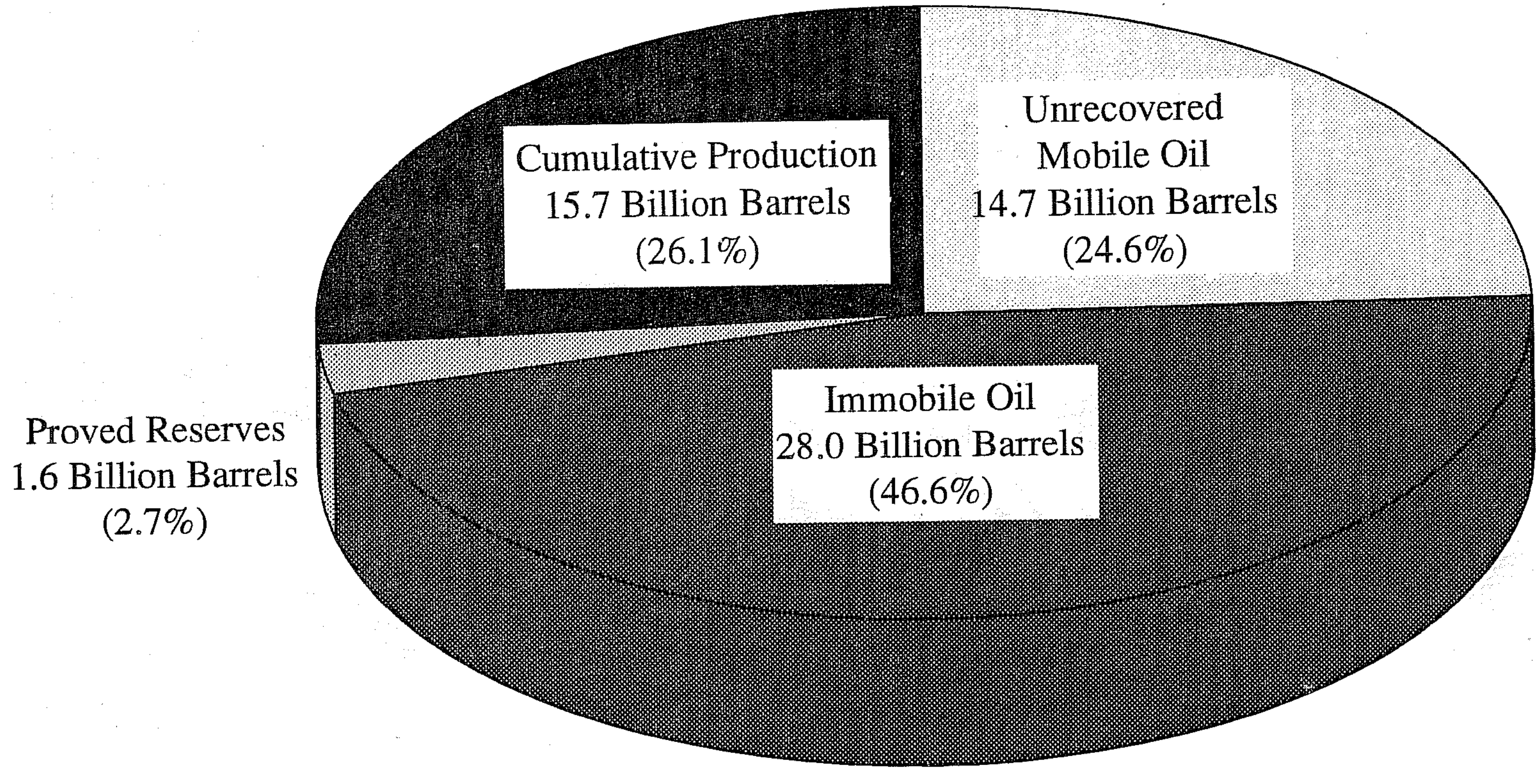
Slope and Basin Clastic Depositional Environments



After Walker, R.G., 1978, "Deepwater Sandstone Facies and Ancient Submarine Fans: Models for Exploration for Stratigraphic Traps" AAPG Bulletin, 62:932-966

Figure II-4

Distribution of OOIP for Slope-Basin & Basin Clastic Reservoirs in TORIS*



Original Oil-In-Place = 60.0 Billion Barrels

* TORIS Reservoirs only

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Table II-1

Distribution of OOIP for Identified TORIS Slope-Basin & Basin Clastic Reservoirs (Billion Barrels)

	Light Oil	Heavy Oil	Total
Original Oil-in-Place	36.8	23.2	60.0
Cumulative Production	9.7	6.0	15.7
Remaining Reserves	1.1	0.5	1.6
Remaining Oil-in-Place	26.0	16.7	42.7

and the Eastern Shelf) contain an additional 13% of OOIP and about 22% of the reservoirs in this class. The remaining 2% of the Class III resource is distributed across six other states: New Mexico (Delaware Basin), Louisiana and Mississippi (South Louisiana Salt Basin), Illinois (Illinois Basin), and Pennsylvania and West Virginia (Appalachian Basin). This section briefly describes the Slope-Basin & Basin clastic reservoirs of California and Texas, providing a history of development as a background to the current state of operations in fields located in these areas.

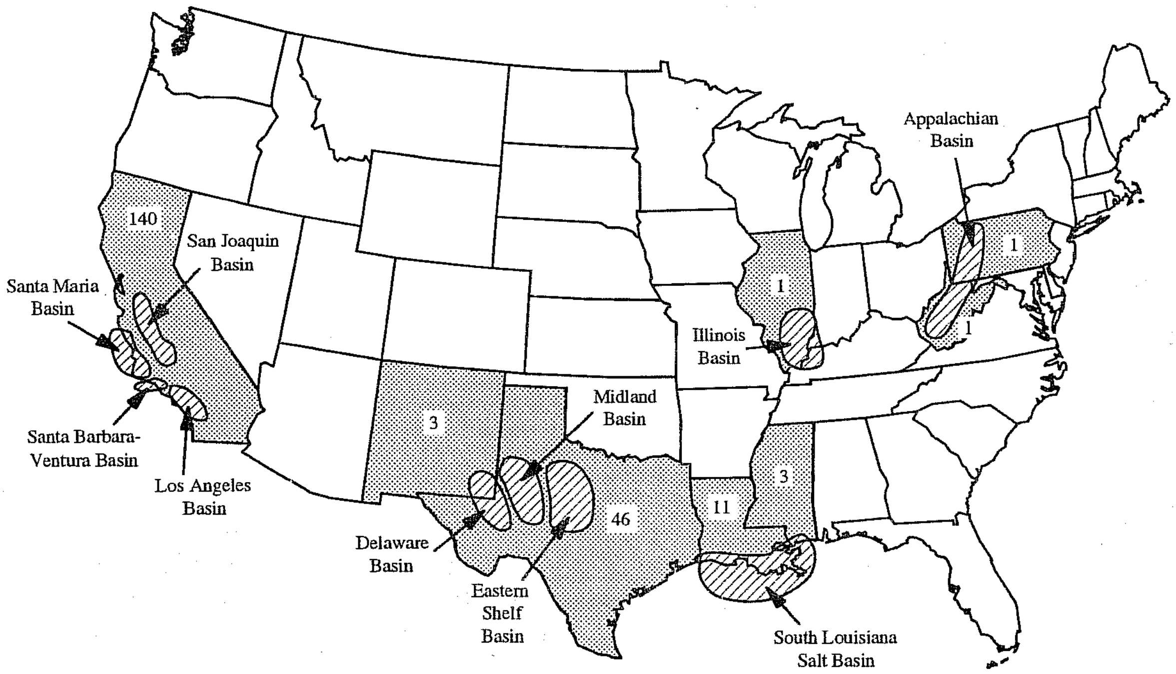
California

The history of exploration and development in California shows that the state's Slope-Basin & Basin clastic reservoirs have been highly productive. The Los Angeles Basin, which has been the most prolific, contains most of the Class III OOIP (slightly over 40%), followed in size by the San Joaquin, Santa Barbara-Ventura, and Santa Maria basins. In California, beginning with the establishment of commercial production in the last quarter of the nineteenth century, the bulk of onshore discoveries was made prior to World War II. Significant offshore production was not established until the 1960s. Slope-Basin & Basin clastic reservoirs in California are dominated by turbidite sands of the Miocene and Pliocene age (Table II-2). Additional production is present in pelagic sediments of the Monterey Formation.

Significant production in the Los Angeles Basin began with the discovery of the Los Angeles City field in 1893. This field soon led the state in production, accounting for almost three-quarters of the 1.2 million barrels produced in California in 1895. The greatest exploration successes in the Los Angeles Basin occurred between 1917 and 1932. All of the large oil fields in the Los Angeles area were discovered during this time period, including the Montebello in 1917, Huntington Beach in 1920, Long Beach and Santa Fe Springs in 1921, Dominguez in 1923, and Wilmington in 1932. The significance of these discoveries was such that, when developed, these fields caused a flood of oil in the market, reducing the price of oil. In 1929, the Long Beach field was producing 190,000 barrels of oil per day (BOPD) and the Santa Fe Springs field yielded 92,500 BOPD.

Typical of reservoir rocks found in the basin subsurface are outcrops of the Miocene Puente Formation in the eastern portion of the Los Angeles Basin. This formation represents deposition on a slope and base of slope apron on the margin of a rapidly subsiding basin.[1] In relation to its size, the Los

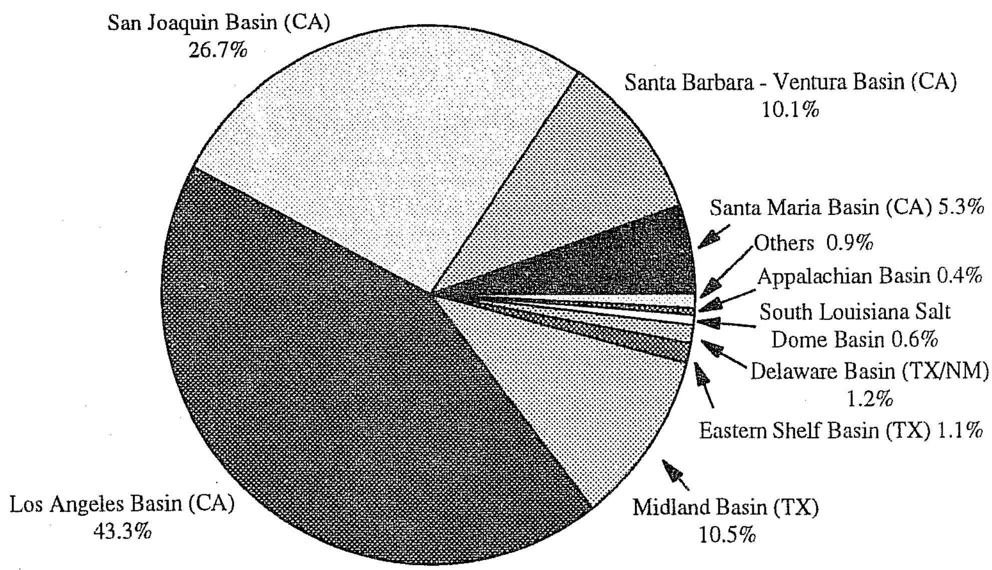
Figure II-5
Location of Slope-Basin & Basin Clastic Reservoirs in TORIS



Source: BPO TORIS, 9/93

Total number of fields/reservoirs in U.S. = 206

Figure II-6
OOIP Distribution of Slope-Basin & Basin Clastic Reservoirs by Basin*



OOIP = 60 Billion Barrels

* TORIS Reservoirs only

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Table II-2

Slope-Basin & Basin Clastic Reservoirs - California Basins

Basin	Producing Formation	Age	Depositional Environment	No. of TORIS Class III Reservoirs
Los Angeles	Puente	Pliocene	Slope-Basin turbidite fans	22
	Repetto	Miocene	Slope-Basin turbidite fans	33
	Puente/Repetto	Mio-Pliocene	Slope-Basin turbidite fans	24
San Joaquin	Temblor	Oligocene	Slope-basin turbidite fans	2
	Stevens	Miocene	Slope-basin turbidite fans	14
	Reef Ridge	Miocene	Slope-basin turbidite fans	3
	Fruitvale	Miocene	Slope-basin turbidite fans	3
	Carneros	Miocene	Slope-basin turbidite fans	1
	Antelope	Miocene	Basin pelagic	1
	Monterey	Miocene	Basin pelagic	2
Santa Barbara - Ventura	Modelo	Miocene	Slope-basin turbidite fans	5
	Pico	Pliocene	Slope-basin turbidite fans	17
	Repetto	Pliocene	Slope-basin turbidite fans	5
Santa Maria	Monterey	Miocene	Basin pelagic	6

Angeles Basin has been one of the most prolific oil provinces in the world, in addition to being one of the most urbanized.

Most of the stratigraphic production in the San Joaquin Basin comes from sandstones of upper Miocene turbidites.[2] As with the Los Angeles Basin, production was established in the late 1800s and early 1900s. Development of the San Joaquin basin began with the 1890 discovery of the Sunset area of the Midway-Sunset field. This was followed by the McKittrick field in 1898, Kern River field in 1899, and the Midway area of Midway-Sunset field in 1900. The years 1910 through 1912 also saw the discovery of four important fields: Elk Hills, Lost Hills, South Belridge, and North Belridge, all of which greatly increased oil production in the state for the 10 years that followed. During the latter part of the 1930s, additional large discoveries were made, including the Greeley and Ten Section in 1936, North and South Coles Levee in 1938, and Paloma in 1939. In 1974, the Yowlumne oil field was discovered in Kern county and, by 1979, was the ninth largest producer in the state.

The Santa Barbara-Ventura Basin was the site of the first truly commercial production in California with the drilling of the Pico 4 well in 1876. By 1885, with the discovery of the Ventura and Newhall fields, state-wide production had increased significantly to 325,000 BOPD. In the Santa Barbara-Ventura Basin approximately 75% of the hydrocarbon production is from the upper Miocene and younger sequence in which excellent petroleum reservoir and source rocks occur.[3] The main hydrocarbon reservoir in the basin is the Pliocene and Pleistocene Pico Formation which contains several giant oil fields of the Rincon trend, including the Venture Avenue field (discovered 1922), the Rincon field (1929), and the San Miguelito field (1931). Offshore exploration in the 1960s yielded two fields: Carpinteria, lying in both federal waters and state tidelands, which was discovered in 1966; and Dos Cuadros, in federal waters, which was found in 1968.

Exploration prospects and reservoirs in existing fields are fewer in the Santa Maria Basin, as compared to the Santa Barbara-Ventura Basin. Reservoirs are mainly restricted to the Miocene Monterey Formation.[4] The onshore Santa Maria Basin has been a productive area for hydrocarbon exploration and development since the early 1900s. Most production is from fractured reservoirs in the Monterey Formation. However, oil has also been produced from the Sisquoc and Point Sal formations. The offshore Santa Maria Basin was actively explored in the early 1980s. During that time, more than one billion barrels of oil were discovered, primarily in the Monterey Formation.[5]

Onshore production in California peaked in 1968. In anticipation of this, operators turned to secondary and EOR techniques to maintain production. The most important EOR method in California is steam injection due to the abundance of heavy crude oil in the state. During the 1970s, the general rise in oil prices, the refinement of steam-injection techniques, and the expansion of steam-injection projects led to record amounts of heavy oil production. Thus, in the 1970s, the increased use of steam in EOR projects largely replaced in-situ combustion (which was widely used in the late 1950s and 1960s). In 1980, steam injection accounted for 30%, or about 104 million barrels, of the state's total production.

Texas and New Mexico

Slope-Basin & Basin clastic reservoirs are found in the Midland and Eastern Shelf basins of Texas and in the Delaware Basin of Texas and New Mexico. Among these three basins, over 80% of the represented OOIP in TORIS is in the Spraberry and Dean sands of the Midland Basin.

In the Midland Basin, production from Slope-Basin & Basin clastic reservoirs occurs in the Permian-aged Spraberry and Dean Formations (Table II-3). The Spraberry and Dean sandstones were deposited in broad tongues that extend from the northern end of the basin southward along the basin axis. The Spraberry trend of fields was discovered in 1947 beginning with the Benedum field. The Spraberry Trend field was subsequently discovered in 1949 and is the largest field in the Slope-Basin & Basin clastic reservoirs of Texas. However, its solution-gas drive, originally underpressured reservoirs are projected to recover only 8% of OOIP. There are more than 10,000 wells in the field, which in the 1980s, was among the most intensely drilled oil fields in the nation. Wells are mostly at 160-acre and locally at 40-acre spacing, and rapid production declines prompted local waterflooding.

Other fields of the Midland Basin producing from the Spraberry Formation include the Pegasus Spraberry (discovered 1952), Ackerly Dean (1954), Jo-Mill (1954), and Calvin Dean (1965). The Spraberry/Dean fan system contains a tremendous amount of oil-in-place. Some estimates place the figure at more than 10 billion barrels. However, low porosity and permeability, high water saturation, and ubiquitous solution-gas drive severely limit the recovery efficiency of this resource. Few reservoirs are projected to recover more than 15% of the oil-in-place. Smaller fields that produce from individual submarine channel reservoirs, such as Jo-Mill, are notable exceptions. The Spraberry trend has been the experimental site for significant technological innovations, among them imbibition flooding, air drilling, and the application of horizontal wells in the development of naturally fractured reservoirs.

Table II-3

TORIS Slope-Basin & Basin Clastic Reservoirs - Texas and New Mexico

Basin	State	Producing Formation	Age	Depositional Environment	No. of Reservoirs
Midland	Texas	Dean	Permian/Wolfcamp	Slope-Basin	3
	Texas	Dean	Permian/Leonard	Slope-Basin	2
	Texas	Spraberry	Permian/Leonard	Slope-Basin	9
Delaware	Texas, New Mexico	Delaware	Permian/Guadalupian	Slope-Basin	17
	Texas	Ford	Permian/Guadalupian	Slope-Basin	1
Eastern Shelf Basin	Texas	Canyon	Pennsylvanian	Slope-Basin	8
	Texas	Cisco	Pennsylvanian/Upper	Slope-Basin	1
	Texas	Penn 5150	Pennsylvanian	Slope-Basin	1
	Texas	Strawn	Pennsylvanian/Virgil	Slope-Basin	1
	Texas	Swastika	Pennsylvanian/Virgil	Slope-Basin	6

In the Delaware Basin, production from Slope-Basin & Basin clastic reservoirs occurs in the Permian-aged (Guadalupian) Delaware sands.[6] The Delaware Sandstone Play is the westernmost oil play in Texas and was established with the discovery of the Wheat field (1925). This was followed by other significant fields such as the Tunstill (1947), Twofreds (1957), Geraldine-Ford (1957), and El Mar (1959). Reservoirs in the Delaware sandstone generally consist of well-sorted, very fine grained sandstone interbedded with siltstone, shales, and some limestone. Reservoirs are small to moderate in size. The largest is estimated to contain less than 160 million barrels of oil-in-place. Many reservoirs are unitized and have low primary recoveries (less than 20%) which necessitates the widespread application of secondary processes, such as waterflooding. Carbon dioxide injection is also being increasingly used.

In the Eastern Shelf of the Midland Basin, Slope-Basin reservoirs occur in the Pennsylvanian-aged Canyon, Cisco and similar sands. These reservoirs were deposited primarily as submarine fan channel fills and associated suprafan lobes in an offlapping-slope system.[7] Reservoir sand bodies contain medium- to thick-bedded, locally conglomeratic sandstone. Oil is stratigraphically trapped by the updip pinch-out of sand facies inherent in the slope-fan system.[6] The largest of a family of more than 50 Upper Pennsylvanian reservoirs include those of the Jameson, Flowers (Canyon), Kelly-Snyder (Cisco), Lake Trammell West (Canyon), and S-M-S (Canyon) fields. All were discovered in the early 1950s. The play is typified by heterogeneous reservoirs and multiple thin completion intervals. Primary production is solution gas drive, and all larger reservoirs have been systematically waterflooded.[6]

Operator Profile for Slope-Basin & Basin Clastic Reservoirs in TORIS

The majority of Slope-Basin & Basin clastic reservoirs have, in the past, been operated by major oil companies (i.e., oil companies having greater than 250 million barrels of domestic liquid reserves). Overall, 59% of the 1991 light and heavy oil production was owned by major oil companies (Figure II-7). Nearly 68% of the light oil production from Slope-Basin & Basin clastic reservoirs in TORIS and 55% of heavy oil production was attributable to major oil companies in 1989 (Table II-4).

Since 1989, production in Slope-Basin & Basin clastic reservoirs has dropped by about 7%. Overall production from light and heavy oil Slope-Basin & Basin clastic reservoirs has declined from 179 million barrels in 1989 to 166 million barrels in 1991. Light oil production has actually increased by nearly 4% since 1989.

Heavy oil production in Slope-Basin & Basin clastic reservoirs has decreased by over 16% since 1989. A shift in the distribution of production between majors and independents can be observed. Large and midsize independents account for slightly larger portions of total production than in 1989 while the portions attributable to majors and small independents decreases.

Table II-4

Operator Profile of Slope-Basin & Basin Clastic Reservoirs in TORIS by Light and Heavy Oil (Million Barrels)

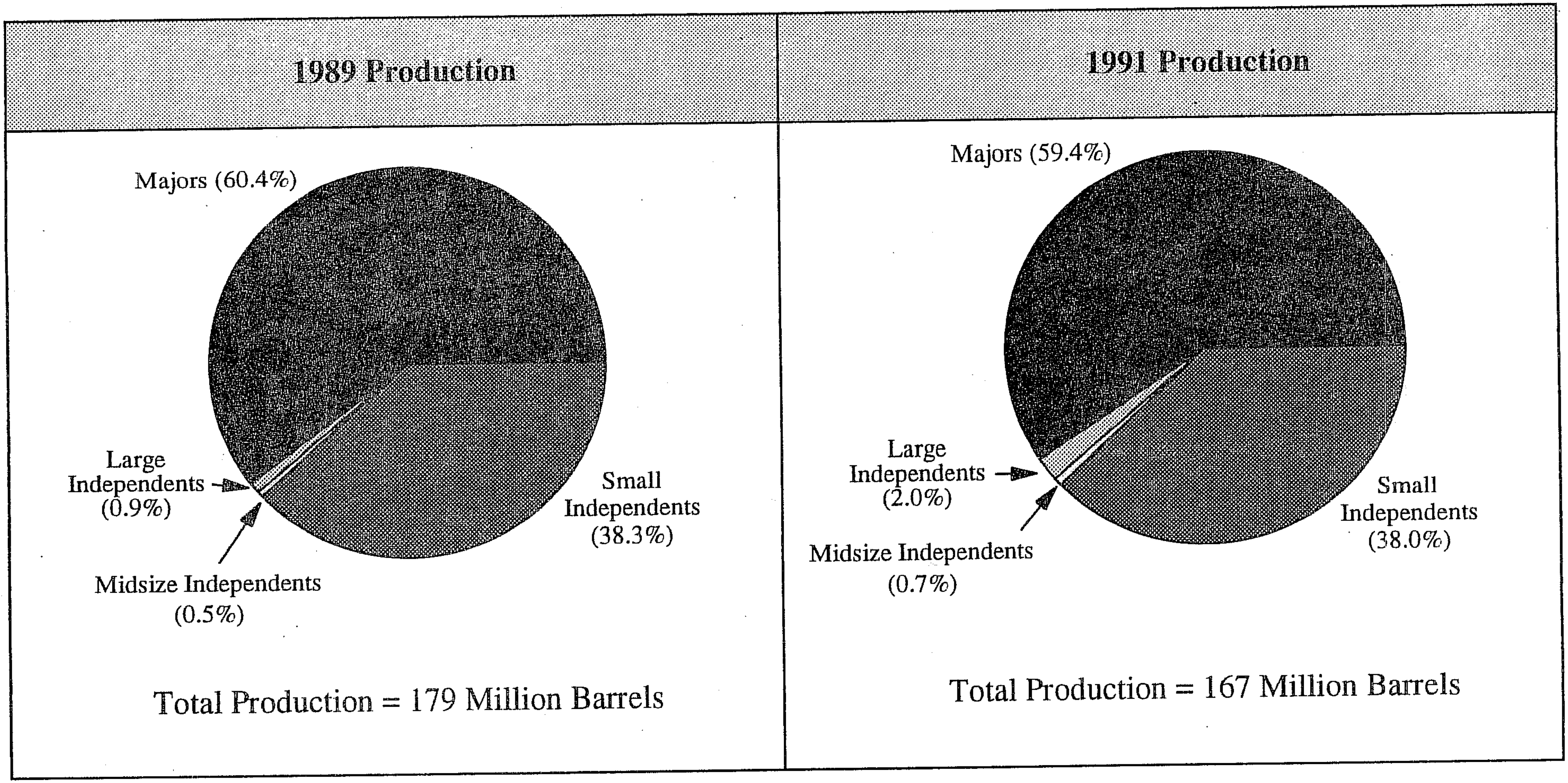
Operator Type	1989 Production			1991 Production		
	Light Oil	Heavy Oil	Total	Light Oil	Heavy Oil	Total
Majors	50.8	57.3	108.1	51.4	47.8	99.2
Large Independents	0.1	1.6	1.7	0.1	3.2	3.3
Midsize Independents	0.2	0.7	0.9	0.1	1.0	1.1
Small Independents	24.1	44.4	68.5	26.4	37.0	63.4
Total	**75.2**	**104.0**	**179.2**	**78.2**	**89.0**	**167.0**

Classified by Domestic Liquid Reserves (OGJ 400,300):

Majors: >250 million barrels
Midsize Independents: >10 million barrels
Large Independents: >100 million barrels
Small Independents: <10 million barrels

Figure II-7

Operator Profile of Slope-Basin & Basin Clastic Reservoirs*
(Light and Heavy Oil)



Domestic Liquids Reserves (OGJ 400, 300)

Majors: >250 Million Barrels
Large Independents: >100 Million Barrels
Midsize Independents: >10 Million Barrels
Small Independents: <10 Million Barrels

* TORIS Reservoirs only

Summary

Slope-Basin and Basin clastic reservoirs are some of the more prolific reservoirs in the United States. Many of these reservoirs are located in south and south-central California, where a significant percentage of them hold a large portion of the nation's heavy oil resource. Many reservoirs of this class are also found in western and west-central Texas. Nearly two-thirds of the oil in these reservoirs is owned by major oil companies, although there appears to be a shift towards increasing ownership by large independents in recent years.

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CHAPTER III

GENERAL SUMMARY OF GEOLOGICAL AND PRODUCTION CHARACTERISTICS OF TERRIGENOUS SLOPE-BASIN AND BASIN RESERVOIRS

Summary

Submarine fans and turbidite systems are important petroleum reserves in sedimentary basins of the United States and worldwide. Six of the top twenty-five oil and gas fields of the United States occur in submarine fans (Weimer and Link, 1991). A better understanding of their formation and genetic types should help provide more effective exploration and development strategies. This literature search was undertaken to summarize the geological and reservoir characteristics of these slope and basin systems including the depositional processes involved, depositional models, dimensions and geometry of these deposits, and expected reservoir quality.

Summaries of the geology of major class III plays (those with more than 8 fields or reservoirs) listed in the TORIS database are presented in this report. The plays addressed are located in Texas and California and include the Upper Pennsylvanian Slope sandstones, Spraberry-Dean formations and Delaware sandstones from Texas; and the Stevens Oil Zone, Puente Formation, Repetto Formation, and Monterey Formation from California. Important basin-slope plays not listed in the TORIS data base include, among others, the Hackberry play (member of the Frio Formation, TX), summarized in this report, and Miocene- to Pliocene-age deposits in Gulf Coast offshore reservoirs, not addressed here.

Analysis of reservoir and production data contained in the TORIS database was conducted for the major class plays to provide examples of the reservoir properties of this group of reservoirs. Comparison of the reservoir characteristics of porosity, depth, net pay, oil gravity, original oil-in-place, and ultimate recovery factor indicated that the four slope-basin reservoirs in California have similar porosity, net pay, and oil gravity compared to the three plays in Texas. Texas plays produce only light oil while California plays produce both heavy oil and light oil. The California slope-basin plays have thicker net pays and higher porosity values than Texas plays, while the initial oil saturation values are similar among all eight plays analyzed. The median ultimate recovery factor of the slope-basin and basin reservoirs in TORIS is 30.4% OOIP. Among the plays analyzed, the Puente Formation reservoirs have the best ultimate recovery factor (33.3%). The Spraberry-Dean, Monterey, and Delaware Formation reservoirs perform relatively poorly with median ultimate recovery factor values of 14.2%, 20.6% and 24%, respectively.

The slope-basin physiographic setting begins at the outer margin of the continental shelf at 45-300 m below sea level, and continues to the base of the slope at depths of 3,000 to 4,000 m below sea level. The dominant depositional process in the slope-basin environment is downslope movement of sediments containing various amount of water called turbidity currents. Turbidity currents, gravity-driven density currents that result from dispersed, suspended sediment, form deposits called turbidites. Turbidites have been considered the "basic building blocks" of many submarine fans. Submarine fans are channel-levee-overbank systems that typically develop on the lower portions of the continental slope but may build outward onto the basin floor, or even into or across deep sea trenches.

Two major classification systems of turbidite deposits include the classical Bouma sequence consisting of a distinct vertical sequence of bedding that reflects waning current flow. A second system was developed by Mutti and Ricci Lucchi (1972) to encompass those deposits not described by the Bouma sequence. This system attempts to link the mechanism of deposition with the depositional environment in ancient submarine fan settings on the channeled slope, on the submarine fan (upper, middle, lower subdivisions), and the basin plain.

Major submarine fan deposits usually develop during periods of low sea level, while only minor turbidite deposition appears to occur during periods of high sea level. Submarine fans tend to form on two types of continental margins that have strong implications for the fan size, geometry, seafloor gradient, and sand/shale ratio. The first type includes tectonically active margins that have narrow shelves and relatively steep slopes. Fans developed on active margins tend to be more localized and are characterized by the development of channel-mouth lobes, high gradients, high sand/mud ratios, braided channels, and small sand-rich fans. Many of the turbidite reservoirs in California were formed in this type of setting. The second type includes tectonically passive margins, where more laterally extensive continental rise wedges are formed, and fans typically lack channel-mouth lobes, have low gradients, low sand/mud ratios, sinuous channels with associated levee facies, and are large mud-rich fans. The turbidite reservoirs of Texas were formed in a setting closer to this type of margin.

In hydrocarbon exploration and production, a clear understanding of lithofacies distribution, sand-body geometry, and reservoir quality is essential to identify sand-filled channels and predict the location of sand lobes. Fans developed on slopes and base-of-slope settings often have a concentration of sand deposition in the inner, middle, or suprafan areas that often results in excellent potential reservoir sands. Different submarine lobe models based on modern submarine fans demonstrate different reservoir geometries and qualities. Braided suprafan lobes are characterized by stacked channel sandstones with good lateral and vertical communication, constituting excellent reservoir facies. Depositional lobes represent sandy channel mouth deposits of the lower fan that exclude channel/levee complexes. Their deposits exhibit sheet-like sand bodies with good lateral and moderate vertical communication and should constitute good reservoir facies. Fan lobes are highly sinuous channel and associated levee systems that are characterized by offset stacked sand bodies with poor lateral and vertical communication, but have the potential to be moderately good reservoir facies. Ponded lobes represent mud-rich slumps in a slope setting and, therefore, comprise poor reservoir facies. The submarine fan and turbidite system is highly complex and variable, therefore a number of models are needed to adequately explain sandbody configuration and reservoir quality.

Submarine fan and fan channel dimensions from both modern and ancient systems can vary by three orders of magnitude. Fan dimensions and geometry are controlled by tectonics (including faulting, flexing, subsidence rates, and active versus passive margins); paleogeography of the basin; amount and type of sediment available including sand/shale ratio; frequency of channel avulsion; slope and fan gradient; and channel sinuosity. Submarine canyon size is controlled locally by the nature of the bedrock underlying the shelf and slope areas.

The use of information from modern submarine fans in the identification of ancient submarine fan lobe types is often difficult because of differences in the tools used, and therefore the types and scale of data obtained. Data from modern fans are typically obtained remotely from acoustical tools due to their occurrence in great water depths. Cores are difficult to obtain, and when possible, typically only record the uppermost 10 to 20 meters. Small scale features usually described from ancient turbidites are below the resolution of acoustical equipment used in the study of modern fans. The largest outcrops may not adequately expose the principal depositional features seen on seismic lines, where channels and their depositional fills may be many kilometers wide and tens to hundreds of meters thick. The lack of comparative data has led to the development of differences in terminology that make comparative studies of modern and ancient systems difficult.

Much of the slope and most of the basin floor are dominated by pelagic muds that limit the reservoir potential for ancient deposits. However, basin and trench-slope settings may include potential reservoir quality deposits of silty contourites and large turbidite systems that have built past the continental rise into the basin or trench. Often these deposits are fed by large entrenched channels or submarine canyons so that coarse sediments tend to bypass the upper slope and become deposited on the trench or basin floor. Axial channels in trenches, and deep sea channels have reduced potential for large petroleum reserves compared to depositional lobes of submarine fans. Sediments filling large, deeply cut submarine canyons may, however, have good continuity of lower sands, and excellent potential for updip hydrocarbon migration. Stratigraphic traps created by mud fill may exist in the upper canyon.

Definition of Geologic Terms

Contour Current: Within ocean basins, differences in water density produce forces strong enough to create water movement. Once movement begins, it is enhanced by the Coriolis effect that deflects currents to the right in the Northern Hemisphere. Once deflected by the Coriolis effect, bottom currents tend to follow bathymetric contours. These currents are referred to as contour currents. Contour currents were originally considered to effect mainly the lower slope and continental rise on western sides of ocean basins. Deposits created by contour currents are called contourites.

Hemipelagic Sediments: These are combinations of terrigenous (land derived) and biogenic (biologically formed) components. The main difference between pelagic and hemipelagic sediments is the greater amount of terrigenous materials (e.g. silts, terrestrial clays) in the hemipelagic sediments.

Littoral Drift: Transportation of sediments by wave-generated nearshore currents moving parallel and adjacent to the shoreline.

Lysocline: The depth within a basin at which there is pronounced increase in the rate of calcite dissolution. The lysocline is functionally defined by the position of the maximum change in foraminiferal composition within the marine oozes due to differential dissolution.

Nepheloid Layer: Nepheloid layers are long-lived low concentrations of suspended clay-size sediment kept above the sea floor by turbulence. Such layers may be as much as 1 km thick.

Pelagic: Refers to sediments of the deep sea as opposed to those derived from the land. These are sediments that are deposited directly from the water column, at depths generally greater than about 500 m, including biogenic materials (radiolarian, diatom, and foraminiferal oozes), terrigenous clays and silts, volcanic sediments that were blown through the air and settled into the oceans, ice-rafted debris, and extraterrestrial materials. As a depth indicator pelagic refers to the general water mass as opposed to the substrate.

Submarine Canyons and Deep Sea Fans: Land-derived and littoral sediments are commonly delivered to the continental slope, continental rise, and the deep ocean basins through very large, erosive features called submarine canyons that incise both continental slopes and shelves. At the mouths of the submarine canyons sediment flow becomes laterally unconfined and there is a decrease in gradient where current speed is reduced causing sediments to accumulate as deep sea (or submarine) fans. Several types of lobes comprising submarine fans have been recognized. One of the more important lobe types that develop just beyond the mouths of upper fan valleys are called suprafan lobes. Suprafan lobes are convex-upward in profile and consist of channeled and unchanneled coarse-grained turbidite deposits. Submarine fans may merge and form very broad accumulations known as submarine aprons.

Turbidity Current: A variety of density current that flows as a result of a density contrast created by turbulently suspended sediment within the body of the current. Turbidity currents may flow at relatively high rates and travel for great distances across inclined or near horizontal substrates. Deposits created by turbidity currents are called turbidites.

Geologic and Production Characteristics of Major Slope-Basin and Basin Plays

Summaries of major slope-basin and basin plays (those with more than 8 fields or reservoirs) included in the TORIS database are presented in this section. The plays addressed include the Upper Pennsylvanian Slope sandstones, Spraberry-Dean formations, and Delaware sandstones from Texas, and the Stevens Oil Zone, Puente Formation, Repetto Formation, and Monterey Formation from California. Important basin-slope plays not listed in the TORIS database include, among others, the Hackberry play (member of the Frio Formation, TX), summarized in this section, and Miocene and Pliocene-age deposits in Gulf Coast offshore reservoirs, not addressed here.

Geologic Characteristics

<u>Upper Pennsylvanian Slope Sandstones, Texas</u>

During Late Pennsylvanian and Early Permian time the broad north-south trending edge of the Eastern Shelf of the Midland Basin prograded basinward 20-75 miles as a sequence of offlapping terrigenous slope wedges. At the base of the slope wedges a sequence of submarine fans formed a series of terrigenous facies 800 to 1,200 ft thick (Galloway and Brown, 1972). The system terminates abruptly updip into massive limestones of the contemporaneous shelf-edge bank system. Downdip the submarine fan facies grade into distal slope sandstones and interbedded basin mudstones and shales. Galloway and Brown (1972) estimated that as much as 80% of the terrigenous clastics of the Eastern Shelf are stored in the Sweetwater slope system. The fans were supplied by remobilized delta front sandstones from delta systems that had built beyond the contemporaneous limestone-bank buildups of the platform margin.

Reservoir sandstones along this trend are at depths of 4,000 to 6,500 ft and consist of submarine fan channel fills and associated suprafan lobes of the offlapping-slope system (Galloway, et al. 1983). Associated facies included fan-channel levee and fan-plain interlaminated mudstone, siltstone, and muddy fine sandstone. Fan sandstones are medium- to thick-bedded and are locally conglomeratic.

The reservoir sandstones occur within the large submarine fan "lobes" which thin and lap out updip against contemporaneous slope and shelf margin deposits. The reservoirs are typically stratigraphic, formed by updip pinchout of sand facies. Galloway, et al. (1983) have illustrated that many of these reservoirs abut buried topography of older Pennsylvanian reefs or carbonate-debris-encrusted toes of the advancing shelf platform.

The individual sand units in the Pennsylvanian Slope sandstones are extremely difficult to isolate and map. Although the designated reservoir "zone" (e.g. fan channel sands) may extend over a substantial area, the individual sand bodies are highly lenticular and discontinuous. Therefore, the play is typified by heterogeneous reservoirs and multiple thin completion intervals. Overlying or underlying shelf-edge limestones are usually correlated and used to map the distribution of the slope wedges. Westward regional dip is often modified by local differential subsidence of the thick slope-prodelta mudstone sequence.

More than 50 oil pools are known from this trend where primary production is exclusively driven by solution gas. Galloway, et al. (1983) indicate that most of the larger reservoirs are unitized and are undergoing (or have undergone) waterflood. But because of compartmentalization, high reservoir heterogeneity, and moderately low permeability, recovery efficiency is limited for these submarine fan reservoirs.

This play consists of a genetically related system of depositionally equivalent or related settings that lie within a single, broadly-defined paleogeographical and basin context.

Spraberry-Dean Formations, Texas

The Spraberry and Dean formations may be divided into three genetic sequences (Handford, 1981), each consisting of several hundred feet of interbedded shale and carbonate overlain by a roughly equal amount of sandstone and siltstone. These sequences record episodes of shelf margin progradation, deep-water resedimentation of shelf-derived carbonate debris, followed by influxes of terrigenous clastics into the basin by way of feeder channels or submarine canyons, and suspension settling of fine-grained sediment from the water column. Clastic members of the Spraberry consist of widespread mappable stratigraphic sequences, 30-80 feet thick, with sharp bases and overall fining-upward patterns.

Reservoir sandstones were deposited as part of a basin-filling submarine fan system that transported terrigenous sediments down the axis of the basin to form elongate fans that onlap the bounding basin margins. The regional study by Handford (1981) suggests that the sands were deposited by a combination of salinity- and density-current underflows and to a lesser degree by turbidity currents and hemipelagic settling. The density-current underflows originated primarily on shelf evaporite platforms, which lay to the north and northwest of the basin. The greatest volume of Spraberry/Dean oil is trapped by updip thinning and pinch-out of sandstones where they onlap the toe of the Eastern Shelf (Galloway, et al. 1983). Only a few fields are simple anticlines.

Spraberry and Dean formations were deposited from debris flows, turbidity currents, saline density currents, and suspension settling. Some sediments were later altered by slumping, soft-sediment faulting, and fluidization. The linear and branching sand thickness patterns of these sequences indicate deposition in channels, while blanket-like patterns reflect deposition from suspension and from splay-like unconfined flows at the distal areas of clastic accumulation where channels loose their identity (Handford, 1981).

Production in the Spraberry trend is strongly dependent on fractures. Regional fracture pattern is locally enhanced by anticlinal folds, producing commercial reservoirs. Due to the regional northeast-southwest fracture system throughout the trend, modified injection patterns are required to successfully flood this highly anisotropic reservoir (Barfield, et al. 1959).

Naturally fractured Spraberry siltstones and very fine-grained sandstone reservoirs have become notorious for rapid decline of pressures. The rocks have porosities averaging 8-10%, permeabilities of <1 mD, and primary recovery by solution gas drive less than 10% of the oil in place (Elkins and Skov, 1963).

Delaware Sandstone, Texas

The Delaware sandstone play occurs in the northern part of the Delaware Basin, New Mexico and Texas. Production occurs from the upper part of the Permian age Delaware Mountain Group (Bell Canyon Sandstone) that is the basinal equivalent of the Capitan Limestone of the Guadalupe Series.

Reservoir sandstones are well-sorted, very fine grained, and interbedded with laminated and burrowed siltstone, organic-rich shale, and limestones. The reservoir sands were deposited by broad, anastomosing, and internally braided channels along the lower slope and floor of the deep Delaware Basin (Bozanich, 1979; Williamson, 1979). These sandstones show abundant evidence of transport by density currents, but lack of turbid density current flow reflected in the clean, well sorted texture makes these Slope-Basin system deposits different from conventional submarine fans.

The productive channel facies occur as southwest-trending broadly lenticular belts. Oil is stratigraphically trapped by lateral updip pinch-out of individual channel-fills. Sealing facies are silty and moderately permeable. The transmissive nature of the basin fill, combined with the eastward-dipping regional potentiometric surface of the sandstones suggests that entrapment is hydrodynamically enhanced (Williamson, 1979).

Reserves occur at moderate to shallow depths of less than 5,000 feet. Porosity averages 20% to 25%, but the fine texture of the reservoirs results in high water saturation and moderate to low permeability. Zones of equivalent petrophysical properties are highly lenticular and stratified within sandstone bodies, reflecting the bedded nature of the submarine channel-fill sands (Galloway, et al. 1983).

Many of the reservoirs are unitized, and low primary recoveries require widespread application of secondary recovery processes. Although waterflood is the dominant recovery process, carbon dioxide injection has also been successfully applied within the play (Kumar, et al. 1980).

Hackberry Sandstone, Texas

Deep-water sandstones of the Oligocene-age Hackberry Member of the Frio Formation produced nearly 23 million barrels of oil and 1.9 million MMcf gas as of 1982 (Ewing and Reed, 1984).

Shale and sandstone of the Hackberry Member of the Frio form a seaward-thickening wedge of sediments in southeast Texas and southwest Louisiana. Most of the lower Hackberry is a sand-rich unit that fills channels eroded as much as 800 ft into pre-Hackberry sediments (Ewing and Reed, 1984). Paine (1968), Brown and Fisher (1977), and Berg and Powers (1980) have shown that these sands were deposited in a submarine canyon-submarine fan environment.

Lower Hackberry sands are lenticular and range from a few feet to more than 150 ft thick. Individual sandstones can be correlated with some difficulty within Port Arthur Field. This field, which was abandoned in 1980, has been described by Halbouty and Barber (1961) and Weise, et al. (1981). These studies and that of Ewing and Reed (1984) indicate that maximum sandstone thickness and best development of the interval occur in narrow, dip-aligned bands.

Both Port Arthur and Port Acres gas/condensate fields are within and on the flanks of the Port Arthur Channel. The main Port Acres reservoir is a stratigraphic trap within the uppermost lower Hackberry sandstone (Halbouty and Barber, 1961). In contrast, the Port Arthur field contains 14 reservoirs within an anticline downdip of a regional growth fault. Maximum thickness of sandstones is along the axis of the Port Arthur Channel and its secondary channels.

The SP log responses indicate that lower Hackberry sandstones were deposited within a highly channeled submarine fan system. Analysis of SP log responses (Ewing and Reed, 1984) indicate all parts of the submarine fan model can be identified within the Hackberry deposits including incised suprafan channels, braided fan-channel-fill deposits, and overbank deposits. Water depths in the pre-Hackberry Frio was probably on the order of 400 feet based on the presence of neritic foraminifers such as *Nodosaria*. Inferred maximum water depth during erosion and filling of lower Hackberry channels was about 1,000 to 1,200 feet.

Geometry of the submarine channels and the succession of facies in the Port Arthur field suggest that the lower Hackberry unit formed as an onlapping submarine channel-fan sequence (Ewing and Reed, 1984) with internal features including bedding and sedimentary structures typical of submarine fan channel and overbank deposition (Paine, 1971; Berg and Powers, 1980). Channel geometries may be mapped using high-quality seismic data, but internal sandstone geometries and fluid contacts are generally not resolvable because of their complexity and depth.

The Hackberry contains two hydrocarbon plays. The updip play is relatively shallow (7-8,000 ft) and lies near the updip limit of deep-water deposition. This play includes some fields from the barrier-bar/strandplain Frio sandstones. The downdip play is gas-rich and geopressured. These reservoirs lie within or on the flanks of the major channel system along the updip margin of deep-water Hackberry facies known as the "Hartburg flexure" which is marked by a line of growth faults. The most productive reservoirs are stacked sand bodies that have the best continuity. Trapping mechanisms range from structural (normal faults with rollover) to stratigraphic (updip pinch-out).

These onlapping slope deposits that infill major erosional canyons and shelf-edge reentrants are particularly productive (Galloway, 1986). Ewing and Reed (1984) report that additional fault-stratigraphic prospects in the channel complex of the deeper play are likely to be found. They concluded that a thorough understanding of the complexities of both overall channel geometry and the internal heterogeneity of Hackberry sandstones should facilitate the discovery of additional stratigraphic reservoirs in both Hackberry plays. For more information about potential reservoirs in the lower Hackberry see LeVie (1985).

Stevens Oil Zone, California

The Stevens Oil Zone is defined as "all oil and gas bearing formations of upper Miocene age within the stratigraphic interval between the top of the Reef Ridge Shale and the top of *Valvulineria californica* or associated faunas of Middle Miocene age" (Elk Hills Engineering Committee, 1957). The reservoirs in this zone are thick lenticular to tabular sheet sandstones and thick intervals of fractured siliceous shale in the upper part of the Elk Hills Shale Member of the Monterey Shale (also known as the Monterey Formation). The term was thus coined for convenience of production engineering efforts and refers to pay zones within the Monterey Formation with no additional stratigraphic implication.

The petroleum reservoirs in the Stevens Oil Zone include, in ascending order, the D, C, B, A, and N zones of the Elk Hills Shale Member and the 24Z (Asphalto) and 26R sand bodies. The reservoirs are primarily developed in fractured shale and thin sandstones. Oil gravities range from about 33° to 41° API. Chemical analyses of formation water from 47 wells in the Stevens Oil Zone at NPR 1 (Elk Hills Field) show chloride content ranging form 1,600 to 27,000 ppm.

The 24Z and 26R sands at Elk Hills Field are typical Stevens producing horizons. They are elongate sand bodies as much as 3 miles long and 1,400 feet thick, but only a few thousand feet wide. In the 24Z sand porosity averages 22% and permeability averages 167 mD. (Maher, et al. 1976).

The 26R sand body has a maximum width of about 4,000 feet, a maximum thickness of 1,470 feet, and a length exceeding 2.5 miles. Average porosity is 24% and average permeability is 223 mD based on analyses from 16 wells (Maher, et al. 1976).

Stevens Oil Zone production from the Elk Hills Shale Member of the Monterey Shale (or Formation) consists of elongate sand bodies that formed as channel turbidite deposits. The Elk Hills Shale Member was deposited in marine water 1,000-3000 feet deep and most clastic sediments were emplaced by submarine landslides and turbidity currents (Bandy and Arnal, 1969, Maher, et al. 1976). Anderson (1963) described the Stevens sands in Asphalto Field as a channel-type deposit, the sands having been deposited contemporaneously with the shales that limit its boundaries, rather than in an erosional channel. Foss (1972) recognized Stevens sands as basin-floor turbidites in the eastern part of the basin and as channel turbidites in the western part.

Monterey Formation, California

The Monterey Formation refers to Miocene strata in California that are unusually siliceous (Isaacs, 1984) and can contain significant amounts of hemipelagic sediments and carbonate intervals. Equivalent Miocene siliceous strata are given a variety of stratigraphic names throughout the Neogene basins of central and southern California.

Monterey strata were deposited near a tectonically active continental margin. Several of the Miocene basins were comparatively nearshore, whereas other basins were comparatively offshore (Figure III-1).

In the Santa Maria and Santa Barbara-Ventura basins the Monterey Formation is dominantly pelagic and differs from the Monterey in the San Joaquin Basin in that it contains moderate to abundant calcite mainly in the form of coccoliths rather than foraminifers and was deposited with a thick sequence of phosphatic marl.

Paleogeographic evolution of the Cuyama Basin during Monterey deposition has been outlined by Lagoe (1984). Submarine fan development was contemporaneous with deposition of pelagic carbonates, siliceous sediments, and terrigenous mud. The Mohnian stage marked the end of marine deposition in the Cuyama Basin. Subsequent Pliocene rocks in this area are all nonmarine.

In the San Joaquin Basin the Monterey Formation consists of biogenic siliceous rocks with a significant terrigenous clastic component. In this basin deposition of the Monterey was controlled by an interplay of basin geometry, San Andreas Fault-related tectonics, fluctuations in sea level, and changes in climate (Graham and Williams, 1985).

In the Los Angeles Basin the Monterey section is commonly referred to as the Phosphatic nodular shale or as the lower Mohnian part of the Puente Formation. In general, there was sufficient clastic "contamination" to prevent deposition of the thick section of pure pelagic and hemipelagic sediments that usually make up the Monterey. The biogenic and fine-grained clastic lithologies that typify the Monterey were deposited only in basin-margin positions during late Mohnian times due to coarse clastic deposition on prograding submarine fans across much of the basin floor.

Much of the Monterey section in all of the basins is a fine grained hemipelagic silt or mud. However, in some areas, particularly the San Joaquin Basin, important interbedded intervals of coarse and fine terrigenous clastic sediments were deposited as turbidites that can be distinguished as the Stevens Oil Zone reservoirs.

Petroleum accumulations are known from Monterey strata exhibiting all stages of diagenesis, however, production is widely recognized to be from naturally or hydraulically fractured reservoirs. Diatomaceous rocks generally do not tend to be brittle, so that more productive fractured reservoirs tend to be in more diagenetically mature sequences where silica is either opal-CT or quartz. Fracture abundance, given in decreasing intensity, is generally related to rock type in the Monterey: chert, porcelanite, dolostone, and marl (Belfield, et al. 1983).

Average porosity in Monterey reservoirs tends to be in the 10-30% range (Isaacs, 1984). Fractures are very important in connecting pores (Stearns and Friedman, 1972) and fracture-related permeability can be extremely high. Fracture permeability as great as 35 darcys have been estimated in the Santa Maria Valley field where initial production rates were commonly 2,500-10,000 BBL/day (Regan and Hughes, 1949).

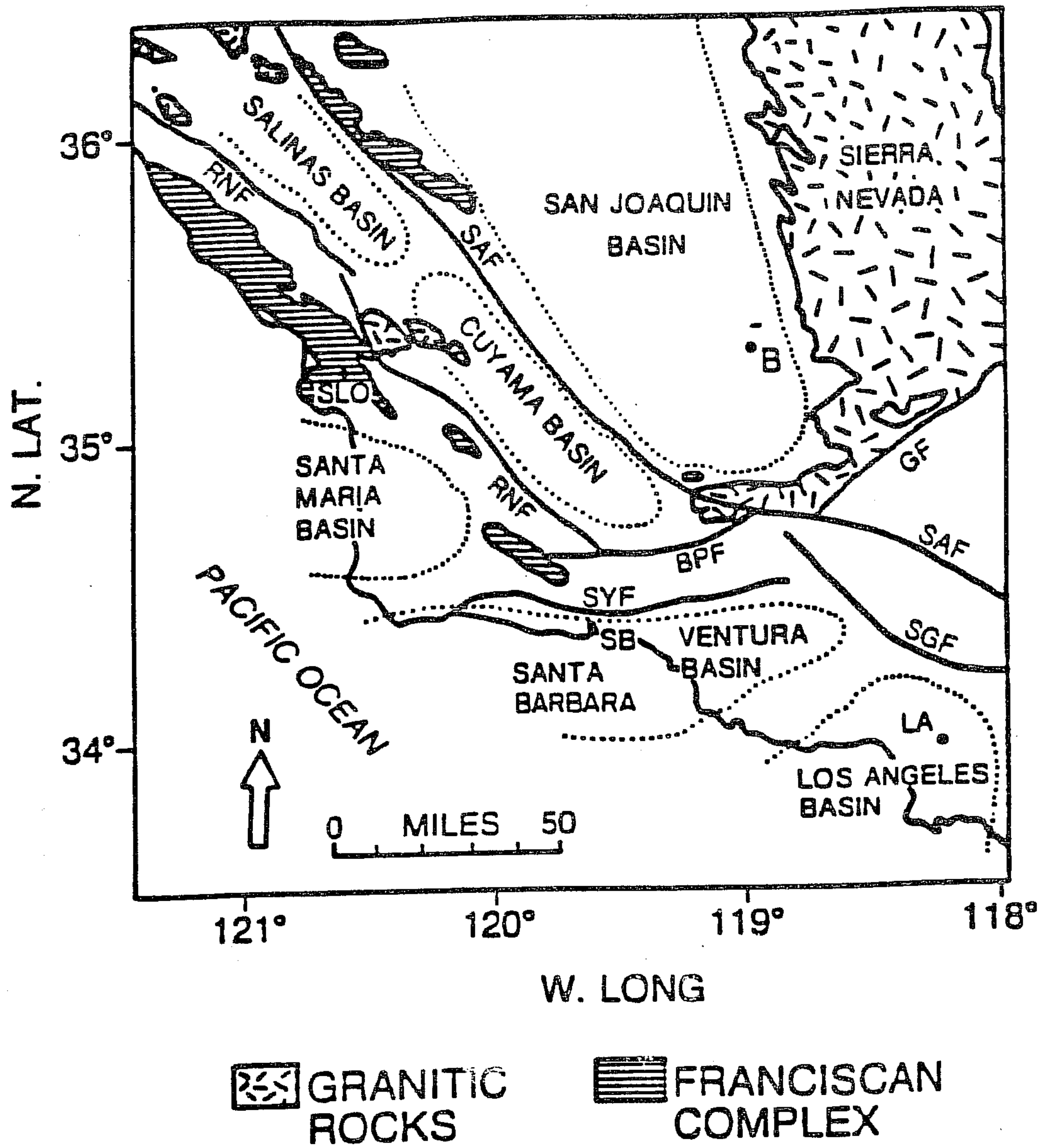


Figure III-1. Major basins in west-central California. Major faults include: R-NF, Rinconada-Nacimiento fault; SAF, San Andreas fault; BPF, Big Pine fault; SYF, Santa Ynez fault; SGF, San Gabriel fault; and GF, Garlock fault. Cities: B, Bakersfield, SLO, San Luis Obispo, SB, Santa Barbara; and LA, Los Angeles. From Lagoe (1984).

Monterey crudes are well known as high-sulfur (2.5-5%) oils with low gravities. Because oils with gravities as different as 8° and 23° may be produced from different horizons within the same field (Calif. Div. of Oil and Gas, 1974), Isaacs (1984) noted that many low gravity crudes produced onshore would be uneconomical to produce offshore. Lillis and Lagoe (1983) concluded that much of the geographical variability in oil gravities in the Santa Maria Basin is related to thermal history or timing of primary migration.

Puente Formation, California

The Puente Formation consists of interbedded turbidite sandstones and mudstones which are exposed in the Puente Hills. The formation attains a maximum thickness of nearly 4,000 meters (9,840 ft) and was deposited as a prograding submarine fan. Yerkes (1972) noted that intraformational breccias suggest that resedimentation including reworking of slump deposits was important within the Puente.

Puente submarine fan facies are similar to those described from other basins. The facies recognized by MacKinnon (1984) include conglomerate, thick bedded sandstones, classical turbidites, thinly bedded mudstones and sandstones and hemipelagic mudstones that correlate with submarine fan subenvironments A, B, C, D/E, and G of the Mutti and Ricci-Lucchi (1972) system (discussed elsewhere in this chapter). Paleocurrent indicators support a southwesterly trending fan. Foraminiferal faunas from all members of the Puente Formation indicate water depths at the time of deposition were greater than 500 m (1,600 ft) (Yerkes, 1972). For a submarine fan facies map and a reconstruction of the upper Mohnian submarine fan facies of the Los Angeles Basin see Redin (1991).

Puente sands from the Long Beach Unit of the giant Wilmington Field are moderately to poorly sorted and rich in feldspar and biotite (Henderson, 1987). Shales are variably indurated, and also micaceous, but become siltier up section. The Ranger zone sands (Puente Formation) have good porosities and permeabilities that appear to vary with depositional facies, suggesting a lithologic control on reservoir quality (Slatt, et al. 1988).

Repetto Formation, California

Lower Pliocene sediments from prograding submarine fans of the northeastern portion of the Los Angeles Basin are known as the Repetto Formation. Within the subsurface, the Repetto Formation is also less commonly known as the lower Fernando Formation (Blake, 1991; Redin, 1991).

During deposition of the Repetto Formation, the Los Angeles Basin continued to receive sediments by hemipelagic and pelagic sedimentation, mass sediment gravity slides and slumps, and mass sediment gravity or density flows, as it had during deposition of the Puente Formation. A major difference during Repetto Formation deposition was the higher influx rate of coarse-grained clastics which caused the pelagic and hemipelagic sediments to become volumetrically less important (Redin, 1991). Consequently, the Repetto Formation is commonly very sandy or conglomeratic and sediment density flows including turbidity flows were the predominant mechanism of sediment transport.

Most of the major oil fields in the Los Angeles Basin produce from sandstones and conglomerates of the Repetto Formation submarine fans. About one-half of the cumulative production to date has come from the Repetto Formation (Redin, 1991).

Repetto sediments in the Ventura Field (Ventura Basin) consist of a structurally-complicated conformable sequence of sands, silts and shales, more than 5,000 ft thick (Hsu, 1977). In the Ventura Basin the Repetto Formation was deposited in a deep basin setting that was subsequently folded into an anticline to form the Ventura Field. Facies relationships indicate that the sands were deposited as elongate lenticular bodies by laterally restricted westerly flowing currents in the deeper parts of the basin. Resulting sand trends are oriented predominantly parallel with the axis of the present anticlinal structure. Much of the terrigenous sediments were carried downslope by currents that flowed within submarine canyons on the sides of the basin before they were deflected into a westerly direction parallel with the basin axis. Hsu concluded from these relations that a major control on sand deposition was by the topographic relief of the basin floor. Most sediments were carried down the submarine canyons by turbidity currents that were channeled by the submarine canyons.

Within the Repetto Formation at Ventura Field the amalgamation of many graded beds forms apparently massive sand sequences more than 100 ft thick. Correlation of individual graded beds which are usually less than 30 feet thick is difficult.

Reservoir and Production Characteristics

Reservoir Properties

Analysis of reservoir and production data was conducted for eight individual plays within slope-basin reservoirs to present examples of reservoir properties of this group of reservoirs. The following plays were selected on the basis of sufficient data for meaningful statistical analysis: 1) Upper Pennsylvanian Slope sands (17 reservoirs) in the Midland Basin in Texas; 2) Spraberry/Dean sands (14 reservoirs) in the Midland Basin in Texas; 3) Delaware sands (18 reservoirs) in the Delaware Basin in Texas; 4) Stevens Turbidite sands (20 reservoirs) in California; 5) Puente Turbidite sands (33 reservoirs) in California; 6) Repetto Turbidite sands (27 reservoirs) in California; 7) Repetto/Puente Turbidite sands (24 reservoirs) in California; and 8) Monterey fractured siliceous shale (11 reservoirs) widespread in coastal California. The median values of formation and production properties of above eight geological plays are listed in Table III-1.

Comparison of distributions of porosity, depth, net pay, oil gravity, original oil-in-place, and ultimate recovery factor of these eight plays are shown in Figures III-2 to III-7. Four turbidite plays of slope-basin reservoirs in California have similar porosity, net pay, and oil gravity in comparison to the three plays in Texas. Figures III-5b and III-5c show distributions of oil gravity of Texas and California slope-basin and basin plays, respectively. Texas plays produce only light oil while California plays produce both heavy oil and light oil. The Puente, Repetto, and Repetto/Puente sands produce relatively heavy oil with median oil gravity around 20° API, Stevens sands produce oil with median gravity of 30° API, while three Texas plays produce light oil of about 40° API (Figure III-5a). The California turbidite plays have higher porosity values and thicker net pays than Texas plays (Table III-1, Figure III-2 and III-4). The mean net-pay thickness of California plays (190 ft) is one order of magnitude greater than that of Texas plays (16 ft).

The initial oil saturation values are similar (60.5 to 74.5%) among the eight plays. With the exception of the Delaware play, the ratios of gross-pay to net-pay range from 2 to 3 indicating significant layering of pay and non-pay rocks in these reservoirs. Due to the thick pay, turbidite plays have significant oil reserves with median OOIP ranging from 87 to 180 MMBBL per reservoir. The Monterey play has an OOIP of 373 MMBBL. Among the three plays in Texas, Spraberry/Dean sands have a significantly higher OOIP of 141 MMBBL per reservoir whereas Upper Pennsylvanian Slope sands and Delaware sands have only 19 and 22 MMBBL, respectively.

TABLE III-1
Median Values of Reservoir and Production Data of Slope-Basin and Basin Plays listed in the TORIS database.

	All Plays Studied	*Upper PA*	*Spraberry /Dean*	*Delaware*	*Stevens*	*Puente*	*Repetto*	*Repetto/ Puente*	*Monterey*
Number of fields	210	17	14	18	20	33	27	24	11
Net pay, ft	122	15	30	15	130	206	150	228	300
Gross pay, ft	300	40	43	17	300	428	300	600	1000
Depth, ft	4391	4325	7350	4085	5550	3738	2867	2800	3487
API gravity	29	41	38	41	30	21	23	18	15
Initial oil saturation, %	69	63	65	61	62	71	70	75	63
Porosity, %	25	15.5	14	22	24.4	28	30	31	33
Original oil-in-place, MMBBL	72.15	19.00	140.94	22.42	88.96	138.50	86.71	180.46	373.65
Cumulative production, MMBBL	22.64	71.10	12.79	5.77	28.16	34.76	28.77	53.74	57.39
Ultimate recovery factor	0.30	0.31	0.14	0.24	0.31	0.33	0.31	0.32	0.21

Abbreviation of the plays are as follows: Upper PA= Upper Pennsylvanian Slope sands in the Midland Basin, TX; Spraberry/Dean=Spraberry and Dean sandstones in the Midland Basin, TX; Delaware=Delaware Mountain Group sands in the Delaware Basin, TX; Stevens=Stevens Oil Zone in California; Puente=Puente Formation in California; Repetto=Repetto Formation in California; Repetto/Puente=combined Repetto and Puente Formation reservoirs in California; and Monterey=Monterey Formation in California.

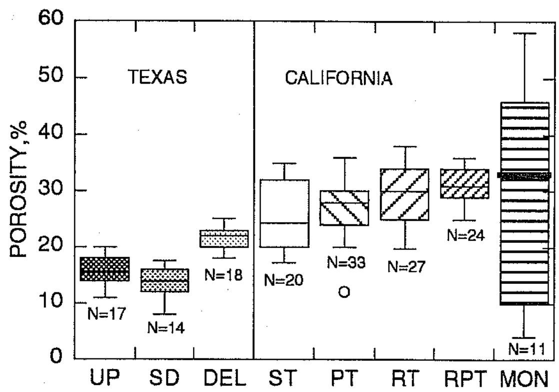


Figure III-2. Porosity of eight plays in the Slope-Basin reservoirs listed in the TORIS database. The y-axis displays the range of the data and the x-axis displays the name of geological plays (UP = Upper Pennsylvanian, SD = Spraberry and Dean Formations combined, DEL = Delaware, ST = Stevens Sand, PT = Puente Formation, RT = Repetto Formation RPT = Repetto and Puente Formations combined, MON = Monterey). See text for explanation of symbols.

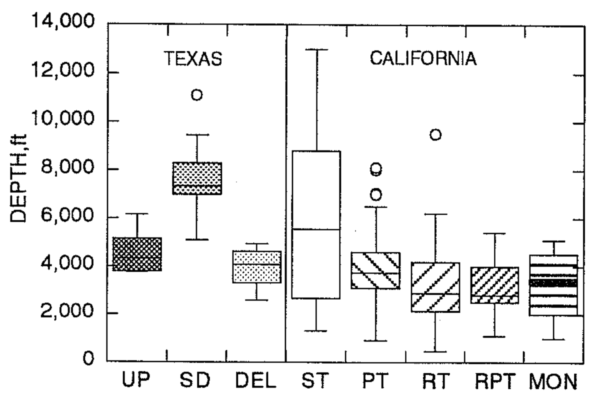


Figure III-3. Reservoir Depth of eight plays in the Slope-Basin reservoirs studied. (For explanation of abbreviations, see Figure III-2).

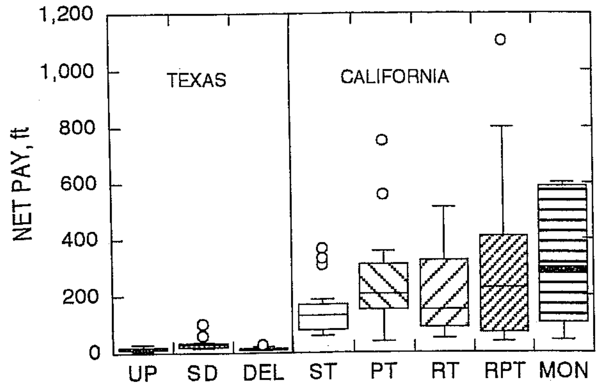


Figure III-4. Net Pay of eight plays in the Slope-Basin reservoirs studied. (For explanation of abbreviations, see Figure III-2).

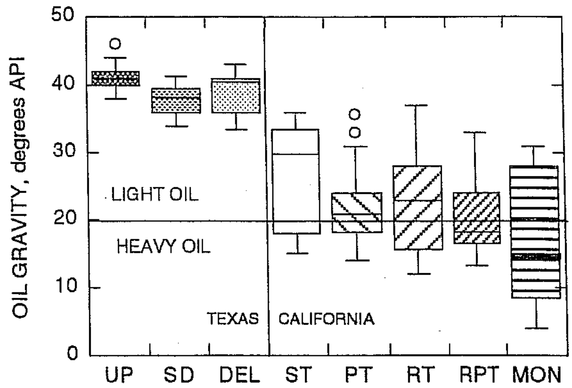


Figure III-5a. Oil Gravity of eight plays in the Slope-Basin reservoirs studied. (For explanation of abbreviations, see Figure III-2).

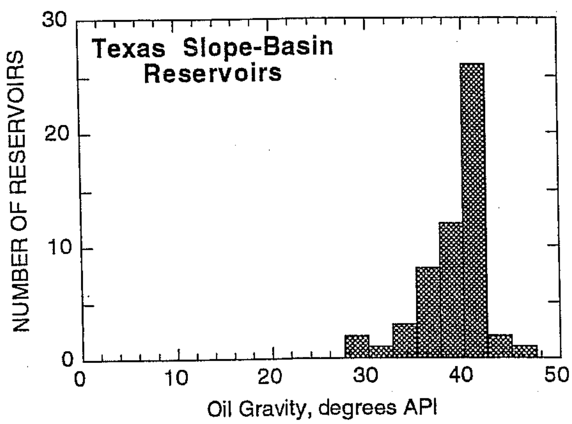


Figure III-5b. Histogram of Oil Gravity from the Texas Slope-Basin reservoirs in the TORIS database.

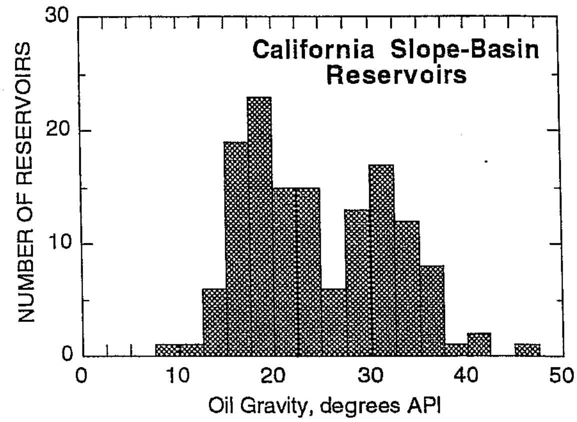


Figure III-5c. Histogram of Oil Gravity from the California Slope-Basin and Basin reservoirs in the TORIS database.

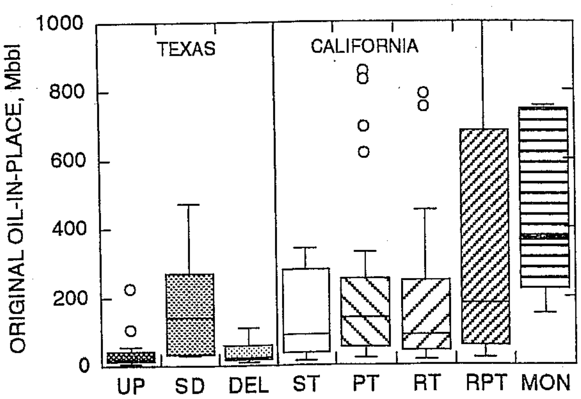


Figure III-6. Original Oil-in-Place of eight plays in the Slope-Basin reservoirs studied. (For explanation of abbreviations, see Figure III-2).

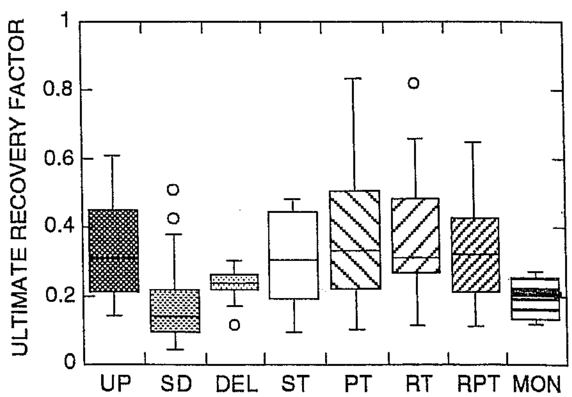


Figure III-7. Ultimate Recovery of eight plays in the Slope-Basin reservoirs studied. (For explanation of abbreviations, see Figure III-2).

The Spraberry/Dean sands in Texas are quite different in reservoir properties from other plays analyzed. Spraberry/Dean sands have a tremendous volume of oil-in-place (median 141 MMBBL), however, the low porosity (14%) and corresponding low permeability, severely limits recovery from these sands. Among the eight plays analyzed, the Spraberry/Dean sands have the lowest ultimate recovery (14% OOIP), and are deeper (7,350 ft) than other slope-basin plays (2,800 to 5,550 ft). The low permeability and solution-gas drive mechanism common in these reservoirs severely limit recovery. In solution-gas drive reservoirs, reservoir pressures decline rapidly and continuously resulting in lower oil recovery than reservoirs with gas cap or water drive. Fractures associated with folds appear to improve recovery, particularly in poor, thinly interlaminated Spraberry/Dean sandstone and siltstone reservoirs (Galloway, et al. 1983).

The Monterey play has the thickest net pay (300 ft), highest porosity (33%), highest OOIP (373 MMBBL), and cumulative recovery (57.4 MMBBL) among the eight plays. The 11 reservoirs of Monterey play analyzed show wide distributions in rock properties due to different facies. The porosity of the Monterey play ranges from less than 10% to more than 40% with a median of 33%.

Heavy oil reservoirs generally require small well spacing for efficient production due to the high oil viscosity. Compared to the larger well spacing, the smaller well spacing provides a greater pressure gradient which may overcome the high fluid viscosity in heavy oil production. For the reservoirs listed in the TORIS database, 10-acre well spacing is common among all slope-basin reservoirs producing <28° API oil. For oil of 28° API or greater, 40- and 20-acres well spacing are typical, however well spacing as large as 160-acres is adopted occasionally.

Class III reservoirs have a median ultimate recovery factor of 30.4% OOIP (Table III-1, Figure III-7). Among the plays analyzed, the Puente Formation reservoirs have the best ultimate recovery factor (33.3%). The Spraberry/Dean, Monterey, and Delaware Formation reservoirs perform relatively poorly as indicated by the ultimate recovery factor with median values of 14.2%, 20.6% and 24%, respectively. The fine texture of the Delaware sands results in moderate to low permeability, and pay zones are highly lenticular and stratified, which may explain the poor ultimate recovery.

Injection patterns in the Spraberry/Dean sands were modified to parallel the regional northeast-southwest fracture system (Barfield, et al. 1959; Guidroz, 1967). Utilizing end effects of capillary pressure, cyclic waterflooding was developed to accelerate the oil production from the rock matrix of Spraberry sands. Field performance (Elkins, 1953) proved this cyclic waterflood was capable of producing oil from the matrix at least 50% faster and with lower water cut than is imbibition of water at continuous waterflood.

Slope and Basin Deposition

Physiographic Setting

The slope and basin extends from the seafloor shelf break to the abyssal or basin plain (Figure III-8). It includes both the slope proper (the region generally of steepest gradient defined as greater than 1:40 or 1.5° by Heezen, et al. (1959) and the adjacent slope rise and deep-sea fan environments that commonly separate the lower slope margins from the basically flat deep-sea plains.

The continental slope begins at the break in slope at the outer margin of the continental shelf that begins between 150-1000 ft (45-300 m) below sea level. The slope is generally inclined between 3 to 6°(Shepard, 1973), but locally increases to values in excess of 15°, especially on the walls of submarine canyons. Gradients on the continental rise are generally less than 1:40 (Figure III-8) and decrease basinward. The surface gradient of major deep-sea fans is generally comparable with that of the continental rise. The depth of the slope-rise boundary is variable, averaging 4,000 m on Pacific margins and around 3,000 m on Atlantic margins (Shepard, 1973).

The environments of the continental slope may be divided into two groups, the slope proper and the base of slope. The continental slope proper often possesses the most irregular topography of all the continental margin settings. Such irregularities were ascribed by (Kelling and Stanley, 1976) to four principal factors (erosion, deposition, diastrophism, and slumping) which may act independently or in concert to produce the most distinctive topographically negative features of the slope, large submarine canyons. Although seismic profiles generally indicate an erosive nature of the canyons, many appear to have formed from a combination of erosion and deposition (Rona, 1970; Shepard, 1973). Other features that are common to many slopes include gullies smaller than submarine canyons. Most slope gullies are on the prograding front of modern or ancient deltas which are building into deep water (e.g. off of the Mississippi Delta).

Most slopes are cut at many places in their upper parts by submarine canyons that connect to deep sea fans. These fans build significant sediment bodies onto lower slopes, continental rises, the abyssal plain, and even within trenches (Bouma, 1979). The upper slope today is typically an area of non-deposition, with only local progradation and canyon filling (Galloway and Hobday, 1983). The most important subenvironments of the base-of-slope are submarine fans, fan valleys, distributary channels, and suprafan lobes (Figure III-9) Submarine fans (or sediment cones if the deep sea fans are associated with major active deltas) are generally envisioned as subarcuate wedges of sediment. Most submarine fans are characterized by flat-floored fan valleys leading directly from submarine canyon mouths at the base of slope and are generally bordered by levees (Normark, 1970a). A more detailed description of fan types is given below.

Modern oceanic margins may be divided into three major categories that have implications for deposition on continental slopes (Inman and Nordstrom, 1971; Kelling and Stanley, 1976). First are tectonically active margins which have narrow shelves and relatively steep, fault-defined slopes, that often display a stepwise configuration. Although wide continental margins are rare, localized deep-sea fans are frequently found. True subduction margins are flanked by deep trenches while trenches are normally lacking off margins defined by transcurrent (or tensional) faults. The western coast of North America is a typical example of the latter type of margin.

The second type of margins are passive margins that are generally represented by wide shelves, prograding slopes of moderate gradient, and wide, laterally extensive continental rise wedges. The eastern margin of the United States and the continental edge of northwestern Europe are examples of this type of ocean basin margin.

The third type of margins, buttressed margins, are less well defined in physiographic terms. They are generally characterized by very wide and shallow shelves with a thick sediment cover (e.g. South China Sea). Continental slopes on these types of margins frequently have a very low gradient that is sometimes modified by salt diapirs (e.g. northern Gulf of Mexico).

Ancient cratonic basins, in contrast to modern continental shelf margins, may never have had well-developed shelf/slope breaks or slopes that extended into thousands of feet of water. In that case the systems must be recognized based on more than depth or steep original dip. Useful criteria include facies associations and their vertical and lateral context, as discussed below.

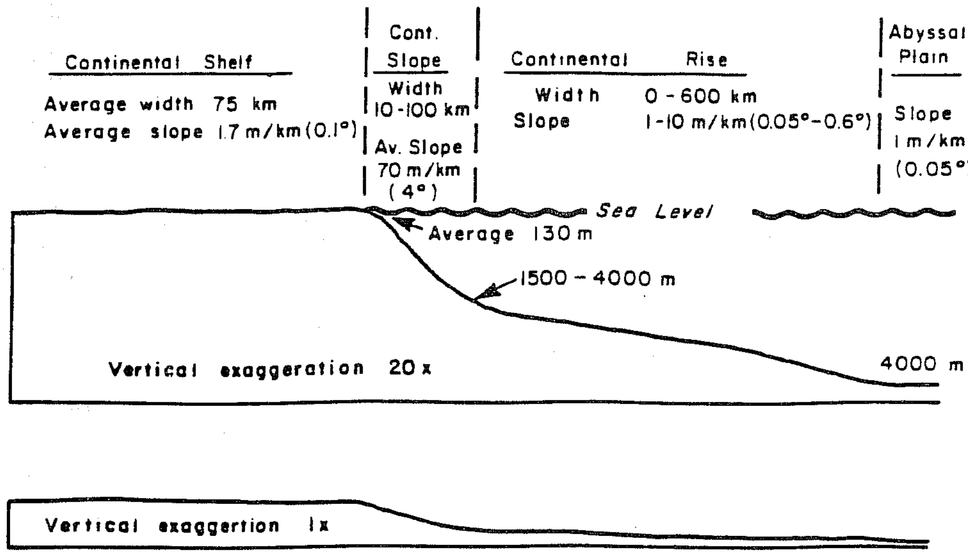


Figure III-8. The principal elements of a continental margin. Modified from Drake and Burk (1974). Taken from Cook, Field, and Gardner (1982).

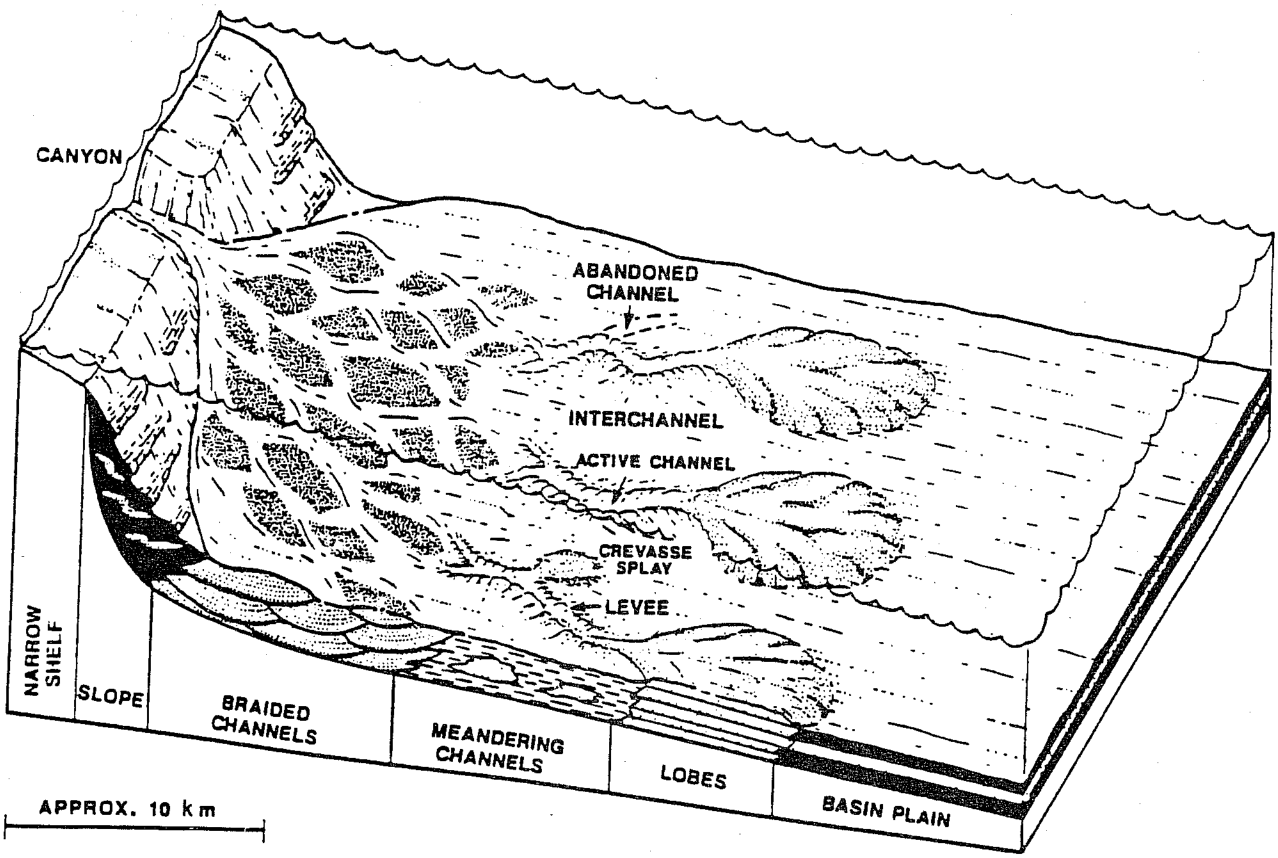


Figure III-9. Schematic view of an active-margin fan with channel-mouth lobes. These lobes may be classified as suprafan lobes. From Shanmugam, et al. (1988) and Shanmugam and Moiola (1991).

Mass Transport

The dominant depositional process in slope-basin environments is mass transport. The term mass transport (defined by Cook, Field, and Gardner, 1982) encompasses the *en masse* downslope movement of material containing various amounts of water and for which gravity provides the driving force. There is an extensive literature about mass transport mechanisms, including the papers listed in Middleton and Hampton (1973) and Cook, Field, and Gardner (1982).

Mass transport can be divided into three types: rockfalls, slides, and sediment gravity flows (= "mass flow"). Slides and sediment gravity flows can be further subdivided on the basis of internal mechanical behavior and dominant sediment support mechanisms.

Rockfall. This process refers to the freefall and rolling of individual blocks along steep slopes. Deposits are referred to as talus accumulations (Cook, Field, and Gardner, 1982).

Slides. Slides can be divided into translational (glide) and rotational (slump) types (Varnes, 1978). Shear planes in translational slides are mainly along planar or gently undulating surfaces that are sub-parallel with underlying beds. Shear planes of slumps are concave-upward.

Sediment Gravity Flows. Sediment gravity flows, are classified by the nature of the dominant sediment-support mechanism. In the case of debris flows, the sediment and water have finite strength and their dominant internal mechanical behavior is plastic. Grain flows behave either as a plastic or a fluid. Liquefied flows, fluidized flows, and turbidity flows are considered to behave mainly as fluids where the sediment-water mixture has no internal strength.

In sediment flows, more than one mechanism will be important (Middleton and Hampton, 1973), so that the name given to a particular deposit reflects the interpreted dominant transport mechanism. In addition, other mechanisms, such as traction, may operate during the last stages of deposition and modify some of the structures and textures of the final deposit. Mass transport processes are an area of active research and rapid change of information.

Turbidite Facies

Gravity-driven density currents that are due to dispersed, suspended sediment in the current are known as turbidity currents (Middleton, 1969). Turbidites are deposits created by turbidity currents (Walker and Mutti, 1973; Walker, 1984a). Turbidity currents and their deposits are commonplace in modern ocean basins and turbidites are common deposits in ancient basin settings.

These deposits are both extensive and volumetrically significant. In addition to deposition along continental margins, ancient turbidites may also have been deposited in some epeiric seas, lakes, block faulted continental borderlands, and elongate intracratonic troughs as well as the more widely recognized "deep water" habitat of modern submarine fans and basin plains. (Walker and Mutti, 1973; Walker, 1984a).

Very little is known about turbidite flow velocities. Fortunately, submarine cable breaks caused by a turbidite triggered by the Grand Banks earthquake of 1929 were well documented. Uchupi and Austin (1979) calculated velocities of 20.3 m/sec at the cable broken 183 minutes after the quake and 11.4 m/sec at the cable broken 13 hours 17 minutes after the earthquake. The Grand Banks turbidite appears to have traveled several hundred kilometers across the essentially flat Sohm Abyssal Plain. Walker (1984a) lists potential triggering mechanisms for turbidites as earthquakes, spontaneous failure or rapid deposition, and sediment liquifaction by cyclic wave loading.

The Bouma sequence, proposed by Bouma (1962), (Figure III-10) is considered the "classical" turbidite model that basically consists of a waning flow model. This classical deposit may be identified by a surprisingly short list of descriptors (Walker, 1984a): 1) Sandstones and shales are monotonously interbedded through many tens or hundreds of meters of stratigraphic section. Beds tend to have flat tops and bottoms, with no scouring or channeling on a scale greater than a few centimeters; 2) Sandstone beds have sharp, abrupt bases, and tend to grade upward into finer sand, silt and mud; 3) Abundant markings, classified as tool marks, scour marks, and organic markings filled in by the turbidity current are present on the undersurface of the sandstone; 4) Within the sandstone beds, combinations of parallel lamination, ripple cross lamination, climbing ripple cross lamination, convolute lamination and graded bedding have been noted by many authors.

According to Walker and Mutti (1973) the most important criteria used to subdivide turbidite and associated resedimented beds include:

1. Grain size.
2. Bed thickness and sand/shale ratios.
3. Bedding regularity, presence or absence of channels.
4. Sole mark assemblages.
5. Internal structures and textures
    a. Conglomerate pebble fabrics, presence or absence of grading
    b. Massive bedding in sands, with or without dish structures.
    c. Variations in the Bouma sequence, particularly recognition of beds beginning with divisions B or C.
6. Paleoecological indicators.

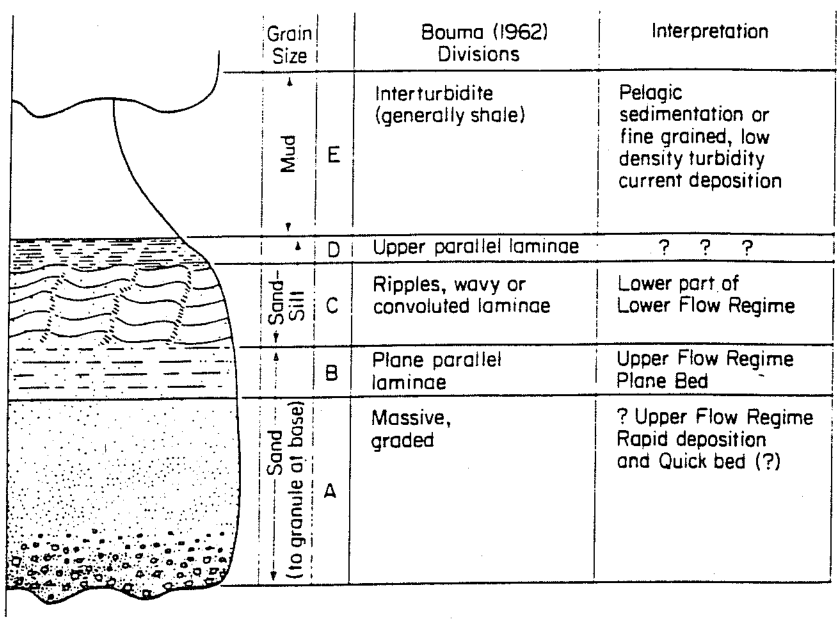


Figure III-10. Ideal sequence of structures in a turbidite bed. This sequence is called a Bouma sequence after the man who first recognized it. After Bouma (1962) with interpretation from Walker (1965) and Middleton (1967). Taken from Blatt, Middleton, and Murray (1972).

General Turbidite Facies Classifications

The brief description of turbidites given above applies to what can be termed "normal" or "classical" turbidites, i.e. those that can be reasonably well described by the Bouma sequence (Bouma, 1962; Walker and Mutti, 1973). However, not all turbidite sediments are encompassed by the turbidite model of Bouma (Mutti and Ricci Lucchi, 1972) and there are a number of resedimented deposits associated with normal turbidites that cannot be described using the Bouma sequence. These include:

Massive Sandstones: These lack interbedded shaly interbeds, commonly contain "dish" structures, and are believed to be the deposits of fluidized sediments flows or grain flows (see Lowe, 1976).

Coarse Massive and Pebbly Sandstones: These are very irregularly bedded commonly scoured, and ungraded. Such beds have been called fluxoturbidites, indicating a poorly defined transport process transitional between turbidity currents and watery slides or slumps (Dzulynski, et al. 1959).

Clast-Supported Conglomerates: These can be either massive and lacking any internal structure, or they can be stratified, with distinct clast orientation and imbrication indicating deposition from turbulent flows.

Matrix-Supported Beds: These facies include a diverse group of poorly to unstratified rocks which are commonly unsorted and show evidence of deformation. Included are slumps, slides, debris flows, and other exotic facies. For more detailed discussion (see Walker, 1978, 1984a and b).

Another system of turbidite classification that has shown great promise through widespread application was brought forward by Mutti and Ricci Lucchi (1972) based on studies of thick turbidite successions in the northern Apennines, Italy. The Mutti and Ricci Lucchi scheme has been modified over the years (Mutti and Ricci Lucchi, 1975; Mutti, 1979), however their basic classification of turbidites and related facies has remained essentially the same. A useful summary of the Mutti and Ricci Lucchi system modified by Walker and Mutti (1973) is presented in Table III-2.

Mutti and Ricci Lucchi system (facies A-G) divided the common turbidite facies of the northern Apennines into the following facies (Figure III-11):

A. Arenaceous-conglomerate facies
B. Arenaceous facies
C. Arenaceous-pelitic facies
D. Pelitic-arenaceous I
E. Pelitic-arenaceous II

Pelitic indicates muddy or shaly lithology.

Intercalated with Facies A-E are associated facies that are not strictly turbiditic, such as those related to submarine landslides, or otherwise deformed beds, and those related to "normal" sedimentary mechanisms, particularly the basinal rain of pelagic or hemipelagic fines. The associated facies include:

F. Chaotic facies
G. Hemipelagic and pelagic facies.

Brief descriptions and interpretations of the various turbidite facies according to the Mutti and Ricci Lucchi (1972) scheme follows.

TABLE III-2

Basic classification of turbidite and other resedimented facies based upon Mutti and Ricci Lucchi (1972) and Walker (1967, 1970). From Walker and Mutti (1973).

BOUMA SEQUENCE NOT APPLICABLE	FACIES A -- Coarse grained sandstones and conglomerates A1 Disorganized conglomerates A2 Organized conglomerates A3 Disorganized pebbly sandstones A4 Organized pebbly sandstones. FACIES B -- Medium-fine to coarse sandstones B1 Massive sandstones with "dish" structure B2 Massive sandstones without "dish" structure.
BEDS CAN REASONABLY BE DESCRIBED USING THE BOUMA SEQUENCE	FACIES C -- Medium to fine sandstones -- classical proximal turbidites beginning with Bouma's division A. FACIES D - Fine and very fine sandstone, siltstones - classical distal turbidites beginning with Bouma's division B or C. C-D FACIES SPECTRUM -- can be described using the ABC index of Walker (1967). FACIES E -- Similar to D, but higher sand/shale ratios and thinner more irregular beds.
BOUMA SEQUENCE NOT APPLICABLE	FACIES F -- Chaotic deposits formed by downslope mass movements, e.g. slumps. FACIES G - Pelagic and hemipelagic shales and marls - deposits of very dilute suspensions.

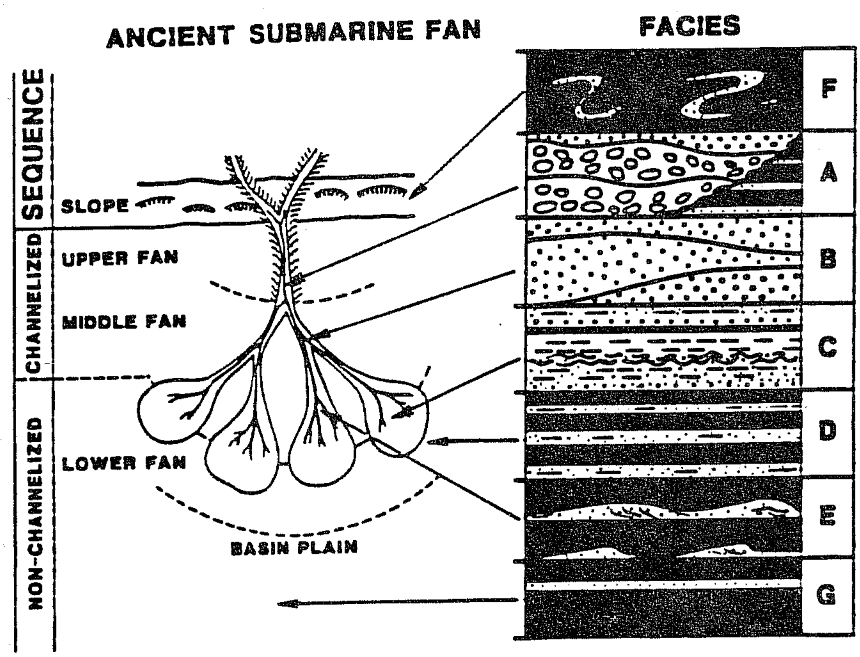


Figure III-11. Diagrammatic scheme of major submarine fan environments and turbidite facies associations. Facies nomenclature is from Mutti and Ricci Lucchi (1972). From Shanmugam, Damuth, Moiola (1985).

A. *Arenaceous-conglomeratic facies*

This facies is characterized by beds and strata of medium- to very coarse-grained sandstone with locally sparse pebbles and true conglomerates. The thickness of single beds ranges from one to more than ten meters; bedding contacts are flat-parallel, flat-concave, bioconvex or irregular, and are commonly clearly defined but recognizable only by close examination of grain size variations or alignment of intraformational clasts. Lateral extent of beds is limited to several tens or hundreds of meters, and the lateral variations in thickness are frequent and abrupt with very abundant erosional channels and interdigitation of beds. Sand/shale ratio is very high and intercalated pelitic (muddy) layers are commonly reduced to discontinuous partings or are completely lacking. Internal structures in these beds are generally limited to grading that is evident in the coarser fraction or over the entire range of grain sizes.

B. *Arenaceous facies*

This facies is characterized by fine to coarse sandstones (finer than facies A) with relatively more interbedded argillaceous layers. Dish structures may or may not be present. These sandstones occur in thick, massive lenticular beds, however, they are more laterally continuous than those of facies A.

These bedded sandstones are deposited from grain flows, however, in this case, during the process of deposition there is tractive action on the sand particles. The structure and fabric of these sandy beds indicates upper-flow regime, particularly that of antidunes.

It should be noted that Bouma sequences are not applicable to accumulations of facies A or B, nor to facies F or G described below.

C. *Arenaceous-pelitic facies*

Facies C contains turbidites of the classical sense. Facies C contains medium to fine sandstone turbidites that begin with Bouma division A (see Figure III-10). Beds tend to be sharp and flat based, regularly bedded, and with good lateral bedding continuity. The sandstones range from about 10 cm to 1 m in thickness and have typical sand/shale ratios of about 5:1. Each sandstone tends to grade up into a shaly division (Bouma E). These are the classical proximal turbidites of Walker and Mutti (1973).

D. *Pelitic arenaceous facies I*

Facies D also contains classical turbidites that can be described using the Bouma sequence, but normally the base divisions (Bouma A and commonly B divisions) are missing. Bases of beds are sharp and flat. Grading is prominent. Grain sizes tend to be in the fine sand to silt range with bed thicknesses ranging from about 1-10 cm. Sand/shale ratio is low (1:1) or less. Local biological activity may be sufficient to disrupt bedding completely so that homogenized massive siltstone results. These BCDE, BDE, and CDE divisions (Bouma, 1962) represent "distal" turbidites of Walker (1967) that may be deposited on the lower fan, basin plain, or laterally in overbank positions equivalent to channelized proximal turbidites.

E. *Pelitic-arenaceous facies II*

Although similar to facies D, facies E has 1) higher sand/shale ratios (near or greater than 1:1), 2) coarser grain size and less well sorted, 3) thinner, more irregular beds and 4) more discontinuous beds with wedging and lensing. Commonly, tops of sandstone intervals are not graded, but are in sharp contact with overlying shales.

F. Chaotic facies

This facies contains all beds that have been transported downslope by mass movement after deposition. Deposits assigned to this facies should show clear evidence of having been previously deposited elsewhere in the basin and evidence of having been remobilized and moved en masse to the present location. Thus landslide beds, slumps, olistostromes, olistolites, and slump breccias would belong to facies F, but mud flows and sand flows would probably deposit beds assigned to facies A or B. Pebbly mudstones are hard to fit into a facies scheme as some might belong in facies F, but others might belong to facies A or G.

G. Hemipelagic and pelagic facies

Facies G consists of pelagic and hemipelagic shales and marls, either silty or calcareous, with indistinct and poorly-developed lamination, or distinct, even parallel bedding. Stratigraphic position is important- in many basins facies G occurs immediately before and/or after turbidite sedimentation, and also may accompany it as intercalations between two major turbidite sequences.

Major Depositional Systems

Slopes subjected to terrigenous clastic influx may be divided into three distinct but interrelated morpohogenic types according to Galloway and Hobday (1983): submarine aprons, submarine rise prisms, and submarine fans. Of these only the submarine fans show distinct environmental subdivisions.

Submarine Aprons

Mass waste deposits (a general term for gravity-driven down slope movement of large masses of rock and sediment) of the upper slope and shelf edge that are supplied by slumping and debris flows that may or may not terminate before reaching the basin floor are called submarine aprons (Galloway and Hobday, 1983). Most of the slumps that supply the submarine apron, however, are small, locally distributed, and only intermittently active. Because slump-generated turbidites are randomly interbedded with debris-flow deposits, the internal organization of submarine aprons is chaotic.

The Quaternary slope apron of the Gulf Coast is typified by low sand content deposits consisting of pelagic mud drapes, layered turbidite sequences and chaotically-bedded slumped tongues (Woodbury, et al. 1978).

Current-Molded Submarine-Rise Prisms

Contourites are particularly evident on the western margins of some ocean basins where they contribute significantly to the continental rise. The "rise prism" or contourite deposits off Cape Hatteras are dominantly silt and clay comprising bedforms with heights of 10-100 m and wavelengths of up to 12 km, and have steeper south-westward slopes that correspond to the flow direction of the bottom-hugging contour current in the western Atlantic (Rona, 1970; Bouma and Hollister, 1973). Because of their position within basins, contourites may provide significant late-stage modification of the upper portions of distal submarine fan deposits developed on western basin margins.

Submarine Fans

It has long been recognized that "depositional fans" represent dominantly turbidity-current material deposited as the result of a decrease in slope at the mouths of submarine canyons (Menard, 1955). Growth pattern of submarine fans was first described by Normark (1970b) based on detailed study of only two modern (and relatively small) fans, La Jolla and San Lucas fans off the Pacific coast of North America. A detailed review of modern submarine fans was given by Normark (1978) and a general model for facies distribution on submarine fans was presented at the same time by Walker (1978). Shortly after the Normark (1970b) paper important reviews of Italian ancient submarine fans were presented (Mutti and Ghibaudo, 1972; Mutti and Ricci Lucchi, 1972; and others) that promoted fan models similar to that which Normark had derived from modern sediment studies. Until very recently this single fan model has been used as the basis for determining facies relations, fan stratigraphy, and sand-body prediction.

In the sections below, the general fan model based primarily on modern fans will be described, significant variations in the model will be outlined, and the problem of comparing modern with ancient fans will be briefly discussed.

General Fan Model

Three distinct divisions of the fan are widely recognized (see Figure III-11): 1) upper fan, characterized by leveed fan valleys, 2) middle fan, where rapid deposition at the terminus of the leveed valleys builds a suprafan, 3) lower fan, which is not channeled and is free of major topographic relief. The relative proportion of the fan surface comprising each division is highly variable and is a product of basin shape and type and rate of sediment supply. Fan divisions described below are based on generalities extracted from studies of many fans (Normark, 1970a).

Upper Fan. Because most deep sea fans have a single submarine canyon, the upper fan is fed by one active depositional valley or feeder channel that is continuous with the canyon. Depositional valleys (opposed to incised, erosional channels) are characterized by prominent levees and the valley floors are commonly elevated above the surrounding fan surface. The leveed-valley complexes may be extremely large. For instance, on the Bengal fan, the complex is about 100 km wide and 500 m in thickness (Normark, 1970a). Upper fan channels are also proportionately large. The single meandering channel on the upper Rhone fan is 2-5 km across, and is flanked by levees up to 75 m high (Bellaiche, et al. 1981).

There appears to be a rough proportionality between the dimensions of the depositional valleys of the upper fan and the overall size or fan radius. Normark reported that both the width of the leveed valley complex and the cross-sectional area of the valley both increase with increasing fan size. This relationship excludes fan valleys that have been extensively modified by significant erosional downcutting. The relationship between upper fan valley size and overall fan size may be used for exploration purposes, but further quantification of dimensions is difficult (Normark, 1978).

During aggradational stages of deposition thick, coarse sands and gravels are characteristic of the upper fan (Normark and Piper, 1972; Nelson, 1976; Walker 1978). Lateral migration of the valley-floor channels may lead to undercutting and slumping of the finer grained sediments of the valley walls.

Active depositional channels are filled with sandy sediments that decrease in sand content, as do the levees, with increasing distance from the valley axis. Levees of the upper fan channel tend to be composed of fine-grained alternations of thin sandstone beds and mudstones of thin-bedded turbidite origin. Ancient examples of the levee facies could be confused with similar facies on the basin plain (Walker, 1978).

Holocene green muds of hemipelagic origin blanket the surface of many modern submarine fans, including channels, levees, and upper fan interlobe areas (Normark and Piper, 1972; Nelson and Kulm, 1973, Damuth and Kumar, 1975). These mud blankets may be deposited during rising sea levels associated with temporary abandonment of terrigenous clastic sediment supply, create up-section and updip seals, and complicate overall fan stratigraphy.

Feeder channels, or submarine canyons, act mainly as conduits to transport sand and gravel down the fan. The canyons may be plugged by conglomeratic sands, slumps, or debris flows, or by clays or mudstones. As mentioned above, deposition of fines during relative sea level rises cut the fan off from its original source of clastic sediments (for example, the Mississippi fan, Bouma, Stelting, and Coleman, 1985).

Middle Fan. The middle fan can be distinguished by a depositional bulge that appears convex-up in radial profiles of modern fan surfaces. This feature, which is present at the terminus of the major active valley on the upper fan, was termed the suprafan by Normark (1970a). The middle fan is characterized by shifting suprafan lobes.

The suprafan is characterized by numerous unleveed distributary channels (or channel remnants) that develop as a result of rapid migration and deposition within the distributary system. Suprafan development is thought to depend upon such variables as the local bottom slope and the rate and grain size of sediment supplied through the valley on the upper fan. In some cases, little more than a channel-mouth bar may form; in others, sand lobes comprised of coarsening- and thickening-upward sequences may be relatively free of channel development.

Numerous authors (see papers in Bouma, Normark, and Barnes, 1985a & b) have noted that on conventional seismic reflection profiles, the suprafan surface appears hummocky with discontinuous subbottom reflectors.

Recognition of modern suprafans is based on the following four features (Normark, 1978):
1. Irregular, local bathymetric relief as seen on conventional reflection profiles.
2. Overall convex-upward relief of this region of irregular relief.
3. Association of these bathymetric characters with coarse-grained turbidites.
4. Development of this morphology at, or immediately downslope of, the termination of the major valley on the upper fan.

Basin Plain and Lower Fan. These smooth, low-gradient areas are characterized by slow hemipelagic deposition only interrupted periodically by turbidity currents. Deposition is very regular, evidence of channels is absent, and deposition is dominated by classical turbidite sequences, which are very thin bedded on the basin plain but become thicker bedded toward the middle fan.

Fan End-Member Types. Tectonic, sedimentary and sea-level controls interact to produce submarine fan types that are intermediate between end-members of types described by Nelson (1984). The end-member types of submarine sediment cones (Table III-3) include debris aprons, radial fans, and elongate fans. Debris aprons develop in small (generally less than 10 km diameter) basins, along carbonate platforms and at the base of the continental slope. These aprons are fed by line (along an entire section of continental slope) or numerous local sources, and are characterized by non-channelized sediment-gravity flow deposits. Debris aprons in Crater Lake, Oregon are an example. Radial fans typically are intermediate-sized (10-100 km diameter) and form in restricted basins fed by local rivers or littoral drift cells. These fans are characterized by sand-rich deposition in middle fan depocenters (often suprafan lobes) at the end of inner-fan leveed valleys. Navy fan off the California continental borderland

TABLE III-3

Petroleum potential of ancient debris aprons, radial fans, and elongate fans predict from modern fan characteristics of source beds, reservoir beds, morphologic setting and tectonic history. From Nelson an Nilson (1984).

	RESERVOIR BEDS	MORPHOLOGIC SETTING AND TECTONIC HISTORY	OVERALL PETROLEUM POTENTIAL
DEBRIS APRONS OR WEDGES (~ < 10 km width)	*SEDIMENT SOURCE-Local, slides, slumps and sediment gravity flows off open slopes. *SEDIMENT COMPOSITION-Variable, coarse-grained in local basins muddy on open continental slope. IN SMALL BASINS: *SAND GEOMETRY-Base of slope non-channelized sand or gravel bodies associated with organic-rich slope muds *GOOD SAND BED CONTINUITY *HIGH RESERVOIR: MUD FACIES RATIO	*MORPHOLOGIC SETTING-Small basins of continental slopes, borderlands, carbonate platforms, lake basins. Debris wedges at the base of continental slopes *BASIN FLOOR-Bounded by open slopes with local valleys. *TECTONIC HISTORY-Variable. Deposits generally not subducted except in trench wedges.	INTERMEDIATE-HIGH *Typically organic-rich source beds. *Good vertical sand-bed continuity in small basins and carbonate systems with favorable diagenetic history. *Total fan sediment thickness may be limited. *Tectonic preservation of fan sand bodies is typical.
RESTRICTED BASINS WITH RADIAL FANS (~ < 10-100 km diameter)	*SEDIMENT SOURCE-Well sorted, local river and littoral drift beach sand. *SEDIMENT COMPOSITION-Recycled clastics with low / matrix. *SAND GEOMETRY-Suprafan & channelized sand bodies associated with organic-rich basin muds. *GOOD VERTICAL CONTINUITY in sand beds. *HIGH RESERVOIR: MUD FACIES RATIO in suprafan lobes & channels	*MORPHOLOGIC SETTING-Basins of continental borderlands and marginal seas. *BASIN FLOOR-Partly surrounded by slopes. Usually several submarine canyons funneling littoral drift sand to fan. *TECTONIC HISTORY-Variable. Deposits generally not subducted.	HIGH *Typically organic-rich source beds. *Good sand bed continuity in suprafan lobes & channels *Low-matrix recycled sand with typically favorably diagenetic history. *Potential for great thickness of fan sediments. *Tectonic preservation of sand sand bodies is typical.
OPEN OCEAN BASINS WITH ELONGATE FANS (~ > 100 km diameter)	*SEDIMENT SOURCE-Muddy river sand. *SEDIMENT COMPOSITION-Variable, often with high percent matrix. *SAND GEOMETRY-Outer fan and abyssal plain and channel mouth sand lobes associated with organic-poor basin muds. *POOR VERTICAL CONTINUITY IN SAND BEDS INTERMEDIATE TO LOW RESERVOIR: MUD FACIES RATIO in outer fan lobes, good is channels.	*MORPHOLOGIC SETTING-Open ocean abyssal floor with deep-sea fans of large diameter. *BASIN FLOOR-Continental slope bounds one side. Single major river source feeds fan. *TECTONIC HISTORY-Abyssal ocean basin floor typically undergoes subduction tectonics.	LOW *Typically organic-poor source beds. *Poor sand bed vertical continuity in outer fan lobes. *High-matrix sand with high lithic content and unfavorable diagenetic history. *Sediment thickness least in outer fan lobe area. *Tectonic destruction of fan sand bodies is typical.

is an example of a radial fan. Large elongate fans are typically greater than 100 km in diameter and develop on the open ocean basin or abyssal sea floor. These fans are normally mud-rich and are characterized by extensive channel systems that deposit sand lobes in the outer fan and inner abyssal plain regions. Astoria fan off the Columbia River, Oregon is an example.

Fan Lobes Types and Reservoir Quality

Shanmugam and Moiola (1991) discussed four types of lobe models and their reservoir properties (suprafan lobe, depositional lobes, fan lobes, and ponded lobes). A summary of reservoir properties of these lobe types are presented in Figure III-12. In addition they included some discussion of three other lobe types (channelized lobes, leveed-valley lobes, and erosional lobes) for completeness. Their work forms the basis for the following description of lobe types and implied distinctly different reservoir properties.

Suprafan Lobes. The suprafan is a depositional bulge or "lobe" on the fan surface; it is a delta- or fan-like deposit that probably forms as turbidity currents exit from the confined leveed valley.

Suprafan terminology refers to a morphological feature that develops due to rapid deposition of coarse (sandy and pebbly) sediment. *Braided Suprafan lobes* display the following characteristics: 1) they develop at the termination of the upper fan valley; 2) they exhibit an overall convex-upward relief in radial profile (this can be discerned on seismic sections); 3) they contain coarse-grained turbidites (predominantly sands); 4) their inner parts are channelized and outer parts are unchanneled; and 5) they represent middle fan regions.

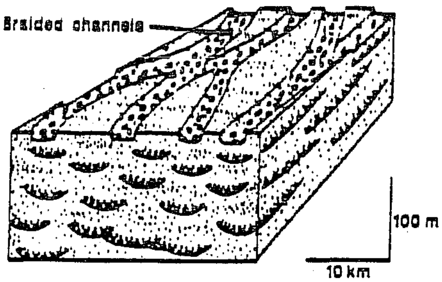
Because the suprafan lobe concept was developed from modern fans that generally have not been sufficiently cored, there are no standard sedimentological criteria to recognize suprafans in cores or outcrops. Suprafan lobes appear to be typical of certain small, sand-rich modern fans that commonly develop on active-margin settings; they are not representative of large mud-rich fans that develop on mature passive-margin settings.

Depositional Lobes. The general characteristics of the depositional lobes of ancient submarine fans (Mutti and Ghibaudo, 1972; Mutti and Ricci Lucchi, 1972; Ricci Lucchi, 1975; Mutti, 1977, 1985; Mutti and Normark, 1987) include: 1) they develop at or near mouths of submarine-fan channels; 2) they show an absence of basal channeling; 3) they usually display thickening-upward depositional cycles; 4) they are composed dominantly of facies C of the Mutti and Ricci Lucchi (1975) scheme; 5) their grain size commonly ranges from medium to fine sand; 6) their beds are laterally continuous and can extend over several tens of kilometers; 7) they exhibit sheet-like geometry; 8) their common thickness range is 3-15 m; 9) their stratigraphic occurrence usually is above basin plain deposits (facies G and D of the Mutti and Ricci Lucchi, 1972, classification) in a progradational system; 10) they occur in the outer/lower part of fans; and 11) they tend to develop primarily in active-margin settings.

According to the suggested definition of depositional lobe by Shanmugam and Moiola (1991) it is critical that the depositional lobe be used only to represent sandy channel mouth deposits of the lower fan that excludes channel/levee complexes. The difference between channel mouth and channel levee deposits is critical in terms of sand-body geometry and reservoir quality. Channel-mouth depositional lobes commonly exhibit high lateral continuity of sand bodies and high depositional porosity (good reservoir quality), whereas levee deposits show poor lateral continuity of sand layers and poor depositional porosity (poor reservoir quality).

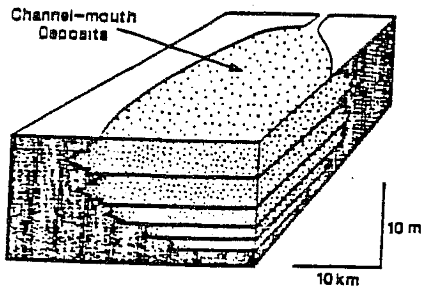
CONCEPTUAL MODEL	RESERVOIR PROPERTIES

(A) **SUPRAFAN LOBES (Walker, 1978)**



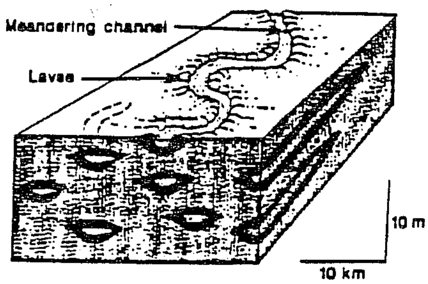
Sand-body geometry	:Stacked
Turbidite facies	:A and B
Sand content	:90-100%
Vertical communication	:Excellent
Lateral communication	:Excellent
Reservoir quality	:Excellent

(B) **DEPOSITIONAL LOBES (Mutti, 1977)**



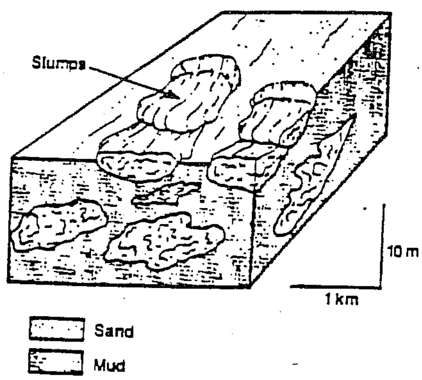
Sand-body geometry	:Sheet-like
Turbidite facies	:C and D
Sand content	:50-80%
Vertical communication	:Moderate
Lateral communication	:Good
Reservoir quality	:Good

(C) **FANLOBES (Bouma et al., 1985a)**



Sand-body geometry	:Lenticular
Turbidite facies	:A and B (channel): E and F (levee)
Sand content	:10-50%
Vertical communication	:Poor (strike and dip section)
Lateral communication	:Poor (strike section)
Reservoir quality	:Moderately good in channel facies

(D) **PONDED LOBES (Nelson et al., 1985)**



Sand-body geometry	:Chaotic
Turbidite facies	:F
Sand content	:10-30%
Vertical communication	:Very poor
Lateral communication	:Very poor
Reservoir quality	:Poor

Figure III-12. Expected reservoir properties of four major fan-lobe models. From Shanmugam and Moiola (1991).

Depositional lobe sequences (see Figures III-9 and III-11) are usually composed of thick sandstone beds with very thin interbedded mudstone partings near the upper part of the sequence, and thin sandstone beds with relatively thicker interbedded mudstone beds near the lower part of the sequence.

At the bedform scale the system is aggradational; however, the entire lobe package is a result of progradation. Simultaneous aggradation and progradation produce thickening-upward depositional lobe cycles. Thickening-upward cycles (characteristic of ancient depositional lobes) have also been reported from ancient deep-marine braided channel facies (Hein and Walker, 1982). Shanmugam and Moiola (1991) report that the major difference is the type of facies: depositional lobes are composed exclusively of sandstone with well-developed Bouma sequences
(facies C), whereas graded channels are usually composed of conglomerate and pebbly sandstone that does not exhibit Bouma sequences (facies A or B).

Because there are very few well-documented sequences that exhibit most of the criteria of depositional lobes, Shanmugam and Moiola (1991) suggested that the term "depositional lobe" be applied only to channel-mouth sequences that exhibit properties such as thickening-upward cycles and turbidite facies C. In modern fans it is impossible to establish the presence of depositional cycles and facies C because cores of sandy sections of adequate length are seldom recovered (Normark, et al. 1986). Therefore, until lobe deposits are documented in detail from modern fans, they further suggest that the use of the term "depositional lobe" be restricted to ancient fan sequences only.

Fanlobes. Fanlobes are highly sinuous, often meandering channel and associated levee systems that were originally defined acoustically, where each fanlobe complex is characteristically separated from the next by intervening thin mud-rich overbank/levee facies that have distinct continuous reflections. A fanlobe is considered the equivalent of a seismic sequence (Bouma, et al. 1989). Thus ancient submarine fans that can be shown to consist of meandering channel/levee facies may be considered fanlobes.

Ponded Lobes. This type of lobe is characterized by a lack of channels, and the dominance of chaotic facies composed of base-of slope unsorted mass movement deposits. They represent mud-rich slump facies associated with slope environments (Shanmugam and Moiola, 1991). Turbidite facies F and D were identified as being typical of the ponded lobes of the Ebro fan. Because of low sand content and poor lateral sand-body connectivity they would comprise poor reservoir facies.

Reservoir Performance Controlled by Submarine Channel Facies. This example of facies-controlled production performance in the A-10 North Pool of the Sansinea Oil field, Los Angeles Basin, CA is included because it may be typical of many channeled submarine fan oil fields. The better part of the reservoir consists of the channel core facies that represent the better quality lower channel fill sands and can be modeled as a simple layered reservoir with excellent lateral continuity. Surrounding the reservoir core is the complex of channel flank facies composed of upper channel fill, natural levee, and interchannel/interlobe silty muds that contain areally-limited reservoir beds in partial communication with each other and with the channel core sands.

The A-10 North Pool oil accumulations in the Puente and Repetto sands are trapped along the Whittier Fault by a combination of fault truncation and updip pinchout of submarine fan sands, as well as local anticlinal structures (Harding, 1974). The reservoir consists of a northeast-southwest trending submarine channel complex of sand, silt, and shale fill. Sands are cleanest along the axis of the preserved channel complex and generally become interbedded with shales and eventually grade into discontinuous thin, watered-out silty sands along the channel margins. Based on detailed log correlations and core descriptions two distinct facies, channel core and channel flank facies, were identified within the channel fill sequence (Cutler, Montoya, and Ucok, 1989).

The channel core facies consists of higher energy sediments and was deposited at the base of the channel complex. This facies is comprised of several 50-150 ft thick, laterally continuous sands with some thin interbedded shales. The channel core sands are fine to coarse-grained and locally pebbly. Channel core sands are generally well sorted and have only minor authigenic clay cement. The pore system is well connected primary intergranular porosity ranging from 22% to 30%. Permeability varies from 50-200 mD.

The channel flank facies is composed of lower-energy sediments and was deposited as an amalgamation of lenses or pods flanking and in some cases overlying the channel core sands. Individual thicknesses in channel flank facies vary from 10 to 100 feet with thick shale interbeds. Channel flank sands are silty and fine-grained and contain abundant dispersed and micro-laminar clay that are dominantly smectite with minor amounts of illite and chlorite. Porosity in the channel flank sands ranges from 20-28%, which is not significantly different from the channel core sands. Permeability is, however, significantly lower, with values ranging from 10-80 mD. Lower permeabilities in the channel flank facies are ascribed to the finer grain size and the presence of abundant clays (Cutler, Montoya, and Ucok, 1989).

The overall sequence of this channel complex exhibits a fining-upward trend that represents either gradually lower energy levels or transgressive fill by hemipelagic slope muds. The channel margin facies probably include upper channel fill, natural levee deposits, and interchannel to inter-lobe slope muds of the middle fan region.

Both faulting and stratigraphic variability complicate the reservoir. Only the channel core sands have significant lateral continuity and relatively consistent log character. Continuity within the channel flank facies is much poorer and is reflected in rapid lateral changes in log character. Shale interbeds separate many of the reservoir sands and act as permeability barriers to vertical fluid flow. Because the shales are thin, even minor faulting can cause separate zones to come into contact. Such small scale faulting is beyond mapping resolution (Cutler, Montoya, and Ucok, 1989) and its effect on reservoir performance is very difficult to ascertain.

Nearly all of the wells in the channel core facies show high drainage efficiency due to excellent sand quality and to good lateral reservoir continuity. These are the sands that consistently have low reservoir pressures (during advanced primary depletion) due to greater production from the highly permeable, laterally continuous portion of the pool. Channel flank facies show a much poorer drainage efficiency due to lower reservoir quality caused by lower permeability in silty sands, poor reservoir communication, and thin areally limited sand extent.

Sand Body Geometry and Dimensions

Braided Suprafan Lobes-Stacked Channel Sand Bodies. Braided channel facies of suprafan lobes are excellent reservoir facies because of their high sand content and connectivity. The sand bodies are well connected both laterally and vertically (Figure III-11). Outer non-channelized parts of the suprafan lobes, poorly documented in outcrops, is expected to be composed of sheet-like sand bodies. Based on the lateral switching of suprafan lobes documented for modern fans (Normark, 1978), Walker (1978) developed a model of suprafan lobe switching complete with offset stacking of sand bodies that has implications for reservoir geometry. The braided channel part of the suprafan lobes may lack internal permeability barriers; however, the blanket of mud overlying the suprafan lobe would act as a permeability barrier between stacked suprafan lobes. These suprafan lobes with mud blankets could form excellent stratigraphic traps. Shanmugam and Moiola (1991) also noted that thick accumulation of sand in the middle fan in combination with compaction might explain mounded reflections of ancient fans.

Shanmugam and Clayton (1989) provide us with an example of a hydrocarbon producing braided submarine channel from the North Midway Sunset field in California. They showed that the Potter reservoir is up to 100 m thick, does not have interbedded muds, is laterally continuous (for more than 500 m), and is highly permeable (>10 Darcys).

Depositional Lobes: Sheet-Like Sand Bodies. Sheet-like sand bodies of depositional lobes were considered to be good reservoir facies (Shanmugam and Moiola, 1991; Figure III-12B). The depositional lobe model of Mutti (1985) stressed sheet-like sand bodies that may be either attached or detached from their feeder channels. Depositional lobes and unchanneled sand bodies, should have good lateral communication, on the order of tens of kilometers (Shanmugam and Moiola, 1991), but vertical communication may be impaired somewhat because of the presence of mudstone beds interbedded with classical turbidite sandstones, especially on the lobe fringe areas.

Fanlobes: Lenticular Sand Bodies. Fanlobes are characterized by lenticular sand bodies of meandering channels and associated mud-rich levee facies (Figure III-12C) of large modern fans such as the Mississippi and Amazon. As such the fanlobe sands are considered to have only moderately good reservoir quality because of impaired sand body connectivity. Offset stacking of fanlobes is characteristic. Adjacent turbidite sands of meandering channels are typically separated from each other by mud-rich overbank or levee facies. These meandering channel sands are expected to be more continuous in the dip direction than in the strike direction, making it difficult to correlate sand bodies even across short distances (Shanmugam and Moiola, (1991). On the other hand, sharp lateral variations in sandstone thickness in meandering channel sands is likely to produce stratigraphic traps.

Ponded Lobes: Chaotic Sediment Accumulations. The ponded lobe model of Nelson, et al. (1985) consists of slumped, chaotic sediments. Sand bodies are spatially disconnected (Figure III-12D) and their geometry and dimensions are highly variable and not predictable. Reservoir quality is low because of the contorted nature of the sands and lack of communication created by incorporated mud layers.

The most favorable combination of characteristics for petroleum prospects in terrigenous clastic basins are found in small (<100 km) radial fans of restricted basins. These fans, according to Nelson and Nilson (1984) possess favorable characteristics of associated organic-rich source beds, thick clean reservoir sands, favorable thermal histories, limited diagenesis within the sands, and tectonic preservation of stratigraphic traps. The petroleum potential of ancient debris aprons, radial fans, and elongate fans predicted from modern fan characteristics are compared in Table III-3.

Sandbody/Channel Dimensions. Dimensional variations in modern and ancient submarine fan systems are summarized in Tables III-4 and III-5. Most of the dimensional information provided in the literature discusses the relative size of whole fans (fan radius) and widths and lengths of channel systems (Normark, 1970a) or relative thickness vs. fan radius relationships (Nelson and Nilsen, 1984) rather than the size of individual sandbodies. Quantitatively determined relations are poorly understood, mainly because of a poor data base. However, at least one paper (Wetzel, 1993) has shown that for most river-fed deep-sea fans that form on unconfined abyssal plains width/length ratio is about 0.2 at the base of the slope, and reaches a maximum of 0.5 farther downdip. Wetzel (1993) also indicated that a good estimate of the volume of such fans developed on a planar base may be approximated as 0.35 x area x maximum thickness.

More general reviews of key descriptive features of modern and ancient fans (Barnes and Normark, 1985) and dimensions of representative modern submarine canyon-fan systems (Nelson, 1984; Table 6) point out the tremendous variation in overall fan size. For example, all of the 23 fans illustrated by Barnes and Normark (1985), except for the Indus and the Chugach fans, could be crowded inside the outline of the Bengal fan. They also point out that the Indus fan is about one-third greater in size than the state of Texas, while the Navy fan would easily fit within the submarine canyon feeding the Bengal

TABLE III-4
Dimensions of representative submarine canyon-fan systems of the world. nm - nautical miles. From Nelson (1984).

	Name of canyon-fan system[1]	*Dimensions*[2] *canyon (length) nm*	*km*	*fan (length) nm*	*km*	*fan (width) nm*	*km*	*Gradient canyon*		*Gradient fan*	
1	Bering (U.S., Alaska)	220	(407)	--	--	--	--	0°27'	1:125	--	--
2	Zhemchug (U.S., Alaska)	126	(233)	--	--	--	--	0°48'	1:71	--	--
3	Ganges-Bengal (India)	100	(183)	1,390	(2,570)	590	(1,091)	0°27'	1:128	04'	1:890
4	Congo (Africa)	120	(222)	150	(278)	100	(185)	0°34'	1:101	15'	1:227
5	Monterey (U.S. Calif.)	60	(111)	165	(305)	120	(222)	1°31'	1:38	14'	1:250
6	Mississippi (U.S., La.)	120	(222)	120	(222)	80	(148)	30'	1:117	29'	1:120
7	Astoria (U.S., Ore.)	62	(115)	90	(166)	55	(102)	57'	1:60	18'	1:190
	Willapa (U.S., Wash.)	60	(111)	--		--		58'	1:56	--	--
8	Hudson (U.S., N.Y.)	50	(92)	80	(148)	80	(148)	1°15'	1:46	23'	1:147
9	Rhone (France)	15	(28)	90	(166)	90	(166)	3°11'	1:18	24'	1:144
10	La Jolla (U.S., Calif.)	7.3	(14)	16	(30)	12	(22)	2°17'	1:25	1°04'	1:54
11	Redondo (U.S., Calif.)	8	(15)	4	(7)	6	(11)	2°12'	1:26	1°11'	1:48

TABLE III-5
Size ranges for modern and ancient submarine fans. Data from Barnes and Normark (1985) and Nelson (1984).

	Modern Fans	Ancient Fans
Fan Length (km)	4-800	6.4-2,000
Fan width (km)	6-1,100	4.8-300
Submarine Canyon length (km)	14-407	not available
Overall fan gradient	1:48 to 1:890	not available
Maximum thickness (m)	30 - 5,000+	170-10,000
Dominant grain size	clay - medium/fine sand	not available
Volume (km^3)	not available	3.0-2,000,000

fan. The Bengal fan, if laid along the western coast of North America, would reach from Vancouver, British Columbia to lower Baja California.

Data from the morphometric maps of Barnes and Normark (1985) indicate typical channel height and widths for the various modern fans. According to the data of Barnes and Normark (1985), a typical large fan, the Amazon, has channel depths ranging from 15-120 m and channel widths ranging from 600 to 2,500 m. Both height and width of channels on the Amazon fan decrease rather regularly in the down-fan direction. The channel height/width ratio, however, changes little in the down-fan direction (range of ratios from 0.025 to 0.120). In another relatively large fan, the Mississippi fan, down-fan decrease in height of channel is well developed (range 121 m up-fan, to 5 m more distally) as is the channel width (10,800 m up-fan, 200 m distally) and the height/width ratio shows no significant or systematic change (range 0.011 to 0.082). In a relatively smaller fan, the Navy fan, decreased height (160 m up-fan, 8 m distally) and width (1,000 m up-fan and 430 m more distally) are found in the down-fan direction, while the height/width ratio ranges from only 0.160 (up-fan) to 0.018 (in the down-fan direction).

Problems with Current Submarine Fan Models

In response to increased research and economic interest in modern submarine fans and ancient turbidite sequences a meeting of interested specialists was called in the fall of 1982. The Committee on fans (COMFAN) meeting resulted in an excellent volume summarizing current knowledge about submarine fans and related turbidite systems edited by Bouma, Normark, and Barnes (1985b). An excellent article in this volume by Bouma, Normark, and Barnes (1985a) summarized many of the problems in research on modern and ancient submarine fans. Much of the following discussion is taken verbatim from this article:

> The lack of a common data set to compare modern submarine fans and ancient turbidite sequences is the result of differences in both the scale of observation and data acquisition methods. It may be possible, if not probable, that no common data set for comparison exists. Data from ancient turbidite units provide details primarily on layer thickness, distribution in lateral and vertical senses over short intervals, composition, grain size, color, sedimentary structures on bedding plane, trace fossils, and paleocurrent directions. Marker beds that provide basin-wide time correlations generally are rare.
>
> Studies of modern submarine fans can provide a good insight into basin size, shape, gradients, surficial facies, and source area(s). The acoustic stratigraphy or acoustic facies, or both, can be identified for some fans, allowing correlation of units across the basin. The total thickness of the fan systems also can be established with acoustic techniques. Detail of internal structure decreases with depth of acoustic penetration on seismic reflection records and , basically, these high-resolution techniques cannot provide the details comparable with those observed in outcrops. Although sediment cores can provide details similar to those from outcrop studies, the short cores only sample the uppermost sediment. Deep drilling with continuous coring, such as the Deep Sea Drilling Project and the new Ocean Drilling Project, might eventually narrow this gap.
>
> Models and inferred transport/depositional processes for modern submarine fans are typically based on surface morphology, planimetric shape, and surficial sediments. Differential compaction of fine-grained and coarse-grained sediments, together with erosion, partial masking, and tectonic influences, prevent the reconstruction of paleosurfaces of ancient systems over large areas. Models constructed from ancient turbidite facies concentrate on stratigraphic variations and vertical sediment sequences. Lack of a common comparative factor and differences in approach to studies of modern and ancient systems, therefore, have resulted in different terminologies.

Perhaps the most important conclusion reached by the COMFAN review was that, at present, it is extremely difficult to make direct comparisons between modern submarine fans and ancient turbidite sequences, basically because of differences in the types of data collected as well as differing scale relations.

Many of the points outlined in the discussion above (Bouma, Normark, and Barnes, 1985b) can be modified or expanded. For example, in an overview paper concerning the comparison of modern and ancient turbidite systems Mutti and Normark (1987) found that a useful comparison must represent depositional systems similar in such characteristics as type of basin, size of sediment source, physical and temporal scales, and stage of development. They noted that many fan sedimentation models do not meet these criteria. Mutti and Normark (1987), not surprisingly came up with their own list of faults in existing fan models. Very briefly these include:

- Not all turbidite systems have formed submarine fan sequences.
- It is necessary to recognize the major factors that control the growth of submarine fan complexes. Kolla and Macurda (1988) picked up on this point when they acknowledged that although it has been known for some time that sea level changes greatly affect development of deep-water turbidite and fan systems, the timing and type of turbidite events in these systems may also depend on the nature of available sediments, tectonic setting, size, and gradients of the basin.
- Comparison of modern and ancient fans, or modern with modern and ancient with ancient, cannot provide valid results unless the scale of observations is similar. Similarly seismically-defined "lobes" of submarine fans are almost always an order of magnitude larger than "lobes" defined by sequences of rocks in outcrop.
- Studies of modern and ancient turbidite systems are based on different types of data that provide different degrees of resolution and reflect differing physical attributes of the deposits. Many conclusions about modern submarine fan sedimentology and geometry have been derived from seismic interpretations that have not been proven by the drill bit.
- There are complications caused by the terminology used to describe turbidite systems.

Deep Ocean Basin Sedimentation

The Deep Sea Environment

Abyssal plains and adjacent oceanic and continental rises form the deepest receiving areas, aside from trenches, of continental detrital materials. Continentally-derived materials may be delivered to the deep-sea floor by density flows, such as debris flows or turbidity currents, or fine-grained detrital material may be eroded from the sea floor and transported by ocean bottom currents creating a dilute, near bottom suspension of sediments called a nepheloid layer (Ewing and Thorndike, 1965). Although most terrigenous clastic debris has been deposited by the time it reaches the lower slope or continental rise, very small particles may be carried in the marine water column for considerable distances before raining down on the benthos as hemipelagic sediment. At higher latitudes terrigenous materials may be delivered to the deep sea floor by ice rafting. Bouma and Hollister (1973) indicated three additional sources that may be distinguished including pelagic, chemical and volcanic-derived sediments. Also, deep basin sediments may be reworked by sediment gravity flows (e.g. distal turbidites) and contour currents.

Deep Oceanic Tidal Currents

Currents in the deep sea are driven by gravitational pull on water masses of differing density causing dense cold polar waters to sink and move toward the equator. They are therefore fluid gravity flows according to the definition of Middleton and Hampton (1973). The rotation of the earth deflects these bottom-hugging currents toward the western side of basins. In modern ocean basins these deep bottom currents are known as geostrophic contour currents because of their tendency to flow parallel to bathymetric contours (Heezen, et al. 1966). With the advent of continuous seismic profiles it was recognized that there are large accumulations of fine-grained sediments that are preferentially deposited along basin margins by contour currents. In order to differentiate this material from downslope-transported (distal) turbidity deposits the term "contourite" was introduced (Hollister and Heezen, 1972).

Bouma and Hollister (1973) indicated that because most contour currents are associated with global circulation patterns, they are observed on the western margins of open oceanic basins. Some enclosed seas, such as the Gulf of Mexico, are large enough for circulation patterns to operate similarly. It would appear that the deep basinal tidal currents require a basin size of at least 100 mi^2.

Types of Deep Basin Sedimentation

Bouma and Hollister (1973) differentiated three main descriptive types of deep sea sediments on the basis of composition, color, texture and origin:

Red clays consist of "chocolate brown," very-fine grained sediments (more than 80% finer than 30 μ in diameter) with less than 30% $CaCO_3$. It is found at depths greater than 5,000 m. Normal depositional rates are on the order of 0.1-1.0 mm per thousand years.

Biogenic oozes are lighter colored (white, cream, or straw colored) sediments found on shallower basin floors (2-4 km deep) that are composed mostly of the tests of siliceous and carbonate plankton (e.g. foraminifers, radiolaria, diatoms, coccoliths). Biogenic oozes give way to red clays at depths of 3,000-5,000 m (Griffin and Goldberg, 1963). Normal depositional rates vary between 1-5 cm per thousand years. Due to $CaCO_3$ solubility, undisturbed pelagic carbonate oozes are increasingly rare below the lysocline and do not accumulate below the calcite compensation depth, which is variable in both time and space (Tucker and Wright, 1990).

Terrigenous muds are green or greenish gray to black, contain more than 30% continentally-derived sand and silt grains, and generally contains more than 50% materials coarser than 30 microns in diameter. Terrigenous muds may contain as much as 10% to 15% organic material. This lithology is found along continental margins and is, therefore, the type most likely to be redistributed by bottom currents.

Based on the classification listed above Bouma and Hollister (1973) concluded that contourites and turbidites are dominantly redistributed terrigenous sediment. Turbidity currents tend to receive their sediments from an elevated or continental source in contrast to contour currents that rework whatever sediment is more locally available. Due to their generally high organic content and relatively coarser grain size (compared to other abyssal sediments), they are probably the most significant potential source rock for hydrocarbons within the deep sea.

Mutti and Normark (1987) strongly believe that most modern submarine fans have been effected, in one way or another, by bottom currents. Thus, the most important aspect of contourites (the resultant deposits created by large-scale oceanic circulation) may be that they, as a rule, substantially modify submarine fans. Consequently, direct comparison between modern and ancient deep sea fans may be greatly impaired.

During the Deep Sea Drilling Program/Ocean Drilling Program (Austin, et al. 1988) six major classes of fine-grained deep sea sediments have been recognized: pelagic clay, pelagic biogenic siliceous, transitional biogenic siliceous, pelagic biogenic calcareous, transitional biogenic calcareous, and terrigenous. Two of these groups of sediments are calcareous.

Distal turbidites and contourites are of minimal interest for hydrocarbon exploration. Significant reservoirs developed in such sediments are unlikely, unless they have been diagenetically altered, creating secondary porosity or have inherited a well developed fracture system. Either type of deposit, however, could supply source rocks for nearby proximal turbidite sands.

Deep Sea Trench Sedimentation

Trenches are the deepest known basins. They are generally asymmetrical with steep (often 10°) inner slopes and more gentle (5°) outer slopes (Rupke, 1978). Fault-controlled perched basins are common within trenches and act as local sediment traps. Trenches are also commonly subdivided by tectonic movements along their axes.

Basin plains in most trenches are very elongate (up to hundreds of kilometers), however, they tend to be only a few tens of kilometers wide. Thickness of sediment fill ranges from a few hundred meters to 2 km with the thickest part being on the landward side and creating a wedge-shaped fill in transverse section.

Depositional models for trench and trench-slope sedimentation (Figure III-13) have been presented by Underwood, Bachman, and Schweller (1980) and Nelson and Nilson (1984). In the model of Underwood, Bachman and Schweller (Figure III-13A) several important variables that affect trench sedimentation are emphasized including overall rates of sedimentation, rates of plate convergence, size and regional distribution of submarine canyons, size and distribution of tectonic ridges, basement highs and depressions on the down-going block, and the relative position of sea level.

In addition to gross structural controls, the presence of large or small submarine canyons is very important in determining the type and distribution of sediments within the trench. This is because large submarine canyons with correspondingly large sediment loads are able to deeply entrench and maintain their channels across continuously developing barrier ridges of the lower slope. Deep incisions created by large canyons allow the sediment load to effectively bypass the entire trench slope and ultimately be deposited on the trench floor. Distributary channels and other submarine fan-like facies may locally develop at the mouths of large submarine canyons within the trench. Most of the sediment transport within the trench, in contrast to slope fan systems, is along the regional depth gradient (strike) of the trench axis (Underwood, Bachman, and Schweller, 1980). Trench floor sediments may originate from multiple submarine canyons along the length of the trench or major sediment input may be from one end of the trench.

In contrast to large canyons, the sediments issuing from smaller less erosive canyons and "slope gullies" are usually dammed (ponded) by the trench-slope break or by one of the tectonic ridges on the lower slope. This is particularly important because it means that most coarse-grained turbidite deposits that are not funneled through the large canyons are trapped in fore-arc basins.

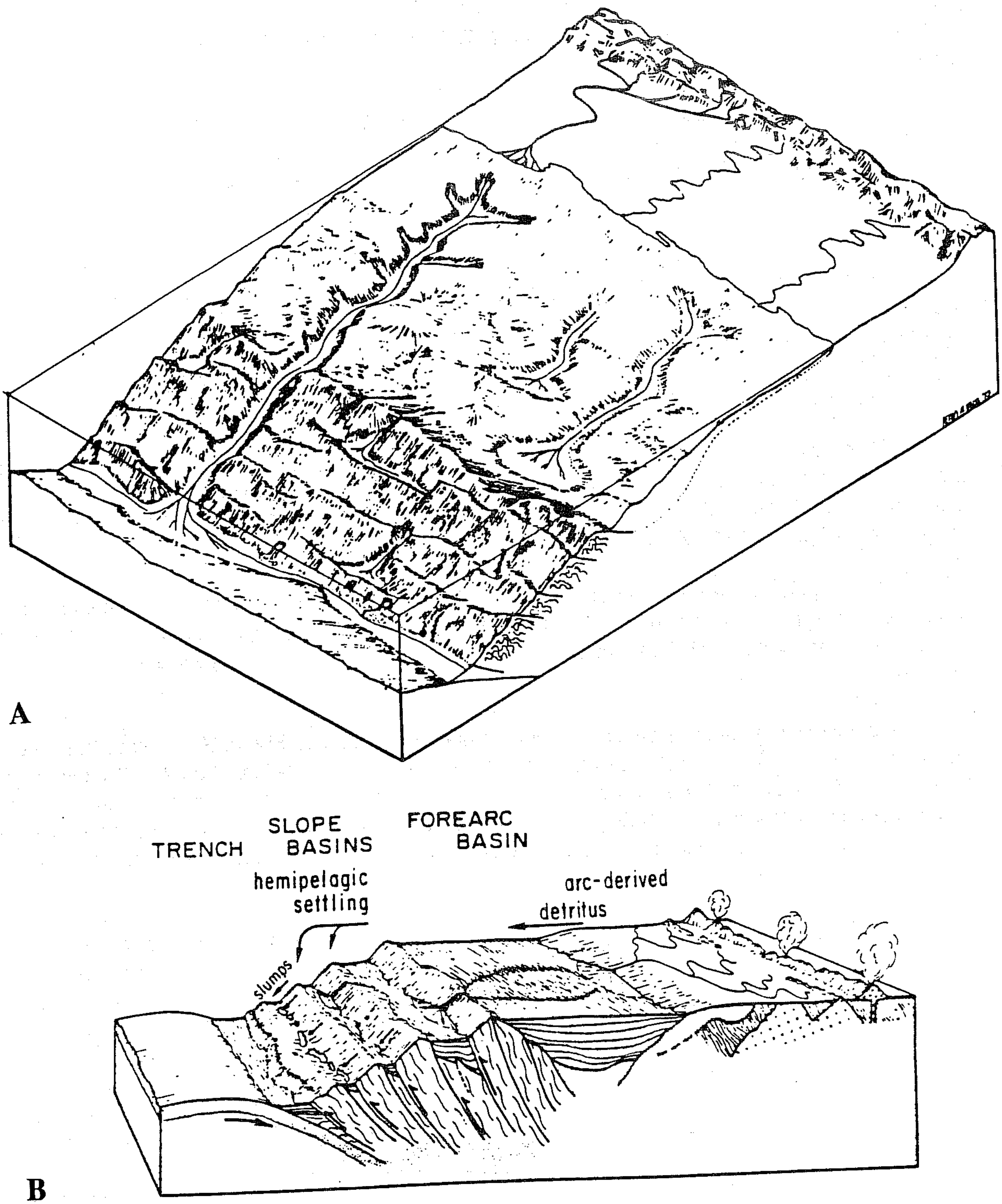


Figure III-13. (A) Geomorphic aspects of general trench and trench-slope sedimentation showing the influence of tectonic ridges and submarine canyons on sediment transport and deposition. From Underwood, Bachman, and Schweller (1980). (B) Model for trench-slope sedimentation in the Nisa beds, Indonesia. Sedimentation in small basins near the base of the slope was by slumping from topographic highs and hemipelagic settling. Higher on the slope, some thrusts became inactive allowing basins to combine. Terrigenous detritus from the arc is fed into the basins by canyons forming coarsening-upward sedimentary sequences. From Nelson and Nilson (1984) after Moore, et al. (1980).

Hemipelagic muds dominate the lowermost portions of the landward trench slope; however, trench-floor deposits may include fan-shaped bodies of turbidites with distributary channels, flat-lying turbidites with large axial channels, unchannelized flat-lying turbidites or sheet sands, and hemipelagic deposits. This occurs because of the importance of upslope trapping and bypassing through large canyons (Underwood, Bachman, and Schweller, 1980).

Sediments within the large trench basin, or within most of its structurally-defined elongate sub-basins, are transported primarily parallel to the strike of the basin margin. Only large, broad, flat-floored basins on the upper slope (forearc) would be expected to contain true fan-shaped bodies of sediment with transport directions at a high angle to the margin (Underwood, Bachman, and Schweller, 1980).

Reservoir potential for ancient deposits from the lower trench is minimal. Lenticular and linear fill of axial channels in trenches, deep sea channels, and submarine canyons all have reduced potential for large petroleum reserves compared to depositional lobes of submarine fans (Nelson and Nilson, 1984). Fill in large, deeply cut submarine canyons, however, may have good continuity of lower sands, excellent potential for up-canyon hydrocarbon migration, and excellent stratigraphic traps formed by permeability barriers of upper canyon mud fill (Picha, 1979). Greater potential may exist higher on the landward trench slope where sandy turbidite deposits may have been tectonically ponded. Increased potential for reservoir development may also be associated with fan-like deposits at the mouths of deeply-incised submarine canyons that have broached the slope-trench break (Figure III-13B).

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CHAPTER IV

ENHANCED OIL RECOVERY PROJECTS IN CLASS III RESERVOIRS CURRENT STATUS

Incremental oil production from ongoing enhanced oil recovery (EOR) projects in Slope-Basin & Basin clastic reservoirs is primarily the result of thermal processes applied to fields in southern California. In fact, a single process in one field in the San Joaquin Basin is responsible for over 90% of the current incremental EOR production from Slope-Basin & Basin clastic reservoirs -- steam injection in the Midway-Sunset field.[1,2] While Midway-Sunset and several other California fields have been targets for the application of other processes, notably immiscible CO_2 injection, alkaline flooding, in-situ combustion, and polymer flooding, none of these processes have produced any significant volume of oil relative to steam injection. Notable Class III EOR projects outside California include the miscible CO_2 injection projects in Texas and Mississippi and a miscible hydrocarbon gas injection project in offshore Louisiana. The following sections discuss ongoing improved recovery projects in California (heavy oil) and non-California (light oil) Class III reservoirs.

Current Heavy Oil EOR Projects in California

About 50% of the total oil produced in California is incremental oil resulting from thermal (primarily steam injection) projects (Table IV-1). Several of the larger fields with ongoing thermal projects also have significant amounts of secondary (waterflood) production from Class III reservoirs. In many cases, steam injection projects are currently or have been implemented in the formations classified as Slope-Basin or Basin deposits.

In particular, Midway-Sunset, South Belridge, and Wilmington have significant production from Slope-Basin & Basin clastic reservoirs, and Midway-Sunset and South Belridge also have significant EOR production. These fields are the first, second, and fifth ranked producers in California, respectively. The Midway-Sunset and Wilmington fields are two of the largest fields in the nation. As of 1993, only Prudhoe Bay and East Texas have produced more oil.[3] However, a far greater amount of Class III production from Midway-Sunset field is dependent on steam injection than in either South Belridge or Wilmington.

Most of the incremental EOR production in California Slope-Basin & Basin clastic reservoirs is the result of steam drive or cyclic steam stimulation. The Midway-Sunset field currently contributes more than 50 million barrels per year of thermally enhanced oil production. Significant other EOR applications include three in-situ combustion projects in the Midway-Sunset and West Newport fields and an immiscible CO_2 flood in the Wilmington field. Each of these projects are discussed separately in this chapter.

<u>Thermal EOR in the Midway-Sunset Field</u>

In-situ combustion was the first thermal enhanced recovery process attempted in California, predating steam injection by several years. Standard Oil Company of California (now Chevron) began the first in-situ combustion project in Midway-Sunset in 1956, but discontinued injection after only 10 months. Other companies continued to test in-situ combustion in other fields however. Hot water injection and downhole heaters were also tested as methods for reducing oil viscosity and increasing productivity. Two operators, Tidewater Oil Company and Shell Oil Company, began experimenting with steam injection in the Kern River, Yorba Linda, and Coalinga fields between 1960 and 1962.[4] Despite

Table IV-1

Incremental Production from Ongoing Thermal Projects in California Fields with Slope-Basin & Basin Clastic Reservoirs in TORIS (Million Barrels/year)

Major Fields with Class III Production and Thermal Recovery Projects	Total 1991 Production	Incremental Thermal Production	Thermal % of Total	% of Total 1991 Production from Class III Reservoirs
South Belridge	55.0	41.4	75*	21
Cat Canyon (E&W)	1.1	0.7	66	77
Cymric	10.4	9.8	94*	8
Edison	1.0	0.3	25	6
McKittrick	1.5	0.7	49*	49
Midway-Sunset	61.4	52.7	86*	99
Newport West	0.5	0.2	38*	90
Oxnard	0.4	0.3	90*	93
Wilmington	24.8	1.3	5*	99
Yorba Linda	0.9	0.9	99*	97
Total	157.0	108.4	69	
Total State	**350.7**	**172.2**	**49**	

* Some portion of ongoing thermal production is from Slope-Basin & Basin clastic reservoirs.

Note: Currently there are 14 ongoing EOR "efforts" reported in California Slope-Basin & Basin clastic reservoirs (Table IV-2). However, some of these efforts are made up of many small projects which are not individually reported in the literature. As an example, within the Midway-Sunset field there are at least 40 individual steam drive and cyclic steam projects (Table IV-3). In that field alone, roughly 5,400 to 5,500 wells are cyclically steamed and 600 to 700 wells produce steam drive oil, driven by 650 to 800 injectors.

Source: Annual Report of the State Oil & Gas Supervisor, California Department of Conservation, Division of Oil and Gas (1991).

Table IV-2

California Ongoing EOR Projects Slope-Basin & Basin Clastic Reservoirs

Field	Operator	Project Type	Pay Zone	Depth (ft)	Start	Area (acres)	Wells Prod.	Wells Inj.	Incremental Oil (BOPD)	Avg °API	References
Midway-Sunset	Mobil	In-situ Comb.	Moco	1,500	1960	150	31	3	900	14	1, 2, 26
Midway-Sunset	Santa Fe	In-situ Comb.	Potter	1,700	1982	24	40	10	700	12	1, 2, 27
Midway-Sunset	Various	Steam drive and Cyclic Steam	Various	1,500 - 5,000	1963+	4,900+	6,283	651	130,101	12	1, 2, 6-22
Wilmington	Champlin	Immiscible CO_2	FB III Tar	2,500	1980	150	12	9	small	14	6, 28
Wilmington	Union Pacific	Steam drive	Tar	2,500	1989	130	50	35	3,500	14	1, 6
Yorba Linda	Shell	Steam drive	Upper Conglom.	500 - 1,000	1971	310	203	15	1,500	12	1, 6
Yorba Linda	Various	Cyclic Steam	Shallow Zone	< 500	1960	--	104		1,050	13	6
West Newport	Mobil	In-situ Comb.	Miocene A/B	1,600	1958	300	139	36	980	13	1, 6, 24
West Newport	Various	Cyclic Steam	Miocene A/B	1,600	1964	--	74		--	13	6
Oxnard	Various	Cyclic Steam	Pliocene Tar	1,850	1964	--	53		950	6	6
McKittrick (Main)	Various	Cyclic Steam	Upper	1,200	1962	--	207		800	14	6
McKittrick (Main)	Various	Steam drive	Upper	1,200	1965	--	--	29	550	14	6
Cymric	Various	Cyclic Steam	Reef Ridge	2,250	1967	--	90		1,950	13	1
South Belridge	Various	Steam drive	Diatomite	1,000	1963	--	--	3	small	10+	1, 6

Sources: California Department of Conservation, *Division of Oil and Gas, 77th Annual Report of the Oil and Gas Supervisor -1991, 1992; 1991 Annual Review of California Oil and Gas Production*, Conservation Committee of California Oil and Gas Producers, 1991; G. Mortis, "EOR Increases 24% Worldwide; Claims 10% of U.S. Production", *Oil and Gas Journal*, April 20, 1992, v. 90, p. 51.

Table IV-3

Slope-Basin & Basin Clastic Reservoir Steam Projects Within the Midway-Sunset Field by Operator (April 1992)

				Wells		
Operator	Pay Zone	Start Date	Area (Acres)	Prod.	Inj.	Inc. Oil (BOPD)
Arco	Potter	72	8	31	4	880
Arco	Potter	75	108	98	15	3,800
Arco	L. Monarch	83	34	13	2	1,300
Arco	Monarch	81	40	70	10	2,475
Arco	Monarch	72	9	35	4	485
Arco	Sub. Lake	84	15	12	0	105
Arco	Metson	69	50	60	15	1,125
Arco	Potter	72	200	50	3	500
Arco	Potter+	--	--	40	1	2,100
Arco	Potter	77	107	210	18	7,000
Arco	Potter	86	40	77	0	750
Arco	Potter+	--	80	95	11	900
Arco	Potter+	--	70	59	4	600
Arco	Potter+	90	80	188	5	5,000
Arco	Potter	90	120	247	4	7,000
Arco	Marviz	--	80	36	4	650
Arco	Potter	86	160	236	80	3,200
Chevron	Potter	78	23	36	5	2,650
Chevron	Monarch	75	84	243	81	9,000
Chevron	Webster	83	84	44	10	2,300
Exxon	Monarch	90	--	200	100	1,300
Mobil	Monarch	70	400	381	32	8,300
Mobil	Potter	67	140	376	21	10,500

Table IV-3 (Continued)

Slope-Basin & Basin Clastic Reservoir Steam Projects Within the Midway-Sunset Field by Operator (April 1992)

				Wells		
Operator	Pay Zone	Start Date	Area (Acres)	Prod.	Inj.	Inc. Oil (BOPD)
Santa Fe	Potter	85	100	350	45	4,350
Santa Fe	Potter	64	900	880	--	15,900
Santa Fe	Spellacy	70	400	500	--	4,000
Santa Fe	Spellacy	91	30	30	8	0
Shell	U. Spellacy	79	70	66	0	1,300
Shell	Lower	89	68	78	10	1,300
Shell	Sub. Hoyt	83	143	205	26	5,700
Shell	Potter	71	400	650	34	12,500
Shell	Monarch	80	85	145	12	4,400
Texaco	Potter	81	77	27	9	1,422
Texaco	Potter	77	27	51	7	565
Texaco	Potter	89	38	62	11	880
Texaco	Potter	91	24	24	6	100
Texaco	Potter	77	36	72	15	1,200
Unocal	Potter	74	81	59	19	614
Unocal	Potter	77	50	79	20	1,550
Unocal	Potter	69	150	165	0	2,000
Total			**4,600+**	**6,280**	**651**	**130,101**

Source: Oil and Gas Journal EOR Database, April 20, 1992.

Note: A total of 5,392 cyclic steam wells and 785 steam drive injectors are listed in the 77th Annual Report of the State Oil and Gas Supervisor (Reference 6, p. III-30) for the Midway-Sunset field. The variation between the numbers reflects reporting discrepancies as well as the inclusion of steam drive producers in the "producing wells" total above.

attempts at secrecy, their success became known and led to an overnight jump in the value of heavy oil properties and the widespread application of steam injection. Between 1963 and 1965, the number of "steam soak" projects, characterized by steam injection for several weeks followed by a shut-in period and then production of the heated oil jumped from 29 to 267.[5]

The first steam project in the Midway-Sunset field began in 1963. Steam augmented production (both cyclic steam and steam drive) has risen more or less steadily since then (Figure IV-1). In 1991, there were 10,820 producing wells in the field, with 5,392 undergoing steam cycles and 785 steam drive injectors operating full time.[6] While the Midway-Sunset field's Class III incremental EOR production has risen steadily, incremental thermal oil from other California Slope-Basin & Basin clastic reservoirs has remained at about the same level, primarily coming from Slope-Basin zones in the Wilmington, Yorba Linda, and Cymric fields.

Historically, the typical Midway-Sunset steam soak operation has involved the injection of 5,000 to 6,000 barrels of steam over a 10 to 15 day period followed by a 2 to 15 day soak time, and then a production period of 100 to 350 days.[7,8] The wells are cycled multiple times (many wells have received 30 or more cycles), with a decline in peak production rate as cycles are added (Figure IV-2).[9] Cyclic steam stimulation is a very effective method for increasing oil production in heavy oil reservoirs, particularly if the reservoir rock is discontinuous, making a steam drive operation less practical. In the Midway-Sunset field, production rate increases of 5 to 10 times the "cold" production rate are typical.[10]

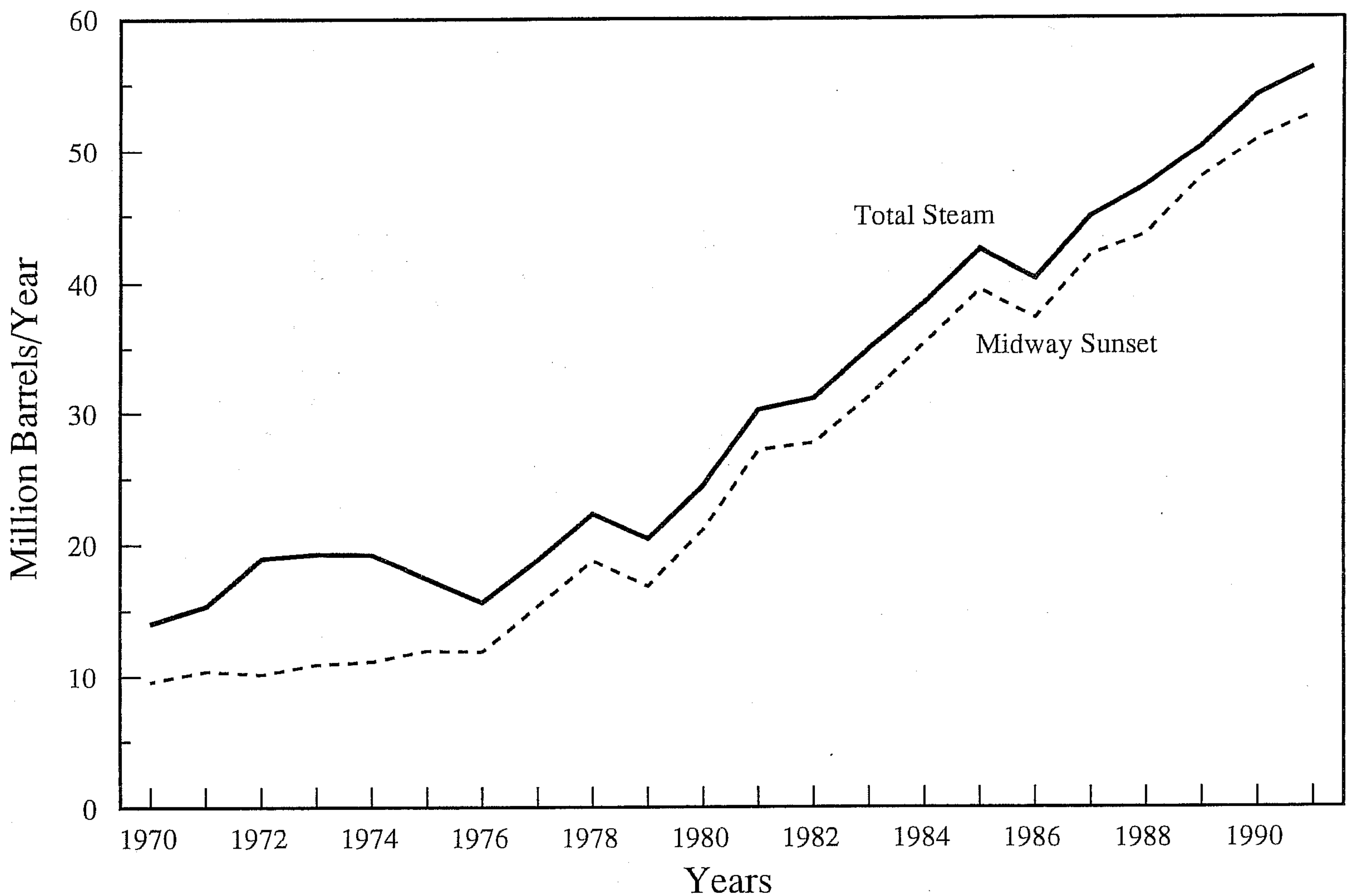
When the productive formation has high continuity, operators may decide after several cycles to convert a cyclic steam project to steam drive (steamflood). Several steam drive projects have been initiated in Slope-Basin & Basin clastic reservoirs in California and in the Midway-Sunset field in particular.[11,12,13,14,15] These projects have steam-to-oil ratios of between six and ten barrels of steam per barrel of incremental oil, well above the average for all California thermal operations in general and the Midway-Sunset field in particular. While some steam drive (and in-situ combustion) projects are still underway in Midway-Sunset reservoirs, the Slope-Basin formations there respond particularly well to cyclic steam stimulation. The use of cyclic steam injection processes is far greater in the Midway-Sunset field, than in other fields in California. The proportion of cyclic steam injection has increased slightly over the last decade (Figure IV-3). In the Midway-Sunset field, the steam-to-oil ratio has increased over time, as is normal for reservoirs using this EOR technique.

Some operators are finding the expansion of steamdrive projects worth consideration. Arco plans to expand an upper Miocene Potter sand steamflood and a Monarch sand steamflood over the 1994-1995 time period.[16] The Potter flood operation, recently expanded in 1991, will have three to five more injectors added in the future. The Monarch project will add 26 injectors, doubling the present injection rate. Arco was the top Midway-Sunset steam injector in the first quarter of 1993.

Recently, a variation of the cyclic steam process, termed "sequential steam", has been reported as a worthwhile technique for efficiently processing thick, steeply dipping, heavy oil sands of the type present in the Midway-Sunset field.[17] In dipping reservoirs, gravity drainage can significantly improve the overall recovery from steamed wells, particularly when the steam travels updip and heats portions of the reservoir beyond the normal drainage area of the well (Figure IV-4). Santa Fe's experience has shown that a combination of infill drilling and subsequent steam injection into alternate offsets in rows, on strike, sequencing from down- to updip (Figure IV-5), achieves higher recoveries than either random cycling or conventional steam drive.

Figure IV-1

Incremental Oil Recovered from Steam and Cyclic Steam Processes in California Slope Basin & Basin Clastic Reservoirs

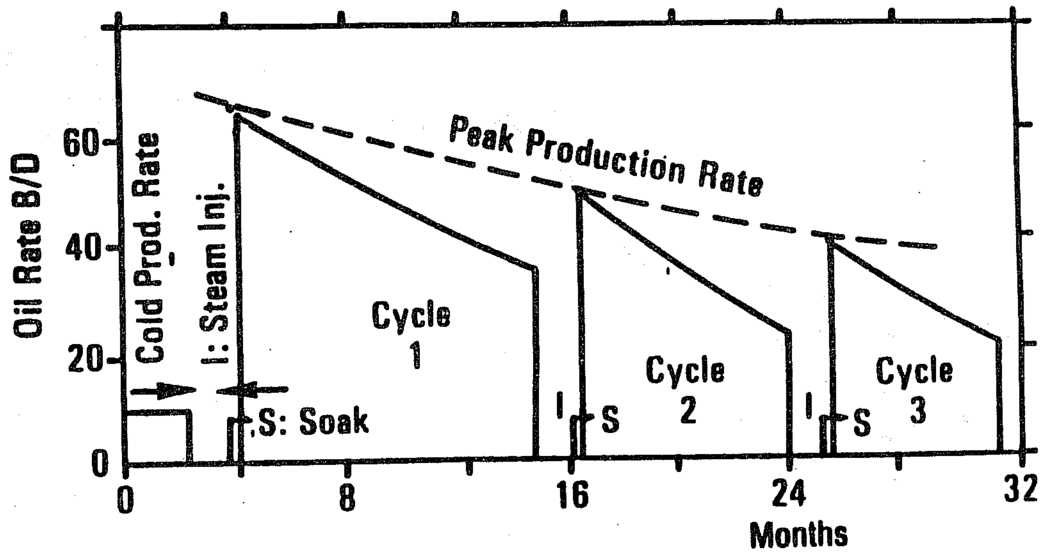


Source: Annual Report of the State Oil & Gas Supervisor California Department of Conservation, Division of Oil & Gas (1970-1991)
OGJ (April 20,1992) EOR Database

CL3\ STEAM

Figure IV-2

Typical Performance of a Cyclically Steamed Well

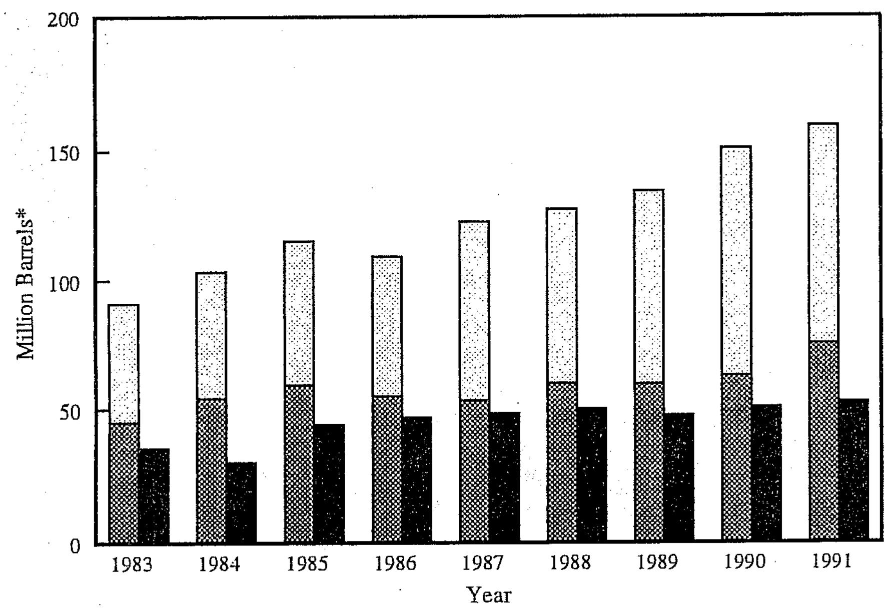


Source: Farouq, Ali, S.M. and R.F. Meldau, "Current Steamflood Technology," (Oct. 1979), p.1332-42.

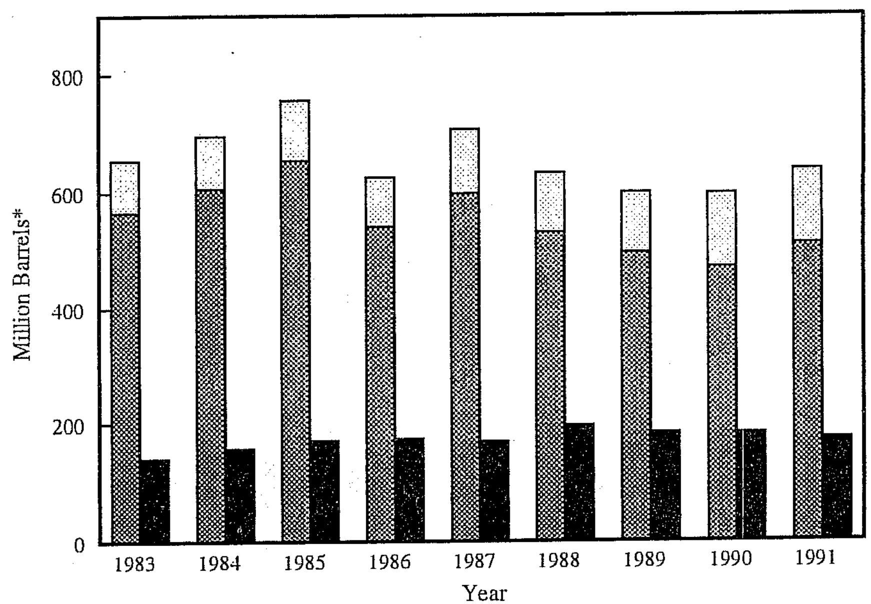
Figure IV-3

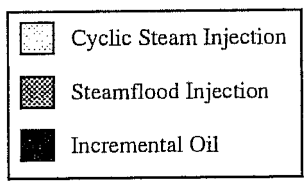
Steam Injection and Thermal Enhanced Oil Recovery (1983-1991)

A) Midway-Sunset Field



B) California



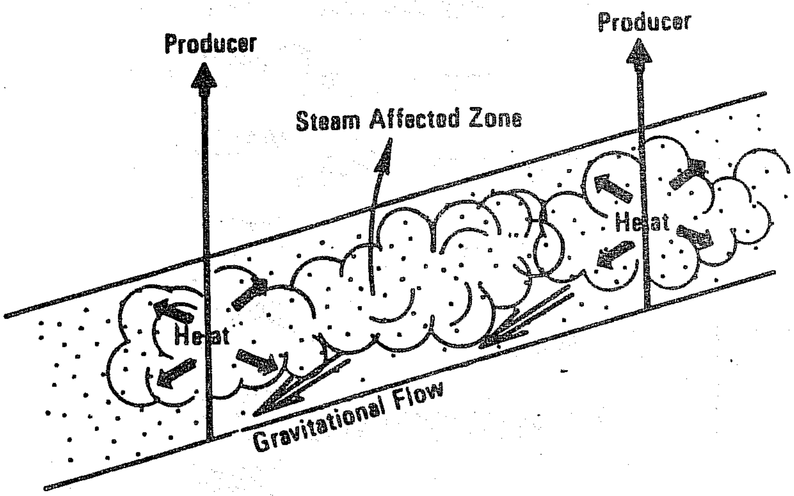


* Cold water equivalent of steam or stock tank oil

Source: Annual Reports of the Oil and Gas Supervisor, 1983-1991, California Department of Conservation

Figure IV-4

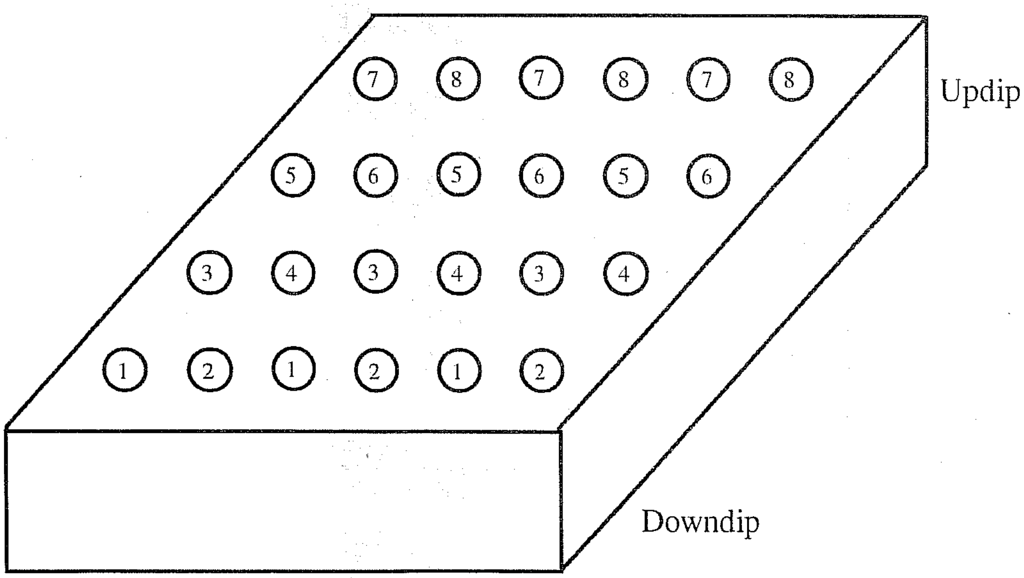
Cyclic Steam Stimulated Producers with Drainage Area Overlapped and Gravity Drainage Taking Place



Source: Carcanna, A., Applied Enhanced Oil Recovery (New Jersey (Prentice-Hall) 1992, p. 46.

Figure IV-5

Schematic of Sequential Well Steaming Plan



Wells are steamed in order: 1,2,3,4,....

Other researchers have sought to improve the performance of steam drive operations in Midway-Sunset and other fields through the use of chemical additives. These additives are designed to improve both the displacement efficiency and the vertical sweep efficiency of the steam drive. In one example, injection of a slug of thermally stable surfactant along with compressed air resulted in an improvement in performance that lasted several years.[18] No increase in injection pressure was observed, indicating that the steam-foam mixture was not improving the steam injection profile. However, the surfactant did seem to improve the efficiency of the gravity drainage process. In another case, a proprietary sulfonate was injected along with nitrogen, in multiple slugs. Injection pressures increased, apparently improving the steam injection profile and resulting in 53,000 barrels of incremental oil that would otherwise have been bypassed by the steam.[19]

In a third test by Unocal in the Potter sand at Midway-Sunset, a sulfonate/nitrogen/brine mixture was injected continuously during steam injection.[20] Injection pressures rose and 207,000 barrels of incremental oil production was attributed to the use of surfactant foam. Despite some surfactant degradation, the chemical additive was successful in directing steam toward unswept areas.

Caustic, in the form of sodium metasilicate, has been added by operators to both steam drive injectors and cyclic steam wells in the Midway-Sunset field. The idea behind this was to create natural in-situ surfactants. The results in the steam drive were not promising, but the steam soak operation appeared to benefit from the additive. It is conjectured that this may be due to permeability improvements resulting from asphaltene removal near the wellbore.[21]

A survey of steam additive projects indicated that their use over the last decade has been successful in a majority of the published cases. Two mechanisms appear to be the basis for incremental production:

(1) A detergency effect that causes asphaltenes to dissolve and favorably modifies rock wettability and relative permeability characteristics.

(2) Diversion of steam by foam generation which reduces steam channeling and steam override problems.[22]

Published data place the cost per barrel of incremental oil between $1 and $6, mostly for the additive itself and any noncondensable gas used in its application (e.g., nitrogen).

Non-Steam Heavy Oil EOR Projects in California

While the cyclic steam and steamflooding operations are responsible for the majority of incremental EOR production from Slope-Basin & Basin clastic reservoirs in California, several other ongoing applications deserve mention. Of particular note are in-situ combustion operations in the West Newport and Midway-Sunset fields and an immiscible CO_2 injection project in the Wilmington field.

The in-situ combustion project in the West Newport field began in 1958 and is still in operation. Currently, there are 36 air injectors and over 130 active producing wells in this 300 acre project.[23] A significant portion of the incremental oil produced at West Newport has come from productivity improvement in outlying wells beyond the actual pattern producers.[24] Currently, about 350,000 barrels of incremental oil is produced with the injection of about 1.5 Bcf of compressed air annually.[25] This equates to an air-to-oil ratio of about 4 Mcf per recovered barrel of oil. More than 13 million barrels of incremental oil have been produced at West Newport through in-situ combustion operations.

The in-situ combustion projects in the Midway-Sunset field have been carried out in conjunction with steam injection and primary production mechanisms. Mobil's 150 acre, three injector project in the Moco zone had significant primary production rates prior to the start of air injection, and primary production mechanisms probably contributed to the early thermal oil response.[26] This project is still producing about 500 barrels of incremental oil per day (BOPD). Santa Fe began a smaller, more closely spaced project in 1982 which is currently producing about 700 BOPD of incremental oil. Both of these projects have been reported as profitable as recently as 1992.[27]

Of considerable interest is the recent (1991) reactivation of an immiscible CO_2 injection project undertaken by Champlin Oil Co. in the Wilmington field. Champlin reported on the success of its pilot test in 1986, after 50 months of CO_2 injection into the Tar zone of Fault Block III in the Wilmington field.[28] The pilot was expanded in 1984-85 and then deactivated following the oil price drop of 1986. Injection was begun again in 1991.[29] Champlin determined that a gross CO_2 requirement of between 6 and 10 Mcf per incremental barrel was needed for the recovery obtained, depending upon the degree of CO_2 leakoff from the flood area. While not profitable itself, the pilot project suggested that with economies of scale, a well bounded reservoir, and recycling of CO_2, the process could be economic. Immiscible CO_2 displacement reduces oil viscosity as the CO_2 dissolves in the oil and increases oil volume, decreasing the residual oil saturation in a manner somewhat analogous to thermal processes which utilize heat to achieve a similar viscosity reduction. Due to their generally shallow depths and because the high pressure required to achieve miscibility will exceed the fracturing pressure of the shallow formations, heavy oil Slope-Basin & Basin clastic reservoirs will almost always be candidates for an immiscible rather than a miscible CO_2 injection process. Success will depend on the properties of the specific oil within the heavy oil reservoir and how that oil responds to CO_2.

Other non-thermal EOR projects in California's heavy oil reservoirs have included caustic (alkaline), micellar-polymer, and polymer injection operations (Table IV-4). At present, no significant volumes of incremental oil are attributed to any of these processes in California's Slope-Basin & Basin clastic reservoirs. However, some of these projects have references that highlight the potential benefits and problems of heavy oil recovery using chemical processes. A flurry of chemical (and CO_2) projects were implemented in the early 1980s, but most were discontinued within five years. The contribution of chemical processes to the incremental EOR oil stream was largely confined to those years (Figure IV-6).

For example, after two years of operation, the operator of the Wilmington micellar-polymer pilot predicted that about 140,000 barrels of incremental oil would be produced from a 10 acre area.[30] This was about two-thirds of the expected recovery and the difference was largely attributed to operating problems related to sand production and bacterially generated corrosion.

The Wilmington field FB VII Ranger zone caustic flood was a 91 acre pilot project carried out over three years. Although laboratory case tests showed a potential for recovery of about 6% of the OOIP, a high degree of alkali consumption in the reservoir, coupled with wellbore plugging problems due to scale deposition resulted in no measurable improvement in oil recovery.[31]

While many EOR processes have been tested in California Slope-Basin & Basin clastic reservoirs cyclic steam injection is clearly the most successful based on the results to date. While recently developed chemical additives have been shown to improve the performance of thermal projects, conventional chemical injection projects have not been proven economic. Immiscible CO_2 injection appears to show promise as a technique for reducing heavy oil viscosity in much the same way as steam; however, it appears to be very closely tied to specific oil characterization and a series of difficult lab experiments are needed prior to initiating field activities in untested reservoirs. Given the increasing level of environmental regulation associated with steam generation, this process may prove to be a viable alternative to steam if an inexpensive source of CO_2 can be found.

Table IV-4

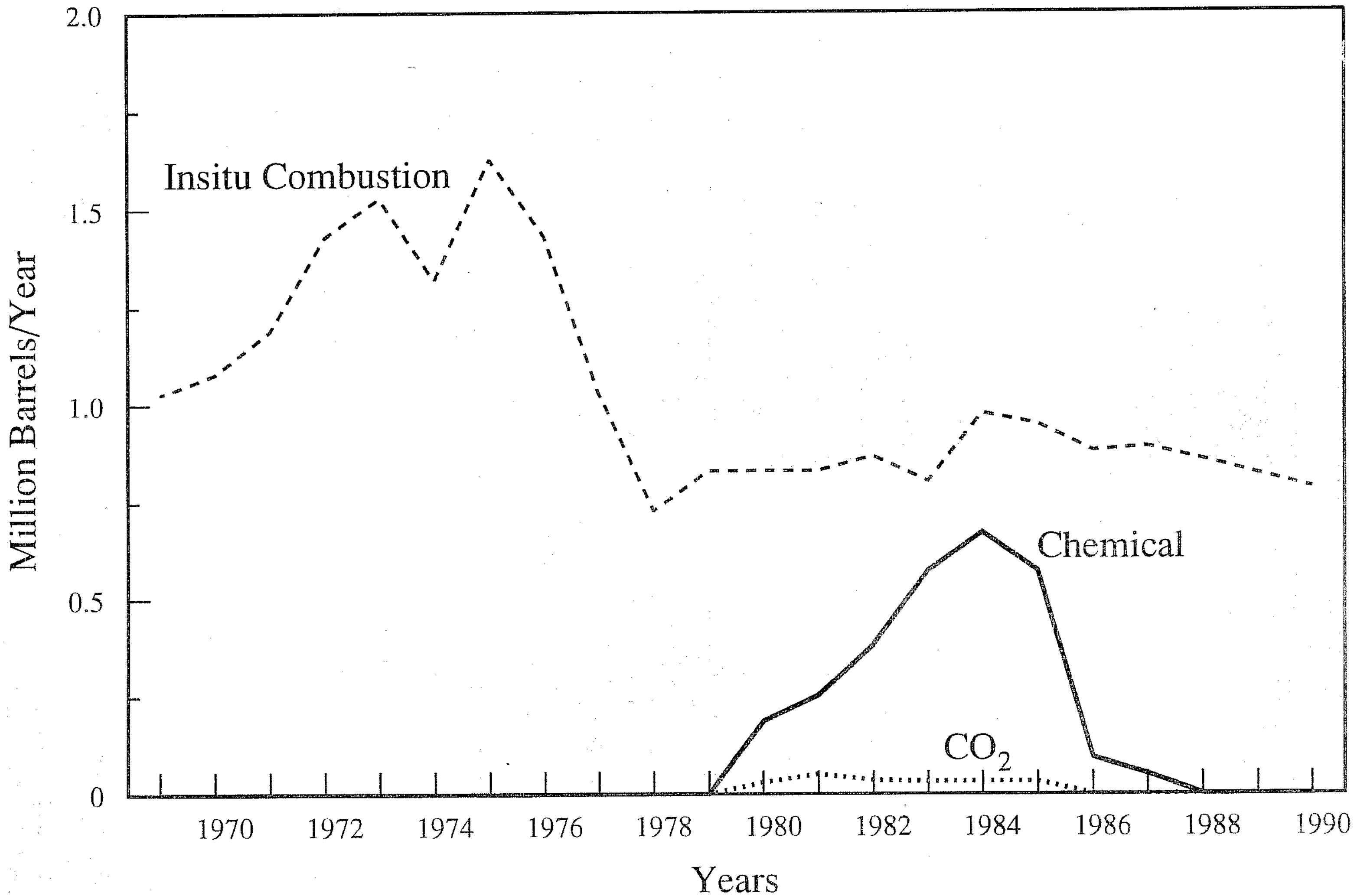
Discontinued Non-Thermal EOR Projects in California Slope-Basin & Basin Clastic Reservoirs

Field	Operator	Start Date	End Date	Process Type	Zone	Ref.
Wilmington	THUMS/DOE	1977	1986	Caustic	FB VII Ranger	31
	LBODC/DOE	1977	1984	Micellar-polymer	FB VB U. Terminal	30
	LBODC	1981	1989	Immiscible CO_2 WAG	FB V Tar	6, 28
	Exxon	1981	1984	Polymer	FB I Ranger	1
	LBODC	1981	1986	Caustic	FB IV Ranger	6
	Xtra Oil Co.	1983	1986	Immiscible CO_2 WAG	FB I Ranger	6, 28
	Mobil	1969	1972	Polymer	FB V Ranger	6
Torrance (Joughin Unit)	Superior	1980	1986	Caustic	Main	6
Huntington Beach	Aminoil	1979	1987	Caustic	L. Main	6
	Aminoil	1981	1982	CO_2-WAG	A-37 onshore	6
East Coyote (Hualde Dome Unit)	Union Oil	1982	1985	Immiscible CO_2 WAG	Pliocene/ Miocene	6
Whittier	Chevron	1983	1987	Alkaline	Repetto	6
Richfield (East Dome Unit)	Texaco	1983	1987	Alkaline	Chapman/ Kraemer	6
West Coyote	Chevron	1983	1984	Polymer	Upper 99	6
Ventura	Texaco	1983	--	Polymer	C-Block	6
Beverly Hills/ West Pico	Oxy USA	1984	--	Polymer	Repetto-Main	6
Dos Cuadras (Offshore)	Unocal	1986	1991	Polymer	EP/FP zones	6
San Miguelito	Conoco	1980	1990	Caustic	3rd Grubb	6
Orcutt (Main)	Unocal	1981	1984	Alkaline	Pt. Sal	6
North Coles Levee	Arco	1981	1984	CO_2 miscible	Stevens	6

LBODC = Long Beach Oil Development Company
THUMS = Texaco, Humble, Union, Mobil, Shell group

Figure IV-6

Incremental Oil Recovered from Non-Steam Processes in California Slope-Basin & Basin Clastic Reservoirs



Source: Annual Report of the State Oil & Gas Supervisor California Department of Conservation, Division of Oil & Gas (1970-1991)

EOR Applications in Non-California Slope-Basin & Basin Clastic Reservoirs

Beyond California, published accounts of the application of EOR processes to Slope-Basin & Basin clastic reservoirs have been limited to miscible floods -- CO_2 in west Texas and Mississippi and hydrocarbon gas in South Pass Block 61 in the Gulf of Mexico (Table IV-5). The Ford Geraldine and Twofreds fields of west Texas have been undergoing CO_2 injection into the Class III Delaware sandstone since 1981 and 1974, respectively. While both are considered technical successes, they have some operational differences. The following sections describe in greater detail their particular characteristics.

Twofreds Field Miscible CO_2 Injection Project

The Twofreds field is located in west Texas, approximately 17 miles north of Pecos, Texas. Production is from the Ramsey zone of the Delaware sandstone, which in turn is the uppermost sand member of the Permian Bell Canyon sequence.[32] The Delaware sand is extremely fine-grained and well sorted with a permeability of 28 md.[33] Primary production began in 1957 and continued until water injection began in 1963. The initial water saturation in the eastern side of the field was higher than in the western portion of the field, and water injection was delayed in that area. Once begun, injection in the eastern side did not elicit as great a response as on the western side.[33]

CO_2 injection began in the east side in 1974 after production had reached a secondary economic limit. Exhaust gas alternating with water was used to chase the CO_2 slug between 1980 and 1986. Water injection was continued until 1990, and the east side project has nearly completed its tertiary production life with only about 100 to 150 BOPD currently being produced. East side incremental production has been 2.4 million barrels of oil with the injection of 25.3 Bcf of CO_2, 2.5 million barrels of water, and 3.4 Bcf of exhaust gas. With CO_2 recycling, net CO_2 utilization to date is 8.0 Mcf per barrel of oil recovered on the eastern side of the field.[33]

Expansion of the CO_2 project to the west side of the Twofreds field began in the early 1980s as CO_2 became available from the east side of the field. Incremental oil recovery to date is estimated at 2.1 million barrels with a current cumulative net CO_2 utilization of 11.2 Mcf per barrel of oil recovered.[33] Purchased CO_2 injection was discontinued in 1992, and recycled gas WAG (water-alternating-gas) was initiated in 1993.

The Twofreds field was the first field-scale CO_2 injection project in a sandstone formation in Texas and in over 20 years of operation, has resulted in the recovery of more than 4 million barrels of tertiary oil. If the remaining western portion of the field behaves consistently with the eastern section, close to 16% of the OOIP will be recovered fieldwide by miscible CO_2 injection.[33]

Ford Geraldine Miscible CO_2 Injection Project

Conoco initiated a miscible CO_2 injection project in a 3,850 acre area of the 8,400 acre Ford Geraldine Unit of Reeves and Culberson counties, Texas in 1981. Begun after a staged waterflood was nearing its economic completion but leaving nearly 80% of the OOIP in the reservoir, the project was designed to utilize CO_2 from the Lone Star gas plant, which processed high CO_2 content gas from the Elsinore field in Pecos County, Texas.[34] The 112 mile pipeline was operational in 1981, several years before the large trunklines bringing CO_2 into west Texas from the McElmo Dome, Sheep Mountain, and Bravo Dome fields were completed (Figure IV-7). However, a deteriorating gas market caused the gas plant to operate sporadically. The lack of a dependable CO_2 supply hampered development plans and resulted in the shut-in of producers and an inability to maintain reservoir pressure. In 1985, Conoco

Table IV-5

Ongoing Non-California Slope-Basin & Basin Clastic EOR Projects

					Current Wells						
Field	Operator	Project Type	Start	Area (acres)	Prod.	Inj.	Pay Zone	Inc. Oil (BOPD)	Ave. °API	Depth (ft)	References
Twofreds (TX)	Enron	Miscible CO_2	1974	4,392	45	36	Ramsey Sand (Delaware)	500	36.4°	4,820	1, 32, 33
Ford Geraldine (TX)	Conoco	Miscible CO_2	1981	3,850	91	69	Ramsey Sand (Delaware)	1,500	40°	2,680	1, 34-37
Tinsley (MS)	Pennzoil	Miscible CO_2	1981	1,120	11	3	Perry Sand	150	39°	4,800	1, 38
South Pass Blk. 61 (OCS)	Arco	Hydrocarbon Miscible (10 projects)	1981-1989	950	32	12	Pliocene-Miocene Sands	7,035	29-41°	4,900-9,100	1, 52

arranged for CO_2 to be supplied from the Big Three Pipeline, which distributes CO_2 transported from Colorado via the Cortez Pipeline.[35] However, with the supply assured, Conoco has proceeded with a staged expansion of the flood and currently produces about 1,500 BOPD of incremental oil.[36] Conoco estimates that the CO_2 flood will ultimately recover 13% of OOIP, or nearly 13 million barrels.[37]

Tinsely Field Miscible CO_2 Injection Project

Pennzoil has operated a miscible CO_2 injection project at the Tinsley field in Yazoo County, Mississippi since 1981. The project is close to reaching its economic limit at this point, but about 150 BOPD of incremental oil is still being produced from the 11 wells. The source of CO_2 is a Pennzoil well in nearby Rankin County. About 28% of OOIP had been produced by primary and secondary methods when the Tinsley project was undertaken. Miscible CO_2 flooding has recovered an additional 2.8 million barrels; however, the total required investment was several times the original estimate. Escalation of costs coupled with the drop in oil prices has made the Tinsley project uneconomical.[38]

Incremental oil recovery from miscible CO_2 floods in Slope-Basin & Basin clastic reservoirs amounts to about one million barrels per year, less than 1% of California's heavy oil EOR production (Figure IV-8). With the decline in production from the Ford Geraldine field, the most prolific of these projects, and without new initiatives to implement CO_2 injection in other light oil Slope-Basin sandstones, the contribution of non-California Slope-Basin & Basin clastic reservoirs to the stream of EOR production will decline.

Sources of CO_2 for Miscible Flooding in Slope-Basin & Basin Clastic Reservoirs

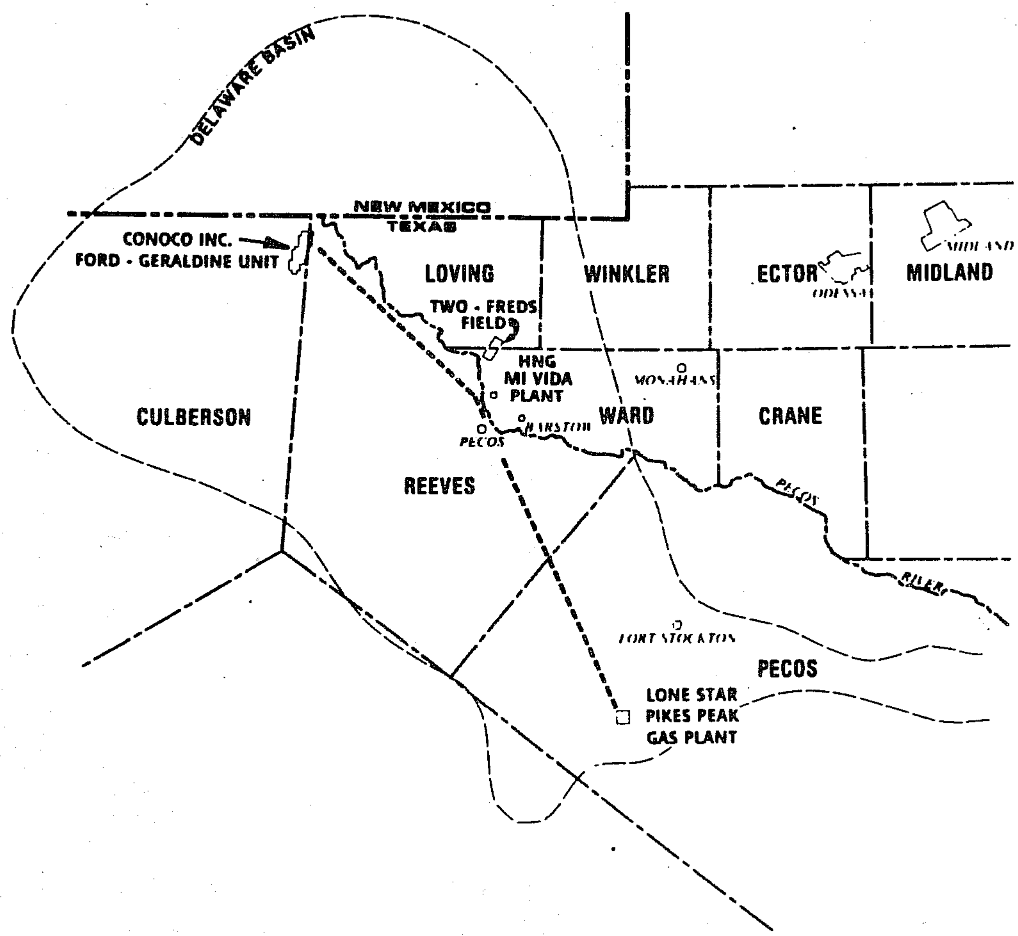
Initial CO_2 flooding projects in the Permian Basin relied on CO_2 removed from natural gas produced from the Delaware and Val Verde basins in Texas. The Ford Geraldine field (and non-Class III fields such as Kelly-Snyder and Crossett) have used gas from these fields, and the Twofreds project has been supplied with gas from the MiVida plant located in western Ward County, Texas. Unfortunately, such a source is dependent on the operating capacity of the plants. If gas production is shut in or cut back, the volume of available CO_2 is diminished.

Significant volumes of naturally occurring high-purity CO_2 exist in the subsurface. These sources are likely to supply the bulk of future needs for CO_2 miscible flooding in Slope-Basin & Basin clastic sandstone reservoirs. This is particularly true in western Texas, where a well developed infrastructure now exists for delivering CO_2 to oil fields with miscible recovery potential. Roughly three quarters of the documented North American CO_2 reserves are in the Colorado-Utah-Wyoming-New Mexico area, occurring at depths ranging from 2,200 feet (Bravo Dome) to 18,500 feet (La Barge area). The location of these CO_2 deposits is a result of the intrusion of igneous material into water-filled carbonates.

The major sources of CO_2 in the U.S. are listed in Table IV-6,[39,40,41] and their locations shown in Figure IV-9. The Pikes Peak and Puckett area gas plants have been a source of CO_2 supply for several ongoing CO_2 floods, as mentioned previously. The three known high purity natural sources of CO_2 for New Mexico and Texas miscible flooding projects are McElmo Dome, Bravo Dome, and Sheep Mountain. The McElmo Dome field is located in Dolores and Montezuma counties of southwestern Colorado. The gas in McElmo Dome/Doe Canyon is 98% CO_2 with only 2% nitrogen and hydrocarbons, a particularly pure source. Published references to reserves in McElmo Dome range from 8.4 to 12 Tcf. It appears that McElmo Dome reserves are at least nine Tcf after accounting for roughly one Tcf of production over the last five to six years, and without any additions to reserves based on the new wells drilled in 1990 and 1991. The Bravo Dome CO_2 unit encompasses over one million acres in portions of

Figure IV-7

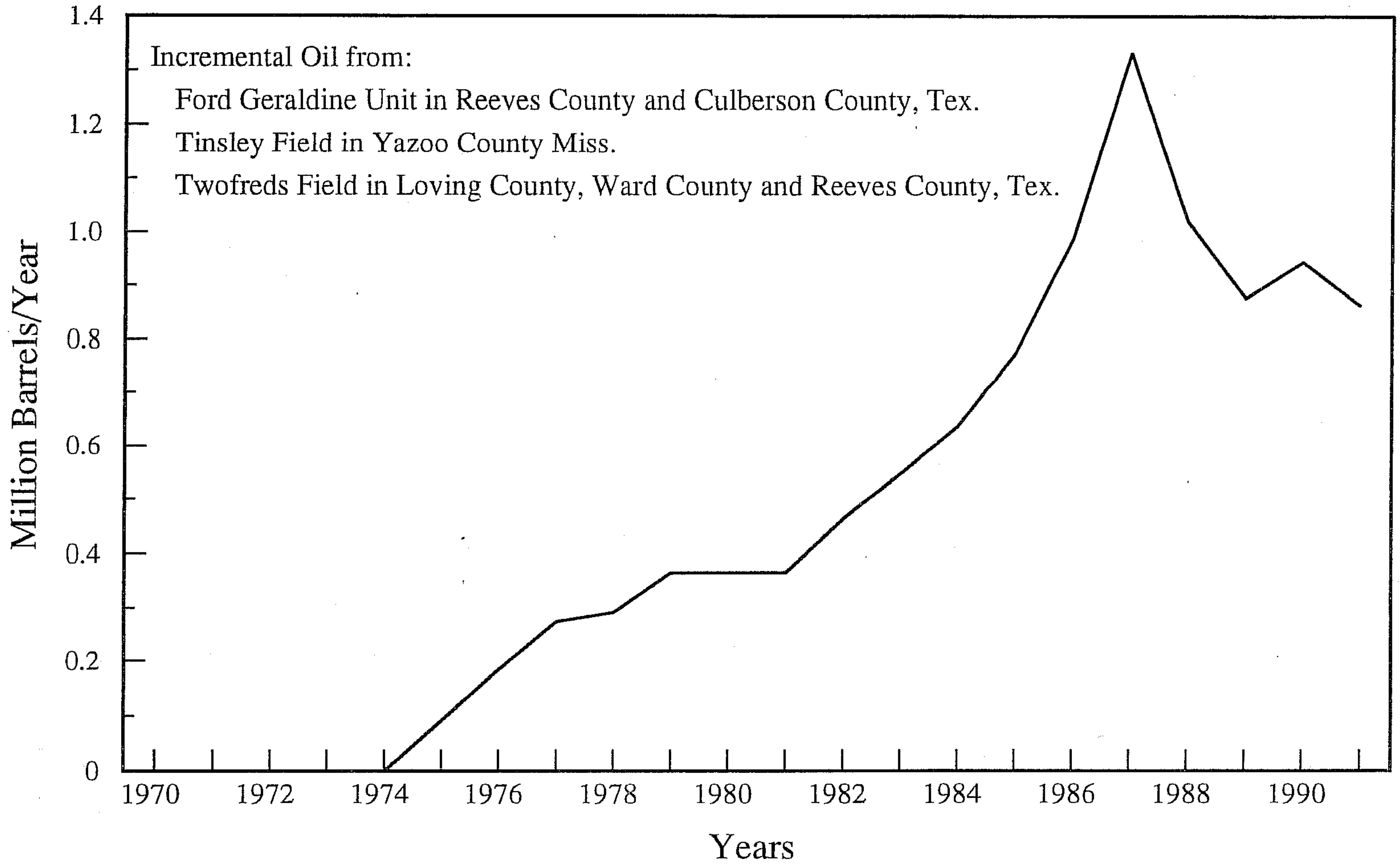
Delaware Basin Showing Ford Geraldine Unit and Twofreds Fields Relative to Sources of CO_2



Source: Phillips, L.A., McPerson, J.L. and Leibrecht, R.J."CO_2 Flood: Design and Initial Operations, Ford Geraldine (Delaware sand) Unit", SPE paper 12197 presented at Annual Technical Conference in San Francisco, CA, Oct. 5-8, 1983

Figure IV-8

Incremental Oil Recovered from Miscible CO_2 Projects in Non-California Slope-Basin & Basin Clastic Reservoirs



Source: Annual Report of the State Oil & Gas Supervisor California Department of Conservation, Division of Oil & Gas (1970-1991)
Pennzoil, Conoco and Murphy E&P Co. (Personnal Communication)
SPE Papers 12197 and 26614; OGJ (April 20,1992) EOR Database

CL3\ NON-CA

Figure IV-9

Major Natural CO_2 Sources

CL3\ SOURCE

Table IV-6

Major Natural CO_2 Sources in the United States

Field	Location	Reserve Size (Tcf)
High Purity Sources (96-99% Pure CO_2)		
McElmo Dome/Doe Canyon	S.W. Colorado	9+
Bravo Dome	N.W. New Mexico	7-8
Sheep Mountain	S.E. Colorado	1-0.5
Jackson Dome	S.W. Mississippi	2-4
Kaiparowitz Basin	S. Central Utah	1-3
Farnham Dome	Central Utah	1-3
Lower Purity Sources (50-85% Pure CO_2)		
LaBarge - Big Piney Areas	S.W. Wyoming	20+
Paradox Basin	S.E. Utah	1
Val Verde/Delaware Basins	S.W. Texas	0.5-1.0

Union, Harding, and Quay Counties, New Mexico. Published reserve estimates for the Bravo Dome field range from six to 11 Tcf. It appears that in 1986, reserves were about 8.4 Tcf and that subsequent production has reduced this to roughly seven Tcf.

CO_2 production from the Sheep Mountain field located in Huerfano County, Colorado comes from the Dakota and Entrada sandstone formations. Sheep Mountain gas is 97% pure CO_2 and total acreage is roughly 8,500 acres. Published reserves estimates for Sheep Mountain range from one to 2.5 Tcf. Based on information supplied by the Colorado Oil and Gas Conservation Commission, original reserves of one Tcf have been depleted by more than 50%, and a decline in deliverability will begin in late 1993.

Jackson Dome in central Mississippi (Rankin, Scott, and Madison Counties) is another natural source of CO_2 where development has taken place. Sufficient drilling has been done to prove up an estimated 1 Tcf of CO_2 reserves, and undrilled acreage is thought to have a potential of at least an additional 2 Tcf.[42] Shell is the most active developer of these reserves and supplies three ongoing CO_2 floods (non-Class III projects in the Little Creek, Olive, and West Mallalieu fields) from their roughly 50,000 acres of CO_2 holdings.[42] CO_2 is supplied via the 91-mile Choctaw Pipeline, which terminates near McComb, Mississippi. The smaller scale CO_2 flood underway at Pennzoil's Tinsley field is connected to Pennzoil's CO_2 supply well at Jackson Dome by a 43-mile line. An extension of the Choctaw line (the Evangeline Pipeline) carries CO_2 an additional 150 miles from Mississippi to Shell's Weeks Island field in south Louisiana.

Infrastructure for Supplying CO_2 to Slope-Basin & Basin clastic Reservoirs

Before the 1980's, the only CO_2 pipeline was the Canyon Reef Carriers Line built in 1972 to carry CO_2 from the Pecos County gas plants to the Kelly-Snyder (SACROC) CO_2 flood. However, when the potential for CO_2 miscible flooding in the Permian Basin was realized, the three major trunklines (Cortez, Bravo, and Sheep Mountain) were constructed in 1983 and 1984. Subsequently, private companies built additional lines to carry CO_2 south to the rest of the Basin. These pipelines, the Central Basin Pipeline (operated by Enron) and the Big Three Pipeline (operated by Big Three Industries) became operational in 1985 and 1986 (Figure IV-10).

The Cortez pipeline is designed to carry dry, supercritical carbon dioxide from McElmo Dome to the Permian Basin. It is the longest, largest such pipeline in existence. The initial capacity of 650 MMcf per day has been boosted to 850 MMcf per day, and can be expanded to one Bcf per day.[42,43] The Bravo Dome Pipeline has been carrying CO_2 from the Bravo Dome field since late 1984. The 20-inch line is capable of delivering 380 MMcf per day and ends approximately three miles north of Denver City in the Wasson field area.[44] Most of the gas it delivers is injected into the Amoco and Exxon units of the Slaughter and Wasson fields. CO_2 production from Sheep Mountain is transported via the Sheep Mountain pipeline. The northern 183 miles of this line is 20 inches in diameter and capable of delivering 330 MMcf per day. At a point just south of Bueyeros, New Mexico, the diameter is expanded to 24 inches, which increases its capacity to 500 MMcf per day.[45] This is to accommodate gas from Bravo Dome, delivered via the Rosebud line. Overall, the CO_2 distribution system is well developed and currently operating below capacity.[46,47,48,49,50] The lines heading south from Denver City can deliver gas to practically any portion of western Texas and eastern New Mexico with a minimal amount of lateral line requirements.

Offshore Gulf of Mexico EOR Projects in Slope-Basin & Basin Clastic Reservoirs

Another area where miscible flooding of Slope-Basin & Basin clastic reservoirs is underway is in the Louisiana offshore area. Arco initiated 10 miscible injection projects in South Pass Block 61 Field between 1981 and 1985.[51] All of these involved upstructure injection of produced natural gas (in some cases with added natural gas liquids (NGLs)) and production of the miscibly displaced oil from down-dip wells. Four of the ten projects were relatively large (>100 acres), but none were greater than 320 acres. Arco reported a total of 7,035 BOPD of incremental oil from nine of these projects in 1992, with the smallest project (29 acres) being discontinued in 1991. Currently, only field gas (no added liquids) is being injected to chase the previously injected miscible slug of natural gas and NGLs. Arco is considering the possibility of cycling lean gas through the reservoir to extract liquids once the miscibly displaced oil has been recovered.[52]

Summary

The greatest portion of the incremental oil produced by EOR techniques in Slope-Basin & Basin clastic reservoirs is thermal EOR production in California's reservoirs, primarily the Midway-Sunset field (Figure IV-11). Only about 5% of the total EOR incremental oil produced during the last two decades is non-thermal. While other advanced secondary recovery (ASR) processes may have been attempted in Slope-Basin or Basin clastic reservoirs (most likely polymer flooding in Delaware sandstone reservoirs of southwestern Texas), the results have not been widely reported. While infill drilling has undoubtedly been carried out in many Slope-Basin & Basin clastic reservoirs, particularly as part of the conversion to waterflooding and subsequent to steam injection or CO_2 injection, these efforts have not been widely discussed in the literature.

Figure IV-10

Major CO_2 Pipelines Servicing the Permian Basin and the Rocky Mountain States

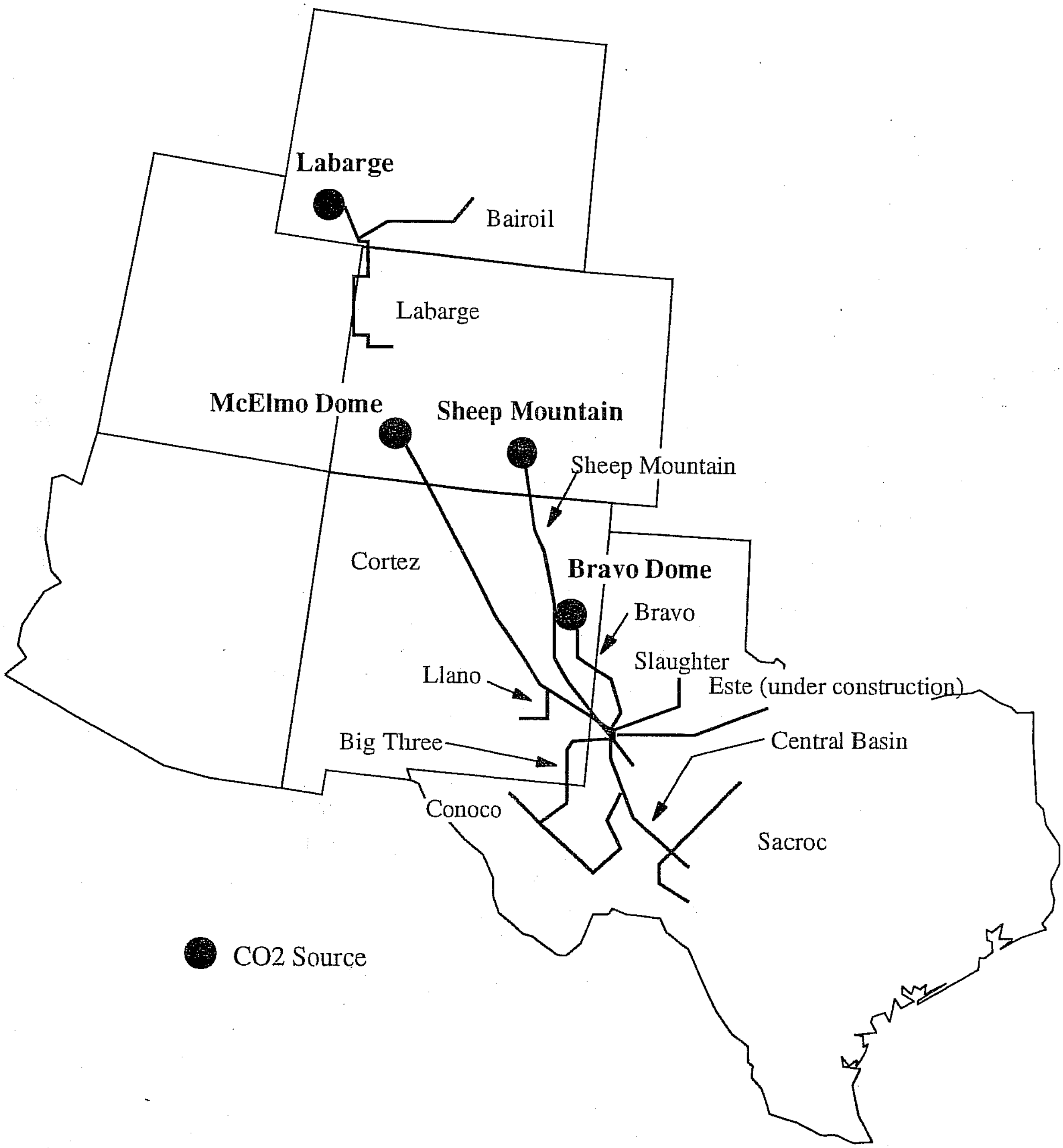


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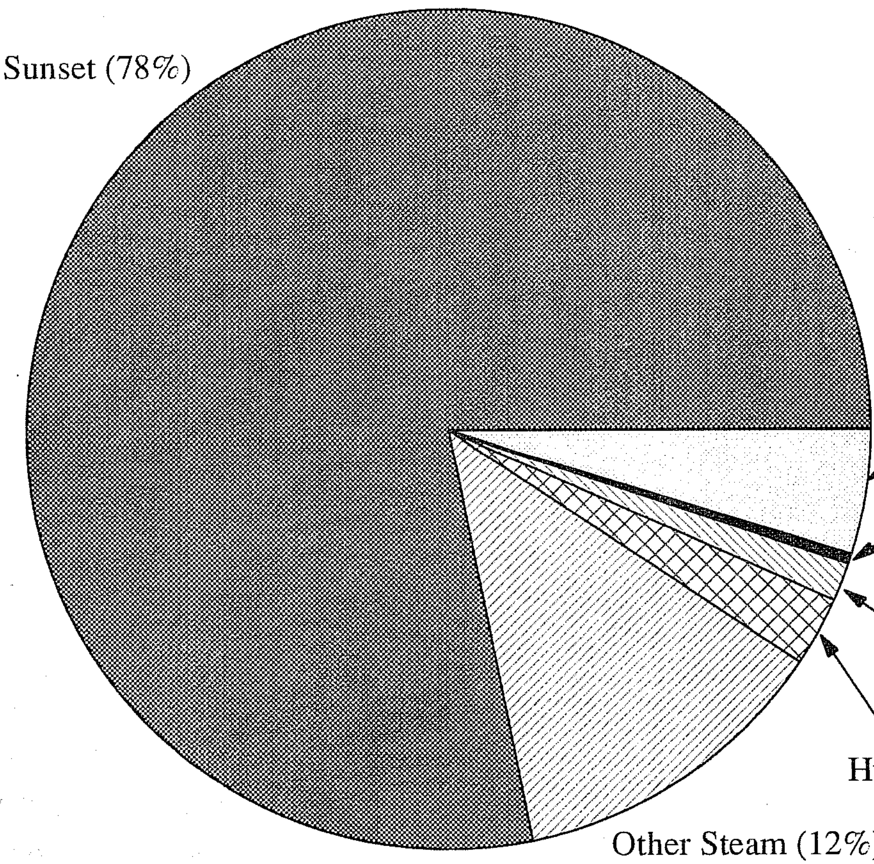
Figure IV-11

Incremental Oil Recovered due to EOR Since 1970 in Slope-Basin & Basin Clastic Reservoirs



Total Incremental Oil Recovery = 747 Million Barrels

Source: Annual Reports of the State Oil & Gas SupervisorCalifornia Department of Conservation, Division of Oil & Gas (1970-1991)
Pennzoil, Conoco and Murphy E&P Co. (Personnal Communication - Oct. 1993)
SPE Papers 12197 (Oct. 1983) and 26614 (Oct. 1993); OGJ (April 20,1992) EOR Database

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CHAPTER V

TECHNICAL AND OPERATIONAL CHALLENGES OF SLOPE-BASIN & BASIN CLASTIC RESERVOIRS

The most significant topics related to the production of oil from Slope-Basin & Basin clastic reservoirs are summarized in this chapter and issues of continuing importance are highlighted. Based on an analysis of the petroleum engineering and geological literature, this analysis has focused on the more significant TORIS Class III reservoirs as determined by original oil-in-place, remaining oil-in-place, and advanced recovery potential. The topics and many of the conclusions should be applicable to a majority of the fields in the Slope-Basin & Basin clastic class of reservoirs. Discussions related to these fields include the following:

(1) Operational and design issues (technical, environmental, and economic) related to enhanced oil recovery processes and completion practices;

(2) Reservoir characterization issues associated with the geology and production performance of Slope-Basin & Basin clastic reservoirs; and

3) Reservoir management issues associated with the integration of reservoir characterization and operational parameters to maximize recoverability throughout the economic life of the reservoir.

The more significant issues related to post-secondary production from Class III reservoirs, as determined by a search of the available literature, are highlighted in Figure V-1, and discussed in the following sections of this chapter. Potential environmental impacts related to the application of improved recovery technologies in Class III reservoirs are dealt with in Chapter VII of this report. This brief discussion is based upon a literature review and is meant to provide an overview of current technical and operational challenges related to the application of improved recovery technologies in Slope-Basin & Basin clastic reservoirs. It is not intended to be an exhaustive list of topics for future research.

Operational and Design Issues

Thermal Oil Recovery

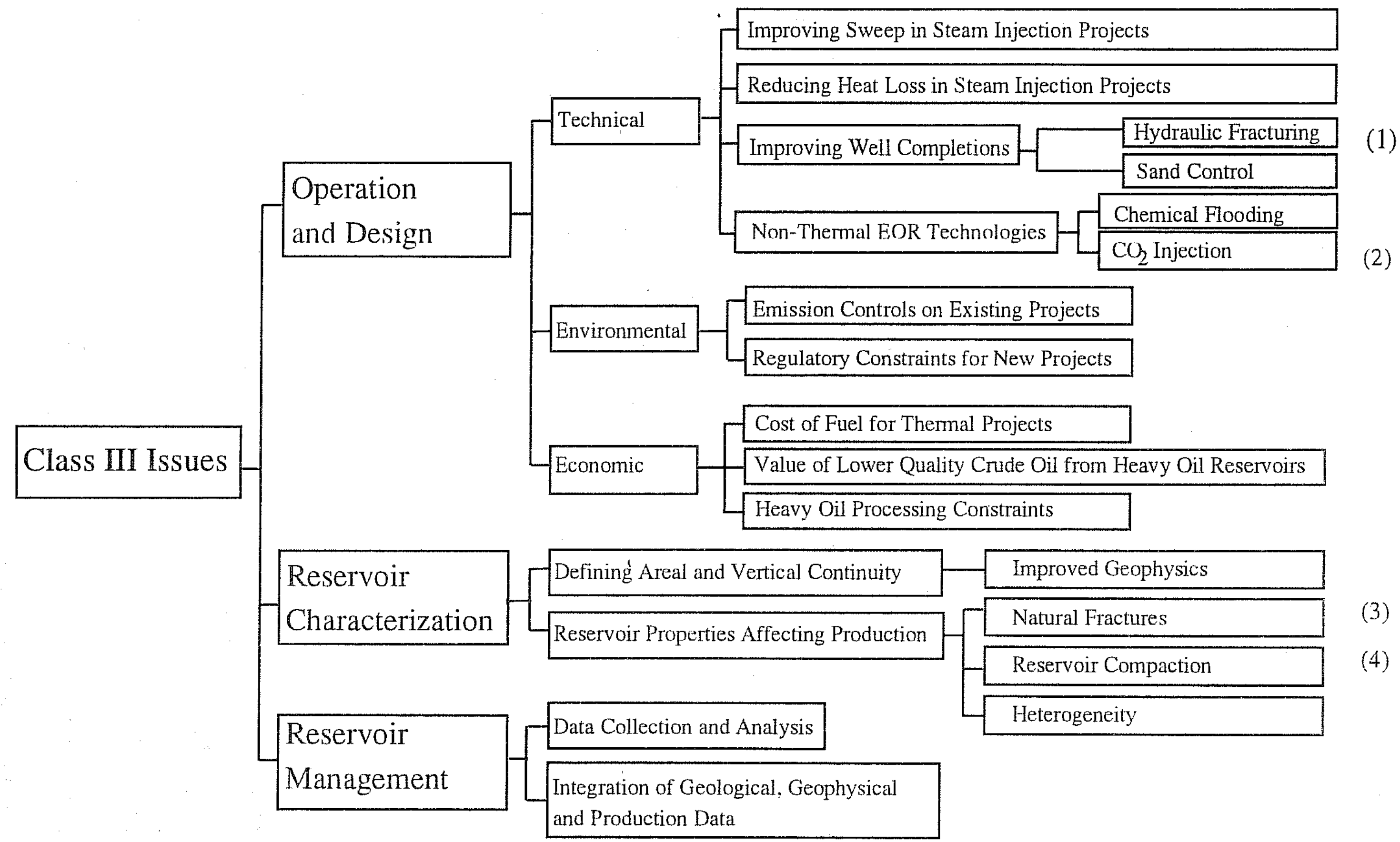
There are many technical challenges facing producers of Slope-Basin & Basin clastic reservoirs. To the extent that a large portion of Class III production is from heavy oil reservoirs, these challenges are faced by all heavy oil producers. Two technical challenges are specifically related to steam injection in Class III reservoirs: (1) the need to improve vertical and areal sweep efficiency in highly layered reservoirs, and (2) the need to maximize recovery from cyclic steam operations.

Sweep Efficiency Improvements

A common problem with steamdrive projects is that the high temperature (low density) steam tends to rise to the top of the reservoir or channel through high permeability zones, leaving uncontacted portions of the reservoir with high oil saturations. Because turbidite reservoirs often have many layers

Figure V-1

Examples of Technical and Operational Issues in Slope-Basin & Basin Clastic Reservoirs



Notes:

(1) Examples such as Diatomite and Delaware Sandstone
(2) Examples such as CO_2 Miscible and Immiscible Processes
(3) Examples such as Monterey and Spraberry Formations
(4) Examples such as Turbidites and Diatomite

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of productive unconsolidated sand separated by laterally extensive shales, the importance of maintaining vertical conformance among layers is critical.

One approach to solving the steam channeling problem has been to inject a foaming agent with a non-condensible gas (such as nitrogen). The foam resists the flow within the established steam channel, diverting steam to other intervals of the formation. There are two methods of application: a small slug of foam injected with the steam to control injection profiles ("steam-foam treatment"), or a continuous injection of foam with the steam throughout the life of the project ("steam-foam process"). A number of researchers have published results on field applications of this technology.[1,2,3,4,5,6] In the majority of published cases the additives have been successful.[7] In addition, caustic additives and thin-film spreading agents (TFSA) have worked well in cyclic applications, while surfactants have been effective in both steamdrives and cyclic operations. Two mechanisms can be identified as instrumental in recovering additional oil through injection of these additives: (1) a detergency effect which dissolves asphaltenes and modifies the wetting characteristics of the rock, thus, improving the productivity of the near-wellbore area, and (2) the diversion of steam towards unswept areas through foam generation.[8]

Thermosetting plastics have also been utilized to improve steam injection profiles.[9,10] These materials form a permanent plug and are generally considered applicable in thinner intervals. During the past three years, high temperature gels have been developed and successfully applied to reduce steam channeling and steam override in mature thermal projects.[11] These relatively inexpensive gel treatments divert steam from existing thief zones and increase incremental oil production. Additional advances in the area of chemical augmentation of steam injection to improve performance will help to achieve the high thermal recovery potential of Class III reservoirs.

The use of horizontal and radial wells to improve sweep efficiency is an emerging technology. For example, Unocal has used a horizontal injector to efficiently heat a previously unswept portion of the Potter Formation, a Class III reservoir currently under steamflood in the Midway-Sunset field.[12,13] Observation well data from this project confirm that the vertical injectors are distributing heat less effectively than the horizontal injector.

Although steamdrive projects have been proven economic in Class III reservoirs,[14] cyclic steam injection appears to be more widely applied in the steeply dipping reservoir of the Midway-Sunset field. The need to continually optimize recovery using this method is also evident, as shown by efforts to improve recovery through sequential steam injection.[15] Refinements to already proven thermal applications will be required to help maintain heavy oil production rates from fields which have had their more easily developed areas processed and from fields or reservoirs which have been unable to support less efficient steam injection techniques.

Horizontal well drilling to improve ultimate recovery in Class III reservoirs has demonstrated mixed results. Horizontal well technology was proven to be successful in accelerating oil production and improving ultimate recovery from the Stevens sand in the Elk Hills field.[16,17] Four horizontal wells have been drilled and placed on production since 1989. Horizontal wells in the 26R reservoir were utilized to drain downdip "wedge oil", which would be marginally economic to develop using conventional vertical wells. The horizontal wells yielded improved oil recovery at highly economic rates by paying out in 3 months and reducing gas cycling costs. Estimates of additional recovery from the 26R sand reservoir as a result of horizontal well development are as high as 10% of OOIP.

In the Spraberry and Dean sands in west Texas, eight attempts have been made to drill and complete horizontal wells, and the results have been disappointing to date. The horizontal wells drilled perpendicular to the assumed fracture trend did better as a group, however, analysis of individual well performance indicates that this fracture azimuth is not the only factor controlling production.[18] A decrease of fracture conductivity with a decrease in pore pressure, seen from vertical wells, was considered as one reason for the sharp declining of production.

Steam Quality

Another technical challenge facing producers of heavy oil from Class III reservoirs is the efficient delivery of high quality steam to the reservoir without heat losses in the wellbore. Losses within the wellbore are currently minimized through the use of insulation. Typically, an insulating additive is included in the cement used to set the casing, insulated tubing is installed, or an insulating gas blanket in the casing/tubing annulus is used. Wellbore heat loss is actually more of an economic challenge than a technical one. The costs of implementing available technology are too high given the value of this production.

For the past twenty years there has been an attempt by industry to develop a downhole steam generator to reduce wellbore heat losses. Currently, no downhole steam generator is in use commercially. There are experimental generators of three basic designs: (1) the hot combustion gases mix directly with feed water and the resulting gas/steam mixture is injected into the reservoir; (2) the combustion gas is conducted to the surface after heating the water;[19] and (3) electricity is used to generate steam downhole.

Well Completion

Well completion and production issues in Class III reservoirs are related to several topics depending upon the specific sub-class of Slope-Basin & Basin clastic reservoirs being produced. For example, low permeability diatomite reservoirs in the South Belridge field (< 2 md with 50% porosity and 60% oil saturation) have been stimulated using massive hydraulic fracturing treatments since the mid-1970s. Hundreds of fracture treatments have resulted in high initial post-treatment rates but rapid early decline. Improvements to fracture treatment design are continuing through the use of tiltmeter surveys, tracer surveys, and computer simulation. By understanding the reasons for fracture conductivity loss and the behavior of flow through fractured rocks, optimal completions can be designed to maximize recovery of this important Class III resource.[20,21]

New fracturing techniques must also be developed to improve productivity from turbidite pay intervals in the Delaware Formation of Texas. For example, oil production in the Brushey Canyon sands is from stratigraphically trapped lenticular sandstone bodies overlain by shale and/or dense dolomite, and separated from a water producing sand by a thin shale barrier. A "pipeline" fracture technique has been developed that is capable of selectively placing high concentrations of proppant across these relatively thin pay intervals, resulting in highly conductive propped fractures, longer term oil production, and reduced water-oil ratios.[22] Developments such as this can help to improve the economics of wells producing from highly laminated turbidite formations.

Many Slope-Basin formations are unconsolidated and prone to sand production. This is particularly true in the high permeability zones of the Southern California heavy oil formations and in offshore Gulf of Mexico turbidite formations. The conventional method for handling this problem is the use of gravel packs or wire-wrapped screen. New, cost effective techniques for limiting sand production from these formations, particularly in horizontal wells, could help to improve additional development of Class III reservoirs.

Non-Thermal Enhanced Oil Recovery

Non-thermal EOR technologies have been applied in Class III reservoirs, and there are specific technical challenges related to their wider application. Chemical floods have seen some success and researchers have shown that while pilot project recoveries have been encouraging, operational problems resulting from sand production and bacterially induced corrosion have undermined the economics.[23] Widespread application of chemical floods in Class III reservoirs will not be seen until these operational problems are solved, concurrent with the development of lower-cost chemicals.

Several field tests have shown the potential for immiscible injection of carbon dioxide in Class III reservoirs to improve recovery of heavy oil in poorly waterflooded zones.[24,25] Of major importance are efforts which focus on the minimization of CO_2 aggravated corrosion problems, the cost-effective separation of CO_2 from produced gases, and the optimization of CO_2 injection cycles and/or WAG (water alternating gas) injection schedules for specific reservoir conditions. Technologies which improve the cost effectiveness of CO_2 injection as an alternative to steam could generate a considerable demand for CO_2 in Southern California that may justify connection with a high quality source of CO_2.

Miscible flooding with CO_2 has been shown to be quite effective in several non-California examples.[26,27] One of these examples has been used to demonstrate the economics of miscible CO_2 injection in small-to-medium size fields close to an established CO_2 distribution infrastructure.[28] The further application of miscible CO_2 injection to light oil reservoirs in non-California Class III reservoirs will depend upon technologies which can improve the cost effectiveness of CO_2 injection, particularly in an era of lower oil prices. These technologies include the use of a carefully designed exhaust gas WAG to displace a CO_2 slug and the optimization of injection on a pattern basis using state-of-the-art monitoring techniques.[29]

Environmental and Economic Issues

Much of the potential for Class III reservoirs is to be found in thermal recovery. To remain competitive, ongoing and newly developed thermal recovery projects must survive increased fuel costs, increased environmental costs and constraints, and a reduced value for low gravity crude. Efforts to reduce steam generator fuel requirements, increase efficiency, and reduce emissions all will be required in order to capitalize on the full recovery potential in Class III reservoirs.

For example, heavy oil producers in California have recently begun to convert their lease crude-fired steam generators to natural gas.[30] Gas-fired generators do not require expensive SO_x scrubber units, they receive air quality permits more readily, and are generally more energy efficient. Also, the co-generation of steam and electricity in natural gas-fired thermal operations is economically attractive because the electricity generated in the process can be used on-site or can be sold to the electric utility grid. One estimate shows the gas requirements for these cogeneration facilities growing from 760 MMcf/day in 1989 to over 1.0 Bcf/day in 1995, and remaining above 1.0 Bcf/day until the year 2010.[31] Because operating costs are the single largest cost component affecting thermal oil recovery project economics (with fuel costs accounting for the largest portion of operating costs), changes in the efficiency of gas usage in steam generators could play a role in expanding the number of economic projects.

The economic success of steam injection projects is generally measured by their energy efficiency, which is characterized by the steam/oil ratio -- the volume of steam in barrels (cold water equivalent) required to produce a barrel of incremental oil. From 1970 through 1981, the energy efficiency of California steam injection projects declined, despite the continued success and development of these projects.[32] The overall steam/oil ratio increased from about 2.5 in 1970 to more than five in 1981 (Figure V-2). This trend was due to the maturing of many of California's best thermal recovery candidates and the expanding conversion of cyclic steam projects to steamdrive projects -- a process which generally produces more of the remaining oil-in-place, but requires a higher steam/oil ratio. Since 1981, the massive South Belridge field's contribution has increased (at a more favorable steam/oil ratio of 2.6 versus a statewide average of 3.3 in 1989). Also, numerous improvements in reservoir characterization and extraction technology have resulted in increased thermal EOR efficiency. These improvements have included the increased use of more sophisticated reservoir management techniques and infill drilling to improve reservoir contact,[33] the use of mobility control and steam directing agents to better direct steam to unswept oil zones, the use of more efficient steam generators,[34,35] and the use of co-generation. Continued efforts to improve the efficiency of the steam injection process will play an important role in expanding the number of projects economically qualified to recover heavy oil in Slope-Basin & Basin clastic reservoirs. However, the development of California heavy oil may be inhibited by downstream constraints.

There is some concern whether the refining industry in the state can accept significant additional volumes of heavy, lower-quality crude. While the potential for large scale production exists, the market for heavy crude on the West Coast is not robust. There is a surplus of conventional Alaskan North Slope crude, which by law cannot be exported (with the exception of a small volume to Canada). In addition, the demand for light, high value refinery products (e.g., jet fuel) is increasing relative to heavy, low-value products (e.g., residual fuel oil). Refineries are already finding it difficult to deal with higher volumes of lower quality feedstocks and the large volumes of petroleum coke produced by their conversion to light products. While this is an issue which is not specifically related to heavy oil from Class III reservoirs, it is part of the larger economic equation which will determine the extent to which Class III potential is developed.

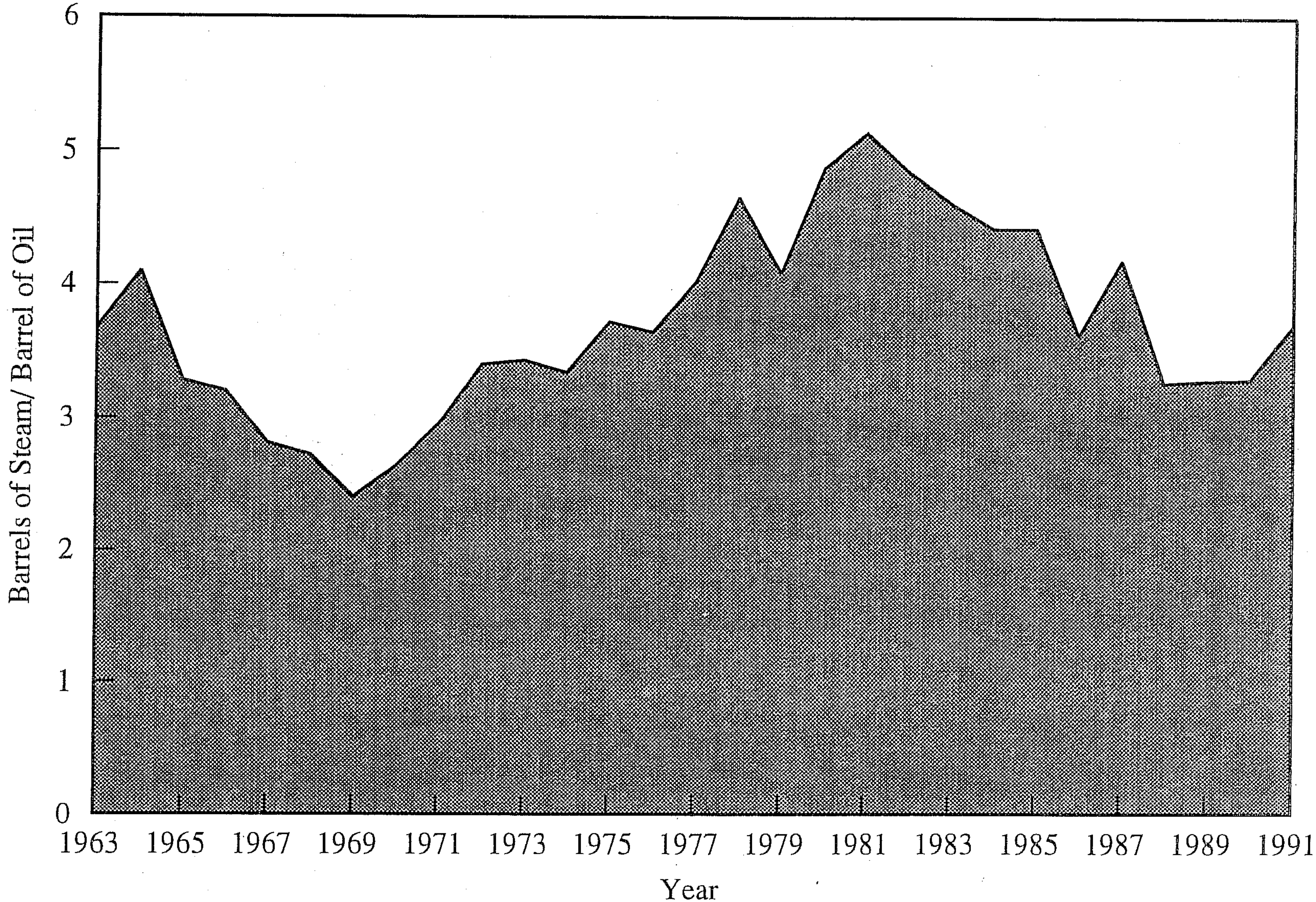
Reservoir Characterization

Most potential reservoir rock sequences in slope-basin environments are thought to be deposited as mixed grain size sediment gravity flows or turbidity currents. These often originate as submarine slumps that move rapidly down canyons in the continental slope and then spread out over the basin in broad lobate fans. The deposits vary as the distance from the channel increases (becoming progressively finer) and in the lower part of the fan typically consist of thin, laterally extensive sand beds separated by muds. These "turbidite" sands are generally uniform in thickness and laterally extensive, but have extremely poor vertical continuity between sands due to a tendency for the sands to be fining upward into interbedded shales. The coarser channel sands can be very thick but generally have a much smaller areal extent than the turbidite deposits. Thus, the challenge of reservoir characterization in slope-basin reservoirs is generally one of correlation and mapping of sandbodies. This can be particularly difficult when prograding fans build out over older deposits.

Proper reservoir characterization is essential in order to plan, implement, and optimize infill drilling, waterflood, or enhanced oil recovery projects in such highly stratified Slope-Basin & Basin clastic reservoirs. For example, an understanding of reservoir character can aid in deciding on the most efficient well spacing for cyclic steam projects, the optimum completion zone for each well, the length of interval to be completed, and the expected response to steam.[36] Improved reservoir characterization has become more important over the years as conventional oil recovery practices (primary and conventional waterflooding) have tended to result in low overall recovery, prompting the initiation of improved recovery projects. Project performance and recovery have been improved when detailed reservoir engineering and geological data have been integrated to accurately characterize the reservoir. Many of these same issues

Figure V-2

Average California Steam/Oil Ratio (1963-1991)



are important in other classes of reservoirs, and documented methodologies for dealing with them have wide ranging applicability.

The Class III reservoirs change rapidly vertically and horizontally in their continuity, due to the deposition of the sands as sheets over very short geological time periods. It is important from a development standpoint to be able to ascertain the continuity for well planning. The vertical resolution of today's 2D seismic puts many of the productive reservoirs below the tuning thickness and consequently below the perception of the interpreter. There is a significant advantage to the industry in improving the seismic acquisition and processing for shallow reservoirs. Laterally, the same resolution problem is present as the interpreters attempt to discern the extent of the reservoirs.

In the upper Miocene fan-channel complexes of the Midway-Sunset field, there is good lateral transmissibility, especially in the direction of channel flow (also in the direction of dip) but vertical transmissibility is not as good due to silt layers. Detailed correlations dividing the sand package into individual sand members is important to make certain that each member is being steamed. Since log analysis of newly drilled wells shows that laterally continuous shales act as barriers to vertical fluid flow between steamed sections, spacing as small as 1.25 acres per well is justifiable in some areas. Knowing the differences in production between sand packages due to rock character can help to define specific completion and injection procedures to maximize production.

In one example of reservoir characterization, a major program of infill redevelopment of the major zones in the Long Beach Unit of the Wilmington field was undertaken during the mid-1980s to improve waterflood conformance.[37] Following a detailed reservoir characterization effort, redevelopment of the major zones using shorter subzone completions in intervals of higher remaining oil saturation was successful in materially improving vertical waterflood conformance, oil production rate, and reserves.

In a more recent example in the same Class III field, proprietary well log software has been used to correlate flow-units in a series of basin-floor turbidite reservoirs in the densely drilled Long Beach Unit. This work was undertaken to provide a quantitative description of reservoir architecture for use in modeling of similar reservoirs where the density of well control is much less, and to ensure the success of a waterflood optimization program.[38] Similar studies have been done on outcrops of turbidite sandstones of the Pico Formation (upper Pliocene) at the Ventura field to gain insight into their continuity.[39]

Through detailed analyses of the depositional and diagenetic histories of fields, operators have been able to arrive at a better understanding of reservoir performance. Detailed assessment of the geologic history of formations allows for the identification of porosity, permeability, and pay trends which are typically correlatable with well productivity or injectivity variations. For example, the reservoirs of the Ram/Powell field, one of the largest deepwater Gulf of Mexico fields discovered to date, are stratigraphic traps within the turbidite sands of a Miocene deep sea fan. A geologic model of the field based upon 3-D seismic, well logs, and conventional core data was constructed to support development scenarios.[40] This analysis has determined that the fan system is composed of nine or more elongate, lens shaped fanlobes which aggrade laterally within an unrestricted intraslope basin. Fan architecture varies but the main reservoirs occur within the channel/levee facies. The design of such an integrated geologic model is essential to the optimal development of slope-basin deposited reservoirs; continued efforts to improve the technologies needed to create these models is of primary importance.

Another example of the important role of reservoir characterization is the work of the Texas Bureau of Economic Geology researchers related to the detailed characterization of several west Texas fields producing from the Spraberry Formation, a Class III submarine fan deposit.[41] Analysis of several fields both within and outside the Spraberry Trend, showed that the historically low recovery from this tight sandstone was at least partially due to a high degree of stratification and lateral complexity. Infill drilling programs must be designed to account for the distinctive architecture of the formation. In particular, strategic infill locations based on depositional axes and recompletion of existing wells in bypassed reservoir compartments in interaxial areas were found to have excellent economic potential.

Predicting the performance of Class III reservoirs under primary, secondary, and tertiary production mechanisms requires that reservoir managers have a good understanding of the special behavior of these reservoirs. Two important examples are: (1) reservoir compaction associated with highly porous Gulf of Mexico (GOM) turbidite and California diatomite zones, and (2) production from the naturally fractured Monterey Formation in California.

Most deepwater GOM turbidite reservoirs are highly geo-pressured and may have limited aquifer support with little chance for economic injection to support pressure. GOM turbidite pore volume compressibilities exhibit a remarkable range in behavior, both in magnitude and variation with stress.[42] Compaction can reduce permeability 4 to 5 times more than porosity on a relative basis. Understanding the degree of expected compaction is important to determine the magnitude of seafloor subsidence and its impact on structure design, the magnitude of stress on casing, and the impacts on reservoir productivity (both positive and negative).

The rapid decline in oil production in hydraulically fractured wells producing from the diatomite formation of the Belridge oil field can at least in part be attributed to a low matrix compressive strength and long-term creep of the soft formation into the proppant pack.[43] Again, developing an understanding of the behavior of this Class III formation under fluid withdrawal conditions is critical to maximizing production.

The fracture density of the naturally fractured Monterey Formation has a strong influence on the producing life of Monterey reservoirs. The contribution of matrix or shales to oil production remains significant even at low matrix permeabilities because of the large surface area resulting from intense fracturing and lamination of brittle lithologies in this Class III reservoir.[44] Studies have shown that gravity drainage and gas reinjection have increased recovery from fractured layers, but gas reinjection also decreased oil migration from the matrix, and the net effect of pressure maintenance was negative. Understanding the behavior of these complex systems requires reservoir characterization technologies which incorporate state-of-the-art techniques.

For example, seismic amplitude studies have been combined with structural mapping and core analysis to help predict the spatial distribution of fracture intensities (and thus areas of highest oil producibility) for the Monterey Formation within the Point Arguello field offshore California.[45] Seismic amplitude decreases in the more highly defined areas of the field, and strong correlations were found between mean fracture density and distance to the nearest fault and the radius of curvature of the folded formation. The methodology developed by Padgett, Nester, and others, permits the use of a seismically derived structure map to predict fractured reservoir characteristics.

Reservoir heterogeneity can influence recovery of available oil in the Class III reservoirs. This heterogeneity can be reflected in compartmentalization, sand character, clay content and oil character. The depositional nature of these Class III reservoirs can lead to the isolation of reservoir compartments containing uncontacted oil. Rapid lateral changes in sand character and permeability due to scour and deposition can lead to volumes of the reservoir that are not in pressure communication with the well drainage patterns. There is room for investigations into pressure responses that reflect this occurrence.

Sands from the same source may be amendable to the same type of enhanced or secondary recovery techniques. Tying two reservoirs to the same clastic source may lead one to consider similar development plans. The provenance of the sand in the reservoir requires good samples from the wells (either cores, sidewalls, or shaker samples). These samples can be useful in reservoir description and can highlight the need for improved reservoir characterization.

The description of the clay types and volumes found in a reservoir is extremely important in reservoir characterization. Hydrophilic clays can significantly impact if not terminate water flooding. Some clays absorb chemicals on their surface and can drastically affect the performance of chemical floods. Recognition and description of the clays and their distribution within the sand package can become the controlling factor in the successful completion of a development program.

The type of oil (waxy, etc.) as well as the API gravity of the oil affect both production and production rate. Heavier oils, as found in the California Class III reservoirs, are extremely hard to move through the existing pore network. The wax and paraffin content of the oil determines which chemicals can be applied to the reservoir to enhance production. The research that is done in this area is a leverpoint for the entire DOE program. As domestic production matures, the average oils from mature reservoirs are becoming increasingly heavier. Research in present heavy oil reservoirs can be applied directly to other fields as they enter this late stage of production.

Reservoir Management

Due to the stratigraphically complex nature of Slope-Basin & Basin clastic reservoirs, such reservoirs often require the development and implementation of dynamic, integrated reservoir management strategies in order to optimize recovery. Proper reservoir management requires the integration of development geology, geophysics, reservoir engineering, drilling engineering, production/facilities engineering, and field operations in order to facilitate EOR project design, implementation, and optimization. Much of this integration of geological and engineering thinking will probably take place in front of the monitor screens of computer workstations, where log analysis, geophysical interpretations, structure maps, and simulation runs are generated, analyzed, and modified.

One example of the successful use of reservoir management strategies in a Class III reservoir is Conoco's work at the Ford Geraldine field in west Texas. A CO_2 flood has been underway there since 1981, with expansions in 1988 and 1990. An erratic CO_2 supply during the 1981-1985 period delayed the flood's response, but nearly 2000 BOPD of incremental oil is now being produced.

The Ford Geraldine Unit flood was designed in 1981 based on predictions from a history match of the Twofreds field CO_2 flood performance, a project then underway in another nearby Delaware sandstone field. A simple spreadsheet model was used to calculate post-injection production for each pattern in the flood and sum these for the unit. In 1990, a field-scale miscible model was used to history match the flood and economic predictions and slug-size optimizations are now based on this model.[46] Modeling of the Ford Geraldine flood as part of a reservoir management process has led to several improvements:

- Careful monitoring and testing has been successful in minimizing corrosion, wellbore damage, and out-of-zone CO_2 losses;

- A produced gas gathering and recycling system was determined to be a cost effective means of expanding the flood; and

- The collection of data from many aspects of the flood has been used to establish a data base, which provides input for monitoring the flood and planning future expansion.

For example, pattern balancing is carried out at least twice per year, with adjustments based on shut-in bottom hole pressures, oil production rates, and cumulative pattern injection. A pattern reservoir pressure target of 1,300 to 1,400 psi is maintained, keeping each portion of the reservoir above the minimum miscibility pressure while keeping the pressure low enough for safety and CO_2 efficiency. Project data are brought from the data base into data sets for direct comparison with model predictions.[47]

Summary

The technical challenges facing operators active in Class III reservoirs are generally related to finding more cost effective ways of applying known technologies, in order to maximize production in an era of high operating costs and low oil prices. This dilemma is particularly true in the large number of Class III reservoirs producing heavy oil with thermal assistance. In these fields, the value of the crude oil is decreasing as the costs of producing it are rising. Innovative technological solutions will be required to avoid the loss of a significant resource. Improvements are required in steam injection practices, reservoir characterization capabilities, and reservoir management techniques.

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CHAPTER VI

FUTURE ADVANCED OIL RECOVERY POTENTIAL IN CLASS III RESERVOIRS

Slope-Basin & Basin clastic reservoirs hold a significant promise for future oil recovery in the United States. As the remaining reserves of 1.6 billion barrels are produced by existing techniques, the application of additional recovery technologies to the Class III reservoirs could yield nearly 5.4 billion barrels of incremental reserves. These reserve additions are possible through the development and application of technology in the area of enhanced oil recovery (EOR) and advanced secondary recovery (ASR) techniques.

However, if technology development is delayed, a significant portion of the potential reserves in Class III reservoirs will be lost due to abandonment (approximately 1.4 billion barrels by the turn of the century). Based on their historical importance, large recovery potential, and impending abandonment, the U.S. Department of Energy (DOE) is focusing a significant portion of its R&D program on Slope-Basin & Basin clastic reservoirs.

Resource Evaluation Method

The analysis of EOR and ASR potential presented in this chapter is based on databases and models available in the Tertiary Oil Recovery Information System (TORIS). This system was adapted and validated by the National Petroleum Council (NPC) in 1984[1] and is maintained and updated by the U.S. Department of Energy's Bartlesville Project Office. TORIS consists of comprehensive oil reservoir databases and detailed engineering and economic evaluation models for a variety of EOR and ASR technologies. The models address reservoirs individually in order to estimate production potential and investment and operating costs. The anticipated performances of all applicable EOR and ASR processes are also compared. Decline curve models project reservoir abandonment dates and ultimate recovery. This analysis of Slope-Basin & Basin clastic reservoirs is based on over 200 such reservoirs represented in the TORIS data base as listed in Appendix B.

TORIS was originally designed to evaluate EOR processes which target remaining immobile oil. The capabilities of TORIS have since been expanded to incorporate the evaluation of the unrecovered mobile oil (UMO) resource. Unrecovered mobile oil, the target for ASR operations, consists of uncontacted or bypassed oil that is physically displaceable by water. "Uncontacted" oil is trapped in isolated portions of the reservoirs not in contact with wells at the current spacing, while "bypassed" oil is in pressure communication with existing wells but remains unswept by secondary processes.[2]

The resource potential documented within TORIS is estimated for two technology levels: *implemented technology*, which assumes the more extensive application of currently available technology, and *advanced technology*, which assumes that the scope and the application of existing technology is extended as far as current laboratory or field data justify to overcome current technical and economic limitations. These cases were originally defined by the NPC (1984) for immobile oil (EOR), and were expanded by the DOE (1990)[3] to include unrecovered mobile oil. Examples of technological improvements include increased injectant sweep efficiency, increased injectant tolerance to "severe" reservoir conditions (temperature, salinity, etc.), decreased chemical retention, improved process displacement efficiency, and reduced injectant costs. A more detailed description of advanced technology assumptions is given in the NPC (1984) report on *Enhanced Oil Recovery*. Tables VI-1 and VI-2 show examples of the implemented and advanced technology screening criteria for selected ASR and EOR processes.

Table VI-1

Screening Criteria for Advanced Secondary Recovery Candidates

	Polymer Flooding		Profile Modification	
	Implemented	Advanced	Implemented	Advanced
Reservoir Temperature (°F)	<200	<250	<180	<250
Formation Brine Salinity (ppm)	<100,000	<200,000	<100,000	<200,000
Permeability (md)	>20	>10	>20	>10
Oil Viscosity (cp)	<100	<150	<100	<150

Table VI-2

Screening Criteria for Enhanced Oil Recovery Candidates

	Miscible	Surfactant		Alkaline	
Screening Parameter	Implemented & Advanced Technologies	Implemented Technology	Advanced Technology	Implemented Technology	Advanced Technology
Oil Gravity (°API)	≥25	--	--	<30	<30
Oil Viscosity	--	<40	<100	<90	<100
Reservoir Temperature (°F)	--	<200	<250	<200	<200
Permeability (md)	--	>40	>10	>20	>10
Reservoir Pressure (psia)	≥MMP*	--	--	--	--
Brine Salinity (ppm)	--	<100,000	<200,000	<100,000	<200,000
Rock Type	Sandstone or Carbonate	Sandstone	Sandstone or Carbonate	Sandstone	Sandstone

*MMP denotes minimum miscibility pressure, which depends on temperature, crude oil composition, and injectant gas

Future Recovery Potential

As shown in Figure VI-1, oil production from Slope-Basin & Basin clastic reservoirs in TORIS has declined by 19% since 1977, dropping from 198 million barrels per year in 1977 to about 162 million barrels per year in 1991. The heavy oil production has been fairly steady at a rate of 70 to 80 million barrels per year since 1980. The light oil production, however, has declined at a rate of 4% per year from 1980 through 1991. This trend will certainly continue unless improved recovery techniques are applied to the Slope-Basin & Basin clastic reservoirs in order to capitalize on the massive remaining mobile and immobile resources or economics improve.

TORIS technical and economic models are used to estimate the magnitude of increased recovery potential resulting from the application of new EOR and ASR projects in known Slope-Basin & Basin clastic reservoirs. Key technical and economic assumptions made in this analysis include the following:

- The incremental recovery potential is projected over two price and technology scenarios: a near-term case which assumes current level of oil price ($20/B) and implemented or existing level of technology; and a "mid-term" case based on higher oil prices ($32/B) and advanced technology. All oil prices reflect West Texas Intermediate crude oil price (WTI) and are stated in constant 1991 dollars. (Note: Recent events have demonstrated that near-term oil price may range significantly below the $20/B level used in this analysis. Lower prices will have a negative impact on the economics of the EOR processes described, and will simultaneously accelerate the abandonment of unrecovered oil in Slope-Basin and Basin reservoirs.)

- The enhanced oil recovery (EOR) techniques analyzed in this report are: CO_2-miscible flooding, chemical flooding (i.e., alkaline and surfactant processes), and thermal recovery techniques (i.e., steam drive and in-situ-combustion). The EOR techniques target the recovery of remaining immobile oil -- 28.0 billion barrels in the TORIS Slope-Basin & Basin clastic reservoirs. Immiscible CO_2 injection, a process analogous to steamflooding which reduces heavy oil viscosity, is not modeled in this analysis.

- The advanced secondary recovery (ASR) techniques analyzed in this report are: infill drilling, polymer augmented waterflooding, profile modification, and the combination of infill with either polymer flooding or profile modification. The ASR techniques target the unrecovered mobile oil (UMO) -- about 14.7 billion barrels in the TORIS Slope-Basin & Basin clastic reservoirs.

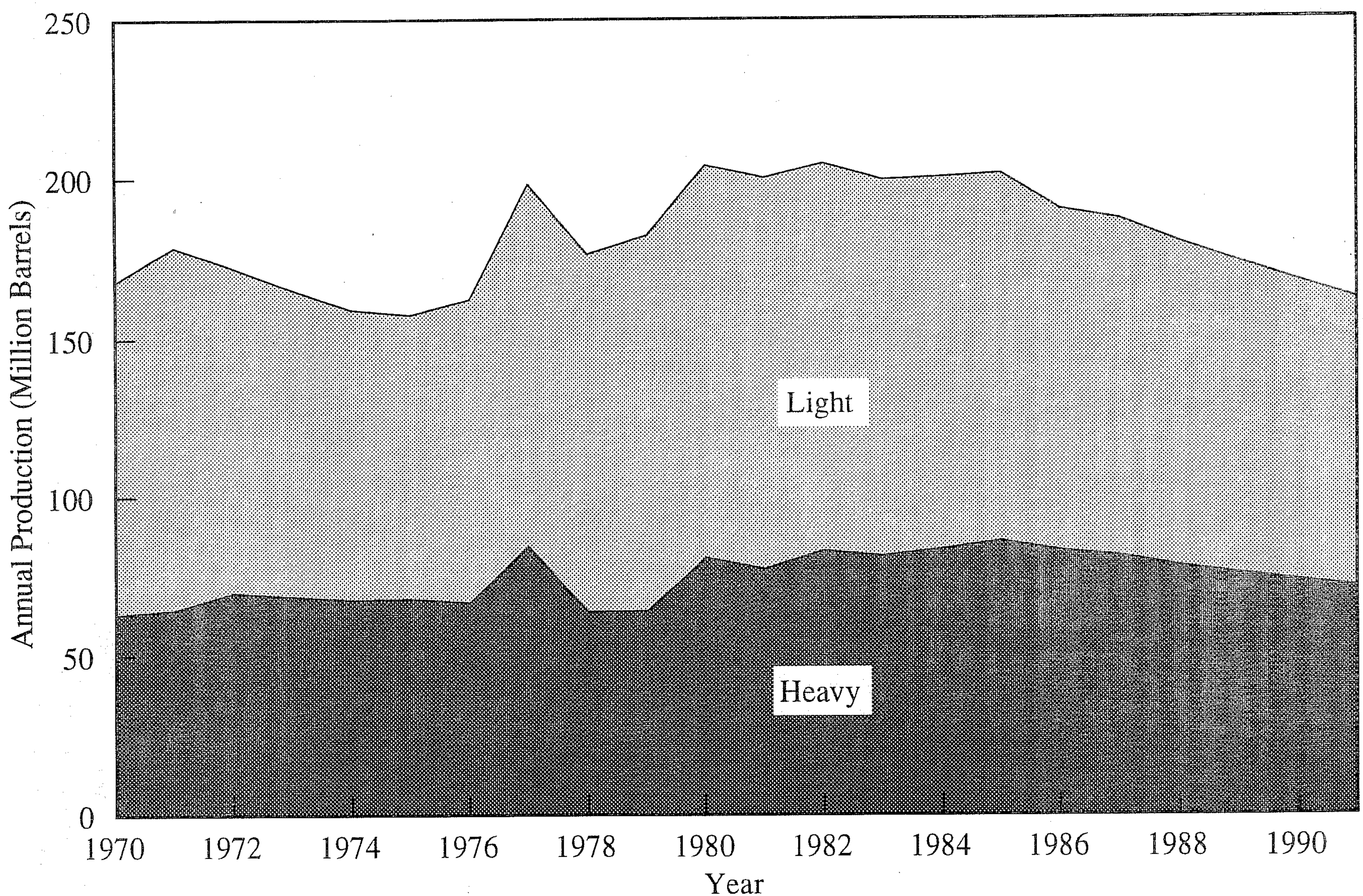
- The term "Incremental Reserves" refers to the future recovery estimated by the analyzed EOR and ASR techniques from the immobile and UMO resource target. Projected incremental reserves are above and beyond the recovery currently attainable by primary and secondary recovery techniques.

- Light oil refers to reservoirs with average API gravity greater than 20 degrees. Heavy oil is defined by API gravity equal to or less than 20 degrees.

Table VI-3 summarizes the potential incremental reserves from EOR and ASR processes for the analyzed Slope-Basin & Basin clastic reservoirs. Under the near-term case, the potential incremental reserves are estimated at 1.8 billion barrels, with 800 million barrels from light oil reservoirs and 1.0 billion barrels from heavy oil reservoirs. The heavy oil reserves are from new EOR projects (86 million

Figure VI-1

Historical Oil Production from Slope-Basin & Basin Clastic Reservoirs*



* All information presented on this page pertains to identified Slope-Basin & Basin clastic reservoirs in TORIS.

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Table VI-3

Potential Incremental Recovery from EOR and ASR Processes

	EOR	ASR	Total
Near-Term Incremental Reserves (Million Barrels) @ $20/B			
Light Oil	180	620	800
Heavy Oil	1,000	0	1,000
Total	1,180	620	1,800
Mid-Term Incremental Reserves (Million Barrels) @ $32/B			
Light Oil	1,730	770	2,500
Heavy Oil	2,900	0	2,900
Total	4,630	770	5,400

barrels) as well as the future expansion of ongoing steam projects in California (920 million barrels). These numbers do not include reserves from the already developed portions of ongoing steam projects. The ASR processes are analyzed only for light oil reservoirs because thermal oil recovery, particularly steamflooding, requires very close well spacing (one to five acres) in order to maintain an effective displacement of the heavy crude. To the extent that there is mobile oil (to water) present in the heavy oil reservoirs, its recovery is reflected in the EOR estimates.

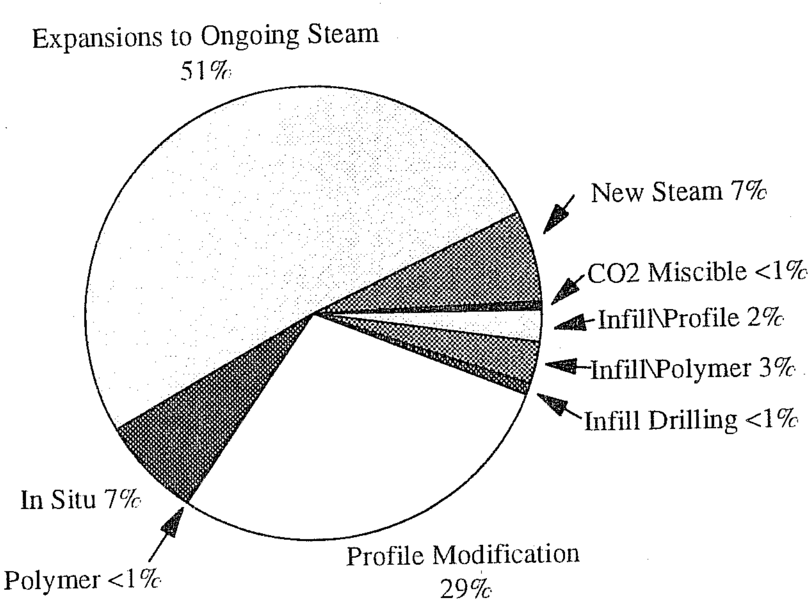
The distribution of the 1.8 billion barrels of recovery potential by process under the near-term case is shown in Figure VI-2. The thermal recovery process (i.e., steam drive and in-situ combustion) appear to be the predominant EOR techniques in the analyzed Slope-Basin & Basin clastic reservoirs. Over 51% of the total near-term recovery potential are attributed to the expansion of ongoing steam flood projects in California. New steam projects and new in-situ combustion projects each account for 7% of the reserve potential. CO_2-miscible projects account for less than 1% of the near-term recovery potential in the analyzed reservoirs. The ASR processes account for nearly 35% of the 1.8 billion barrels of incremental reserves, with profile modification as the most predominant process (Figure VI-2A).

Table VI-3 also shows that higher oil prices and advances in technology could significantly increase the reserve potential in Slope-Basin & Basin clastic reservoirs. The recovery potential under the mid-term is projected to reach 5.4 billion barrels by EOR and ASR processes. A total of 2.9 billion barrels of the mid-term recovery potential is from heavy oil reservoirs, and the remaining 2.5 billion barrels is from the light oil reservoirs. The distribution of the mid-term recovery potential by process is shown in Figure VI-2B. Similar to the near-term case, the predominant EOR processes are thermal recovery techniques, collectively accounting for over 55% of 5.4 billion barrels of mid-term reserves. Chemical flooding (i.e., alkaline and surfactant processes) account for about 30% of the reserve potential. The contribution of CO_2-miscible flooding is estimated at less than 1%. The remaining 14% of total reserves are attributed to ASR techniques, primarily profile modification.

Figure VI-2

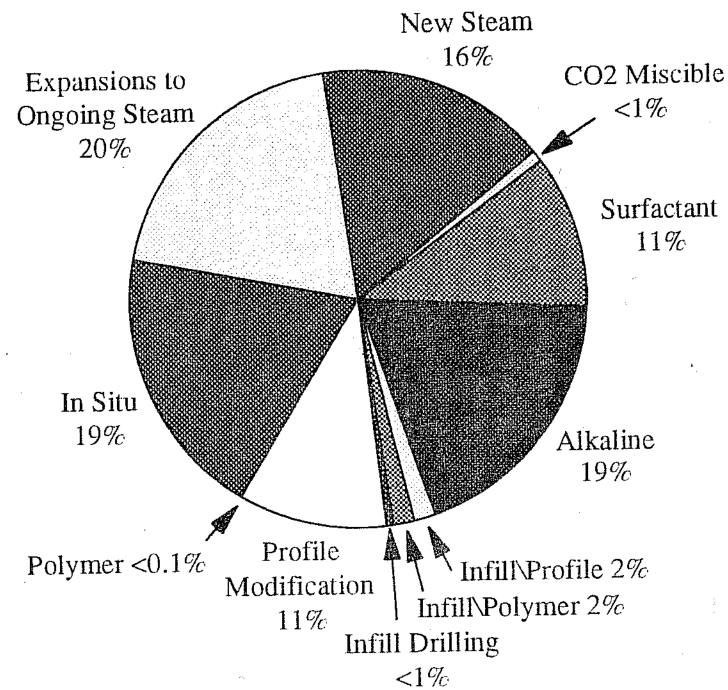
Incremental Recovery Potential By Process*
(Light and Heavy Oil)

(A) Near-Term Potential
$20/Bbl Oil Price, Implemented Technology



Total Reserves = 1.8 Billion Barrels

(B) Mid-Term Potential
$32/Bbl Oil Price, Advanced Technology



Total Reserves = 5.4 Billion Barrels

EOR Processes = Alkaline, Surfactant, CO2 Miscible, Steam, and In Situ
ASR Processes = Polymer, Profile Modification, Infill Drilling and Infill Drilling in Combination with Other Processes

* All information presented on this page pertains to identified Slope-Basin & Basin clastic reservoirs in TORIS.

As of October 8, 1993
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Geographic Distribution of Future Recovery Potential

Figure VI-3 shows the geographic distribution of incremental EOR and ASR potential in the lower 48 states. The largest potential is concentrated in the state of California, particularly in the San Joaquin, Santa Maria, Santa Barbara-Ventura, and Los Angeles basins. In these basins, steamflooding projects hold significant promise for future oil recovery. Under the near-term-case (Figure VI-3A), the total reserve potential of 1.8 billion barrels is distributed among four states, California (96%), Louisiana (<1%), Mississippi (<1%), and Texas (2%). A similar trend also holds true for the mid-term case where nearly 96% of 5.4 billion barrels of incremental reserves are from the California reservoirs (Figure VI-3B).

It is important to note that all reserve potentials presented in the report reflect only the analyzed reservoirs in TORIS as listed in Appendix B. *To the extent that there are other Slope-Basin & Basin clastic reservoirs not represented in TORIS, the recovery potential is underestimated and its geographic distribution is understated. Figure VI-3 is not fully representative of the nationwide distribution of Slope-Basin & Basin clastic reservoirs, and the DOE recognizes that there are other Class III reservoirs with recovery potential which are not displayed.* This is particularly true in the case of the Federal OCS areas of the Gulf of Mexico, where a significant number of Slope-Basin and Basin reservoirs are located and where coverage in the TORIS database is limited.

Potential Resource at Risk Due to Abandonment

The potential benefits of EOR and ASR technologies are put at risk by the continued abandonment of marginally productive oil reservoirs over time. If reservoirs which have reached the end of their economic life under primary and secondary recovery methods are abandoned before potentially profitable EOR or ASR projects are established, the cost of initiating such projects in the future becomes prohibitively expensive. In effect, the target EOR and ASR resource will be lost. Figure VI-4 shows the impact of abandonments on recovery potential for both the near-term and the mid-term scenarios.

Projections for the near-term case indicate that 40% of the incremental recovery potential of EOR and ASR processes could be lost due to abandonment by 1995. An additional 5% could be lost by the year 2000, if no new technologies are applied to Class III clastic reservoirs. By 1995, 720 million barrels of recoverable oil could be abandoned, and by the turn of the century, the resource at risk could rise to 800 million barrels.

The potential losses due to abandonment under the mid-term case are even more dramatic. Twenty percent of the mid-term resource could be lost by the turn of the century. By 1995, 480 million barrels of EOR and ASR recovery potential are at risk of being abandoned. By the year 2000, 1.1 billion barrels could be lost.

The rapid pace of potential abandonment of Slope-Basin & Basin clastic reservoirs underscores the need to accelerate the application of new EOR and ASR technologies in these fields. The unrecovered mobile and immobile oil in Class III reservoirs should be viewed as a "use it or lose it" resource. If new EOR and ASR projects are not initiated quickly, the resource will be abandoned, and the benefits of advanced technology recovery processes will be lost.

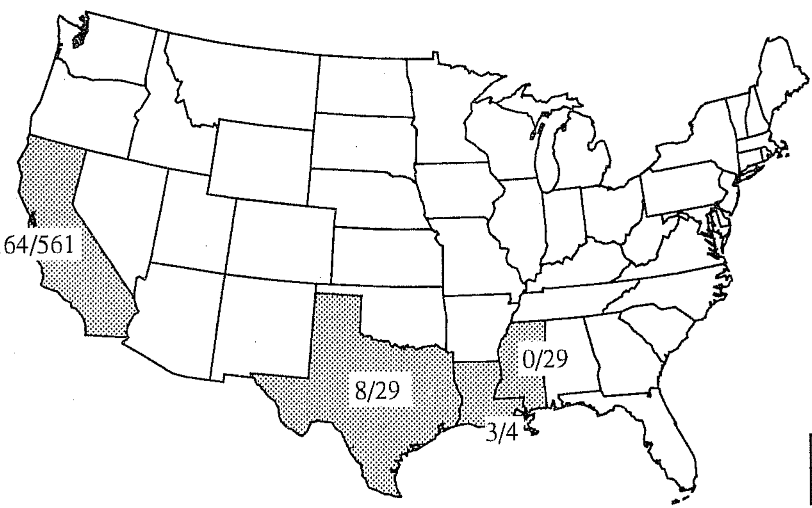
Limitations of the Analysis

The foregoing analysis estimates the maximum potential impacts given the conditions hypothesized. These results are not a forecast of the most likely future impacts, but rather are an upside limit. Several factors would cause the future actual impacts to be less than the maximum potential:

Figure VI-3

Distribution of Future Potential from Slope-Basin & Basin Clastic Reservoirs*

(A) Near-Term Potential (Million Barrels)
$20/Bbl Oil Price, Implemented Technology



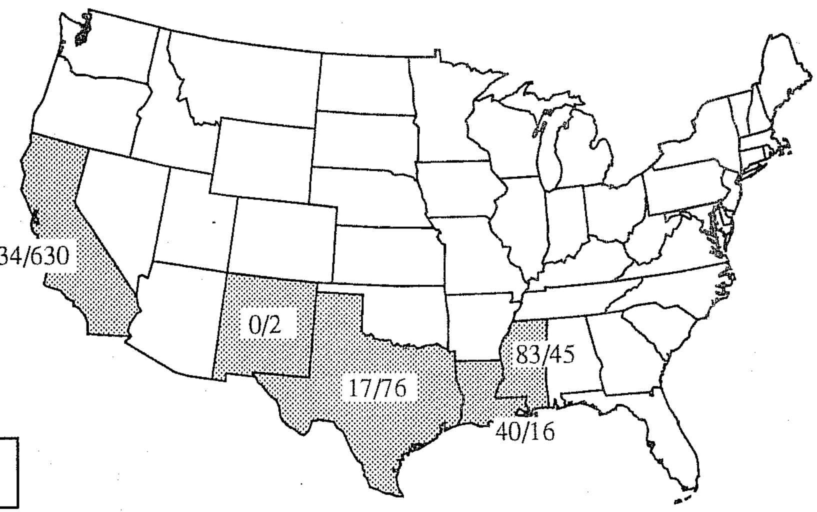
TOTALS

EOR Potential: 1,180 Million Barrels
ASR Potential: 620 Million Barrels

Total Potential: 1,800 Million Barrels

EOR/ASR

(B) Mid-Term Potential (Million Barrels)
$32/Bbl Oil Price, Advanced Technology



TOTALS

EOR Potential: 4,630 Million Barrels
ASR Potential: 770 Million Barrels

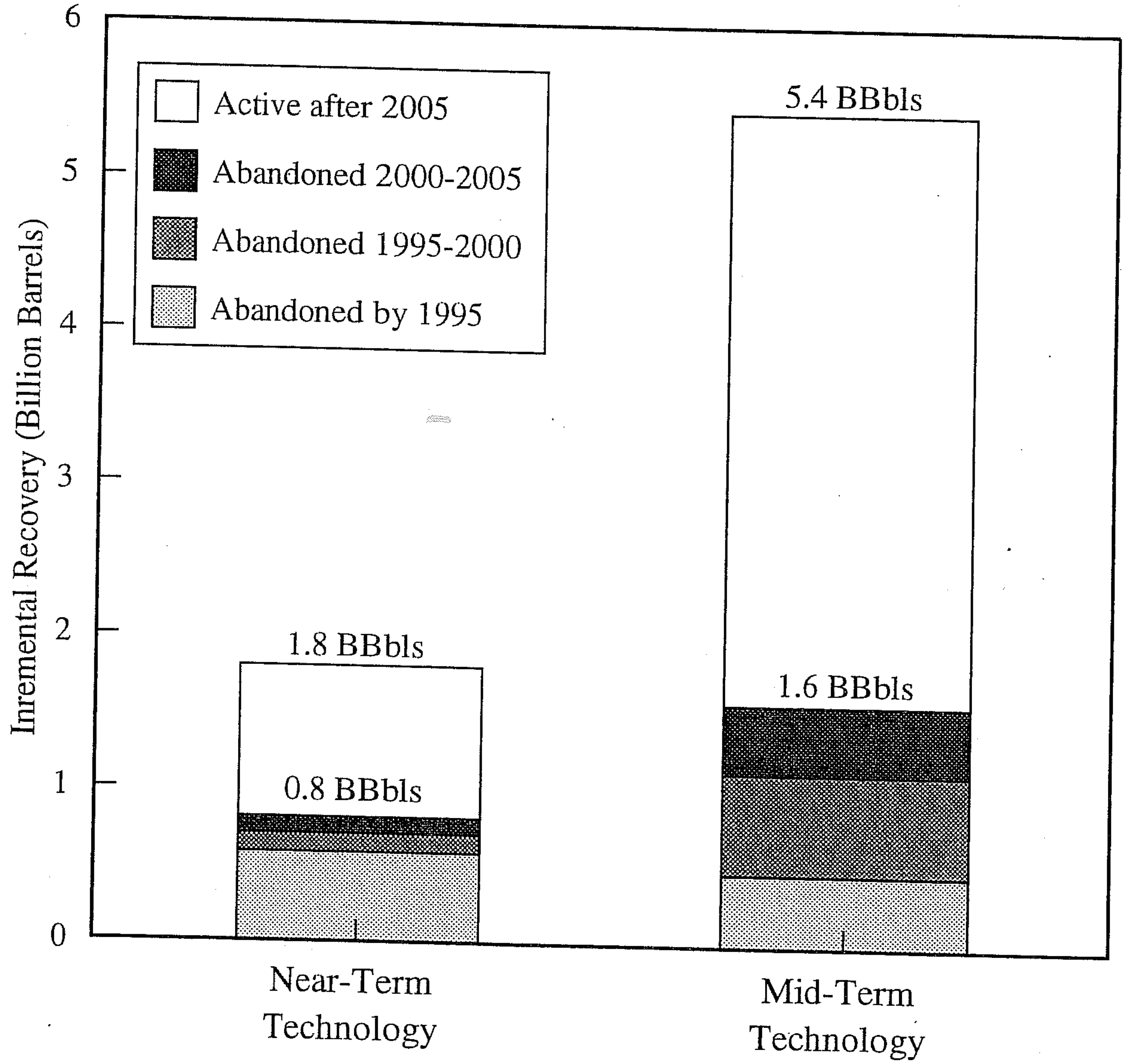
Total Potential: 5,400 Million Barrels

* All information presented on this page pertains to identified Slope-Basin & Basin clastic reservoirs in TORIS. The state reservoir numbers may not add up to the totals shown due to rounding.

CL3\POTENTIAL

Figure VI-4

Effects of Potential Abandonments on Slope-Basin & Basin Clastic Reservoirs*



* All information presented on this page pertains to identified Slope-Basin & Basin clastic reservoirs in TORIS.

CL3\ABANDON

- The results for the advanced technology case assume that the public and private R&D and technology transfer efforts that are currently in progress or being implemented will be fully successful in providing essential advances. A critical measure in the definition of the "success" case is development, demonstration, and commercialization of these advances before the reservoirs containing the targeted remaining oil resource are abandoned. To the extent that anticipated R&D and technology transfer efforts are delayed or result in failures, the potential recovery and corresponding economic benefits could be decreased.

- The economic analysis also assumes that prices remain stable, adjusting only for inflation. To the extent that prices are expected to be unstable or to decline, the full potential of the suggested improved recovery techniques may not be achieved.

- The analysis assumes that all operators have sufficient access to technological expertise and capital to implement all the projects that meet the technical criteria. Insofar as expertise and capital are limited, not all feasible projects will be initiated.

Collectively, these factors will cause the future actual estimates of EOR and ASR to be smaller than the estimated potentials. The magnitude of the difference between the estimated upper limit potential and the most likely forecast is a subject for future investigation.

Summary

The amount of potentially recoverable oil endangered by abandonment establishes an urgency in ensuring application of implemented technologies to light and heavy oil Slope-Basin & Basin clastic reservoirs. The magnitude of the incremental recovery attributable to research-based advanced technology likewise establishes a substantial target for future R&D. Class III reservoirs as represented in TORIS are clearly an important component of the nation's energy resource base.

REFERENCES CITED

1. National Petroleum Council, 1984, *Enhanced Oil Recovery*. Washington, D.C.: NPC, p. 1-94.

2. Interstate Oil Compact Commission Project on Advanced Oil Recovery and the States, 1989, *An Evaluation of the Known Remaining Oil Resource in the State of Texas*. Houston: IOCC, p. I-4.

3. U.S. Department of Energy/Bartlesville Project Office, 1990, *Producing Unrecovered Mobil Oil: Evaluation of Potential Economically Recoverable Reserves in Texas, Oklahoma, and New Mexico*, Bartlesville, OK: DOE/BPO.

CHAPTER VII

ENVIRONMENTAL ASPECTS OF OPERATIONS IN CLASS III RESERVOIRS

The planning, initiation, and operation of all exploration and production (E&P) projects must take into account the potential environmental impacts associated with them. This section will look at many of the environmental aspects of operations in Slope-Basin and Basin clastic (Class III) reservoirs. Areas covered are:

- **Environmental Setting** - Factors such as surface conditions (including aquifer locations) and subsurface conditions that can cause injection well failure are examined.
- **Potential Environmental Impacts of Recovery Technologies** - Unique potential environmental impacts can be associated with EOR and ASR recovery technologies.
- **Regulatory Requirements** - Class III operations can be affected by Federal, state, and local regulations.
- **Economic Impacts** - The potential economic impacts of environmental regulations, in terms of resource abandonments, are examined.

Environmental Settings

The potential environmental impacts associated with operations in Slope-Basin & Basin clastic reservoirs are dictated, in part, by local environmental characteristics such as the location of aquifers and aquifer exchange areas, precipitation, terrain, and the proximity of environmentally sensitive areas such as wetlands. Reservoirs in this class are located primarily in California, Texas, and the Gulf Coast with a few examples found in the Appalachian and Illinois Basins.

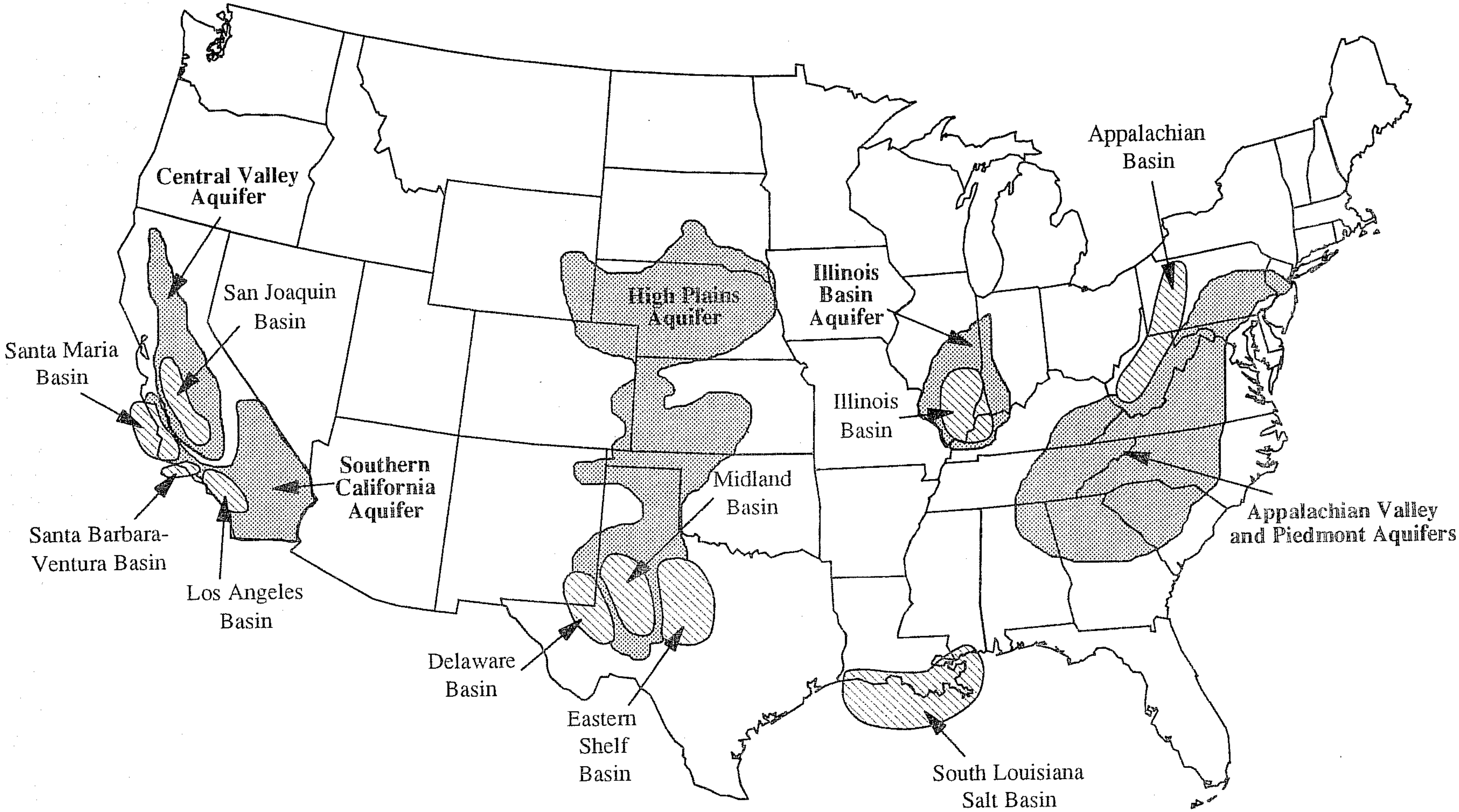
Surface Conditions

Portions of most of the Slope-Basin & Basin clastic reservoirs overlay regional aquifer systems. These reservoirs are found in ten basins: the Santa Maria Basin, the Santa Barbara-Ventura Basin, the Los Angeles Basin, the Delaware Basin, the Eastern Shelf Basin, the South Louisiana Salt Basin, the Illinois Basin, and the Appalachian Basin. Figure VII-1 shows the locations of these basins and the aquifers they overlay.

Three of the ten basins with Slope-Basin & Basin clastic reservoirs are located in the central and western parts of Texas. The Delaware Basin includes portions of west Texas and southeast New Mexico, while the Midland and Eastern Shelf Basins occupy central Texas. Rainfall in these areas averages between 11 and 32 inches per year, with the terrain mainly grassland and desert shrubland (much of the area is used for grazing and ranching). Large portions of each basin overlay the High Plains aquifer system, a regional system extending through parts of Colorado, Kansas, Nebraska, New Mexico, Oklahoma, South Dakota, Texas, and Wyoming. Ground water flow in this aquifer system tends to be from west to east. Because the High Plains aquifer is located largely in semi-arid regions, the recharge area is small and is mainly through precipitation and stream seepage.[1] Natural wetlands of significant value to fish or wildlife are absent from these basins.

Figure VII-1

Location of Slope-Basin & Basin Clastic Reservoirs and Associated Aquifers



Sources: Bartlesville Project Office, TORIS, September 1993.
USGS, Bibliography of Regional Aquifer -System Analysis Program, 1991.

The San Joaquin, Santa Maria, Santa Barbara-Ventura, and Los Angeles basins stretch inland from Central California to the southern coast of California. Rainfall averages from 18 to 22 inches per year. The terrain in the San Joaquin Basin is predominantly irrigated farmland, with the terrain in the coastal basins mainly open woodland. The San Joaquin Basin overlays the Central Valley Aquifer system, a small system flanked by the Sacramento River to the north and the San Joaquin River to the south. The remaining California basins overlay the Southern California aquifer system.[2] Natural wetlands are largely absent from all of these basins, with the exception of a small acreage of wetlands in the northern section of the San Joaquin Basin.[3] However, the presence of scattered populations of threatened and endangered species throughout central and southern California creates many environmentally sensitive areas.

The Illinois Basin is located in the southern part of Illinois, the southwestern corner of Indiana, and the northwestern corner of Kentucky. This area is very flat and mostly cultivated. Rainfall averages between 39 and 43 inches per year. The Illinois Basin overlays the Illinois Basin aquifer system. A limited number of natural wetlands are scattered throughout the southern part of the basin.

The South Louisiana Salt Basin includes all coastal and offshore areas in Louisiana. Rainfall averages between 58 and 62 inches per year, making the coastal terrain a combination of swamp and marshland. This area features one of the densest concentrations of natural wetlands in the United States.[4]

The Appalachian Basin stretches from the western part of Pennsylvania through the southwestern part of West Virginia. Rainfall averages between 41 and 50 inches per year. The terrain ranges from woodland and forest (with some cropland and pasture) to ungrazed forests. Small portions of this basin overlay the Appalachian Valley and Piedmont aquifer systems. These systems cover as far north as New Jersey and as far south as Georgia. Natural wetlands and other environmentally sensitive areas are largely absent within the basin.

Casing Corrosion Potential

In 1988, a study was prepared for the American Petroleum Institute that attempted to determine realistic probabilities of injection well failure due to external casing corrosion. This study identified areas of the United Sates where the potential existed for corrosion-related failures that could allow the release of injected water into an underground source of drinking water (USDW). Studied regions were classified as having significant, possible, or minor potential for external casing corrosion to cause leaks.[5] It should be noted that these classifications are relative terms, as even in areas with significant casing corrosion potential, the absolute risk of well failure is very small. This section includes background information on the use of water injection wells and a summary of corrosion potential for all Slope-Basin & Basin clastic reservoirs.

The largest waste stream generated by exploration and production (E&P) facilities is produced water; it makes up 98 percent of the total wastes generated by E&P facilities.[6] Most of these waters are reinjected, either for disposal or enhanced recovery processes. Operators in the two states which combine for over 90 percent of the studied Slope-Basin & Basin clastic reservoirs, California and Texas, re-inject 57 percent and 98 percent, respectively, of the produced water they generate.[7] The contamination of USDWs by a faulty water injection well is the greatest potential risk from this disposal practice. The external corrosion of an injection well's casing is the primary cause of well failure that could potentially lead to aquifer contamination. One relatively effective way to reduce casing corrosion is through the drilling of cathodic protection wells, which attach one or more anodes to the well casing. Weak electric currents flow from the anode to the casing and help to offset the current associated with possible corrosion.

Of the ten basins with Class III reservoirs, one exhibits significant potential for external casing corrosion to cause leaks, four exhibit possible potential for external casing corrosion, and five exhibit minor potential for external casing corrosion.[8] The Delaware Basin of western Texas and southeastern New Mexico is the only region to exhibit *significant* potential for external casing corrosion to cause casing leaks. This assessment of potential is based on both the reported extensive application of cathodic protection and the age of the basin's producing reservoirs (most are over 60 years old). Despite this potential, casing failures rarely occur. However, additional protective measures may be warranted in areas of this basin.

The four regions exhibiting *possible* potential for external casing leaks are the Santa Maria Basin, the Santa Barbara-Ventura Basin, the Los Angeles Basin and the San Joaquin Basin. The cathodic protection of well casings is not a common practice in these basins. Cathodic protection is especially uncommon in the San Joaquin Basin, as the relatively close well spacing makes it difficult to operate without causing electrical interference between wells.

The five basins exhibiting *minor* potential for external casing leaks are the Eastern Shelf Basin, the Midland Basin, the South Louisiana Salt Basin, the Illinois Basin, and the Appalachian Basin. The classification of the Eastern Shelf and Midland basins is based on the limited application of cathodic protection throughout the area. The application of cathodic protection in the South Louisiana Salt Basin is also limited, and corrosive subsurface brine zones are absent. However, external casing corrosion in South Louisiana reservoirs with producing lives greater than 50 years (most reservoirs in this region have producing lives between 10 and 15 years) has the potential to become a problem in the future. The Illinois and Appalachian basins also have a minor potential for external casing corrosion due to the shallow producing depths and the absence of corrosive subsurface zones.[9]

Potential Environmental Impacts of Slope-Basin & Basin Clastic Recovery Technologies

Advanced secondary and tertiary recovery techniques increase the potential for environmental impacts from E&P operations by increasing the level of production and extending the duration of operations. Although many of the potential environmental impacts resulting from advanced oil recovery techniques are similar to those of conventional recovery operations, additional potential risks can be present.

There are several potential environmental impacts shared by all advanced recovery technologies. The additional producing and injection wells, roads, and facilities needed for more intensive field development extend the time and amount of land necessary for the project. These additional injection and production facilities can increase the emission of potentially hazardous air pollutants and also increase the potential for the pollution of surface water and ground water from injected materials.[10]

The majority of the Slope-Basin & Basin clastic resource base (over 98%) is located in five basins: four basins in central and southern California and the Midland Basin in central Texas. Reservoir properties in these basins are especially amenable to both thermal recovery methods (including the expansion of ongoing steamfloods, the initiation of new steamfloods, and in-situ combustion) and chemical flooding methods (including profile modification, surfactant flooding, and alkaline flooding). Thermal recovery methods are expected to be responsible for 65% of incremental resource recovery in the near-term and 55% in the mid-term. Chemical flooding processes are expected to account for 29% of incremental resource recovery in the near-term and 40% in the mid-term. Infill drilling and CO_2-miscible flooding are expected to be responsible for the remainder of both near-term and mid-term incremental resource recovery. Each of these advanced oil recovery techniques has potential environmental impacts. They include the shared potential impacts mentioned above and more technology-specific risks.

The main environmental concern associated with thermal recovery operations involves the emission of potential air contaminants from steam generators used in steam injection operations and air compressors used for in-situ combustion. Other potential environmental impacts associated with thermal operations may include additional land demands (a substantial increase in the number of producing wells can result), the contamination of surface water and ground water (produced water can become contaminated with thermal enhancement chemicals prior to disposal), and the contamination of soils (additional volumes of solid wastes, such as scrubber sludges and water treatment wastes, often require disposal).

Chemical EOR processes, such as surfactant or alkaline flooding, also present potential hazards to the environment. The concerns associated with these processes center around the transportation, on-site manufacturing, and handling of the various chemicals required. Air quality may be threatened by fugitive emissions from the manufacturing of chemicals, surface water or ground water may be contaminated by chemical spills or leaks, and soils could become contaminated during the disposal of wastes generated during chemical manufacturing. A complete summary of the potential environmental impacts associated with both thermal and chemical advanced recovery techniques is presented in Table VII-1.

Regulatory Requirements Affecting Slope-Basin & Basin Clastic E&P Operations

The primary Federal environmental statutes that affect Slope-Basin & Basin clastic E&P operations include the following:

- Resource Conservation and Recovery Act
- Safe Drinking Water Act
- Clean Water Act
- Clean Air Act and the Clean Air Act Amendments
- Endangered Species Act.

Other Federal regulations that may impact these operations include:

- National Environmental Policy Act
- Comprehensive Environmental Response, Compensation, and Liability Act
- Superfund Amendments and Reauthorization Act
- Oil Pollution Act
- Toxic Substances Control Act.

In addition to a discussion of the requirements established under these Federal statutes (some of which are administered on the state level), additional or more stringent state requirements will also be discussed. Requirements in the states of California and Texas will be highlighted since the majority of the Slope-Basin & Basin clastic reservoirs is in these states.

<u>Federal Requirements</u>

E&P wastes, including drilling muds, cuttings, and other associated wastes, are considered to be non-hazardous under Federal Resource Conservation and Recovery Act (RCRA) definitions (they are exempted from RCRA Subtitle C requirements) and are regulated under state and regional solid waste disposal programs in accordance with RCRA Subtitle D. Individual states have jurisdiction when deciding

Table VII-1

Potential Environmental Impacts Associated with Thermal and Chemical Advanced Recovery Techniques

Area of Concern	Thermal EOR Processes	Chemical EOR/ASR Processes
Air Quality	• Emissions from steam generators used in steam injection and air compressors used for in situ combustion can increase levels of air pollution. They include: — SO_2 (Sulfur Dioxide) — NO_x (Nitrogen Oxide) — PM-10 (particulate matter less than 10 microns) — TSP (Total Suspended Particles) • Hydrogen sulfide (H_2S) and hydrocarbons may be emitted from producing wells, along with the potential release of other fugitive emissions from field process equipment.	• Fugitive emissions from the on-site manufacture of chemicals.
Land/Water Use	• The initiation of thermal recovery processes in certain heavy oil fields (predominantly in California) can lead to a increase in the number of producing wells.	• Water demands for surfactant and alkaline slugs and possible reservoir preflushing or postflushing could potentially place a strain on local water supplies. This impact would be particularly high if a waterflood was not already in progress.
Water Quality	• Produced water can potentially be contaminated by toxic combustion agents or thermal efficiency enhancers. This could potentially lead to the contamination of surface water or ground water supplies if disposal well injection equipment is faulty. • Application of produced water from thermal EOR processes for beneficial surface use could impact ground water supplies, if contaminants were present. • Stormwater runoff or natural drainage over or through a production site can lead to contamination of water sources.	• Surface water and ground water can potentially be contaminated through spills and/or leaks of chemicals during their transportation, on-site manufacturing, or handling. • Application of produced water from chemical EOR/ASR processes for beneficial surface use could impact ground water supplies, if contaminants were present. • Stormwater runoff or natural drainage over or through a production site can lead to contamination of water sources.

Table VII-1 (Continued)

Potential Environmental Impacts Associated with Thermal and Chemical Advanced Recovery Techniques

Area of Concern	Thermal EOR Processes	Chemical EOR/ASR Processes
Solid Waste Disposal	• Disposal of scrubber sludges, water treatment wastes, and wastes from wellhead gas cleanings may potentially result in soil contamination.	• Disposal of contaminated wastes generated by on-site chemical manufacturing may potentially result in soil contamination. • Disposal of water treatment and filter media wastes can potentially lead to soil contamination.
Other	• Steam generators, steam injection equipment, and aboveground steam flow lines pose a potential burn hazard to humans and animals. The presence of relatively large numbers of endangered and threatened species in certain regions of California makes this risk greater in specific oil fields. • Steam generators and air compressors can operate at high noise levels. • Compressed air injection lines tend to accumulate lube oil which may pose an explosion hazard. • Thermal EOR operations in wetlands should take special measures to protect salinity regimes and waterlogged soil.	• Chemicals used in flooding processes can leave potentially explosive dust accumulations. • Surfactant and alkaline flooding chemicals such as sodium hydroxide and sodium carbonate are corrosive to tissue. • Chemical EOR/ASR processes in wetlands should take special measures to protect salinity regimes and waterlogged soil.

Sources: National Petroleum Council. *Enhanced Oil Recovery*, June 1984.

Madden, Michael P., Robert P. Blatchford, and Richard B. Spears. *Environmental Regulations Handbook for Enhanced Oil Recovery*. Prepared for the U.S. Department of Energy, Assistant Secretary for Fossil Energy, December 1991.

if wastes exempted from Federal RCRA requirements are also exempt from state regulation as hazardous waste. State programs also set requirements for permits and financial assurance and specify construction and siting requirements for pits and other support facilities. The exact requirements faced by operators vary by state, as site-specific requirements have been implemented by many states to better protect environmentally sensitive areas.[11]

The Safe Drinking Water Act (SDWA) seeks to prevent the contamination of drinking water or potential drinking water sources by regulating underground injection practices (through the development of Underground Injection Control (UIC) programs) and by establishing minimum requirements for injection well construction, operation, monitoring, and reporting. The UIC program established five classes of wells, with Class II wells used for the disposal of waste liquids brought to the surface during oil or gas production, hydrocarbon storage, or enhanced recovery processes. Well construction requirements include appropriate logs and tests of both the injection formation and the adjacent underground formations to ensure that there is no contamination of any underground source of drinking water (USDW). Monitoring requirements include Mechanical Integrity Testing (MIT), with each state determining the appropriate MIT test and frequency as long as they meet or exceed Federal standards. All enhanced recovery operations are affected by SDWA injection well requirements, but thermal operations could be affected the most, due to the large number of injection wells necessary for some thermal recovery processes (such as steamflooding). More stringent Federal UIC regulations are being developed and are expected to be finalized in early 1995.

The Clean Water Act (CWA) regulates the point source discharges of produced water and other wastes into navigable U.S. waters. Point sources are defined as any "discernable, confined, or discrete conveyance from which pollutants are or may be discharged". Permits for point source discharges are required under the National Pollution Discharge Elimination System (NPDES). All discharges under NPDES permits must meet certain performance standards for the type of waste discharged, with treatment of waste streams prior to discharge often required to meet these standards. Stripper wells are currently exempt from all NPDES permitting requirements. The CWA also contains provisions regulating aboveground storage tanks. Operators in state offshore waters and onshore areas where spills may enter the water must have an approved Spill Prevention Control and Countermeasures (SPCC) plan under the CWA. The SPCC plan must contain a detailed facility description and must identify the potential sources of a spill, the protective measures employed to prevent spills, and the methods used to remediate spills that do occur. The location of E&P operations in wetlands is also governed by the CWA, which gives the Army Corps of Engineers approval and permitting authority over operations in these areas.

CWA requirements could potentially have the greatest impact on E&P operations in the southern regions of the Appalachian Basin (due to its proximity to the Ohio, Allegheny, and Monongahela Rivers), the Illinois Basin (due to its proximity to the Mississippi, Ohio, and Tennessee Rivers) and the coastal and offshore regions of the South Louisiana Salt Basin and California basins. The southern California basins may also be affected by local regulations requiring that all produced water generated in the Long Beach and Ventura regions be disposed at CWA-regulated, publicly owned treatment works. Operations in the South Louisiana Salt Basin could also be impacted by the wetland protection regulations of the CWA.

The Clean Air Act (CAA) seeks to protect and enhance air quality by establishing National Ambient Air Quality Standards (NAAQS). Each state has the primary responsibility to provide the Environmental Protection Agency (EPA) with a State Implementation Plan (SIP) that details the methods by which NAAQS will be attained. The SIP must meet all Federal requirements and ensure NAAQS attainment by prescribed dates. The CAA has developed minimum emission control requirements for new and existing mobile and stationary sources. Existing sources are regulated through the SIP, while new sources are regulated by performance standards developed by EPA. These performance standards reflect the degree of pollution control achievable through the best available and adequately demonstrated pollution-control technologies.[12]

The provisions of the CAA and the Clean Air Act Amendments (CAAA) that are most likely to impact E&P operations are summarized below:

- E&P facilities emitting criteria pollutants (sulfur dioxide (SO_2), nitrous oxide (NO_x), carbon monoxide (CO), volatile organic compounds (VOCs), and particulate matter (PM-10)) at a rate greater than 100 tons per year or emitting hazardous air pollutants ((HAPs), any of 189 listed pollutants) at a rate greater than 10 tons per year individually or 25 tons per year in combination are defined as major sources and must apply more stringent emission control technologies. This requirement could force existing thermal recovery projects in California to incur high equipment retrofit costs or proposed projects to be abandoned.

- E&P facilities in certain areas that do not meet EPA's NAAQS (these areas are referred to as *non-attainment* areas) are subject to stringent provisions on emissions of NO_x and VOCs. Existing major stationary sources in non-attainment areas must apply reasonably available control technologies, while new or modified major stationary sources must apply best available control technologies (BACT). BACT is a pollution-control technique defined for categories of equipment and takes into account energy, economic, and environmental effects along with other costs.

  These requirements could have the greatest impact on E&P operations in Class III reservoirs in all four basins in California, as parts of each basin are ozone and PM-10 non-attainment areas. Figure VII-2 shows the areas in California where ozone non-attainment may affect oil production operations in Slope-Basin & Basin clastic reservoirs.

- New permitting requirements are included under the CAAA. Permits are required for the emission of all regulated pollutants, including criteria pollutants and HAPs. An annual emission fee of at least $25 per ton for all registered pollutants except carbon monoxide was implemented. This fee must be paid by all operators of major sources of criteria pollutants and HAPs. Additional requirements related to permitting include emissions inventories, compliance monitoring and reporting, and increased public participation. These new permitting requirements can place a substantial paperwork and financial burden on Slope-Basin & Basin clastic reservoir facilities characterized as major sources.

- Enforcement provisions include both civil and criminal sanctions, large fines, and the potential imprisonment of violators.

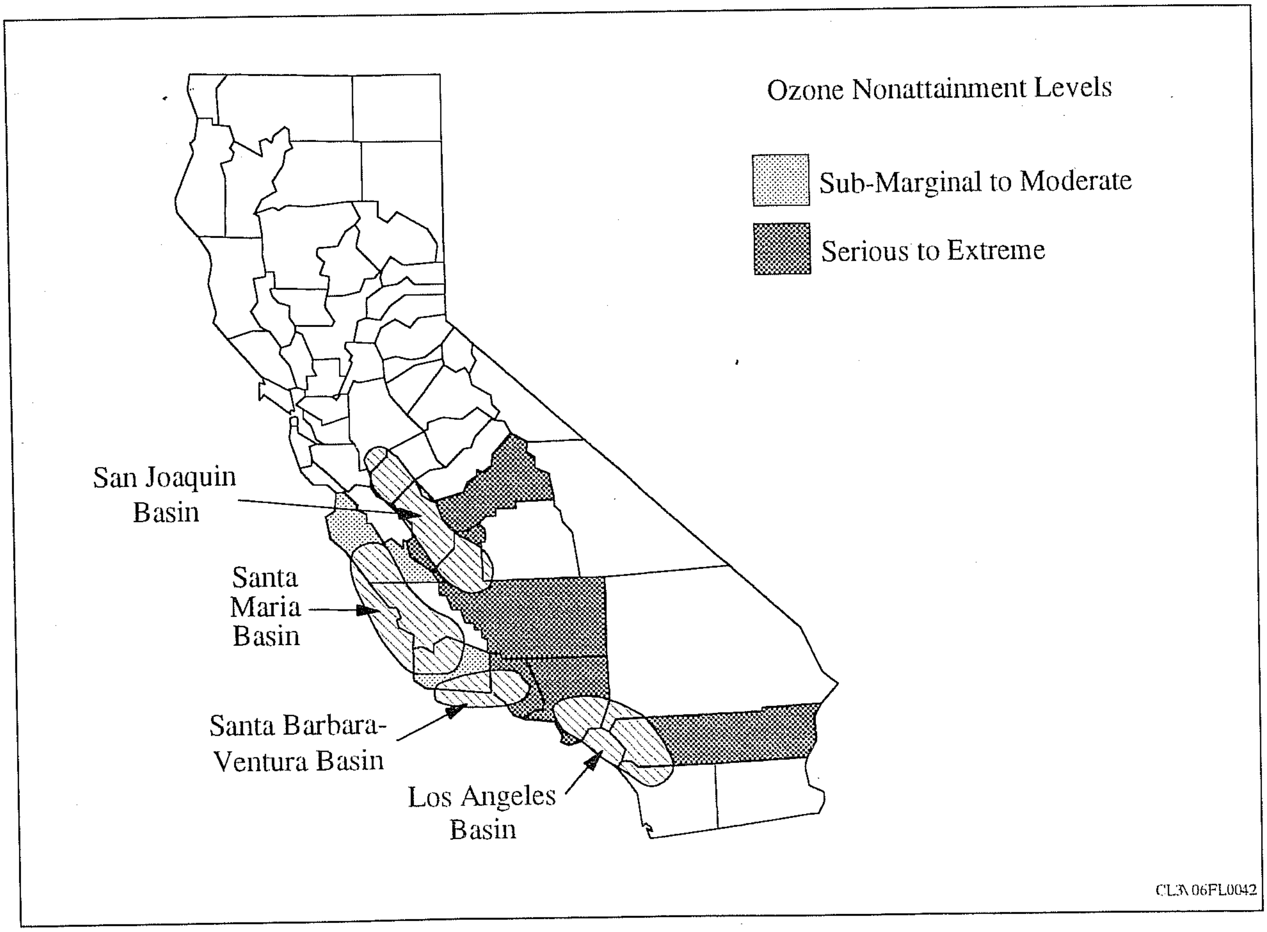
- New procedures for regulating oil and gas industry sources in the Outer Continental Shelf (OCS) shift regulatory authority in all Federal OCS areas other than the Central and Western Gulf of Mexico from the Minerals Management Service to the EPA and require that OCS sources meet the same requirements as sources onshore.[13]

The Endangered Species Act (ESA) is designed to provide for the protection of endangered species of fish, wildlife, or plants. ESA establishes procedures and regulations for determining endangered or threatened species and for governing interstate and interagency cooperation in protecting them. Federal agencies are required to ensure that their activities neither jeopardize endangered or threatened species, nor destroy or modify their habitats. Any E&P operation near the habitat of an endangered or threatened species may be affected by the requirements of this statute. The Class III reservoirs in California are more likely to be affected by ESA than are other areas with Slope-Basin & Basin clastic reservoirs. ESA can impose substantial paperwork burdens, as well as lengthy permit delays, on operators.

The National Energy Policy Act (NEPA) was designed to require Federal decision makers to consider the environmental consequences or impacts before approving Federally funded or sponsored projects. Appropriate NEPA documentation is required for each project with the type of documentation required depending on the potential environmental impacts. An Environmental Assessment (EA) is prepared for a project when ES&H impacts may be significant or uncertain. The EA must address the proposed action, all practicable alternatives, the environmental impacts and cumulative impacts of each alternative, and a list of agencies and persons consulted during preparation of the document.

Figure VII-2

Ozone Non-attainment Levels of Major Oil Producing Counties in California



If significant impacts may result from a Federal action, an Environmental Impact Statement (EIS) may be required. An EIS document provides a full and fair discussion of the environmental impacts associated with a proposed action, and any measures to be taken to mitigate these impacts. An EIS also includes consideration of all alternatives to a proposed action. If an EA concludes that the proposed action does not require an EIS, then a Finding of No Significant Impact (FONSI) is prepared. A FONSI document records the Federal agency position that, based on the analysis provided in the EA, the environmental impacts of an action will not have a significant effect on the environment, and describes the reasons why an EIS does not need to be prepared.

The history of EA analyses has indicated that certain actions have <u>always</u> resulted in FONSI. In order to eliminate duplication of effort, Federal agencies defined these and other substantially similar activities as a category of actions that do not individually or cumulatively have a significant effect on the environment. This Categorical Exclusion Determination (CX) eliminates the need for an EA or an EIS. A proposed action should meet the criteria provided in the NEPA guidelines to be categorically excluded. To date, most research proposals funded under the Oil Research Program have received categorical exclusions.

The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), also known as Superfund, was enacted to clean up waste disposal facilities containing or releasing any hazardous substances designated under CWA and CERCLA or listed under RCRA, CWA, CAA, or the Toxic Substance Control Act (TSCA). Waste streams are exempted from CERCLA notification, liability, or response provisions if they are Federally permitted releases under RCRA, CWA, SDWA, or CAA. Under the Superfund Amendments and Reauthorization Act (SARA), E&P operators must provide notification if certain hazardous substances are present at the facility or released to the environment. Community "right-to-know" regulations under SARA require operators to submit lists of certain chemicals at their facilities to designated local, state, and Federal authorities. Abandoned E&P sites that pose risks to human health or the environment fall under CERCLA and SARA clean-up provisions. CERCLA and SARA can impose substantial financial and paperwork burdens on operators.

The Oil Pollution Act (OPA) is a comprehensive statute designed to expand oil spill prevention activities, establish new Federal authority to direct responses to spills, improve preparedness and response capabilities, ensure that shippers and oil companies are responsible for damages for spills that do occur, and establish an expanded oil pollution research and development program. Operators near navigable waters must prepare spill prevention plans and may have to demonstrate financial responsibility. The OPA could have the greatest impact on Slope-Basin & Basin clastic reservoir operations in the coastal and offshore regions of the South Louisiana Salt Basin, the Los Angeles Basin, the Santa Barbara-Ventura Basin, and the Santa Maria Basin.

The Toxic Substance Control Act (TSCA) was enacted to address the concern that certain chemicals and chemical mixtures may present an unreasonable risk to human health and the environment. The chemicals associated with chemical EOR and ASR processes (which include profile modification, surfactant flooding, and alkaline flooding are subject to TSCA when storage, disposal, or accidental release of the chemicals used occurs. Substantial reporting requirements may be associated with TSCA.

The potential effects of additional paperwork and/or financial burdens imposed by many of the above mentioned Federal regulations could be heightened by the fact that nearly 40% of 1991 production from Slope-Basin & Basin clastic reservoirs was accounted for by small or midsize independent operators. These smaller producers have limited resources with which to meet increasingly stringent regulations and may be forced to plug and abandon their producing wells if compliance costs become too great.

State Requirements

In addition to the Federal requirements (summarized above) faced by E&P operators producing from Slope-Basin & Basin clastic reservoirs, the regulatory programs of the eight individual states in which these reservoirs are located have undergone major changes since the mid-1980s. State regulatory programs have focused on many areas that directly impact operations in Slope-Basin & Basin clastic reservoirs, including well plugging and abandonment, surface impoundments, waste management and disposal, and contingency planning.

Since California and Texas account for the large majority of both the Slope-Basin & Basin clastic reservoirs and resource base, their regulatory programs will be examined individually. The absence of individual mention of the states that account for the minor portion of the Slope-Basin & Basin clastic resource base (Louisiana, New Mexico, West Virginia, Pennsylvania, Illinois, and Mississippi account for approximately 1% of the TORIS original oil-in-place) does not change the fact that they have also made substantial changes to appropriate regulatory programs in the areas mentioned above.[14]

California has one of the most complex and stringent regulatory environments in the United States. State, regional, and local agencies combine to regulate oil and gas E&P operations, with Federal agencies retaining jurisdiction over certain programs, including all operations on Federal lands. This section will include: (1) a summary of California's major oil and gas environmental regulatory programs; (2) a detailed discussion of California's approach towards regulating air quality; and (3) a summary of California's requirements addressing the disposal of drilling wastes and other associated wastes. The potential impacts of various state requirements on operations in Slope-Basin & Basin clastic reservoirs will also be discussed as appropriate.

The Department of Conservation, Division of Oil, Gas, and Geothermal Resources (DOGGR) has extensive requirements addressing the drilling, operation, maintenance, and abandonment of wells, the Class II injection well program, and reserve pit location, maintenance, and closure. The State Water Resources Control Board shares responsibility for reserve pits with the DOGGR, as well as having primary jurisdiction over permitting surface waste disposal and issuing NPDES permits. The Department of Fish and Game, Office of Oil Spill Prevention and Response has authority over all aspects of oil spill prevention and cleanup. The Department of Toxic Substances Control (DTSC) is responsible for classifying waste materials based on their toxicity.

The maintenance of California's air quality is the responsibility of several agencies. The California Air Resources Board (CARB) is a state agency with primary responsibility for coordinating state-wide air quality programs. Air Pollution Control and Air Quality Management Districts (APCD/AQMD) are county or multicounty agencies responsible for implementing state air quality laws pertaining to stationary sources. There are 34 single-county APCDs, five multicounty APCDs, and three AQMDs.

The necessity of a detailed examination of California's approach towards protecting its air quality is highlighted by the following:

- Thermal recovery is the most commonly used enhanced recovery process, accounting for approximately 61% of enhanced recovery production in the United States.[15]

- Over 80% of all oil recovered through thermal processes is produced in California.[16]

- The greatest potential environmental impact associated with thermal recovery involves the emission of potentially harmful air pollutants, and these impacts are not well understood.

- Thermal recovery processes can be expected to account for 65% of incremental resource recovery in the near-term and 55% in the mid-term for Slope-Basin & Basin clastic reservoirs.

California air quality requirements parallel CAA requirements, but are more stringent in some cases. Table VII-2 compares Federal and California air quality standards for certain contaminants.

The California statute that may have one of the greatest impacts on thermal recovery operations is the Air Toxic Hot Spot Information and Assessment Act. In an attempt to prevent localized concentrations of air pollutants, all toxic air contaminants must be listed and inventoried. Thermal recovery operators must provide detailed inventories of SO_2, NO_x, and PM-10 emissions to the local AQMD. The AQMD reviews the inventories and categorizes facilities based on the nature and amount of contaminants and the proximity of the operation to schools, hospitals, day care centers, and residential areas. Facilities designated as high priority must submit a risk assessment which includes dispersion

Table VII-2

Federal and California Ambient Air Quality Standards

Air Contaminant	Federal Standard	California Standard
Nitrous oxide (NO_x)	100 $\mu g/m^3$ (annual average)	470 $\mu g/m^3$ (1 hour average)
Sulfur dioxide (SO_2)	365 $\mu g/m^3$ (24 hour average)	131 $\mu g/m^3$ (24 hour average)
Carbon monoxide (CO)	9 ppm (8 hour average)	6 ppm (8 hour average)
Lead (Pb)	0.25 $\mu g/m^3$ (30 day average)	1.5 $\mu g/m^3$ (30 day average)
Particulate matter (PM-10)	50 $\mu g/m^3$ (annual average)	60 $\mu g/m^3$ (annual average)

Note: Some local California air districts, such as Kern County, are required to adopt the more stringent of the two standards.
Key: ppm = parts per million
$\mu g/m^3$ = microgram per cubic meter

Source: Sarathi, Partha. "Environmental Aspects of Heavy-Oil Recovery by Thermal EOR Processes," *Journal of Petroleum Technology*, June 1991.

predictions. Ten thermal EOR operations were listed as toxic hot spots on the first Kern County APCD list in November 1990.[17]

Another California statute that could impact operations in Slope-Basin & Basin clastic reservoirs is the California Clean Air Act. This law requires all emissions in non-attainment areas to achieve a 5% per year reduction through the year 2010. This is more stringent than the Federal CAAA, which only require a 3% per year reduction. Overlapping this regulation, all existing stationary sources of VOCs and NO_x must apply best available retrofit control technologies by January 1, 1994. This regulation could have the greatest impact in the San Joaquin Basin, the center of California's heavy oil production and thermal recovery operations. Other California air quality requirements that may affect operations in Slope-Basin & Basin clastic reservoirs include the following:

- All new and modified sources must apply BACT.
- No net increase of VOCs or NO_x can occur in any developed area in the state.[18] This requirement could impact the future use of thermal recovery processes in California, since any emissions increase due to expansion must be offset with decreases in other areas or the purchase of emission credits.

California's approach to regulating the management and disposal of drilling wastes and other associated wastes could have additional impacts on the continued operation and future initiation of thermal recovery projects in the state. Drilling wastes containing additives or fluids listed by the California Environmental Protection Agency are considered hazardous and must be disposed at a hazardous waste management unit. Non-hazardous drilling wastes can be buried in pits, used to plug and abandon wells, transported for offsite disposal, landspread, or discharged to the surface (under an NPDES permit). Other associated wastes must be tested according to DTSC requirements to determine whether they exhibit hazardous characteristics. Hazardous wastes must be disposed at a hazardous waste management unit, while non-hazardous other associated wastes can be disposed at approved landfills or other non-hazardous waste disposal facilities. California's stringent regulation of drilling waste and other associated waste disposal can cause operations in Slope-Basin & Basin clastic reservoirs generating greater volumes of wastes to incur higher disposal costs. Recent changes to California's regulatory programs have addressed temporary well abandonment, contingency planning and spill prevention measures, and well bonding (including injection wells).[19]

Texas accounts for 22% of the TORIS Slope-Basin & Basin clastic reservoirs and 13% of the original oil-in-place. As with California, Texas has many state regulatory agencies that work together to regulate virtually all aspects of the oil and gas E&P industry. Unlike California, however, where thermal recovery is the most widely used EOR process, many different types of EOR projects are undertaken in Texas. Therefore, the environmental regulations in Texas must take into account the wide variety of potential environmental risks posed by the various enhanced recovery processes used.

The Texas Railroad Commission (TRC) has primary regulatory responsibility for activities associated with the exploration, development, and production of oil, gas, and geothermal resources, including the management of E&P wastes. The Texas Natural Resource Conservation Commission (TNRCC), which recently formed as a result of a merger of the Texas Water Commission and the Texas Air Control Board, has jurisdiction over the disposal of naturally occurring radioactive materials (NORM), the setting of surface water quality standards, and the control of oil field air emissions. The Texas Department of Health has jurisdiction over the possession, use, transfer, and storage of NORM. The Texas Parks and Wildlife Department evaluates the effects of discharging wastes on fish and wildlife, while the

General Land Office certifies discharge prevention and response plans for coastal and offshore facilities. Recent changes to the environmental regulatory program of Texas have addressed air quality standards (California's were used as a guideline), procedures for receiving drilling permits, well plugging procedures, well bonding, pit construction, and abandonment procedures for cathodic protection wells.[20]

Potential Economic Impacts of Environmental Requirements

Increased environmental compliance costs can be a major factor in project economics. In 1990, a report prepared for the DOE examined the cumulative impact on crude oil supplies of proposed changes under the four primary Federal environmental statutes (RCRA, SDWA, CWA, and CAA). This report found that a stringent regulatory scenario could result in the loss of up to 40 percent of resources that would otherwise be recoverable.[21] The National Petroleum Council (NPC) also examined the cumulative impact of environmental regulatory changes in its 1992 report on U.S. natural gas supplies.[22] The NPC examined a stringent regulatory scenario that represents a willingness to give up some level of supply to gain perceived environmental benefits. Recently, the DOE has applied the same environmental scenarios considered by the NPC to estimation of the impact on oil supplies.[23]

Using available the DOE resource analysis models, the impacts associated with the NPC's stringent environmental regulatory scenario were determined. Impacts were presented in terms of the estimated incremental costs operators could have to incur to comply with each scenario and the crude oil resources that could become uneconomic as a result of imposing the regulations considered. From a TORIS analysis of future recovery potential from EOR and ASR technologies under each scenario, the impacts on future recovery could be examined. The results of this updated cumulative impacts analysis have been sorted by reservoir class to determine the potential impacts of environmental regulations on Slope-Basin & Basin clastic reservoirs. Figure VII-3 shows the resource potential and possible loss due to potentially stringent, future environmental regulations, using the near-term and mid-term price and technology assumptions.

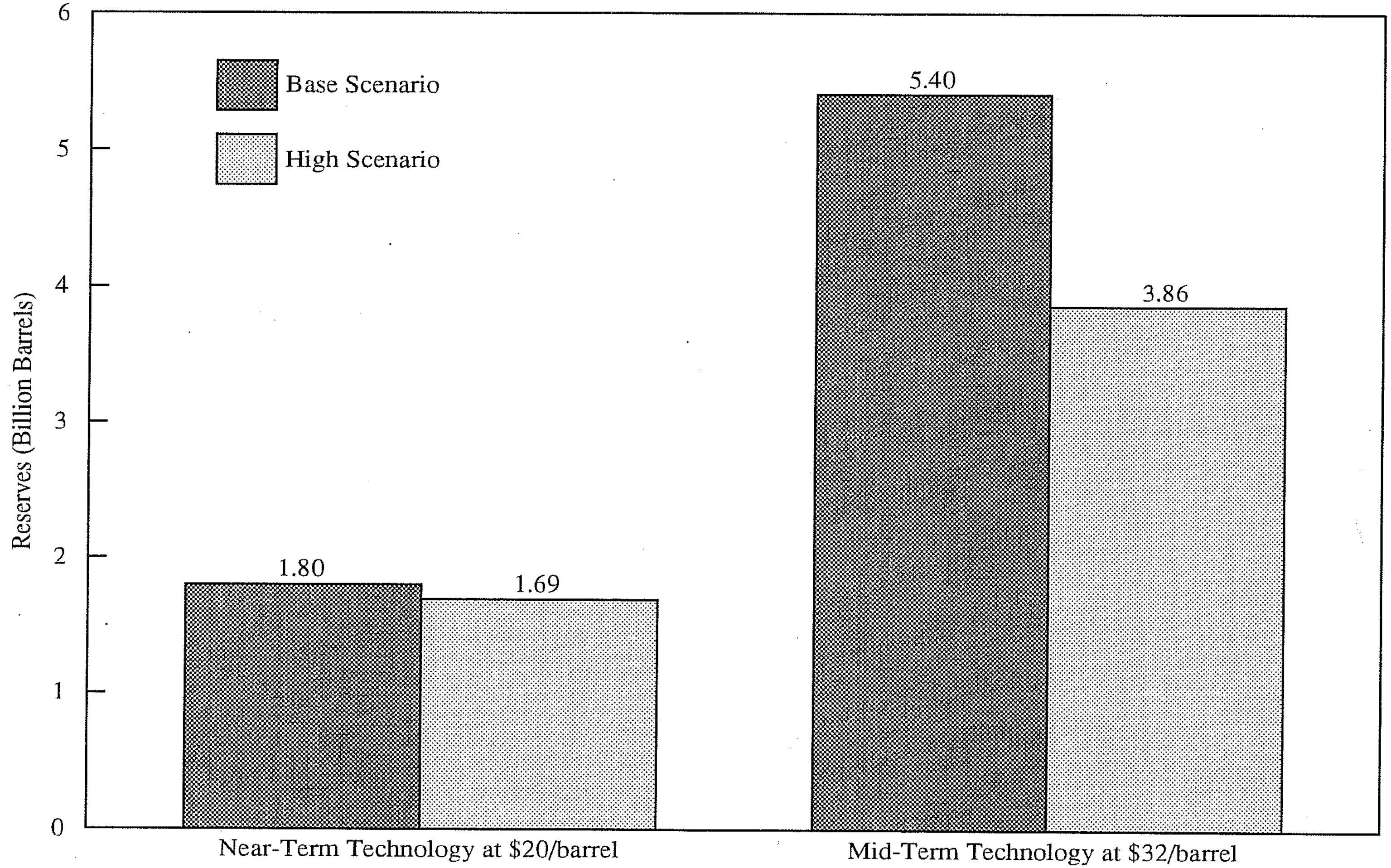
Resource abandonment is a likely result of the potential cumulative impacts of more stringent environmental regulations. With an oil price of $20/B, near-term resource loss could be as high as 110 million barrels in the Slope-Basin & Basin clastic reservoirs. This loss represents 6% of the expected resource recovery in Slope-Basin & Basin clastic reservoirs in the near-term using current EOR and ASR technologies with current environmental regulations. With higher oil prices, the potential impact of stringent future regulations grows. The loss of future EOR and ASR recovery potential in the mid-term could be as high as 1.5 billion barrels, or 27% of the oil that might otherwise be recovered. These possible reductions in future oil recovery potential emphasize the importance of environmental concerns to Slope-Basin & Basin clastic resource recovery.

Summary

There are a number of environmental aspects associated with operations in Slope-Basin & Basin clastic reservoirs. Each of these aspects, ranging from Federal environmental statutes to regional environmental settings, can cause an E&P operation to be delayed, abbreviated, or abandoned. The result can be a reduction in future oil recovery. As the majority of incremental resource recovery can be expected through thermal recovery processes, Federal and state air quality regulations could have the greatest impact on future resource recovery from Class III reservoirs.

Figure VII-3

Resource Potential and Possible Loss Due to Environmental Regulations (Slope-Basin and Basin Clastic Reservoirs



Notes: 1. High regulatory scenario defined by the National Petroleum Council
2. Reserves potential extrapolated from multistate resource total (IOGCC, 1990)

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The Federal Clean Air Act could impact thermal recovery operations in number of ways. Existing projects in certain areas (mainly California) would be forced to incur high equipment retrofit costs to reduce the emission of pollutants, such as carbon monoxide and sulfur dioxide. Permitting requirements under the Clean Air Act Amendments can place a substantial administration and financial burden on Class III operations.

Since the majority of thermal recovery operations take place in California, state and local air quality regulations could also slow or eliminate expansion of thermal projects. California's ambient air quality standards for certain air contaminants are stricter than Federal requirements. In addition, several statutes unique to California (such as the California Clean Air and the Air Toxic Hot Spot Information and Assessment Act) could impact E&P projects by causing operators to purchase expensive air pollution control technologies or emission credits to offset an increase in emissions from the expansion of another project.

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APPENDIX A

OPERATOR PROFILE OF SLOPE-BASIN & BASIN CLASTIC RESERVOIRS

Operator	1991 Oil Production (Barrels)	1991 Oil Production as a Percent of Class Total
MAJORS (over 250 million barrels domestic liquids reserves)		
SHELL WESTERN E&P, INC.	36,156,694	21.74
ARCO OIL & GAS CO.	15,486,075	9.31
TEXACO E&P INC.	9,590,474	5.77
UNION OIL CO. OF CALIFORNIA	8,907,213	5.35
MOBIL PRODUCING INC.	7,973,986	4.79
CHEVRON USA INC.	7,562,838	4.55
EXXON CORPORATION	7,300,390	4.39
MARATHON OIL	3,138,229	1.89
CONOCO INC.	2,211,304	1.33
PHILLIPS PETROLEUM CO.	323,913	0.19
AMOCO PRODUCTION COMPANY	89,006	0.05
ORYX ENERGY COMPANY	23,174	0.01
TOTAL MAJORS	**98,763,297**	**59.37**
LARGE INDEPENDENTS (over 100 million barrels domestic liquids reserves)		
SANTA FE ENERGY RESOURCES INC.	2,378,561	1.43
OCCIDENTAL PETROLEUM CORP.	808,428	0.49
UNION PACIFIC RESOURCES CO.	96,675	0.06
AMERADA HESS CORP.	5,985	0.00
TOTAL LARGE INDEPENDENTS	**3,289,648**	**1.98**

OPERATOR PROFILE OF SLOPE-BASIN & BASIN CLASTIC RESERVOIRS (Continued)

Operator	1991 Oil Production (Barrels)	1991 Oil Production as a Percent of Class Total
MIDSIZE INDEPENDENTS (over 10 million barrels domestic liquids reserves)		
PARKER & PARSLEY PETROLEUM CO.	543,739	0.33
ENRON	215,117	0.13
BHP PETROLEUM (AMERICAS) INC.	113,322	0.07
PACIFIC ENTERPRISES OIL & GAS CO.	95,110	0.06
HALLWOOD ENERGY PARTNERS LP	86,725	0.05
PERMIAN BASIN ROYALTY TRUST CO.	19,274	0.01
AMAX OIL & GAS INC.	14,706	0.01
ADOBE RESOURCES CORP.	8,324	0.01
AMERICAN EXPLORATION CO.	6,772	0.00
TOTAL MIDSIZE INDEPENDENTS	**1,103,089**	**0.66**
SMALL INDEPENDENTS (Approximately 550 companies) (10 million barrels or less domestic liquid reserves)	**63,194,479**	**37.99**
TOTAL PRODUCTION	**166,350,513**	**100.00**

APPENDIX B

SLOPE-BASIN & BASIN CLASTIC RESERVOIRS IN TORIS

State	Fieldname	Reservoir	Formation
CA	ALISO CANYON	PORTER	PICO
CA	ASPHALTO	STEVENS	STEVENS
CA	BELRIDGE NORTH	DIATOMITE	MONTEREY
CA	BELRIDGE NORTH	BELRIDGE 64 ZONE	TEMBLOR
CA	BETA FIELD 9	MIOCENE	PUENTE
CA	BEVERLY HILLS	WEST AREA MIOCENE	PUENTE
CA	BEVERLY HILLS	EAST AREA MIOCENE	PUENTE
CA	BEVERLY HILLS	EAST AREA PLIOCENE	REPETTO
CA	BEVERLY HILLS	WEST AREA PLIOCENE (WOLFSKILL)	REPETTO
CA	BREA OLINDA	PLIOCENE-MIOCENE	REPETTO/PUENTE
CA	BUENA VISTA	555 STEVENS	STEVENS
CA	BUENA VISTA	ANTELOPE SHALE EAST & WEST DOME	MONTEREY
CA	CARPINTERIA (OCS P-0166)	CARPENTERIA OFFSHORE REPETTO	REPETTO
CA	CASMALIA	MONTEREY	MONTEREY
CA	CAT CANYON EAST	MIOCENE	MONTEREY
CA	CAT CANYON WEST	LOS FLORES-MIOCENE	MONTEREY
CA	COLES LEVEE NORTH	RICHFIELD	STEVENS
CA	COLES LEVEE SOUTH	STEVENS	STEVENS
CA	COYOTE EAST	MIOCENE "A"	PUENTE
CA	COYOTE EAST	ANAHEIM	REPETTO
CA	COYOTE EAST	STERN	PUENTE
CA	COYOTE WEST	EMERY E LI38	REPETTO
CA	COYOTE WEST	MAIN 99W	REPETTO
CA	COYOTE WEST	EMERY WEST	REPETTO
CA	COYOTE WEST	TOP OIL	REPETTO
CA	COYOTE WEST	MAIN 99E	REPETTO
CA	CYMRIC	PHACOIDES AND CARNEROS	CARNEROS
CA	CYMRIC	MCKITTRICK FRONT AREA REEF RIDGE	REEF RIDGE (OLIG)
CA	CYMRIC	SALT CREEK MAIN	TEMBLOR
CA	DOMINGUEZ	CALLENDER PLIOCENE, MIOCENE	REPETTO/PUENTE
CA	DOS CUADROS	FEDERAL OFFSHORE	REPETTO
CA	DOS CUADROS	FP WATERFLOOD P-024	REPETTO
CA	DOS CUADROS	EP WATERFLOOD P-0241	REPETTO
CA	EDISON	PORTALS-FAIRFAX AREA WICKER NOZU	FRUITVALE
CA	EL SEGUNDO	MAIN AND WEST AREA	PUENTE
CA	ELK HILLS	STEVENS	STEVENS
CA	GATO RIDGE	TOGNAZZINI	MONTEREY
CA	GREELY	STEVENS	STEVENS
CA	HONOR RANCHO	WAYSIDE	MODELLO
CA	HUNTINGTON BEACH	SOUTH AREA ONSHORE MAIN	PUENTE

SLOPE-BASIN & BASIN CLASTIC RESERVOIRS IN TORIS (Continued)

State	Fieldname	Reservoir	Formation
CA	HUNTINGTON BEACH	SOUTH AREA ONSHORE TAR ZONE	REPETTO
CA	HUNTINGTON BEACH	NORTH AREA TAR BOLSA	REPETTO
CA	HUNTINGTON BEACH	SOUTH, ONSHORE-ASHTON-JONES	REPETTO/PUENTE
CA	HUNTINGTON BEACH	OFFSHORE-JONES	PUENTE
CA	HUNTINGTON BEACH	HUNT AVE. AREA JONES	PUENTE
CA	HUNTINGTON BEACH	OFFSHORE-MAIN	PUENTE
CA	INGLEWOOD	VICKERS	PICO/REPETTO
CA	INGLEWOOD	MOYNIER	REPETTO
CA	INGLEWOOD	SENTOUS	PUENTE
CA	INGLEWOOD	RINDGE	REPETTO
CA	INGLEWOOD	RUBEL	REPETTO
CA	KRAEMER	KRAEMER	PUENTE
CA	LAS CIENEGAS	JEFFERSON	PUENTE
CA	LOMPOC	MONTEREY	MONTEREY
CA	LONG BEACH	NORTHWEST EXTENSION AREA-BROWN	REPETTO/PUENTE
CA	LONG BEACH	OLD AREA-UPPER	REPETTO/PUENTE
CA	LOS ANGELES CITY	MIOCENE ZONES 1-2-3	PUENTE
CA	LOS ANGELES DOWNTOWN	MIOCENE	PUENTE
CA	MCKITTRICK	REEF RIDGE	REEF RIDGE
CA	MCKITTRICK	MAIN AREA STEVENS	STEVENS
CA	MIDWAY SUNSET	OLIG	REEF RIDGE
CA	MIDWAY SUNSET	REPUBLIC	STEVENS
CA	MIDWAY SUNSET	MIOCENE OTHER	STEVENS
CA	MONTALVO WEST	MCGRATH POOL	REPETTO
CA	MONTEBELLO	MAIN AREA BALDWIN 1-2-3	REPETTO/PUENTE
CA	NEWHALL-POTRERO	3RD ZONE	MODELO
CA	NEWHALL-POTRERO	7TH ZONE	MODELO
CA	NEWHALL-POTRERO	5TH ZONE	MODELO
CA	NEWHALL-POTRERO	6TH ZONE	MODELO
CA	NEWPORT WEST	MAIN AREA	REPETTO/PUENTE
CA	ORCUTT	MONTEREY-PT. SAL	MONTEREY/PT. SAL
CA	OXNARD	PLIOCENE & MIOCENE TAR	PICO
CA	PALOMA	PALOMA SANDS (BLACK OIL ZONE)	STEVENS
CA	PRADO-CORONA	SARDCO AREA-HUNTER	PUENTE
CA	PRADO-CORONA	GOEDHART AREA-HUNTER	PUENTE
CA	RAILROAD GAP	ANTELOPE SHALE & VALV.	ANTELOPE
CA	RAMONA	KERN-DEL VALLE	MODELLO
CA	RICHFIELD EAST AREA	CHAPMAN	PUENTE
CA	RICHFIELD EAST AREA	KRAEMER	PUENTE
CA	RICHFIELD WEST AREA	CHAPMAN	PUENTE

SLOPE-BASIN & BASIN CLASTIC RESERVOIRS IN TORIS (Continued)

State	Fieldname	Reservoir	Formation
CA	RINCON	OAK GROVE OTHERS	PICO
CA	RINCON	MILEY-MAIN AREA; OFFSHORE AREA	PICO
CA	RINCON	OAK GROVE RINCON	PICO
CA	SALT LAKE	PLIOCENE/MIOCENE	REPETTO/PUENTE
CA	SAN MIGUELITO	FIRST GRUBB	PICO
CA	SAN MIGUELITO	SECOND GRUBB	PICO
CA	SAN MIGUELITO	THIRD GRUBB	PICO
CA	SANTA FE SPRINGS	MAIN AREA OTHERS	REPETTO/PUENTE
CA	SANTA MARIA VALLEY	MAIN AREA-MONTEREY	MONTEREY
CA	SATICOY	SANTA BARBARA	PICO
CA	SATICOY	PICO	PICO
CA	SEAL BEACH	SOUTH BLOCK WASEM	REPETTO/PUENTE
CA	SEAL BEACH	SOUTH BLOCK BIXBY/SELOVER	REPETTO
CA	SEAL BEACH	SOUTH BLOCK MCGRATH	PUENTE
CA	SEAL BEACH	NORTH BLOCK WASEM/MCGRATH	REPETTO/PUENTE
CA	SEAL BEACH	NORTH BLOCK MCGRATH	PUENTE
CA	SOUTH BELRIDGE	DIATOMITE BROWN SHALE	MONTEREY
CA	SOUTH MOUNTAIN	BRIDGE-PLIOCENE	PICO
CA	TEJON GR.-TEJON GRAPEVINE	CENTRAL AREA RESERVE	FRUITVALE
CA	TEN SECTION	441	LOWER STEVENS
CA	TEN SECTION	MAIN AREA STEVENS	STEVENS
CA	TORRANCE	MAIN	PUENTE
CA	TORRANCE	DEL AMO	PUENTE
CA	VENTURA	D-7,8	PICO
CA	VENTURA	D 3,4,5,6	PICO
CA	VENTURA	C BLOCK	PICO
CA	VENTURA	B SANDS	PICO
CA	VENTURA AVENUE	GRUBB D-5	PICO
CA	WHEELER RIDGE	WINDGAP AREA L-36 RESERVE	FRUITVALE/STEVENS
CA	WHITTIER	2ND & 3RD ZONES	REPETTO
CA	WHITTIER	RIDEOUT HEIGHTS (NEW PLIO, OLD)	PUENTE
CA	WILMINGTON	HARBOR AREA FAULT BLOCK VI LOWER TERMINAL	PUENTE
CA	WILMINGTON	TERMINAL AREA FAULT BLOCK II-B RANGER	REPETTO/PUENTE
CA	WILMINGTON	TERMINAL AREA FAULT BLOCK I	REPETTO/PUENTE
CA	WILMINGTON	TOWN LOT AREA FAULT BLOCK II-A	REPETTO/PUENTE
CA	WILMINGTON	TERMINAL AREA FAULT BLOCK II-A TAR	REPETTO
CA	WILMINGTON	HARBOR AREA FAULT BLOCK V TAR	REPETTO
CA	WILMINGTON	TOWN LOT AREA FAULT BLOCK II-A RANGER	REPETTO/PUENTE
CA	WILMINGTON	HARBOR AREA FAULT BLOCK V-A UPPER TERMINAL	PUENTE

SLOPE-BASIN & BASIN CLASTIC RESERVOIRS IN TORIS (Continued)

State	Fieldname	Reservoir	Formation
CA	WILMINGTON	TERMINAL AREA FAULT BLOCK II-A RANGER	REPETTO/PUENTE
CA	WILMINGTON	TOWN LOT AREA FAULT BLOCK III RANGER	REPETTO/PUENTE
CA	WILMINGTON	TERMINAL AREA FAULT BLOCK II-A U.TERMINAL	PUENTE
CA	WILMINGTON	HARBOR AREA FAULT BLOCK IV TAR	REPETTO
CA	WILMINGTON	TERMINAL	PUENTE
CA	WILMINGTON	HARBOR AREA FAULT BLOCK V-B U.TERMINAL	PUENTE
CA	WILMINGTON	HARBOR AREA FAULT BLOCK IV RANGER	REPETTO/PUENTE
CA	WILMINGTON	RANGER	REPETTO/PUENTE
CA	WILMINGTON	TOWN LOT AREA FAULT BLOCK I	REPETTO/PUENTE
CA	WILMINGTON	TERMINAL AREA FAULT BLOCK II-B	REPETTO/PUENTE
CA	WILMINGTON	HARBOR AREA FAULT BLOCK VI RANGER	REPETTO/PUENTE
CA	WILMINGTON	HARBOR AREA FAULT BLOCK VI U.TERMINAL	PUENTE
CA	WILMINGTON	EAST AREA BLOCK VI UPPER TERMINAL	PUENTE
CA	WILMINGTON	TERMINAL AREA FAULT BLOCK III RANGER	REPETTO/PUENTE
CA	WILMINGTON	HARBOR AREA FAULT BLOCK V RANGER	REPETTO/PUENTE
CA	WILMINGTON	TERMINAL AREA FAULT BLOCK III TAR	REPETTO
CA	WILMINGTON	HARBOR AREA FAULT BLOCK IV U.TERMINAL	PUENTE
CA	YORBA LINDA	UPPER CONGLOMERATE	REPETTO
CA	YORBA LINDA	MAIN	REPETTO
CA	YOWLUMNE	YOWLUMNE SAND	STEVENS
CA	ZACA	MONTEREY FRACTURED CHERT	MONTEREY
IL	ST. JAMES	CARPER	BORDEN
LA	SHIP SHOAL 107	RESERVOIR 23 12000' SAND	RESERVOIR 23 12000' SAND
LA	SHIP SHOAL 204	PLEISTOCENE	PLEISTOCENE
LA	SOUTH PASS 61	UPPER M RAAO 2,3	UPPER M RAAO 2,3
LA	SOUTH PASS 61	MID 'M'RAAD 2,3	MID 'M'RAAD 2,3
LA	SOUTH PASS 62	N6-N8 RB	N6-N8 RB
LA	SOUTH PASS 62	M RC	M RC
LA	SOUTH PASS 65	G3-RB	G3-RB
LA	SOUTH PASS 65	G-G1RA	G-G1RA
LA	SOUTH PASS 89	U-1/1	U-1/1
LA	VERMILION 331	L 2/4	L 2/4
LA	WEST DELTA 63 FIELD	LR-54-6	LR-54-6
MS	TINSLEY	WOODRUFF SAND. WEST SEGMENT	WOODRUFF
MS	TINSLEY	SELMA-EUTAW-TUSCALOOSA N. SEG.	UPPER CRETACEOUS SANDS
MS	TINSLEY	WOODRUFF SAND. EAST SEG.	WOODRUFF
NM	EL-MAR	DELAWARE	DELAWARE

SLOPE-BASIN & BASIN CLASTIC RESERVOIRS IN TORIS (Continued)

State	Fieldname	Reservoir	Formation
NM	MASON NORTH	DELAWARE	DELAWARE
NM	PADUCA	DELAWARE SAND	DELAWARE SAND
PA	SARTWELL	HASKILL SAND	ELK GROUP
TX	ACKERLY	DEAN SAND	DEAN SAND
TX	BENEDUM	SPRABERRY	SPRABERRY
TX	CALVIN	DEAN	DEAN
TX	COPE		
TX	EAST FORD (DELAWARE)	DELAWARE SAND	DELAWARE SAND
TX	EL MAR	DELAWARE SAND	DELAWARE SAND
TX	FLOWERS	CANYON SAND	CANYON SAND
TX	FLOWERS, WEST	CANYON SAND	CANYON SAND
TX	GERALDINE	FORD	FORD
TX	GIN SPRABERRY	SPRABERRY	SPRABERRY
TX	GRICE	DELAWARE SAND	DELAWARE SAND
TX	GUEST	CANYON SAND	CANYON SAND
TX	I.A.B., NORTHEAST	PENNSYLVANIAN 5150	PENNSYLVANIAN 5150
TX	JAMESON	STRAWN	STRAWN
TX	JO-MILL	SPRABERRY	SPRABERRY
TX	KELLY SNYDER	CISCO	CISCO
TX	KEN REGAN	DELAWARE SAND	DELAWARE SAND
TX	LAKE TRAMMEL WEST	CANYON	CANYON
TX	MASON	DELAWARE SAND	DELAWARE SAND
TX	MASON NORTH	DELAWARE SAND	DELAWARE SAND
TX	NEWMAN	SWASTIKA	SWASTIKA
TX	PARDUE	SWASTIKA	SWASTIKA
TX	PARDUE	SWASTIKA	SWASTIKA
TX	PARDUE	SWASTIKA	SWASTIKA
TX	PARDUE	CANYON	CANYON
TX	PEGASUS	SPRABERRY	SPRABERRY
TX	QUITO	DELAWARE SAND	DELAWARE SAND
TX	ROUND TOP	CANYON SAND	CANYON SAND
TX	SABRE	DELAWARE	DELAWARE
TX	SABRE	DELAWARE SAND	DELAWARE SAND
TX	S-M-S	CANYON SAND	CANYON SAND
TX	SPRABERRY	DEAN WOLFCAMP	DEAN WOLFCAMP
TX	SPRABERRY	SPRABERRY	SPRABERRY
TX	SPRABERRY, DEEP	SPRABERRY LOWER	SPRABERRY LOWER
TX	SPRABERRY, DEEP		
TX	STRAYBERRY WEST	DEEP	DEEP

SLOPE-BASIN & BASIN CLASTIC RESERVOIRS IN TORIS (Continued)

State	Fieldname	Reservoir	Formation
TX	SULPHUR DRAW	DEAN 8790	DEAN 8790
TX	SWEETWATER	CANYON SAND	CANYON SAND
TX	TEXON, WEST	SPRABERRY	SPRABERRY
TX	TOLAR	SWASTIKA	SWASTIKA
TX	TOLAR	SWASTIKA	SWASTIKA
TX	TUNSTILL	DELAWARE SAND	DELAWARE SAND
TX	TUNSTILL, EAST	DELAWARE SAND	DELAWARE SAND
TX	TWOFREDS	DELAWARE	DELAWARE
TX	WAHA, NORTH	DELAWARE SAND	DELAWARE SAND
TX	WHEAT	DELAWARE SAND	DELAWARE SAND
WV	BLUE CREEK (FALLING ROCK)	WEIR	POCONO

APPENDIX C

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