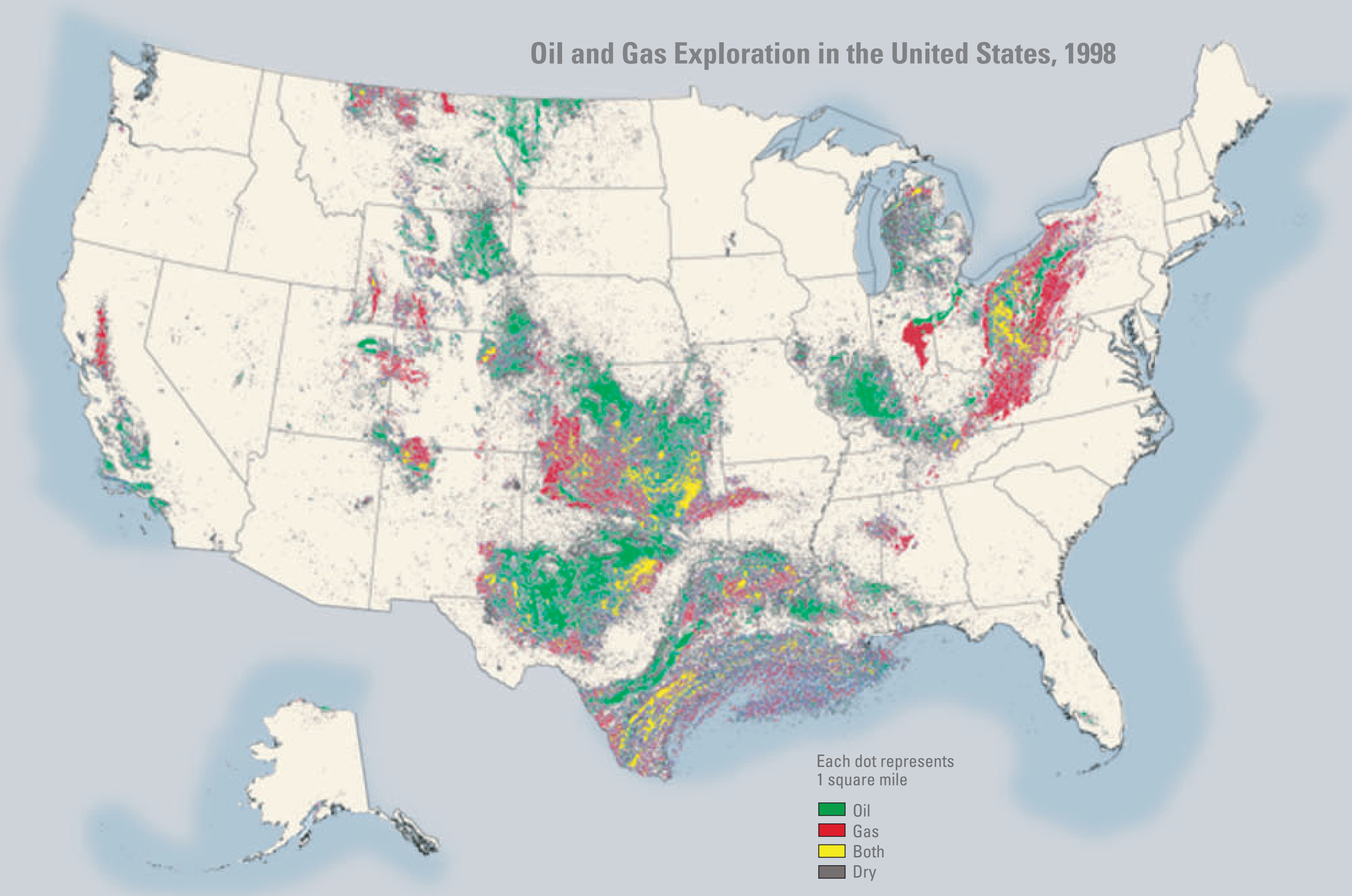
Growth History of Oil Reserves in Major California Oil Fields During the Twentieth Century

Chapter H *of*

Geologic, Engineering, and Assessment Studies of Reserve Growth

U.S. Geological Survey Bulletin 2172–H



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Cover. This map represents historical oil and gas exploration and production data for the conterminous United States and Alaska. It was derived from data used in U.S. Geological Survey Geologic Investigations Series I-2582.* The map was compiled using Petroleum Information Corporation's (currently IHS Corporation) database of more than 2.2 million wells drilled in the U.S. as of June 1993. The area of the U.S. was subdivided into 1 mi^2 grid cells for which oil and gas well completion data were available. Each colored symbol represents a 1 mi^2 cell (to scale) for which exploration has occurred. Each cell is identified by color as follows: red, a gas-producing cell; green, an oil-producing cell; yellow, an oil- and gas-producing cell; gray, a cell that has been explored through drilling, but no production has been reported. Mast and others (1998) gives details on map construction.

*Mast, R.F., Root, D.H., Williams, L.P., Beeman, W.R., and Barnett, D.L., 1998, Areas of historical oil and gas exploration and production in the conterminous United States: U.S. Geological Survey Geologic Investigations Series I-2582, one sheet.

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By M.E. Tennyson

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Geologic, Engineering, and Assessment Studies of Reserve Growth
Edited by T.S. Dyman, J.W. Schmoker, and Mahendra Verma

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Growth History of Oil Reserves in Major California Oil Fields During the Twentieth Century

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Abstract

Oil reserves in 12 of California's 52 giant fields (fields with estimated ultimate recovery >100 million barrels of oil) have continued to appreciate well past the age range at which most fields cease to show significant increases in ultimate recovery. Most of these fields were discovered between 1890 and 1920 and grew to volumes greater than 500 million barrels in their first two decades. Growth of reserves in these fields accelerated in the 1950s and 1960s and is mostly explained by application of secondary and tertiary recovery techniques, primarily waterflooding and thermal recovery. The remaining three-fourths of California's giant fields show a pattern of growth in which fields cease to grow significantly by 20–30 years following discovery. Virtually all of these fields have estimated ultimate recoveries less than about 500 million barrels and most are in the 100–200 million barrel range. Three of six offshore giant fields, all discovered between 1966 and 1981, have shown decreases in their estimated ultimate sizes within about the first decade after production began, presumably because production volumes failed to match initial projections.

The data suggest that:

1. Only fields that attain an estimated ultimate size of several hundred million barrels shortly after discovery and have geologic characteristics that make them susceptible to advanced recovery techniques are likely to show substantial late growth.
2. Offshore fields are less likely to show significant growth, probably because projections based on modern seismic reflection and reservoir test data are unlikely to underestimate the volume of oil in the field.
3. Secondary and tertiary recovery programs rather than field extensions or new pool discoveries are responsible for most of the significant growth of reserves in California.
4. Field size data collected over many decades provide a more comprehensive context for inferring reasons for reserve appreciation than shorter data series such as the Oil and Gas Integrated Field File (OGIFF) from the U.S. Department of Energy's Energy Information Administration (EIA).
5. Efforts to project future growth in California fields, and perhaps fields in other regions, should focus on evaluating the potential for enhanced recovery in fields with current estimated ultimate recoveries of about 250–500 million barrels.
6. By analogy with oil, attempts to project growth in gas reservoirs, in California and perhaps elsewhere, should focus on larger fields with lower permeability reservoirs where advances in recovery technology, such as perhaps horizontal drilling, are more likely to add substantial reserves.

Introduction

California oil fields have contributed a very large proportion of additions to domestic reserves in recent years. Almost half of additions to U.S. proved oil reserves in 1997 came from old fields in California (Anonymous, 1998). These fields were discovered between about 1890 and 1930 and contain mostly (but not exclusively) relatively heavy oil ($<\approx 20°$ API). In the San Joaquin Basin (fig. 1), California's most prolific basin and the only one in which much exploration has taken place since the mid-1980s, analysis of the Oil and Gas Integrated Field File (OGIFF) of the Department of Energy's Energy Information Administration (EIA) indicates that 97 percent of additions to reserves in the 1980s came from reserve appreciation rather than discoveries (Caroline Isaacs, unpub. data, 1993). Methodology used in previous USGS national oil and gas assessments (Root and Mast, 1993; Attanasi and Root, 1994; Gautier and others, 1995) has not been entirely successful in projecting this growth. Without at least a qualitative understanding of the factors responsible for the late growth in these old fields, future assessments risk continued imprecise prediction of additions to reserves in this important region, along with perhaps undue influence on other regions stemming from failure to isolate factors peculiar to California.

Figure 1. Index map of part of California showing the three regions discussed in text (Los Angeles Basin, coastal basins, and San Joaquin Basin), and outlines of giant fields. Names are shown for fields mentioned in text.

The long-term growth history of the 52 giant oil fields in California provides a basis for determining what factors have contributed to growth of reserves and for observing styles in growth patterns that are functions of geologic or other characteristics of the fields. Comprehensive field chronologies, including annual data on cumulative production, reserves, and number of producing wells for each field, along with the history of discovery of new pools and areas (a term used in California for field extensions), abandonments of pools or areas, combination of multiple fields into single fields, and chronology of application of secondary and tertiary recovery techniques, provide a basis for inferring influences on reserve appreciation. In addition, growth histories can be examined to search for potential influences common to many fields, either geologic (for example, development of waterflooding technology in fields with good porosity and permeability and sufficiently light oil, or application of newly developed seismic reflection technology at mid-century to find stratigraphic traps) or strategic/economic (such as World War II, increases in the price of oil, or real estate value exceeding oil value), or, conceivably, regulatory (spacing rules, environmental policies).

The information presented in this study, based on data compiled by Tennyson (1998), consists mostly of graphical displays of annual ultimate recovery estimates for California's 52 giant fields, supplemented with additional data for the relatively few fields that have grown more than about 200 million barrels after 30 years since discovery. For two fields that show marked growth, additional information was compiled, quantifying the extent to which secondary and tertiary recovery techniques were applied, in order to evaluate the association between reserve growth and enhanced recovery.

Data

Cumulative production volumes, reserve estimates, and numbers of producing wells were compiled annually as available, along with the chronology of discovery or abandonments of pools or areas and application of secondary recovery technology. The principal sources of production and reserves data were:

1. An early paper containing the first published estimates of field sizes in California (Collum and Barnes, 1924)
2. Production and reserves data published by the American Institute of Mining and Metallurgical Engineers (AIME) in the 1930s (Wilhelm, 1932, 1936, 1937, 1938, 1939; Wilhelm and Miller, 1933, 1934)
3. Annual production and reserves data published by the Oil & Gas Journal beginning in the mid-1940s (Oil & Gas Journal, 1946 to 1978)
4. Annual production and reserves data published by the California Division of Oil and Gas (1977 to 1992) and California Division of Oil, Gas, and Geothermal Resources (1993 to 1999)

The history of pools discovered within the fields and the chronology of secondary recovery programs undertaken in each pool were compiled from California Division of Oil and Gas (1991b) and California Division of Oil, Gas, and Geothermal Resources (1998).

Data were organized as tables and plots, both for individual fields (Tennyson, 1998), and for all the giant fields in three general areas of the State—Los Angeles Basin, San Joaquin Basin, and coastal basins, as well as the six offshore fields (fig. 1). The plots were used to identify fields that showed unusual growth patterns. The exploration, development, and advanced recovery histories of these less typical fields were briefly investigated in order to hypothesize responsible factors.

Analysis of Growth Patterns

San Joaquin Basin

Of the 21 giant fields in the San Joaquin Basin, five stand out as having shown substantial growth, late in their histories—Coalinga, South Belridge, Elk Hills, Kern River, and Midway-Sunset (fig. 2). These fields, all discovered between 1887 and 1919, grew by factors of 1.8 to 17 between 1950 and 1995, with increases in estimated ultimate recovery (EUR) ranging from 400 million barrels to 1.8 billion barrels. Each of the other giant fields in the San Joaquin Basin grew by less than 233 million barrels during the period 1950–1995: four fields (Cymric, Lost Hills, McKittrick, and Mount Poso) grew by volumes ranging from 180 to 233 million barrels, and the remainder grew by volumes generally less than 100 million barrels. Seven grew very little; of these, four are fields that barely exceed 100 million barrels of estimated ultimate recovery.

Midway-Sunset, discovered in the 1890s, is by far the largest of these fields that show late growth. The first published estimate of its size was just under 1 billion barrels in the 1930s. New pools continued to be discovered into the 1950s, and minor pools were discovered as late as 1983 (table 1). The Buena Vista Area of the field was split off as a separate field in the 1950s. In the early 1960s, operators began pilot cyclic steam projects, which proved sufficiently successful that cyclic steam recovery operations became widespread throughout the field (Rintoul, 1995). Fireflooding was attempted in several pools in the 1970s with some success. The development of steamflooding in the 1960s and 1970s, however, was clearly the most significant cause of reserve growth. Reserves were revised upward repeatedly beginning in the late 1960s (fig. 3), at a much greater rate than had typified the earlier period of growth by new pool discovery. An upward revision in 1991 of 500 million barrels of oil was followed in 1999 by another jump in reserves of more than 700 million barrels. From 1988 to 1998, about 80 percent of the oil produced at Midway-Sunset (477 million of 600 million barrels produced) was "incremental" production attributable to enhanced recovery. In the last several years, operators have been experimenting with horizontal wells within steamfloods, but no clear results have yet emerged; a new era of reserve additions is possible if these experiments prove successful.

Oil gravities reported from the pools in Midway-Sunset field where steamflood operations are in progress range from 8° to 14° API; most are 11°–13° API. Porosity in reservoir sands is typically 30–35 percent and permeabilities range from a few hundred to several thousand millidarcies. The field is quite shallow for such an immense accumulation—few wells penetrate below about 7,000 ft (Lennon, 1990), so reservoir temperatures are relatively low, some under 100°F. Thus, the field presents an ideal situation for thermal recovery: excellent reservoir properties but heavy, relatively cool oil.

The Kern River field is another old field containing dominantly heavy oil (10°–16° API). It was discovered in 1899; a gradual decline in production rates over the next 60 years was suddenly reversed in the 1960s when steamflooding was introduced. By the early 1980s, the field's daily production was almost three times what it had been in the initial decade after discovery (Rintoul, 1999).

The striking growth in South Belridge field has been driven by two independent advances in recovery technology: steamflooding and diatomite fracturing. The field produces from two principal reservoirs, shallow Pleistocene deltaic sands that contain heavy oil (13°–14° API), and deeper diatomaceous mudstone in which the oil is lighter (20°–32° API). From discovery in 1911 until about 1950, the field grew by areal expansion, to an EUR of about 80 million barrels, mainly from the

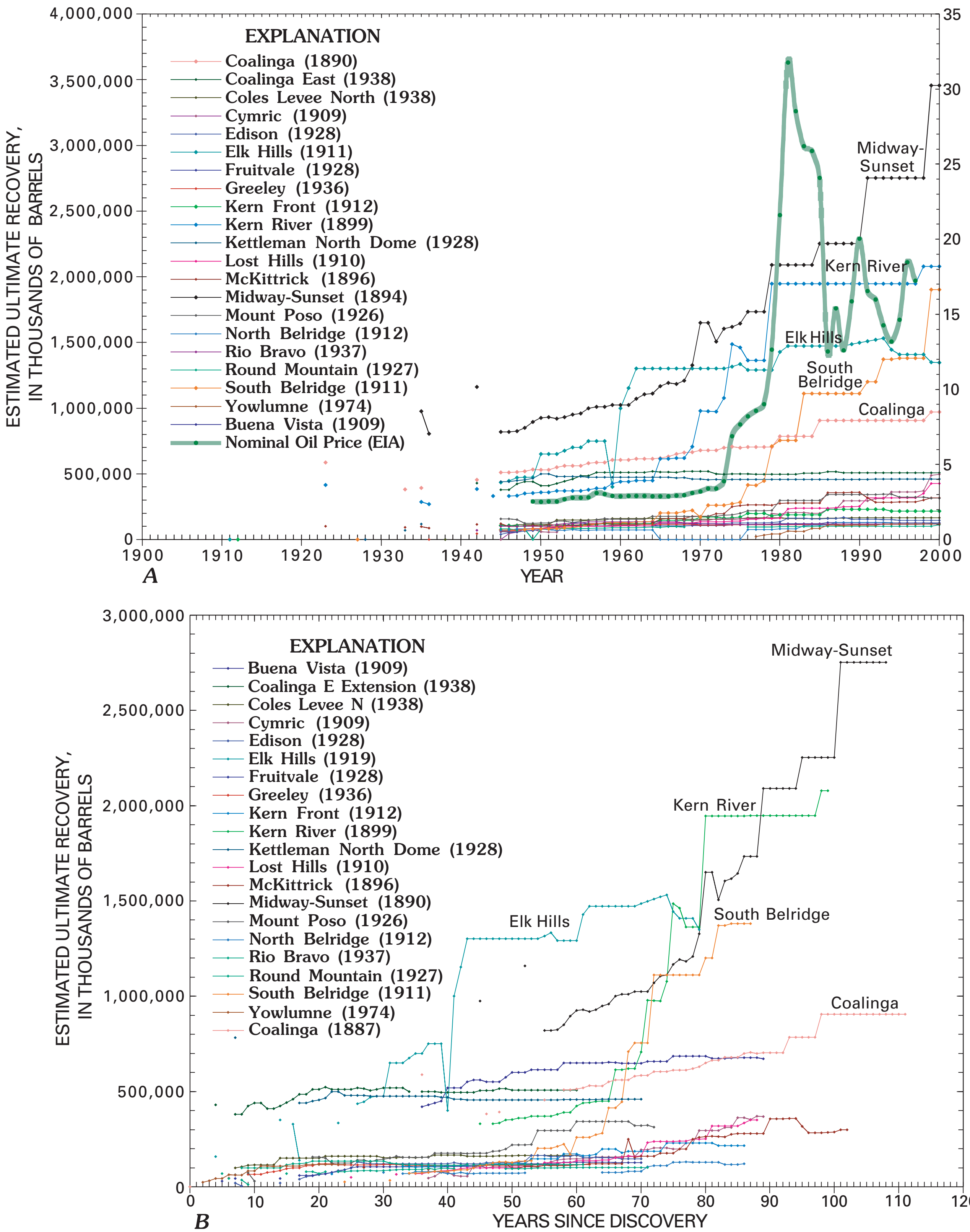

Figure 2. Estimated ultimate recovery (EUR) over time for giant fields in the San Joaquin Basin, plotted *A,* by calendar year, and *B,* by number of years since discovery. Most fields achieved their giant status within two or three decades of discovery and did not grow significantly thereafter. A few larger fields, however, most of which achieved EUR's of close to 500 million barrels within a few decades of discovery, have shown substantial increases in EUR beginning about age 60–70. This "late" growth is largely accounted for by improvement in recovery efficiency attributable to enhanced recovery programs.

Table 1. Chronology of discoveries of pools and application of secondary and tertiary recovery programs in Midway-Sunset oil field.

Year	Discoveries	Secondary and tertiary recovery
1894	Tulare pool discovered	
1902	Monarch pool discovered	
1909	Gusher pool discovered	
1910	Potter and Lakeview pools discovered	
1913	Webster pool discovered	
1920	Mya Tar pool discovered	
1922	Calitroleum pool discovered	
1925	Obispo pool discovered	
1928	Republic pool discovered	
1936	Sub-Lakeview pool discovered	
1941	Marvic pool discovered	
1945	Leutholtz pool discovered	
1947	Pacific pool discovered	
1954		Waterflood started- Calitroleum pool
1957	Moco pool discovered	Waterflood started- Monarch pool
1959		
1960		Fireflood started- Moco pool
1961		Fireflood started- Top Oil pool
1962		Firefloods started- Webster, Monarch, and Tulare pools; waterflood started- Kinsey pool
1963		Steamfloods, cyclic steam started- Tulare, Mya Tar, Top Oil, sub-Lakeview, Potter, Marvic, and Webster pools
1964		Waterflood discontinued- Calitroleum pool
1965		Steamfloods started- Webster and Moco pools; steamflood, cyclic steam started- Monarch pool; cyclic steam started-Kinsey and Leutholtz pools; waterflood discontinued- Monarch pool; cyclic steam discontinued- Kinsey pool
1967		Steamfloods started- Tulare and Kinsey pools; waterflood started- Top Oil pool; waterflood discontinued- Kinsey pool
1968		Steamflood and fireflood started- Potter pool
1969		Waterflood started- Potter pool
1970		Steamflood started- Leutholtz pool
1972		Steamflood started- sub-Lakeview pool; waterflood discontinued- Top Oil pool
1975	Antelope Shale pool discovered	
1976		Fireflood started- sub-Lakeview pool
1977	Pioneer pool discovered	
1979	Pulv pool discovered	Cyclic steam started- Top Oil pool
1980	Pulv pool abandoned (one well)	
1981		Fireflood discontinued- Top Oil pool
1982	Pioneer pool abandoned (one well)	Cyclic steam discontinued- Top Oil pool; waterflood started- Calitroleum pool
1983		Waterflood discontinued- Calitroleum pool
1984	McDonald Shale pool discovered	
1985		Waterfloods started- Tulare and Monarch pools
1986		Steamflood started- Marvic pool
1991		Waterflood started- sub-Lakeview pool; waterflood discontinued- Tulare pool
1992		Waterflood discontinued- Monarch pool
1994		Steamflood discontinued- Top Oil pool
1996		Fireflood discontinued- Webster pool

shallow heavy oil reservoir; the diatomite reservoir had been discovered but did not produce at economic rates. In the 1950s, a pilot in-place combustion project demonstrated that 40–60 percent of the oil in place in the heavy oil reservoir could be recovered (Miller and McPherson, 1992). A cyclic steam project began in the early 1960s, and steamfloods in the 1970s and 1980s pushed EUR to about 400 million barrels—about 40 percent of the oil in place in the shallow reservoir. During the 1970s, methods of successfully fracturing the diatomite were developed. A new operator bought the field in 1979 and began major redevelopment, including intensive development of the diatomite. EUR almost tripled, to about 1.1 billion barrels by 1990, as the previously unrecoverable oil in the diatomite was added to reserves. During the 1990s, expansion of steamflooding, waterflooding in the diatomite, and infill drilling combined to drive expected recovery to 1.9 billion barrels.

The histories of the other old San Joaquin fields in which significant late growth has taken place were not studied in any

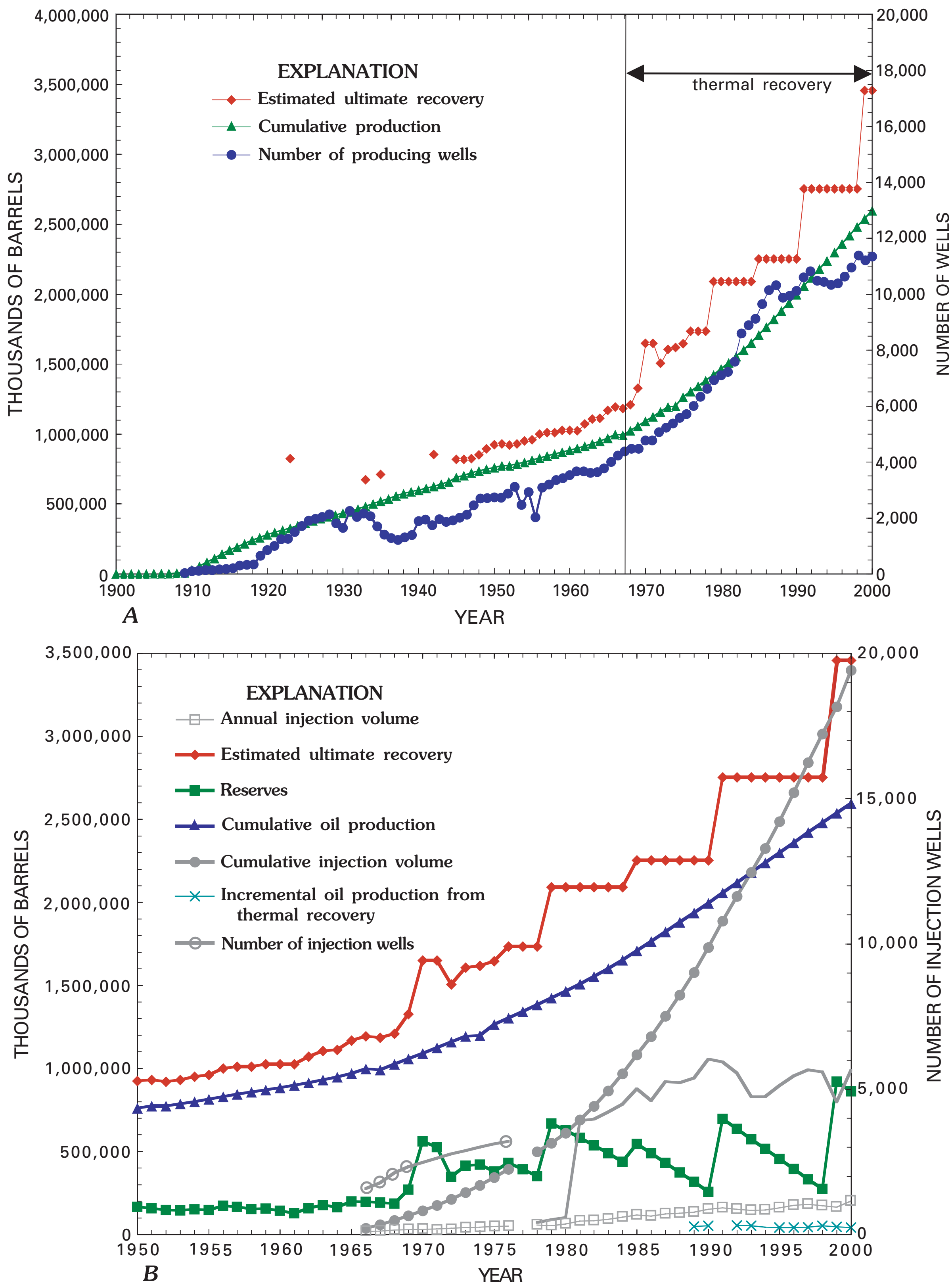

Figure 3. Plots for Midway-Sunset field showing *A*, number of producing wells, cumulative production, and estimated ultimate recovery by year, and *B*, volumes of steam injected, cumulative oil produced, estimated ultimate recovery, reserves, number of injection wells, cumulative injection volume, and volume of oil production directly attributable to thermal recovery ("incremental oil"). Reserves began to be added after thermal recovery was started. (Data on thermal recovery from California Division of Oil, Gas, and Geothermal Resources annual publications.)

detail, beyond noting that enhanced recovery operations are widespread in these fields. Late growth in these fields is almost certainly due to enhanced recovery as it so clearly is in Midway-Sunset, Kern River, and South Belridge fields.

Los Angeles Basin

In the Los Angeles Basin (fig. 4), 12 of the 16 giant fields reached ultimate sizes between 100 and 500 million barrels within the first few decades after discovery and did not grow significantly thereafter. Two fields, Santa Fe Springs and Long Beach, attained sizes significantly larger than most of the rest, but did not grow very much after age 25–30. One field, Huntington Beach, grew past the 1 billion barrel mark at about age 50 and continued to grow in increments totaling almost 300 million barrels until about age 65; waterflooding was begun in this field at about age 40 and appears to be the most probable cause of this late growth. By far the most spectacular example of field growth in the Los Angeles Basin is the Wilmington field (fig. 5; see Mayuga, 1970, for details of field history). Discovered in 1932, this field grew for its first two decades as 12 pools were discovered and developed (table 2), reaching an estimated ultimate recovery of 1 billion barrels at age 20 in 1952. A pilot waterflooding program began the following year in an attempt to halt rapid ground subsidence that had developed over the previous decade as a result of high production rates related to wartime needs; the ground surface had subsided about 30 ft during the 1940s. By the mid 1950s, the results of the waterflooding pilot programs indicated that subsidence had slowed to virtually negligible rates, so unitization agreements were negotiated during the 1950s that would allow for field-wide waterflooding projects. A 1954 seismic survey of the offshore area adjacent to the field showed that the trapping anticline continued several miles offshore, but expansion could not proceed until local authorities were satisfied that subsidence could be avoided. By 1960, it was clear that waterflooding was effective in stopping and preventing subsidence; between 1960 and 1965, the City of Long Beach developed contractual arrangements for offshore expansion, which began in 1965. In 1963, the estimated ultimate recovery of the previously developed part of the field was 1.16 billion barrels of oil; 3 years later, in 1966, as the increase in oil recoverability caused by waterflooding became evident and the reserves due to offshore expansion were added, the estimated ultimate size of the field approached 3 billion barrels (fig. 5). This included 1.16 billion barrels already produced from the onshore area, an additional 0.5–0.7 billion barrels projected in the onshore area as a direct consequence of waterflooding, and an additional 1.0–1.2 billion barrels from the offshore expansion (Mayuga, 1970). Steamflooding was introduced in a few pools in the 1980s. Since 1988, two-thirds of the oil produced at Wilmington has resulted from waterflooding and steamflooding (California Division of Oil, Gas, and Geothermal Resources, 1988–1998)—150.8 million barrels of the 226.1 million barrels produced between 1988 and 1998; waterflooding accounted for 93 percent of this incremental oil. The success of waterflooding at Wilmington is apparently attributable to good reservoir character along with lack of a natural water drive. Porosities in these weakly consolidated submarine fan sands are mostly in the 26–32 percent range; permeabilities vary widely, from about 80 mD in one pool to 1,000–1,600 mD in two of the larger pools (Ranger and Tar). Oil gravity varies considerably: oils in shallower pools have gravities as low as 12°–14° API, and some oils in the field are as light as 25°–32° API. The oil in the biggest pools onshore (Ranger and Tar) ranges from 12° to 25° API (California Division of Oil and Gas, 1991b), and the offshore Ranger pool, which contains three-fourths of the oil in the offshore unit, ranges between 15° and 20° API (Berman and Clark, 1987). Thus, although these oils are somewhat heavy, they are apparently light enough that the artificial water drive supplied by waterflooding brought about a substantial increase in recovery.

The original volume of oil in place (OOIP) at Wilmington was about 9 billion barrels (Bbbl). (Available estimates are 9.6931 Bbbl (Anonymous, 1980), and 8.8 Bbbl (Montgomery, 1998)). Thus the current EUR of almost 2.8 Bbbl represents a recovery efficiency of about 29–32 percent for the field as a whole. Berman and Clarke (1987) estimated that the OOIP in the offshore part of the field (Long Beach Unit) was 3.8 billion barrels, so the OOIP in the onshore part of the field was evidently about 5–6 Bbbl. By the 1990s, cumulative production plus proved reserves were about 1.3 Bbbl in the onshore part and about 1.5 Bbbl in the offshore part, which suggests recovery efficiencies of as much as 26 percent for the onshore and 40 percent for the offshore. It seems likely that the higher recovery efficiency for the offshore is due to the inclusion of waterflooding from the beginning of development. The 1952 pre-waterflooding EUR for the onshore part of the field was about 1 Bbbl; waterflooding has added about 300 MMbbl (million barrels) to the ultimate recovery (about 6 percent of OOIP). This is less than the 500–700 MMbbl projected by Mayuga (1970) and is a relatively minor part of the overall increase since the mid-1960s; most of the fieldwide increase in EUR came from the addition of the oil in the offshore unit with its higher recovery efficiency.

Coastal Basins

Two fields in the coastal province have grown by more than about 200 million barrels—the Ventura field and the San Ardo field (fig. 6). The Ventura field in the Ventura-Santa Barbara Basin, discovered in 1919, grew by seven new pool discoveries between 1922 and 1952, reaching an estimated size of about 800 million barrels at the end of this period. The first waterflood project was begun in 1956. Five more of the total of eight pools were waterflooded in the 1960s and 1970s; all are still active. These waterflooding projects appear to have accounted for much of the additional 200 million barrels of reserves that the field gained in the 1970s and 1980s; about 21 million barrels in reserves were added as recently as the 1990s. Over the last decade, 89 percent (49 million barrels) of the 56 million barrels produced was incremental oil from waterflooding. Oil gravity is around 30° API in all pools. Porosity is about 15–20 percent

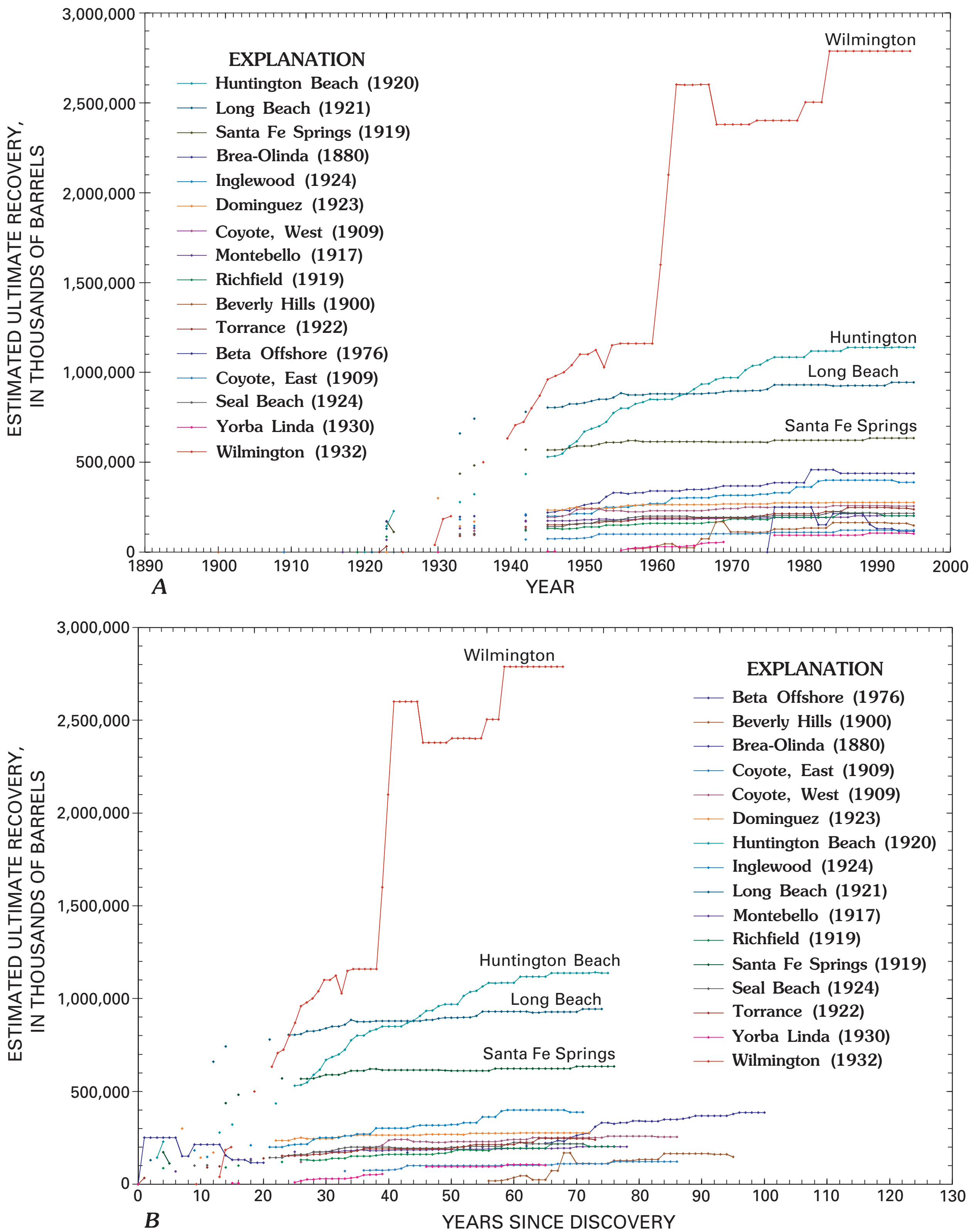

Figure 4. Estimated ultimate recovery (EUR) over time for giant fields in the Los Angeles Basin, plotted *A*, by calendar year, and *B*, by number of years since discovery. Most fields achieved nearly their current ultimate sizes within two or three decades of discovery. Wilmington field, in contrast, approximately doubled in estimated ultimate size, beginning at about age 30, because of widespread application of waterflooding technology, originally applied to halt surface subsidence. Huntington Beach field also grew appreciably during its fourth, fifth, and sixth decades, apparently also as a result of successful waterflooding programs.

Table 2. Chronology of discoveries of pools and application of secondary and tertiary recovery programs in Wilmington oil field.

Year	Onshore area discoveries	Offshore area discoveries	Secondary and tertiary recovery
1932	Ranger pool discovered		
1936	Upper Terminal pool discovered		
1937	Ford, Tar pools discovered		
1938	Lower Terminal pool discovered		
1939		Ranger, Upper Terminal pools discovered	
1942	Union Pacific pool discovered		
1943		Tar pool discovered	
1945	237, Schist pools discovered	237, Schist, Ford pools discovered	
1946			
1947		Union Pacific pool discovered	
1953			Waterflood started- Upper Terminal/Onshore
1954			Waterflood started- Tar/Onshore
1956			Waterfloods started- Ranger and Lower Terminal/Onshore; Lower Terminal/Offshore
1958			Waterfloods started- Ford, Union Pacific/Onshore; Tar, Ranger, Upper Terminal, Union Pacific, Ford/Offshore
1960			Waterfloods started- 237/Onshore and Offshore
1967			Steamflood started- Ranger/Onshore
1969			Polymer flood started- Ranger/Onshore
1972			Polymer flood discontinued- Ranger/Onshore; waterflood discontinued- 237/Offshore
1979	Shallow gas sand pool discovered		Polymer-micellar flood started- Upper Terminal/Onshore and Offshore
1981			CO_2 waterflood started- Tar/Onshore; polymer-micellar flood discontinued- Upper Terminal/Onshore and Offshore; waterflood discontinued- Ford/Offshore; steamflood started- Tar/Offshore
1982			Steamflood started- Tar/Onshore; CO_2 WAG flood started- Tar/Offshore
1989			CO_2 -WAG flood discontinued- Tar/Offshore

in all pools and permeability is 8.8–48 mD. The two 100-million-barrel increases in estimated ultimate recovery in the early 1970s and early 1980s apparently resulted from waterflooding. Although this is a significant amount of oil, it is a minor proportion compared to the 800 million barrels from new pool discoveries between 1919 and 1952. It represents about a 6 percent increase in recovery efficiency based on Hacker's (1969) OOIP of 3.5 Bbbl, from 23 percent to 29 percent.

The San Ardo field in the Salinas Basin was discovered in 1947. All three of its oil pools were discovered by the following year; most of the oil is contained in one pool (Lombardi) that has an oil gravity of about 10° API, porosity of 23–37 percent, and permeabilities of 2,000–3,000 mD. About a decade after discovery, the ultimate recovery of the field was estimated to be about 200 million barrels, but after thermal recovery programs were begun in the 1960s, its ultimate size more than doubled to about 530 million barrels by the mid-1970s.

Offshore Fields

The six California giant fields that lie offshore were all discovered between 1966 and 1981. They are thus just emerging from the 2–3 decade-long interval in which older onshore fields tended to show rapid growth, although delays were unusually long between discovery and initial production at Hondo, Pescado, and Point Arguello fields. These delays were in part due to lengthy field delineation programs and in part to permitting delays stemming from environmental issues. Hondo and Dos Cuadras have grown irregularly, Pescado has not been on production long enough for a trend to emerge, and Point Arguello, Beta, and Carpinteria have shrunk (fig. 7). Point Arguello's operator sold the field in the late 1990s after disclosing that production had declined faster than anticipated, despite attempts to slow the decline by reinjection of produced gas. The rate at which production would

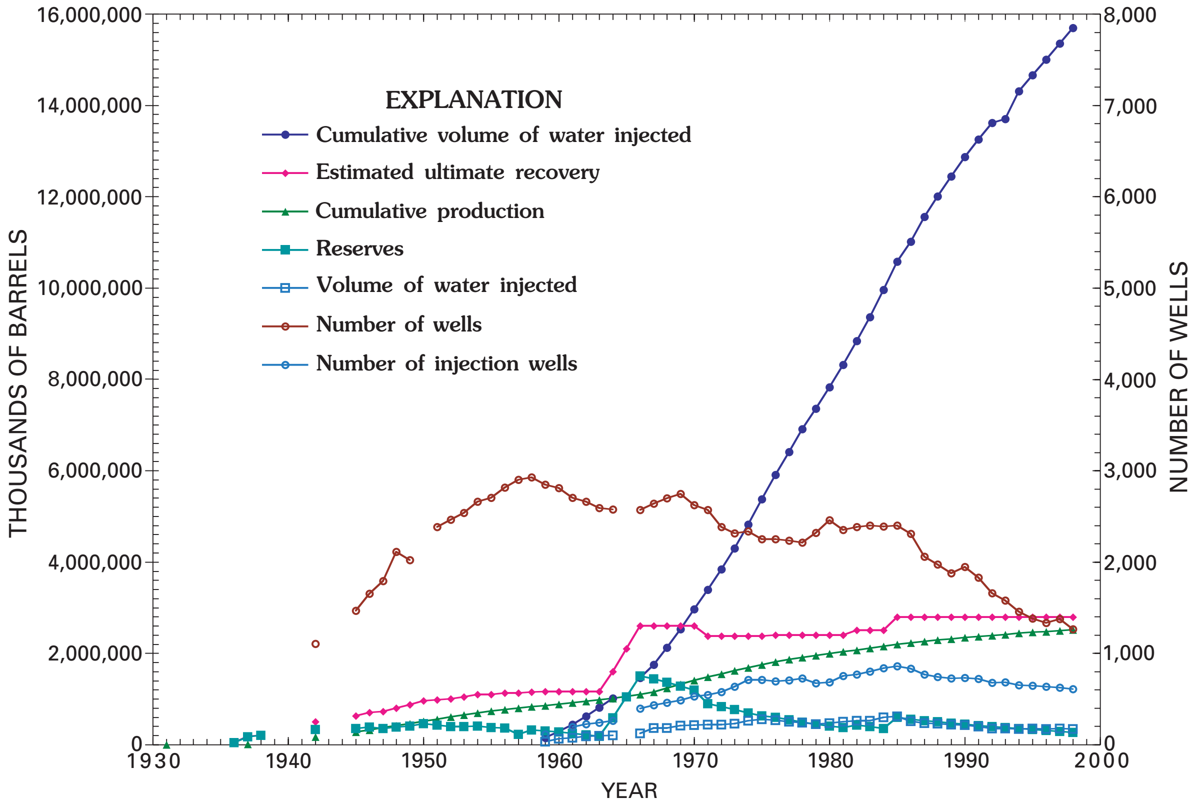

Figure 5. Plot for Wilmington field showing number of producing wells, cumulative production, estimated ultimate recovery, reserves, volumes of water injected, and number of injection wells. Breaks in curves represent years for which data were not available.

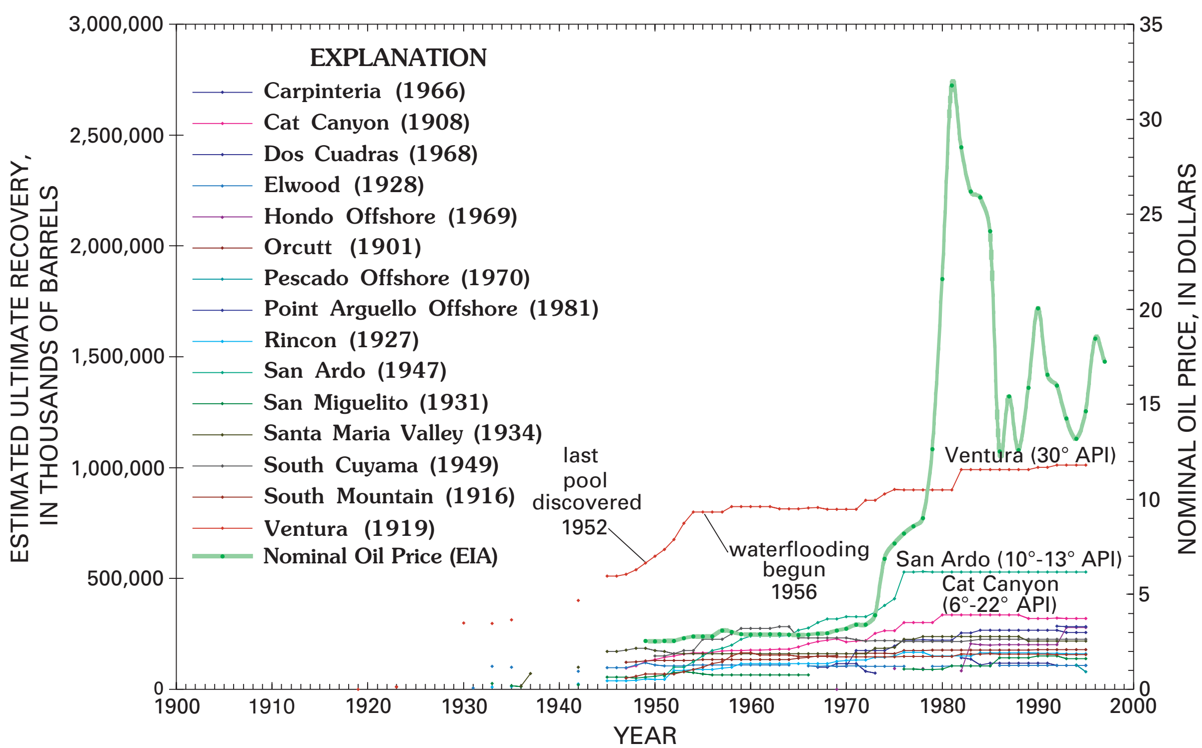

Figure 6. Estimated ultimate recovery (EUR) over time for giant fields in coastal California basins. Late growth in Ventura field (oil gravity 30° API) is attributable to waterflooding and in San Ardo field (10°–13° API) to development of thermal recovery technology.

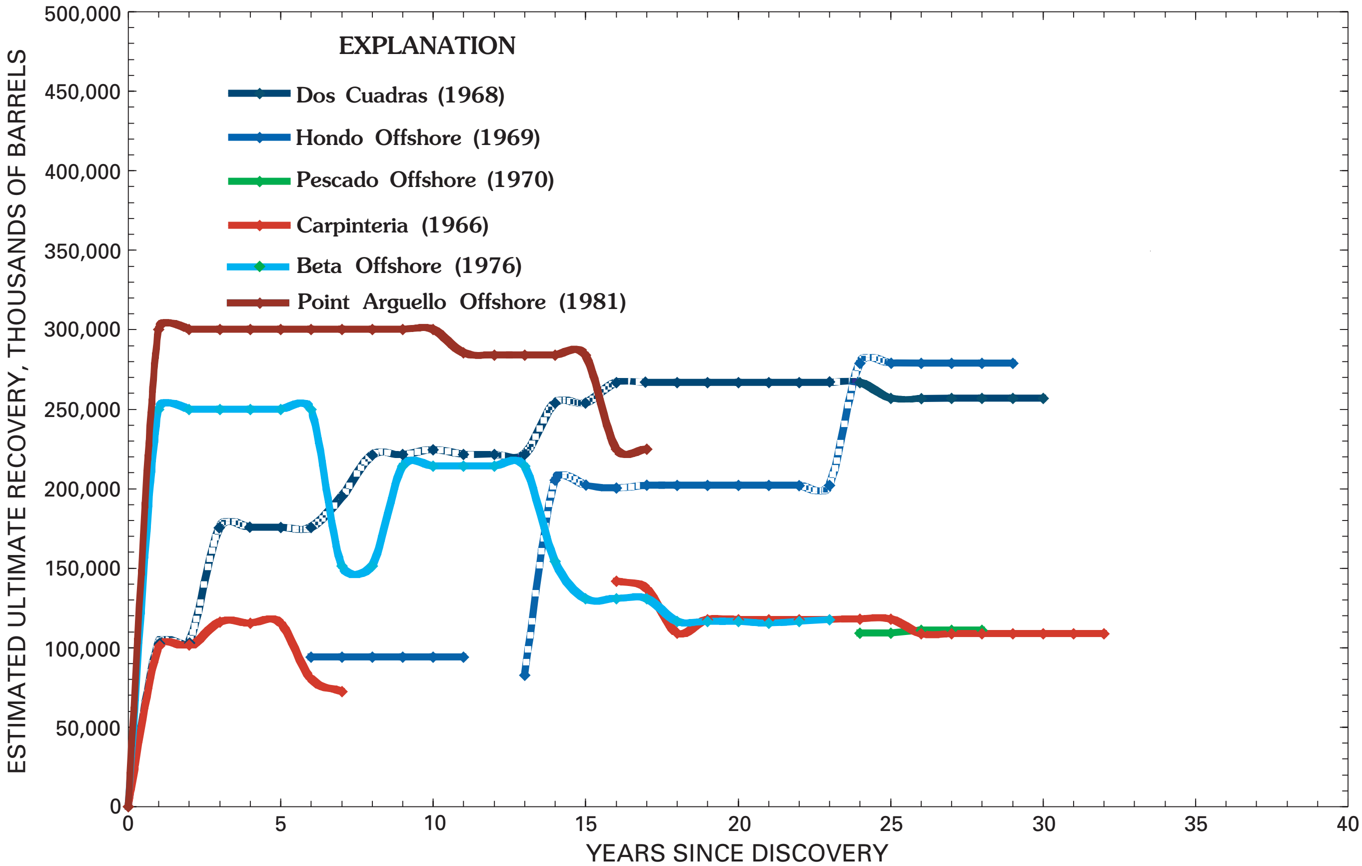

Figure 7. Estimated ultimate recovery for offshore fields, all discovered between 1966 and 1981, plotted against number of years since discovery.

decline was apparently difficult to predict, because the reservoir consists of fractured Miocene chert with highly variable permeability.

It seems significant that three of six offshore fields show negative growth. Several of them are in the early stages of secondary recovery, so it is possible that they may yet grow again. Nevertheless, it seems likely that development projections were overly optimistic on the part of the operators, and that production has not met the predicted levels. This is a very different situation than in the old onshore fields, where few initial attempts were made to evaluate ultimate productivities and development proceeded in a more erratic fashion as economic conditions warranted.

Discussion

The data presented here show that roughly three-quarters of the 52 giant fields in California have followed a pattern of rapid growth in the first two or three decades after discovery, followed by decelerating growth in subsequent decades. Most of these are the smaller fields in the data set, those whose estimated ultimate recoveries do not greatly exceed 100 million barrels. In contrast, the largest fields have continued to exhibit significant jumps in reserves. Increases early in the fields' histories were typically associated with discovery of new pools and field extensions, whereas most of the abrupt increases in estimated ultimate recovery since the 1950s were associated with application of secondary recovery technology, primarily waterflooding and steamflooding. These "late" increases are generally much larger than contributions made by new pool discoveries—some fields have doubled in estimated ultimate recovery as enhanced recovery programs were applied. Offshore fields discovered in the last 30 years have not generally shown the rapid growth typical of older onshore fields, perhaps because extensive studies of ultimate recovery preceded the operator's decisions to develop the fields.

The element responsible for "late" reserve growth, then, is an increase in recovery efficiency. In California, recovery efficiencies are generally low, estimated at 5–30 percent without enhanced recovery programs (California Division of Oil, Gas, and Geothermal Resources, 1993b). Data from individual fields on volumes of oil originally in place or recovery efficiencies are not generally available, but the few published estimates imply 50–100 percent increases in recovery. Estimates referred to in the discussion of the Wilmington field suggest an increase in recovery efficiency from about 26 percent to 40 percent. Lennon (1990) reported estimates for Midway-Sunset field of approximately 4.4 billion barrels of oil originally in place, with

2.25 billion barrels (51 percent) ultimately recoverable; he attributed about half of cumulative production as of 1986 to primary recovery and half to secondary recovery. Schamel and others (1998) referred to typical heavy oil recovery efficiencies of 40–70 percent in steamflooded Midway-Sunset reservoirs. The doubling in EUR in several fields after enhanced recovery began suggests that recovery efficiencies must have roughly doubled, because there are no other apparent causes for the increases in EUR.

The price of oil does not appear to have been directly responsible for the more significant reserve increases in the largest fields, because big jumps in estimated ultimate recovery that were clearly associated with enhanced recovery programs begun in the 1950s and 1960s (at Midway-Sunset, Kern River, Wilmington, and Ventura) preceded inflation of oil prices in the 1970s. Furthermore, substantial increases in ultimate recovery have continued through the late 1980s and 1990s despite the weakening of oil prices during that interval.

The data do not, in any obvious way, point to other controlling influences on reserve appreciation patterns, such as developments in exploration technology, changes in social priorities, economic developments, or strategic needs. Most fields for which reserves data from the 1930s and 1940s exist show some increase in size during the war years of the 1940s, but these increases were relatively minor compared to those associated with secondary or tertiary recovery programs initiated since the 1950s in the largest fields. No effects are apparent of more stringent environmental regulations that began to be imposed in the 1970s, unless one speculates that more fields would have shown significant late growth from enhanced recovery if environmental regulations had not been tightened. The use of seismic reflection technology to improve the understanding of subsurface stratigraphy and structure does not appear to have been associated with any particular episodes of reserve growth; as the quality of seismic data has improved over the last several decades, the number of new pools discovered in existing fields has dwindled, and most of those discovered have not had a significant effect on the field size.

The data summarized here provide a different perspective on reserve appreciation from that of another principal source of data on field size, the confidential Oil and Gas Integrated Field File (OGIFF) maintained by the Energy Information Administration of the U.S. Department of Energy. In addition to its unavailability to most workers, a major shortcoming of the OGIFF database is that it dates only from 1977—after the 1950s and 1960s development of major secondary and tertiary recovery programs and the mid-1970s jump in oil prices—so it provides little information that can be used to infer influences on earlier growth in old or even moderately old fields.

As increase in recovery efficiency appears to be the principal cause of the extreme growth shown by a handful of old California fields, future studies of reserve growth potential should include attempts to identify the geologic characteristics responsible for reservoirs in which primary recovery produces only a low fraction of the oil in place. The most obvious of these is oil gravity, but depositional setting may also be important—most of the late-growth California reservoirs are submarine fan turbidites, for instance. In addition, fields that achieve sizes of at least several hundred million barrels of oil within the first three decades after discovery appear to be the ones in which late growth is most likely to occur.

Whether or not reserve growth in California—which is a very large proportion of such growth nationally in the United States—will continue at its recent rapid pace is not clear. Obviously, increases in recovery efficiency cannot continue indefinitely, so if we assume that the currently achieved recovery efficiencies are approaching their limits, the principal potential for increases in reserves should lie in parts of fields where current enhanced recovery techniques have not yet been applied. We can speculate that growth in California fields may begin to slow soon, as enhanced recovery programs are fully deployed and sweep the last recoverable volumes of oil from the reservoirs.

California's giant heavy oil fields offer little insight into the potential for reserve appreciation in other regions or in gas accumulations, but if, as shown here, improvement in recovery efficiency has as much as doubled estimated ultimate recovery in individual California fields, the identification of oil or gas reservoirs with low primary production recovery efficiencies should be a key to improving our ability to estimate future reserve growth. These presumably include mainly low permeability oil and gas accumulations and heavy oil accumulations.

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