Shepherd, M., 2009, Factors influencing recovery from oil and gas fields, *in* M. Shepherd, Oil field production geology: AAPG Memoir 91, p. 37–46.

5

Factors Influencing Recovery from Oil and Gas Fields

INTRODUCTION

As mentioned at the start of the book, more oil is left behind in oil fields than will be recovered from them by the end of their field life. Numerous factors influence recovery from an oil field including the geological complexity, fluid physics, and economics. Certain operations can be carried out to enhance oil recovery by changing the physical and chemical nature of the formation fluids. The factors influencing gas recovery are also discussed in this chapter. Gas field recoveries are significantly higher than is the case with oil fields.

RECOVERY FACTORS

Oil companies will want to maximize the value of a field by getting as much of the hydrocarbons out of it as possible. However, it is not feasible to recover all of the hydrocarbons from a reservoir. Only a certain percentage of the total hydrocarbons will be recovered from a field, and this is known as the *recovery factor*.

Recovery factors are higher in gas fields than they are in oil fields. Typical recovery factors for gas are about 50–80% (Jahn et al., 1998). There is more scope to improve oil recovery. Global recovery factors for oil are thought to be in the range of 30–35% (e.g. Conn, 2006). If, for example, you can recover 35% of the oil from an oil field, why can you not produce the other 65%? As mentioned earlier, the answer to this is not simple. The magnitude of the recovery factor for an oil field depends on a complex interplay of geological, physical, and economic elements.

A starting point is to look at the various categories of oil volumes within a typical oil field (i.e., a waterflooded oil field) and represent them on a *maturity pie chart* (Figure 31). These categories are residual oil, cumulative production, remaining recoverable reserves, and unrecovered mobile oil (UMO).

Residual oil saturation is the component of the oil that remains trapped within the pores after an oil-bearing sandstone has been swept by water. Somewhere between about 15 and 35% of the total oil in sandstones can end up as residual oil.

The second category comprises *ultimate recoverable oil*; this is the reservoir engineer's best estimate of what the field will produce by the predicted end of field life. This figure can be split into the volume of oil that has been produced so far (the *cumulative production of hydrocarbons to date)*, and the estimate of what is left to produce (the reserves).

The last category is unrecovered mobile oil (UMO), oil that is movable by primary recovery or water injection, but which will be left behind at the end of field life under current reckoning (Tyler and Finley, 1991). If an oil company wants to improve the recovery factor in a field, then this category is where the oil will normally come from.

The unrecovered mobile oil can be subdivided into three subcategories (Figure 32). Target oil is oil that has a large enough volume to justify the cost of a well to recover it. The phrase locate the remaining oil has been used for the workflow involved in finding these volumes (Wetzelaer et al., 1996). This is discussed in more detail in Section 5 of this publication. *Marginal oil* is the category of trapped oil found in volumes just below the economic threshold to justify an infill well. These volumes will become target oil if the oil price increases or if less expensive ways can be found to access them. The third subcategory is *uneconomic oil*, small volumes of bypassed oil or low oil saturations that cannot be produced economically (Weber, 1999).

DOI:10.1306/13161187M913372

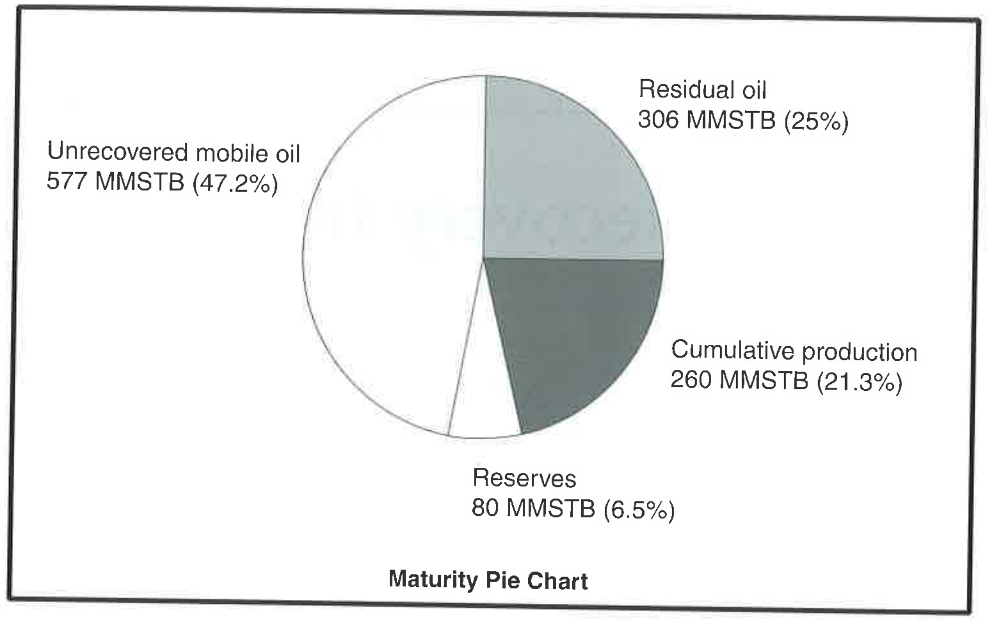


FIGURE 31. An oil volume in a waterflooded reservoir can be divided into categories of residual oil, produced oil, oil reserves, and unrecovered mobile oil. These can be illustrated on a maturity pie chart. Unrecovered mobile oil is the remaining mobile oil left behind at the end of field life if nothing is done to target it. The maturity pie chart illustrates the volumes from the Miocene reservoirs of the Miocene Norte Area, Lake Maracaibo, Venezuela (modified from Ambrose et al., 1997),with permission from the Society of Petroleum Engineers'.

GEOLOGICAL FACTORS CONTROLLING RECOVERY

A key variable controlling the amount of oil recovered from a field is the degree of *geological heterogeneity*. Oil will tend to be stranded within dead ends and low-permeability rock intervals as a consequence of this heterogeneity. An example of a depositional dead end is a back-barrier sandstone thinning and pinching out updip within a lagoonal shale (Figure 33). Patterns of depositional dead ends like this commonly repeat in different fields with similar depositional environments (see Section 7 of this publication for a detailed discussion).

Analysis by the Texas-based Bureau of Economic Geology on Texan oil fields indicates that the type of depositional environment has a major influence on the recovery factor in a reservoir. The less complex and more continuous depositional environments such as barrier-island and wave-dominated deltas commonly show recovery factors of more than 50%. By contrast, the more complex environments, such as fluvial-dominated deltas, show recovery factors of between 20 and 40% (e.g., Tyler and Finley, 1991). Carbonates tend to show lower recovery factors than siliclastic reservoir sediments (e.g., Sun and Sloan, 2003).

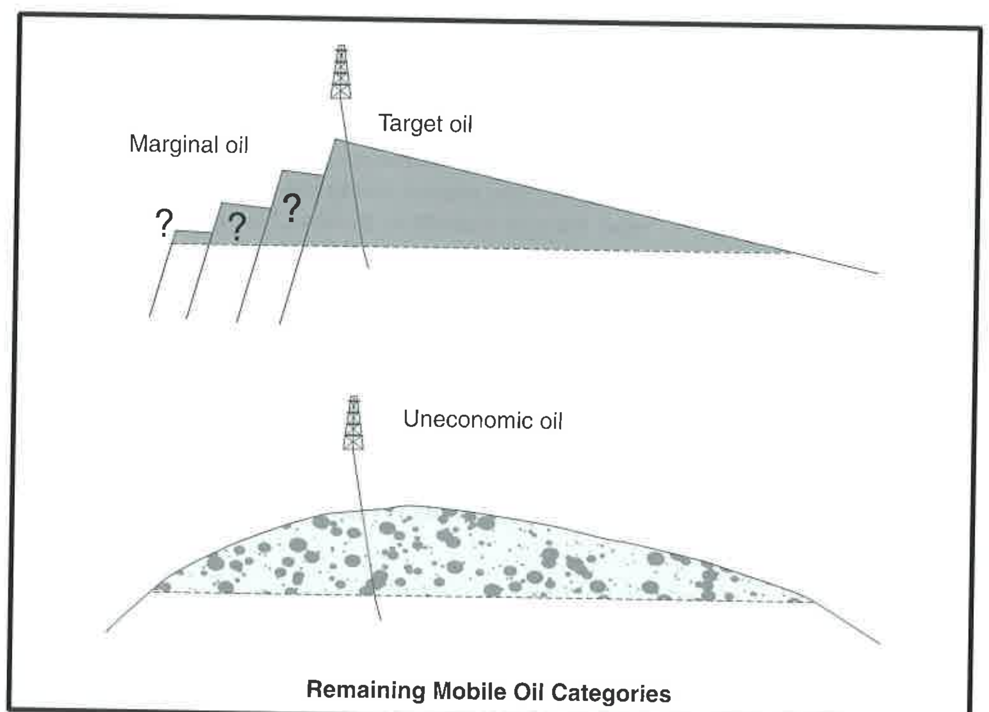
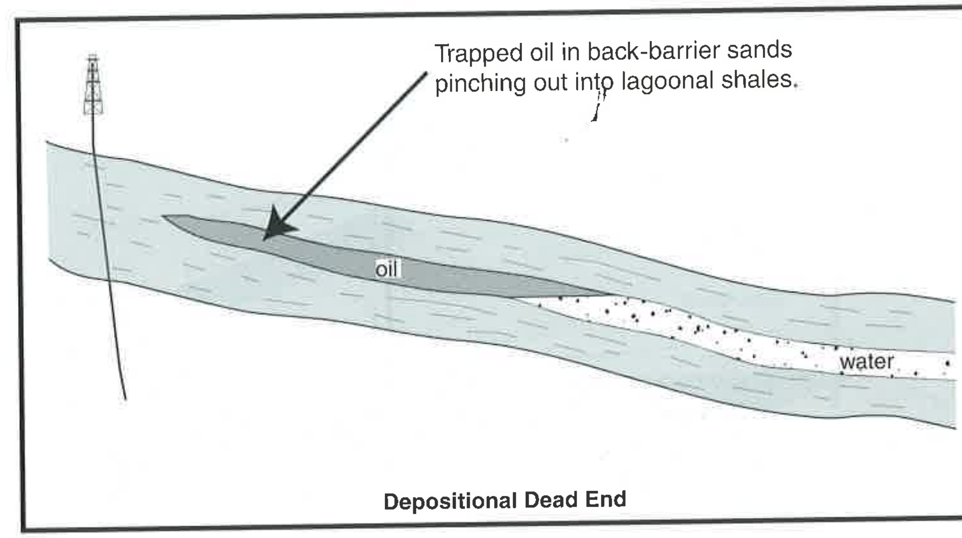


FIGURE 32. The remaining mobile oil in a field can be subdivided into three categories. Target oil columns are large enough to drill with a new well. Marginal oil columns are just below the threshold of profitability to justify an infill well. Uneconomic oil comprises bypassed volumes or patches of low oil saturation that cannot be produced economically.

FIGURE 33. A depositional dead end within a barrier-bar depositional environment.



An extra degree of complexity will result if the reservoir rock has significant volumes of diagenetic cement, particularly pore-filling cement. *Diagenesis*, processes that modify sediments after deposition, can create barriers and baffles within a reservoir in addition to those resulting from primary depositional heterogeneity. Moderate volumes of cement may not cause too many problems with recovery from reservoirs in thick, continuous sandstone intervals. However, in depositional systems where the flow pathways in the reservoir are tortuous and through restricted sand-on-sand apertures, pore-filling cement can destroy large-scale connectivity. The result may be a reservoir with numerous, small, disconnected compartments.

Structural complexity influences the recovery factor from oil fields. Heavily faulted reservoirs will contain numerous structural dead ends, especially if the faults are sealing. If there is a low density of widely spaced sealing faults, the drainage volumes may still end up large enough to remain as oil targets. With an increasing density of faults at a closer spacing, there will be a greater number of marginal and uneconomic volumes, with less target oil volumes.

Where faults are nonsealing and conductive to flow across them, they can increase reservoir connectivity in certain situations. Small nonsealing faults, cutting thick-layered, high net-to-gross reservoir intervals, can create vertical connectivity. However, faults will tend to disconnect reservoirs comprising thin, low net-to-gross channelized systems (Bailey et al., 2002). A network of open fractures can also create widespread connectivity in highly heterogeneous reservoirs such as the more complex carbonate systems.

One type of structural dead end is an *attic oil* accumulation. This is where oil is trapped by a structural culmination above the highest producing interval in a well (Figure 34).

PHYSICAL FACTORS CONTROLLING RECOVERY

Oil Recovery from Primary Depletion

When hydrocarbons are produced from a reservoir, the fluid pressure decreases. As the reservoir pressure is the force pushing the hydrocarbons up to the surface, production rates will start to fall off at the wellheads. Nevertheless, there are mechanisms of natural energy inherent within the reservoir itself, which help to reduce the rate of pressure decline in the wells (Figure 35). The magnitude of this reservoir energy can have a significant influence on primary recovery factors (Levorsen, 1967; Sills, 1992).

A major source of energy is supplied by a large water aquifer in direct contact with an oil zone. This is known as *water drive*. As the oil is produced and the pressure drops, the low-pressure area resulting from production spreads outward into the aquifer. Water has a small compressibility, and the aquifer water will expand as the pressure decreases, flowing into the pore space previously occupied by the oil. Because water compressibility is small, a large aquifer is required for the increase in the volume of the water to be big enough to significantly compress and displace the oil toward the production wells. The volume of aquifer should be at least 10 times the volume of the oil in the oil leg (Jahn et al., 1998). If the water is part of an artesian system with free flowing water, this can also provide a significant source of energy. The primary recovery of oil from water drive reservoirs can be high (35–75%) (Clark, 1969).

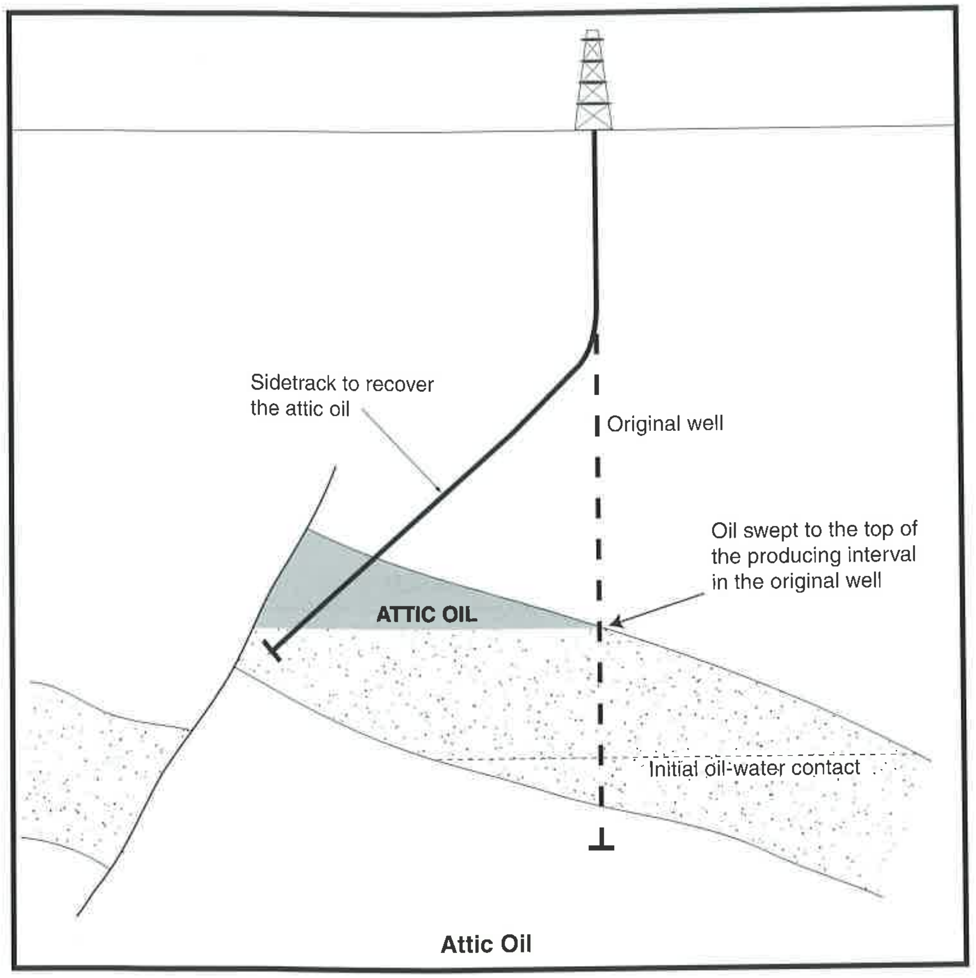


FIGURE 34. Attic oil is oil trapped in a structural dead end above the highest perforated interval in a well. The well can be sidetracked updip to recover this oil.

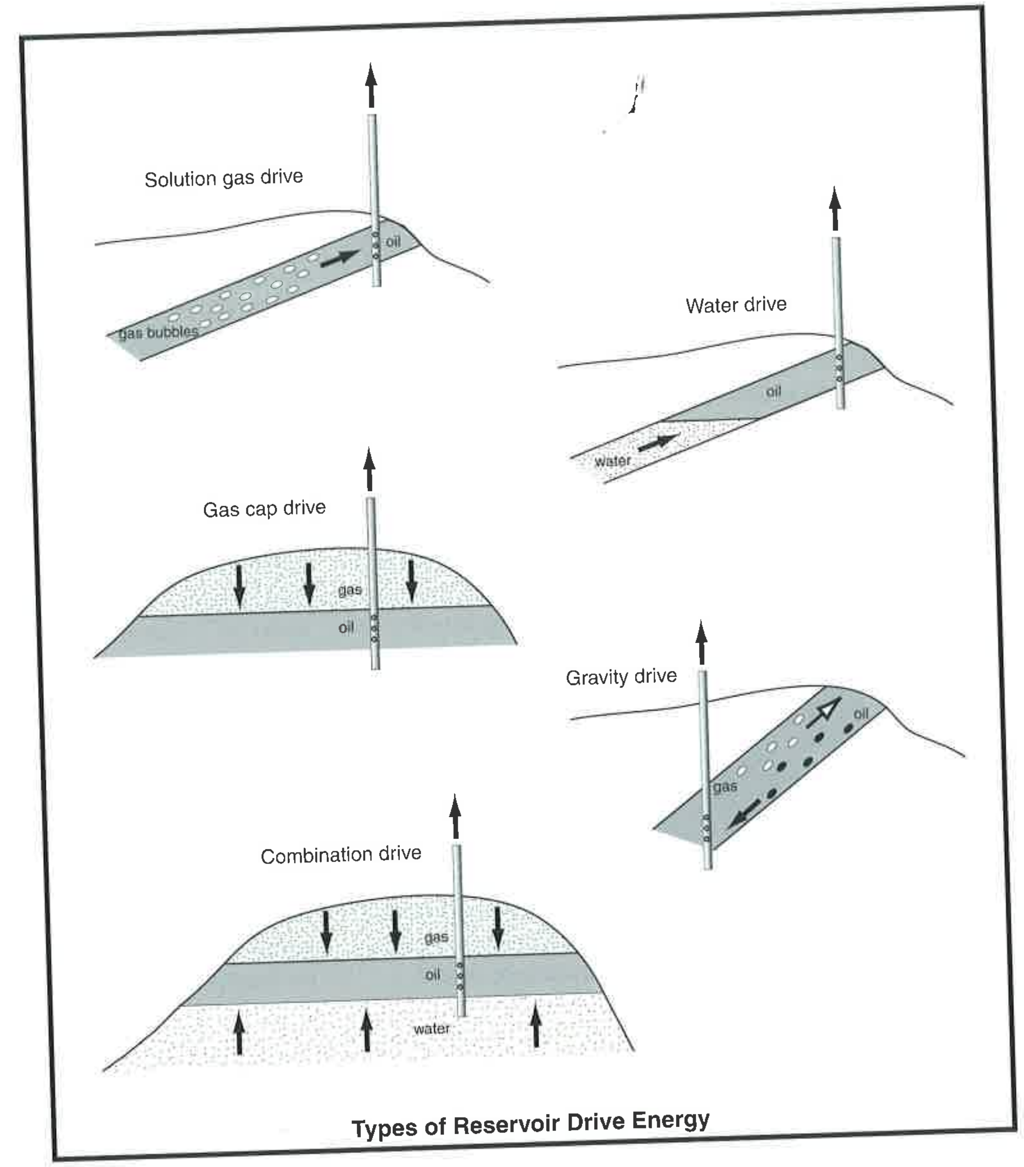
Water drive is a characteristic of reservoirs with laterally extensive reservoir continuity. A study of fields in Texas found that barrier-island, shoreline, and wave-dominated delta sand bodies, which extend over large areas, show strong water drives with high oil recoveries (Ambrose et al., 1991). A classic example of a water drive reservoir is the giant East Texas field in the United States (Halbouty, 1991). Layer-cake reservoir geometry, high permeabilities, and a large aquifer serve to create an effective water drive. This has resulted in a very high recovery factor with 81.8% of the 7326 MMbbls of oil in place expected to be recovered. Highly heterogeneous reservoirs are less likely to be in good communication with an aquifer and will have weaker drive mechanisms.

Another source of energy in oil reservoirs is provided by gas. Gas will expand as the pressure decreases during depletion. North (1985) commented that although a barrel contains 5.6 ft^3 of oil (0.159 m^3), *solution gas/oil ratios* in the reservoir converted to surface conditions are often expressed as values of about several hundred standard cubic feet per barrel. This shows the enormous degree to which gas can be compressed within oil at reservoir pressures and the large amount of energy stored here.

Solution gas drive is a characteristic of laterally restricted reservoirs, which do not have a gas cap and are not extensive enough to have a significant aquifer. As the pressure drops with production, the oil will have a small compressibility and will expand by a limited amount. Gas in solution in the oil is liberated once the pressure decreases below the *bubble point*. When this happens, gas bubbles emerge as a separate phase from the oil. Gas has high compressibility and will expand on decreasing pressure. This results in the compression and displacement of the oil toward the production wells. Once a critical saturation has built up, the gas starts to move toward the pressure sink in the reservoir, driving some of the oil along with the gas (Dake, 1978).

Solution gas drive is a weaker source of energy than water drive. The reservoir pressure declines rapidly and continuously. Dake (1994) described production at pressures below the bubble point as "messy." Gas viscosity is typically 50 times less than oil viscosities, and gas will flow much faster than oil through the pore space. The gas is nonwetting and will move through the center of the pores, leaving much of the oil undisplaced. According to Clark (1969), primary recoveries are always low

FIGURE 35. Various mechanisms of natural reservoir drive energy can support reservoir pressures to an extent. The magnitude of this energy can have a significant influence on primary recovery factors for oil.



in solution gas drive reservoirs, normally in the range of 5–30% of the oil in place.

Where a gas cap exists above the oil leg, *gas cap drive* provides a source of natural reservoir energy. As the pressure drops in the reservoir, the gas cap expands and acts to slow down the rate of pressure decline. The expansion of the gas also displaces the oil downward toward the producing wells. The efficiency with which this occurs depends on the vertical permeability of the reservoir rock. Where the vertical permeability is high, significant recoveries can result. The producing wells will be perforated at some distance below the gas-oil contact to avoid the gas breaking through too early. If this happens, the wells can "gas out"; that is, they will produce only gas and none of the remaining oil. Pressures are maintained more efficiently with a gas cap drive than in a solution gas drive reservoir. Primary recoveries are in the order of 20–40% (Clark, 1969).

A weak source of energy results from *compaction drive*. Reduction in pore pressure with production results in an increase in the *effective stress* as the weight of the rock lying above the reservoir is incrementally transferred to the grain framework of the reservoir. Although this happens to some extent in most producing fields, the effects are more pronounced in relatively unconsolidated reservoir rock. The pores compact in response to the increased effective stress, compressing the contained fluids and giving some support to the reservoir pressure. An example of compaction drive is the San Diego Norte Pilot Project from the Orinoco Heavy Oil belt of Venezuela (de Rojas, 1987). The reservoir sandstones are friable with high porosity and permeability. An analysis of the *rock compressibility* indicates that the oil recovery resulting from compaction could be 8%. An additional 4% is expected to come from solution gas drive, leading to a total recovery factor from primary production of 12%.

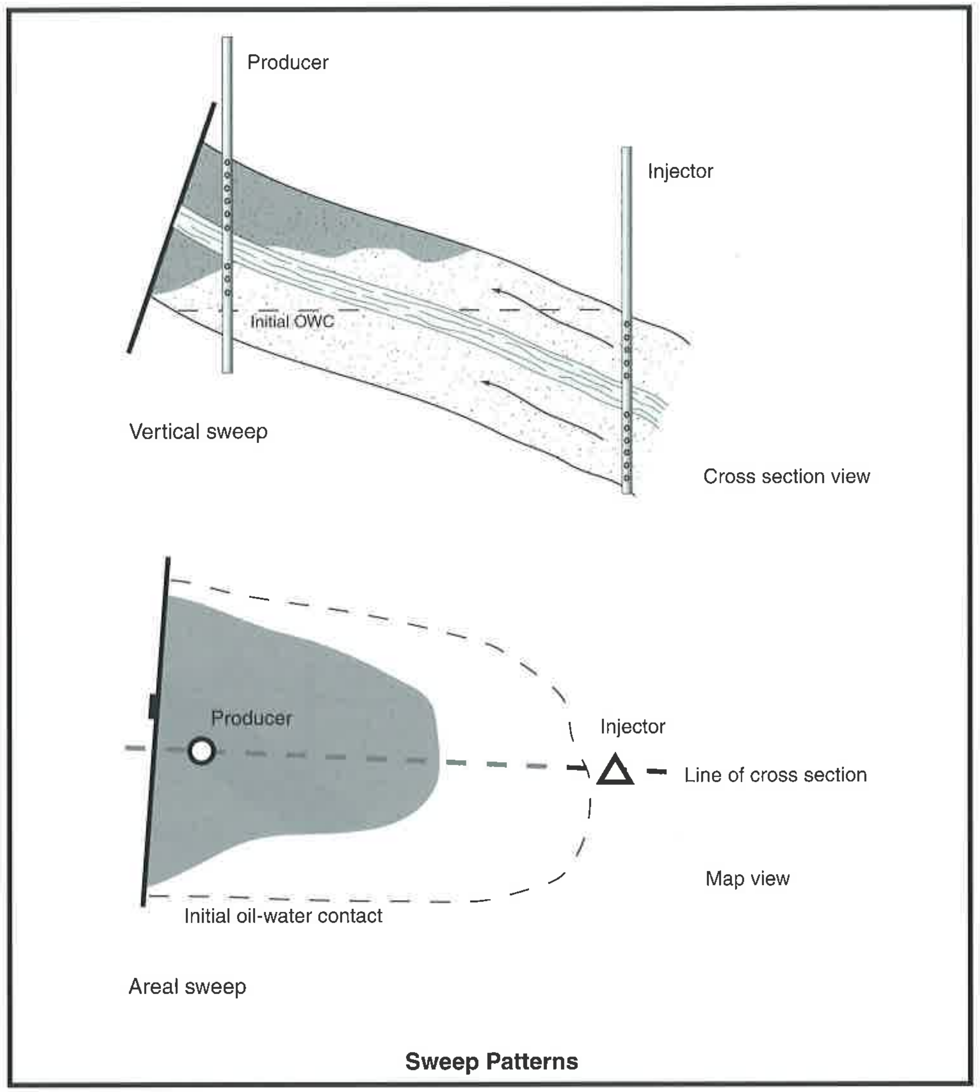


FIGURE 36. Areal sweep is the fraction of the areal extent of the reservoir that has been contacted by injected fluid. Vertical sweep is the fractional part of the reservoir cross section that has been contacted by injected fluid. OWC = oil-water contact.

Gravity drive results from the segregation of oil and gas in a reservoir because of their density differences. It is particularly effective in thick, high-permeability reservoirs or thin reservoirs with steep dips (Sills, 1992).

Many reservoirs show significant primary production resulting from more than one of these processes and this is referred to as a *combination drive.*

Oil Recovery from Waterflooded Reservoirs

Waterfloods increase the recovery from oil fields. Reservoir engineers often refer to the *volumetric sweep efficiency* of a waterflooded reservoir. This is the fraction of the total pore volume in a given part of the reservoir that has been contacted by the injected fluid (Craig, 1971). Common terms used are *areal sweep* and *vertical sweep* (Sarem, 1992). Areal sweep is the fraction of the areal extent of the reservoir that has been contacted by the injected fluid. Similarly, vertical sweep is the fractional part of a reservoir cross section that has been contacted by injected fluid (Figure 36).

The waterflood performance in water-wet reservoirs is largely controlled by the permeability layering at the bed and laminae scale. Water will edge ahead quickly through high-permeability intervals and more slowly through lower permeability rocks. There will then be some readjustment as capillary forces pull water into the smaller pores of the lower permeability intervals; in turn, oil is displaced into the higher permeability rock. The absorption of the wetting phase into a porous rock is called *imbibition*. Once the displaced oil finds a high-permeability pathway through a continuous stream of oil, there is an increased probability of the oil being produced. If the hydrocarbons are produced too quickly, the displacing water volume will advance too fast for efficient recovery by this mechanism. Consequently, many isolated volumes of oil will be left behind in low-permeability rock after the production wells have watered out (Buckley and Leverett, 1942). Thus, in waterflood reservoirs, the

ultimate recovery is sensitive to the offtake rate. In reservoirs with significant vertical permeability variations or fractures, very high initial production rates can lead to rapid water breakthrough, poor sweep efficiency, and lower than expected recoveries. Practical reservoir management involves finding a balance between economic production rates and maximizing the recovery.

Cross-bedded sandstones are not efficiently swept because the foresets and the low-permeability bottomsets can act to impede flow (Weber, 1982). In cross-bedded sandstones, alternating finer and coarser grained foreset laminae can result in significant quantities of capillary-trapped oil (Kortekaas, 1985; Corbett et al., 1992). Weber (1982) quoted an early article by Illing (1939) in which it is recognized that the most difficult sediments to sweep with water are those with numerous coarse and fine interfaces. The low-permeability, finer grained laminae rapidly imbibe water and physically trap oil in the coarser grained laminae. The oil is effectively immobilized in the coarser grained laminae as the interfacial tension between the water in the finer grained laminae and the oil prevents the oil from moving through the pores. Oil is produced more readily parallel to the cross-bedding than across it because of this effect. Huang et al. (1995) found that between 30 and 55% of oil was trapped this way in a coreflood experiment on cross-laminated eolian sandstone under conditions of low-rate flooding. Van Lingen and Knight (1997) considered that because of the predominance of cross-bedding in meandering fluvial sediments, capillary-trapped oil could range from 10% to more than 40% of the movable oil volume, depending on the flow direction and the effect of the bottomsets. In braided river systems, the effect is slightly less with an estimated 10–20% capillary-trapped oil. For shoreface sediments, an estimate of 5% capillary-trapped oil is made (Van Lingen and Knight, 1997).

THE EFFECT OF OIL VISCOSITY ON RECOVERY

Oil viscosity has an impact on the recovery factor. Water will readily displace low-viscosity oil to form a *stable flood front.* The oil is pushed ahead of an extensive cushion of water.

Where the oil is heavier and more viscous, the water will tend to finger through the oil column in an irregular manner, breaking through to the production wells rapidly. Large volumes of water will need to be circulated through the reservoir in order to obtain economic oil recovery. This may not be practical offshore given the high production rates required to keep the infrastructure profitable (Dake, 1994). Onshore, it is more efficient to use methods such as steam flooding or in-situ combustion to recover viscous, heavy oils.

ENHANCED OIL RECOVERY

At the mature phase of field life, methods of *enhanced oil recovery* (EOR) may be instigated. This is also called *tertiary recovery.* EOR projects are designed to change the fundamental physics or chemistry of the reservoir conditions in order to improve the recovery. The method used will depend on the fluid type and the reservoir.

The most common EOR operation uses *thermal methods*, involving steam, heat, or combustion to improve oil recovery. These account for 70% of the world's production by EOR techniques (Nind, 1989). Thermal methods are used for recovering heavy (and viscous) oils with gravities between 10 and 25° API units (Nind, 1989). The operation is used in areas with heavy oil such as Venezuela, Canada, the United States, Russia, China, and Indonesia.

Steam can be continuously injected as a flood called a *steam drive.* An alternative method is *steam soaking,* also known as *huff and puff.* This involves a cyclic operation whereby steam is injected into a production well, allowed to soak for a few days to distribute the heat, and is then followed by a period of oil production from the well. Production is increased by several mechanisms. The steam heats the oil and reduces the viscosity allowing it to flow more easily. In addition, the oil expands by swelling, and changes in the surface tension also improves the flow (Briggs, 1987).

In-situ combustion of the oil in the reservoir has also been used, a technique sometimes known as *fire flooding* (Matthews, 1983; Briggs et al., 1987). The oil is ignited in the subsurface with the fire fed by a continuous supply of air via an injector well. The resultant combustion front moves away from the air injection well toward the production wells. The heat of the fire reduces the oil viscosity and vaporizes the water within the reservoir to steam.

For lighter oil, *miscible drive* operations are used for incremental oil recovery. The idea is to inject a fluid such as methane, liquid petroleum gas, CO_2, or nitrogen that is miscible with the oil phase and thus reduce or eliminate the interfacial tension between the injected fluid and the oil. The oil mixes with the injected miscible fluid and flows readily to the producers (Nind, 1989). Carbon dioxide miscible floods have proved so effective in oil fields in North America that oil companies are willing to transport carbon dioxide long distances to enable this. For example, a 205-mi (330-km)-long pipeline brings CO_2 from a coal gasification plant in North Dakota across the United States-Canada border to the Weyburn field in Saskatchewan.

A variation on the theme is a *water alternating gas* (WAG) flood (Christensen et al., 1998), which is a period of water injection alternated with a period of miscible gas injection. A WAG flood is in operation in the

Magnus field in the UK North Sea; water is injected into three wells for a 6-month cycle followed by gas injection for 6 months (MacGregor and Trussell, 2003). The water injection provides a stable floodfront to sweep the oil, whereas the gas displaces residual and bypassed mobile oil at the pore scale. The combined effect can be the recovery of significant volumes of oil. An increase in recovery of between about 5 and 20% has been reported in reservoirs using WAG floods. Examples of where WAG schemes have been implemented include the Dollarhide, Rangeley Weber, and Slaughter Estate fields in the United States.

Polymer flooding is an operation whereby suitable chemicals are added to injection water to increase the viscosity of the waterflood. The use of polymers is intended to create a more stable flood front and thus improve recovery in fields containing moderately viscous oil (Jahn et al., 1998).

Much effort was put into investigating the use of surfectants as an EOR method in the 1980s. Surfectants were added to injection water to reduce the water-oil interfacial tension. Surfactants can be expensive to use in quantity. More recent methods involve combining surfactant with alkali and polymer chemicals. The alkali chemicals react with acids in the oil to form surfectants within the reservoir. The polymer helps to move the mixture along with the water flood.

Bacteria have also been used to produce incremental oil recovery. Bacterial activity in the reservoir can release gases, polymers, acids, surfactants, and other compounds that may mobilize oil (Moses and Springham, 1982).

ECONOMIC FACTORS

An important economic factor controlling the recovery from fields is whether they are onshore or offshore. Wells are much cheaper to drill onshore, and the overall cost of the operation is substantially less.

Recovery factors are higher for onshore fields compared to offshore fields. Onshore fields tend to be drilled with a closer well spacing than is practical offshore. Typical well spacings are 200–500 m (656–1640 ft) onshore and 500–1000 m (1640–3280 ft) offshore (North and Prosser, 1993). The greater density of wells in onshore fields increases the chance that oil in a reservoir dead end will be found when a producer is drilled (Weber, 1999).

The second reason for better recoveries onshore is that the wells are profitable much longer than offshore wells. For instance, it has been estimated by the U.S. Department of Energy that 20% of all the oil produced in the United States comes from wells producing less than 15 BOPD. No offshore well would make any money from rates as low as this. Offshore fields are expensive to run and will be shut in as uneconomic even when the oil production rate is still relatively high. Production tends to decline asymptotically in a predictable manner, and when an offshore field is abandoned at a high rate of production, there is a long tail of potential production beyond this point that would be economic onshore.

UNECONOMIC OIL

The volume deemed to be uneconomic oil is sensitive to the prevailing economic environment. Oil price, equipment costs, taxation, and other factors will determine the nature of oil field economics.

A subsurface team can influence economic factors so as to produce more hydrocarbons. An example of this is the Angus field redevelopment in the UK Central North Sea. Previously produced through an FPSO vessel, the field was shut in and abandoned once the oil rate had dropped below 7000 BOPD. The *operating expenditure (OPEX)*, which is the cost of the vessel, manpower, and associated logistics, was considered too high at these oil rates for the project to make an economic return. The field was reopened 7 yr later. By building a pipeline back to another producing field, the OPEX was minimized as the hub field covered this. The new operation involved the *capital expenditure (CAPEX)* of building a 21-km (13-mi) pipeline and the drilling of a new well. Renewed production from the Angus field paid back the CAPEX within 6 months. Production thereafter continued to provide revenue. The expected reserves were an extra 5.2 MMbbls of oil that had been previously categorized as uneconomic movable oil (Shepherd et al., 2003).

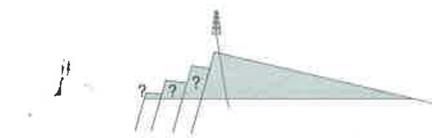
Another way of changing the economic environment is to reduce the drilling costs using cheaper techniques such as coiled tubing or through tubing drilling (see chapter 28 of this publication). The reduced costs can change marginal opportunities into economic targets (Figure 37).

RESERVOIR MANAGEMENT OF GAS FIELDS

Gas fields are managed differently from oil fields. Oil is relatively easy to transport in bulk volumes long distances, whereas this is difficult for gas, unless a very expensive liquid natural gas (LNG) plant is built or there is an extensive regional gas pipeline network. A gas field will typically be developed once a *gas sales contract* has been made to supply the gas to customers living close to the gas field. The contract will involve a commitment to supply a daily volume of gas over a certain period of time. Thus, there is a requirement to be reasonably sure of what a gas field will produce before it starts production. It will be necessary to test every well preproduction to get a good knowledge of well productivity and flow rates (Ikoku, 1984).

FIGURE 37. Factors influencing why oil is left behind in oil fields.

Why Oil is Left Behind in Oil Fields



Geological Complexity

- Reservoir dead ends will trap oil uncontactable by existing wells
    - structural dead ends
    - stratigraphic dead ends
- Number of reservoir compartments
- Permeability layering

Fluid Physics

- Residual oil saturation
- Capillary-trapped oil in cross-bedded sandstone
- Oil viscosity
- Type of reservoir drive mechanism
    - water drive
    - solution gas drive
    - gas cap drive
    - compaction drive
    - gravity drive

Economics

- Oil price
- Taxation, etc.
- Onshore vs. offshore
- Operating expenditure for the infrastructure
- Number of wells
- Wells become uneconomic at low production rates (varies onshore vs. offshore)

Recovery factors are higher for gas than they are for oil, commonly in the range of 50–80% (Jahn et al., 1998). The recovery factor for gas fields is dependent on factors such as the *abandonment pressure*, the *initial pressure*, and the type of reservoir drive mechanism. Recovery can also be sensitive to the engineering of the surface plant. In big gas fields, the installation of compression equipment can lead to higher recoveries.

A key property of a gas is its *compressibility*; gas compresses readily with increasing pressure. Conversely with decreasing pressure, the gas will expand. The measure of how much a gas will expand between the reservoir and surface conditions is the *gas expansion factor*. A typical value for this is 200 (Jahn et al., 1998). Expansion is the main mechanism by which gas is produced to the surface. Once the pressure drops to reduced levels, then surface flow rates may be too low to be profitable. This is the abandonment pressure, which effectively defines the economic limit of flow from a gas field.

One difference between gas and oil is that, as the pressure decreases, oil with its limited compressibility will stay trapped in a reservoir dead end, whereas gas may not remain trapped for too long. The gas will expand on decreasing pressure and a significant proportion of the trapped volume will eventually escape around the edges of the dead end. This is an important factor contributing to high recovery factors in gas fields.

Another factor is that gas has a lower viscosity than oil and will flow through low-permeability rocks that would not produce oil. Hence, gas can be produced economically from poorer quality reservoir rocks. A wider spectrum of rock types will produce gas by comparison to oil.

A strong water drive is unfavorable to gas recovery as water breakthrough to the production wells will make flow rates sluggish and uneconomic at higher pressures than with closed gas reservoirs (Ikoku, 1984). The intensity of the water drive can be a major factor behind the ultimate recovery of gas; a slower encroachment of water will result in higher recoveries. Permeability is also a critical factor in gas reservoirs. Higher permeability results in a high flow rate for a given pressure drop. Thus, the abandonment pressure can be lower for a high-permeability gas reservoir (Ikoku, 1984).

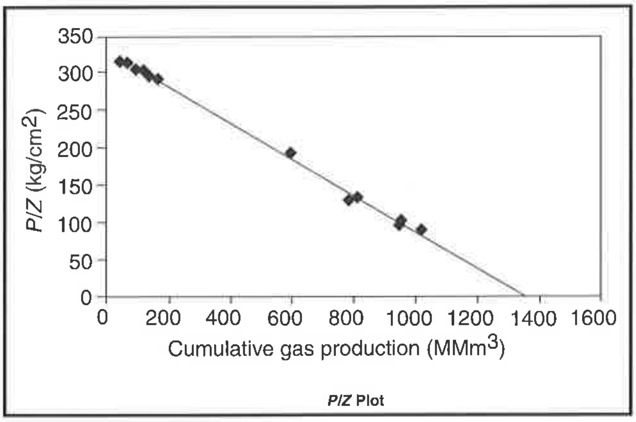


FIGURE 38. P/Z plots are used by reservoir engineers to estimate the contacted volumes in a gas field. This example is from the Novillero gas field in the Veracruz basin, Mexico (from Holtz et al., 2002), reprinted with permission from the Gulf Coast Association of Geological Societies. MMm^3 = million cubic meters.

Gas reservoirs without an aquifer have been called *volumetric (or depletion) reservoirs*. This is because the elementary physics of the gas laws allow the volume of gas in the reservoir to be calculated once a certain amount of gas has been produced. Recoveries are higher (~80–90%) as pressure depletion is much more efficient than a water drive regime, because the wells do not load up with water.

A material balance technique used by reservoir engineers to estimate gas volumes is the *P/Z plot* (Dake, 1978). This is based on the gas law relationship whereby if the volume of a gas is reduced within a closed system, then the pressure will drop in a predictable manner. Two parameters are crossplotted on a graph: pressure, divided by the gas deviation (dimensionless compressibility) factor Z, used in the equation for the nonideal gas law; and cumulative gas production. In closed system reservoirs, the values will plot on a straight-line trend. The trend is extrapolated to the abandonment pressure to estimate the contactable volume of gas (Figure 38). For example, in the Novillero gas field in the Veracruz basin of Mexico, the P/Z plot extrapolates to the base line at a total gas volume of close to 1400 MMm^3 (49.4 bcf) (Holtz et al., 2002). If an aquifer is present, the system cannot be considered closed, and the P/Z plot will deviate from a straight-line trend.

GAS CONDENSATE

Gas condensate is a type of petroleum fluid that exists in the reservoir as a gas at initial conditions but once the pressure drops to the dew point, liquids will start to condense (Jahn et al., 1998). Produced to the surface, both gas and condensate liquids are separated out in the production plant.

Pressures can fall below the dew point in the reservoir, with liquid condensate dropping out near the well bore. This *condensate banking* can lead to a reduction in the gas relative permeability, and gas flow rates can drop off significantly as a result (Ayyalasomayajula et al., 2005). Therefore, there is an incentive with a gas condensate reservoir to keep the pressure above the dew point so as to prevent this from happening. A typical strategy is to recycle gas back into the reservoir to maintain pressure.

24

Petroleum Production

World Oil reported an average global oil production rate of 73.6 million bbl/d (11.7 m^3/d) in 2010. Of that, Saudi Arabia averaged 8.2 million bbl/d (1.3 million m^3/d) (11%) and the United States averaged 5.5 million bbl/d (0.9 million m^3/d) (7.4%).

The API reported that in 2008 there were a total of 1,004,606 producing wells in the United States. Of those, 48% were gas and condensate wells and 52% were oil wells. Texas had the most wells. More than half (54%) of all the world's producing oil wells were located in the United States. Russia was second, followed by China and Canada. The average oil production per oil well in the United States was 10.2 bbl/d (1.6 m^3/d).

A *petroleum engineer* is an engineer who is trained in drilling, testing, and completing a well and producing oil and gas. A *reservoir petroleum engineer* is in charge of maximizing the production from a field to obtain the best economic return.

Well and Reservoir Pressures

Tubing pressure is measured on the fluid in the tubing, whereas *casing pressure* is measured on the fluid in the tubing-casing annulus. The pressure gauge at the top of a Christmas tree measures tubing pressure. *Bottomhole* *pressure* is measured at the bottom of the well. It is measured either as *flowing*, with the well producing, or *shut-in* or *static*, after the well has been shut in and stabilized for a period of time such as 24 hours (fig. 24–1). *Downdraw* is the difference between shut-in and flowing pressure in a well.

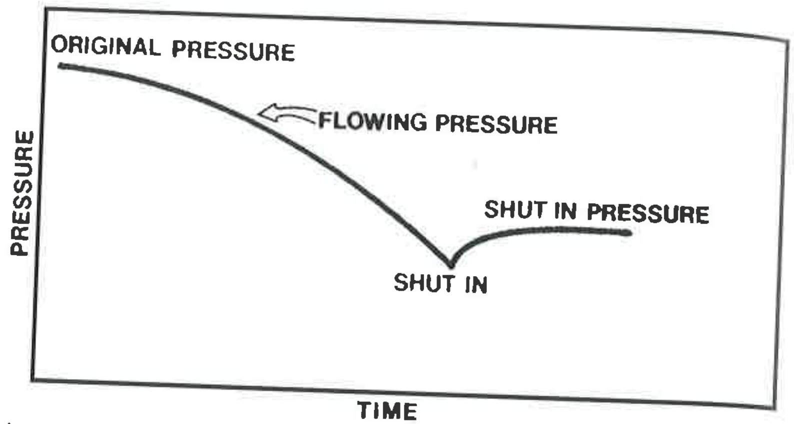


Fig. 24–1. Flowing and shut-in pressure in a well

The original pressure in a reservoir before any production has occurred is called *virgin*, *initial*, or *original pressure*. During production, reservoir pressure usually decreases. Reservoir pressure can be measured at any time during production by shut-in bottomhole pressure in a well. A *pressure bomb*, an instrument that measures bottomhole pressure, can be run into the well on a wireline. A common pressure bomb consists of a pressure sensor, recorder, and a clock-driven mechanism for the recorder. It is contained in a metal tube about 6 ft (1.8 m) long. The chart records pressure with time as the test is being conducted. Temperature can also be recorded on a similar instrument. Another instrument, an *electronic pressure recorder*, can be run on a conductor wire.

Well Testing

Tests on a well are run by the well operator, a specialized well tester, or a service company to determine the optimum production rate. They can use equipment available on the site or portable test equipment. After the well has been completed, a potential test can be run. The *potential test* determines the maximum gas and oil that the well can produce in a 24-hour period. It uses the separator and tank battery on the site to hold the produced

fluids. Potential tests can also run periodically during production and may be required by some government regulatory agencies.

A *productivity test* is run to determine the effect of different production rates on the reservoir. It is made with portable well test equipment (fig. 24-2) that measures the fluid pressure at the bottom of the well when it is shut-in and then during several different stabilized rates of production. The measurements are used to calculate the absolute open flow and the maximum production rate that the well can produce without damaging the reservoir.

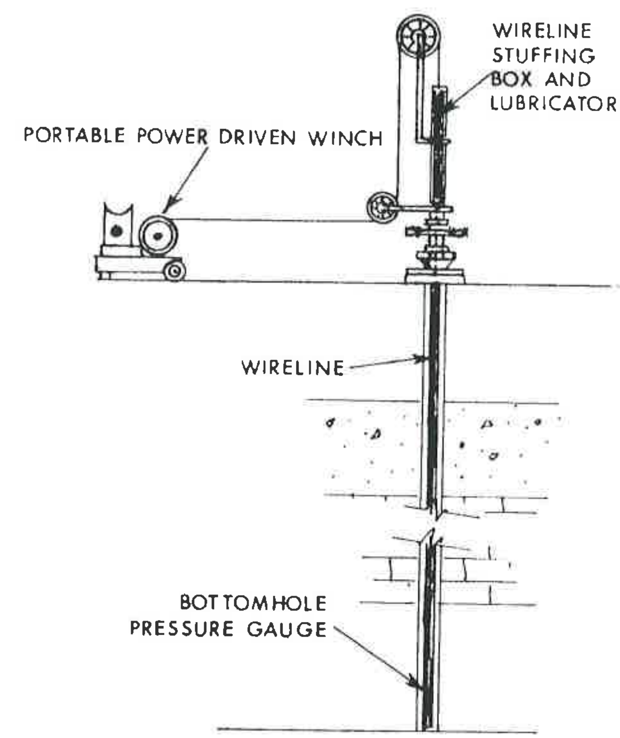


Fig. 24–2. Productivity test equipment

For wells that have a central processing unit, periodic *production tests* can be made to determine how much each well is producing. These tests are run manually or automatically. Oil well test data typically include oil production, water production, gas rate, gas/oil ratio, and flowing tubing pressure. Gas well test data typically include gas rate, condensate production, water production, flowing tubing pressure, and condensate/gas ratio.

Pressure transient testing on a well involves measuring pressures and their flow rates. One type, a *drawdown test*, measures the shut-in bottomhole pressure and then the pressure change as the well is put on production and the pressure drops to a stable, flowing pressure. A *buildup* test measures the flowing bottomhole pressure and then the pressure change as the well is shut in and the pressure rises to a stable, shut-in pressure. A *multirate test*, such as a four-point test, measures the flowing bottomhole pressure at different, stabilized flow rates.

Deliverability is the ability of the reservoir at a given flowing bottomhole pressure to move fluids into the well. *Maximum potential flow* or *absolute open flow* (*AOF*) is the maximum flow rate into a well when the bottomhole pressure is zero. It is a theoretical flow rate that is calculated from a multivariate test. The *production index* (*PI*) of a well is the downhole pressure drawdown in pounds per square inch (psi) divided by the production in barrels per day (bbl/d). Wells on land usually have a PI of greater than 0.1 psi/bbl/day, whereas offshore wells have a PI greater than 0.5. *Inflow performance relationship* (*IPR*) is similar to PI because it plots drawdown against production but is more accurate in that it also accounts for reservoir drive, increasing gas/oil ratios, and relative permeability changes with production.

Gas wells are tested with routine production tests that measure the amount of gas, condensate, and water produced. A *backpressure test* measures the shut-in pressure and the pressures at different stabilized flow rates to determine the well deliverability.

Cased-Hole Logs

After a reservoir in a well has been depleted, a decision must be made to either plug and abandon or recomplete the well. To recomplete, a new oil or gas reservoir must be identified behind the casing. Only the natural gamma ray and neutron porosity logs can be run in a cased-hole. A *pulsed neutron log* is a type of neutron log that emits pulses of neutrons into the formation and measures returning gamma rays. It can distinguish gas and oil from water in the reservoir and is used to find gas and oil reservoirs located behind the casing.

Production Logs

Production logs are run in producing wells to evaluate a problem. They are run either on a wireline through the tubing or on a tubing string. There are several types of production logs.

Tracer logs are used to detect fluid movement in a well. A radioactive tracer is injected into the well at a specific location, and its movement is tracked by recording gamma rays. A *continuous flowmeter* uses propellers on a vertical shaft to measure fluid flow up a well to make a continuous record of flow versus depth in the well. A *packer flowmeter* uses a packer to seal the well at that depth to ensure that all the fluids flow up through the flowmeter in the packer and are measured.

A *noise log* uses a microphone to detect and amplify any sounds in a well. The log can locate where fluids are flowing into the well, and the frequency of the sound can be used to distinguish between liquid and gas. A *temperature log* measures the temperature of fluid filling a well. Before the temperature log is run, the well is shut in for a period of time to allow the temperatures to come to equilibrium. Because expanding gas cools when entering a well, it can be located by a temperature log.

A *manometer* measures pressure in the well at a specific depth, and a *gradiometer* measures a continuous profile of the pressure gradient. A *water-cut meter* measures the amount of water in the fluid filling the well. A *collar log* has a casing-collar locator that uses either a magnetic detector or scratcher to locate the casing collars in a well. It is used to accurately find locations in the well. A collar log is used with a natural gamma ray log to locate where to perforate the casing.

Decline Curves

A *decline curve* is a plot of oil or gas production rate with time made for a single well or an entire field (fig. 24–3). Production rate will decline with time as the reservoir pressure decreases. The *initial production* (*IP*) of a well is the first 24 hours of production and is usually the highest. As the production rate declines, the well eventually becomes a *stripper well* that is barely profitable. Stripper wells are defined in the United States as producing less than 10 bbl (1.6 m^3) of oil per day over a 12-month period or 60 Mcf (2,000 m^3) of gas per day at maximum flow rate, and they receive special tax advantages. The API reported that in 2007 there were a total of 396,537 stripper oil wells in the United States that accounted for about

77% of the total US oil wells. They produced an average of 2 bbl/d (0.32 m^3/d) and accounted for 15.7% of total US oil production.

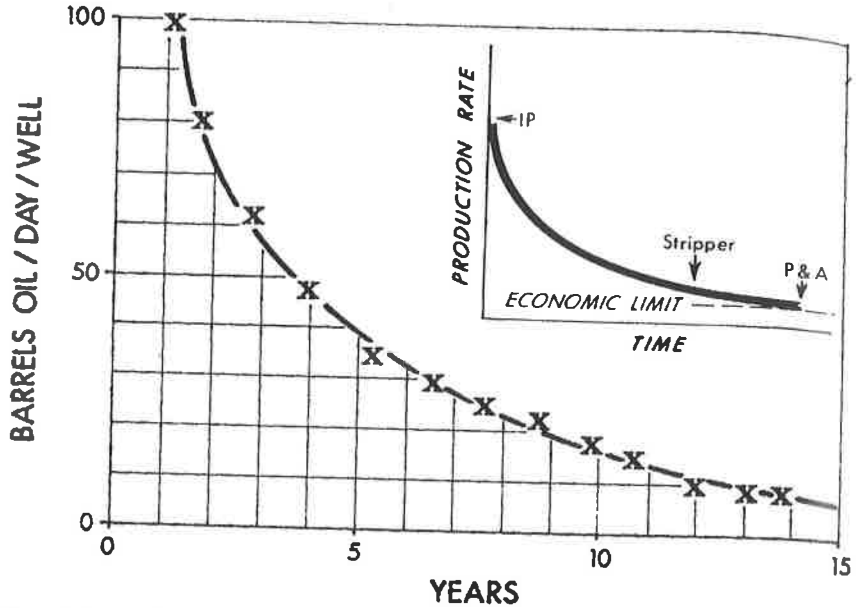


Fig. 24–3. Decline curve

The *economic limit* of a well is when production costs equal net production revenue. It depends on how deep the well is, how much water it produces, where the well is located, and several other factors. When the economic limit of a well is reached, it is plugged and abandoned, or improved oil recovery is initiated. Most wells are designed with a 15- to 20-year life.

The shape of the oil decline curve depends on the reservoir drive (fig. 24–4). Solution-gas reservoirs have a very sharp decline, whereas water-drive reservoirs have almost constant production for the life of the wells. The shape of a free gas cap expansion drive curve is between the curves for solution-gas and water-drive reservoirs. The decline curves for wells producing from a fractured reservoir in a tight sandstone or dense limestone such as the Spraberry field of Texas, or a gas shale such as the Barnett Shale, are very distinctive (fig. 24–5). The well can have a high IP as oil drains rapidly through the very permeable fractures. As the fractures drain, the production rapidly drops. Within a short period, the production settles to a long and steady rate as the oil drains slowly from the relatively impermeable rock into the fractures.

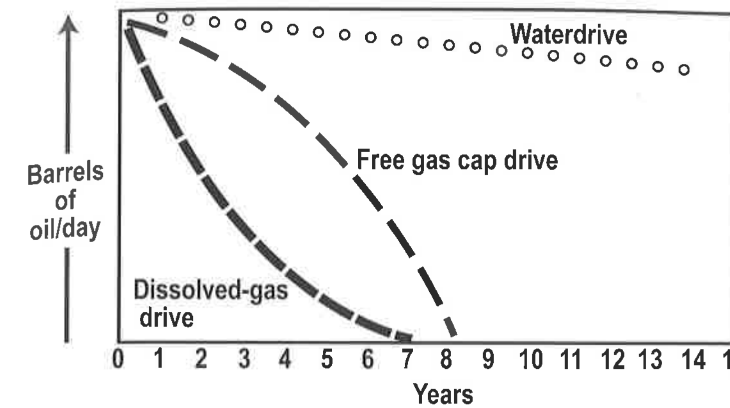


Fig. 24–4. Reservoir drive decline curves

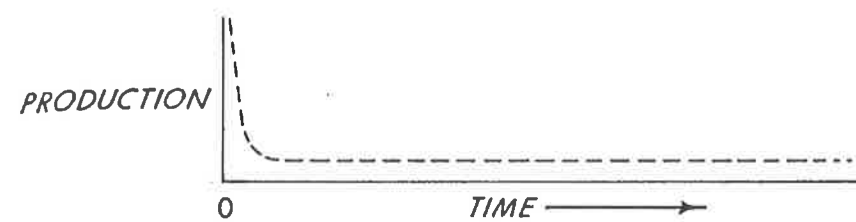


Fig. 24–5. Decline curve for a fractured reservoir

Bypassing and Coning

Drilling and completing a well is an economic investment. The best return on that investment is to produce the gas and oil as fast as possible to recover costs and make a profit as soon as possible.

Many reservoirs, however, are not homogeneous, and there are pockets of oil or gas in less permeable areas. In a water-drive reservoir, the water flows in to replace the oil or gas as it is being produced. If the oil and gas are produced too fast, the water can flow around pockets of oil and gas in less permeable areas in a process called *bypassing* (fig. 24–6). Bypassing seals the oil (*bypassed oil*) and gas (*bypassed gas*) in that area and prevents it from being produced from existing wells. To prevent significant bypassing and have maximum ultimate production, the oil and gas should be produced at a slower rate to allow less permeable zones time to drain.

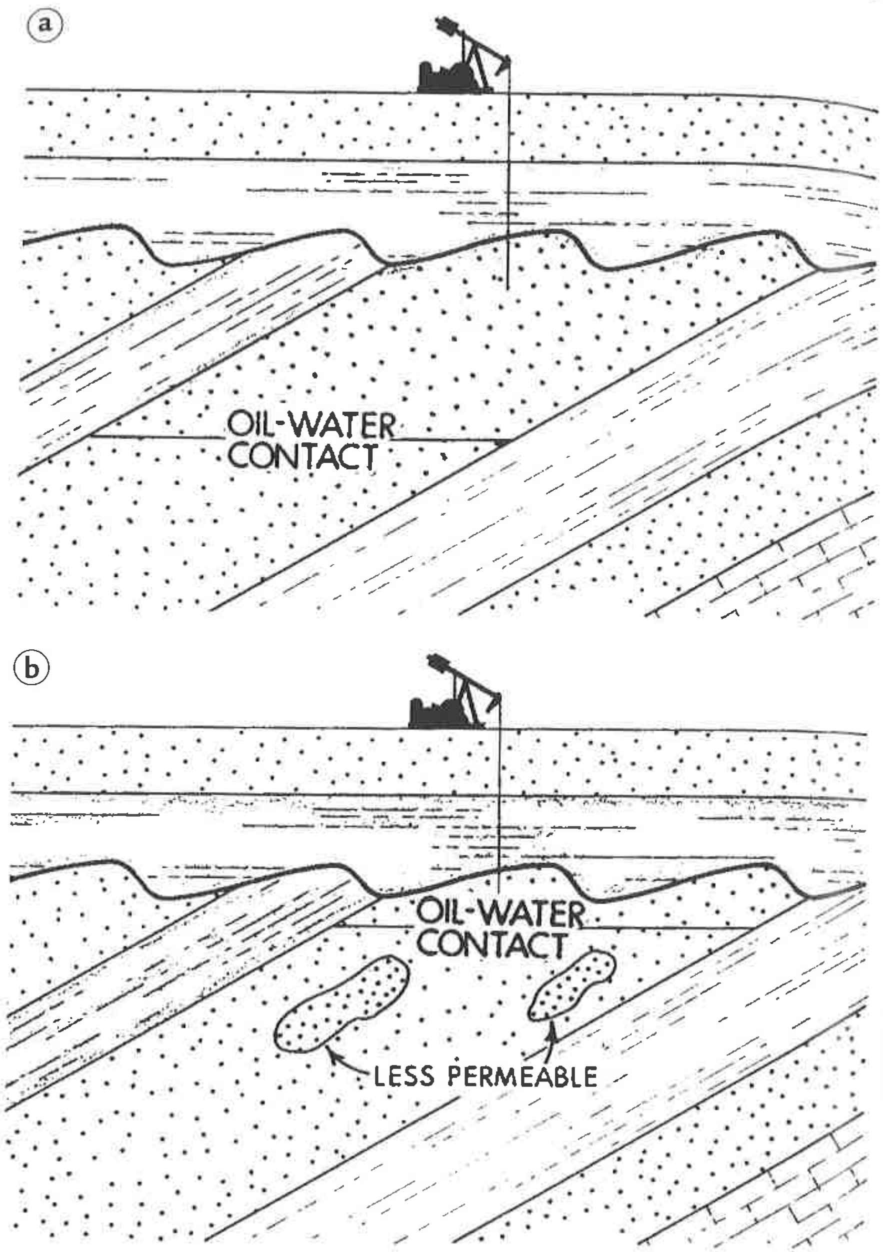


Fig. 24–6. Bypassing (a) before production and (b) after production

Coning is caused by oil being produced too fast. The oil-water contact is sucked up in a bottomwater drive reservoir (fig. 24–7), or the gas-oil contact is sucked down in a free gas cap expansion drive reservoir. This can cause

permanent damage to the well. Horizontal wells can be used to prevent coning. If coning does occur on a horizontal well, it is called *cresting*.

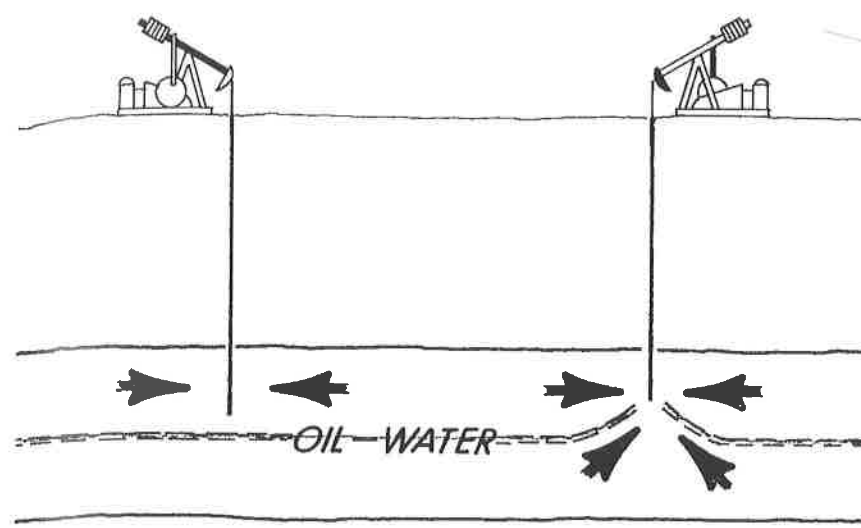


Fig. 24–7. Coning

Cycling

As reservoir pressure drops during gas production from a retrograde gas reservoir, condensate separates out of the gas in the reservoir. The liquid coats the subsurface grain surfaces and is very difficult, if not impossible, to recover. To prevent condensate from separating in the subsurface reservoir, *cycling* is used. Produced gas is stripped of natural gas liquids on the surface. The dry gas is then reinjected through injection wells into the reservoir to maintain the reservoir pressure.

Well Stimulation

Several well stimulation methods can be used to increase the well production rate. These include acidizing, explosive fracturing, and hydraulic fracturing.

Acidizing

A well can be *acidized* or given an *acid job* by pumping acid down into the well to dissolve limestone, dolomite, or any calcite cement between sediment grains. HCl (*regular acid*), HCl mixed with HF (*mud acid*), and HF (*hydrofluoric acid*) are commonly used. HCl is effective on limestones and dolomites, and HF is used for sandstones. For formations with high temperatures, acetic and formic acids are used. To prevent the acid from corroding the steel casing and tubing in the well, an additive called an *inhibitor* is used. A *sequestering agent* is an additive used to prevent the formation of gels or precipitates of iron that would clog the pores of the reservoir during an acid job.

Two types of acid treatment are matrix and fracture acidizing. During *matrix acidizing*, the acid is pumped down the well to enlarge the natural pores of the reservoir. During *fracture acidizing*, the acid is pumped down the well under higher pressure to fracture and dissolve the reservoir rock. After an acid job, the spent acid, dissolved rock, and sediments are pumped back out of the well during the *backflush*. An acid job is also used to remedy skin damage on a wellbore and is called a *wash job*.

Explosive fracturing

From the 1860s until the late 1940s, explosives were commonly detonated in wells to increase production. *Well shooting* or *explosive fracturing* was done with liquid nitroglycerin in a tin cylinder called a *torpedo*. It was run down the well and detonated on the bottom. The explosion created a large cavity that was then cleaned out, and the well was completed open hole. The person in charge of the nitro was called the *shooter*. The technique was both effective and dangerous.

Hydraulic fracturing

Hydraulic fracturing was developed in 1948 and has effectively replaced explosive fracturing. In 2010, over 60% of all wells completed in the United States were fraced. During a *frac job* or *hydraulic fracturing* (fig. 24–8), a service company injects large volumes of frac fluids under high pressure into the well to fracture the reservoir rock (plate 24–1). Frac jobs are done either in an open-hole or a cased well with perforations. A common *frac fluid* is a gel formed by water and *polymers*, long organic molecules that form a thick liquid when mixed with water. Oil-based frac fluid and foam-based frac fluids using bubbles of nitrogen or carbon dioxide can be used to minimize formation damage. Typically, about 0.5% of the frac fluid is composed of additives similar to those used in drilling fluids. The frac fluid is transported out to the frac job in large trailers.

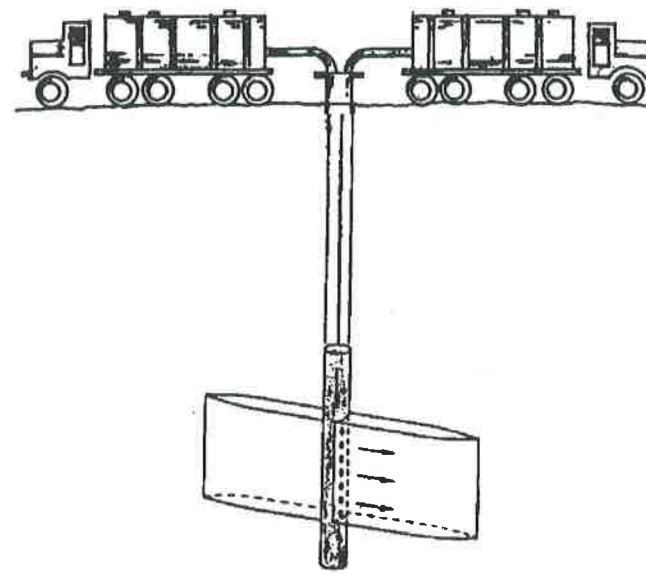


Fig. 24–8. Hydraulic fracturing

Plate 24–1. Hydraulic fracturing an oil well

A frac job is done in three steps. First, a pad of frac fluid is injected into the well by several large pumping units mounted on trucks to initiate fracturing the reservoir. Next, a slurry of frac fluid and propping agents are pumped down the well to extend the fractures and fill them with propping agents. *Propping agents* or *proppants* are small spheres that hold open the fractures after pumping has stopped. The propping agents are commonly well-sorted quartz sand grains. In high-pressure wells, ceramic or aluminum oxide microspheres are used. The well is then *backflushed* in the third stage to remove about 10 to 30% of the original frac fluid.

Crosslinked frac fluids that have a high viscosity necessary to carry the propping agents down the well can be used. A *breaker fluid* is then injected into the well to make the crosslinked frac fluid more fluid and easier to remove during backflush.

Medium and hard (brittle) formations are best for fracturing, because loose formations (unconsolidated) do not permit the propping agents to hold open the fractures. All the equipment used during the frac job is driven onto the site. The frac fluid is mixed and stored in *frac tanks*. The frac fluid is mixed with proppants in a *blender*. Pump trucks are connected to a manifold to pressurize the pad and the slurry and pump them down the well. A *wellhead isolation tool* can be connected to the top of the well to protect the wellhead from the high pressures and abrasive propping agents. The frac job is monitored and regulated from the *frac van*.

Frac jobs are described by the amount of frac fluid and proppants used. The average modern frac job uses 60,000 gallons (227,000 liters) of frac fluid and 100,000 pounds (45,000 kg) of sand. A *massive frac job* is a very large frac job (plate 24–2). There is no exact definition of a massive frac job, but it typically uses more than 1 million gallons (3.8 million liters) of frac fluid and 5 million lb (2.3 million kg) of sand.

A *frac pack* or *frac/pack* uses a viscous gel and a relatively high concentration of sand proppants. It forms relatively short but wide fractures. Frac packs are common in offshore wells.

Hydraulic fracturing is a very common well-stimulation technique that increases both the rate of production and ultimate production. It increases the production rate from 1½ to 30 times the initial rate with the highest increases in tight reservoirs. Ultimate production is increased from 5 to 15%. It is used in all tight gas sand reservoirs and as a common remedy for skin damage in a wellbore.

A well can be fraced several times during its life. In some instances, however, hydraulic fracturing can harm a well by *fracing into water*. The hydraulically induced fractures extend vertically into a water reservoir that floods the well with water.

Plate 24–2. Aerial photograph of a massive frac job. The well is in the center with lines of pumping units and frac fluid trailers on either side. (Courtesy of Halliburton.)

Disposal of Oilfield Brine and Solution Gas

The natural gas produced with oil often creates a disposal problem. It comes from the separators at very low (atmospheric) pressure, and there is usually no market for it. Even with a market, the gas would have to be compressed to pipeline pressure. In the past, it was often burned (*flared*) in the oil fields. This is against the law today in most countries. Flaring still occurs in some situations when any other gas disposal method is not practical or during well testing. The produced gas can be used to increase the ultimate oil production from the reservoir by reinjecting it into the subsurface reservoir in a *pressure maintenance system* (fig. 24–9). Produced wet gas is first gathered and is usually stripped of valuable natural gas liquids. It is then compressed and pumped into an *injection well*. In a saturated oil field, the gas is injected into the free gas cap. In an undersaturated oil field, the gas is injected into the oil reservoir.

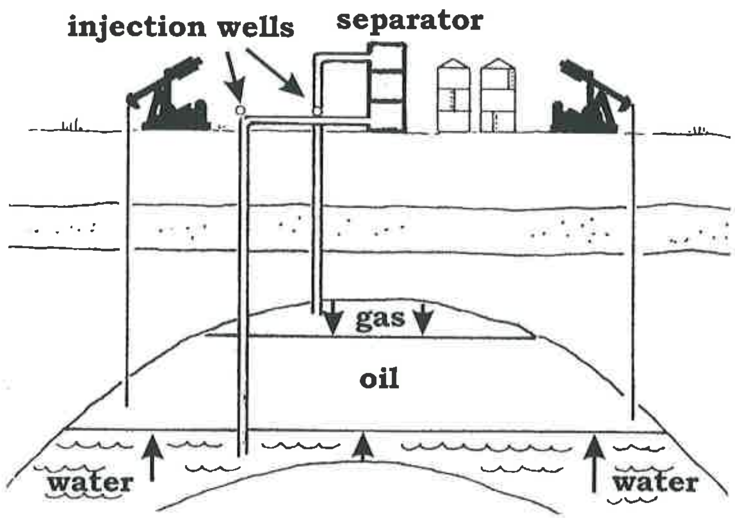


Fig. 24–9. Pressure maintenance system

Gas from the separators can also be given to the landowner to heat his or her home and operate irrigation pumps. This *farmer's gas* can be part of the lease agreement before any wells are drilled. Gas from the separator could also be used to operate equipment in the field such as the engine used to drive a beam-pumping unit.

Oilfield brine from the separators can also be pumped down another injection well into the subsurface reservoir below the oil-water contact as part of the pressure maintenance system. If there is no injection well system available for the well or field, the oilfield brine or the water removed from natural gas is stored in a metal (see chap. 20, plate 20–4) or fiberglass *saltwater tank*. The fiberglass tank is more resistant to corrosion.

A *saltwater disposal well* is used to pump the brine or water into a subsurface reservoir rock (fig. 24–10). The disposal well has to be permitted by a government agency and must meet specific criteria. The oilfield brine cannot be injected into a subsurface freshwater reservoir. The reservoir must already contain naturally saline waters that cannot be used for drinking or irrigation. The reservoir must also be able to sustain the increased pressure of the injected water without leaking into another freshwater reservoir.

If there is no disposal well, the brine is stored in an open fiberglass or metal tank to evaporate and reduce the volume. When the tank is eventually filled, a service company (a *water hauler*) is used to transport the brine to a commercial saltwater disposal well.

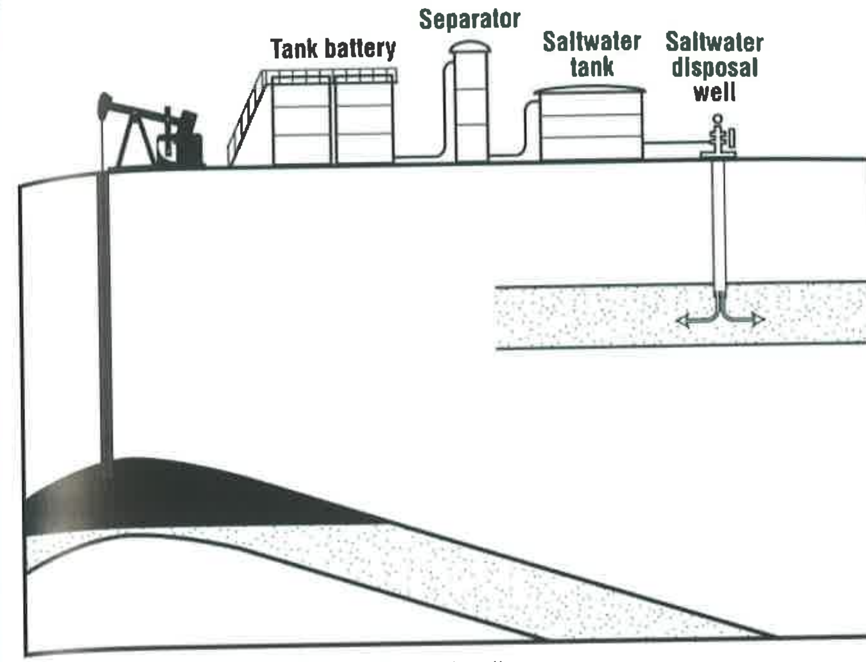


Fig. 24–10. A saltwater tank and disposal well

Surface Subsidence

During production, reservoir pressure decreases, and water usually flows in from the sides and bottom to replace the produced fluids. If water does not replace the produced fluids, the subsurface reservoir rock can compact and the surface of the ground subsides (fig. 24–11). This has happened in the Wilmington oil field in Long Beach, California, which has been producing since the 1930s. Beginning in the 1940s, surface subsidence in the shape of a bowl was noted. The center of the bowl has now subsided a total of 29 ft (8.8 m) leaving much of the city below sea level. A massive water injection program has stopped the subsidence, and the city is now protected from seawater flooding by a dike.

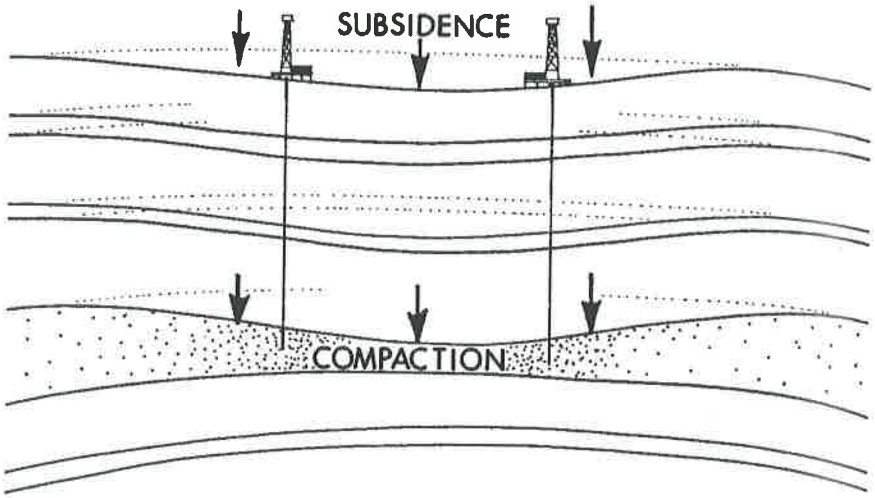


Fig. 24–11. Surface subsidence due to production

The bottom of the North Sea above the Ekofisk oil field has subsided several tens of feet because of compaction of the Ekofisk Chalk reservoir. The subsidence was first noticed in 1984 after the casing in several wells had collapsed, and the level of the boat dock on the platform became submerged. The elevation of the Ekofisk production platform had dropped to a dangerous level. In 1987, the legs of the platform were cut, the deck jacked up, and extensions spliced into the legs.

Corrosion

Corrosion is the chemical degradation of metal. It can be a problem during both drilling and production. Corrosion occurs when metal is exposed to air, moisture, or seawater, or by chemicals such as oxygen, carbon dioxide (*sweet corrosion*), or hydrogen sulfide (*sour corrosion*) in the produced fluids. *Total acid number* is a measure of the acidity and corrosiveness of a crude oil. It is a number expressed in mg KOH/g. Higher numbers are more corrosive.

Exposed metal surfaces on equipment are painted for protection. *Inhibitors* are chemicals that are injected to coat steel in the well and the production facilities with a thin film. The inhibitor can be injected either automatically or manually in periodic batches into the casing-tubing annulus of the well. A concrete coating can be used to protect the insides of flowlines. The tubing in injection and disposal wells is often lined with plastic. Large metal structures such as pipelines and offshore production

structures can be shielded by *cathodic protection*. It involves charging the structure with an electrical charge to prevent corrosion.

Production Maps

A *well status map* is used to analyze production from a field and identify problem wells. The map shows the location of all wells in a field. Producing wells have the well number, barrels of oil and water production per day, and the gas/oil ratio next to them. Injection wells have the well number, barrels of water injected per day, pressure, and cumulative injection in thousands of barrels. A *cumulative production map* lists the total amount of water, gas, and oil that each well has produced up to a specific date. *Bubble maps* are used to show how much each well has produced (fig. 24–12). A circle is drawn around each well with the radius of the circle (*bubble*) proportional to either the well's cumulative production (CUM) or its initial production (IP) of gas, oil, or water.

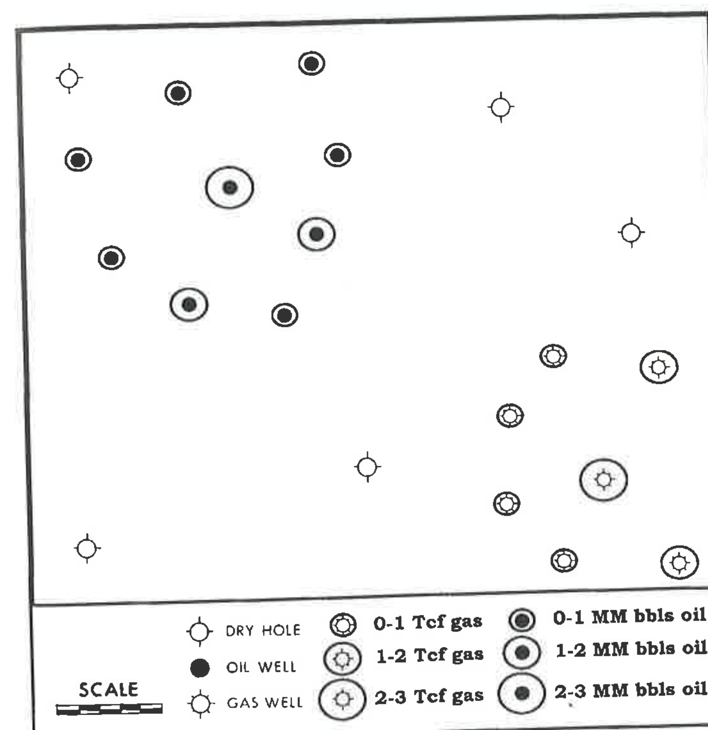


Fig. 24–12. Bubble map

Stranded Gas

Stranded gas is natural gas that has no market. Large reservoirs of stranded gas occur in western Siberia, northwestern Canada, Alaska, and the Middle East. Natural gas can be converted into a liquid to decrease its volume and transport it to a market either as liquefied natural gas or synthetic crude oil. When methane is compressed and cooled to −269°F (−167°C), it becomes a liquid called *liquefied natural gas* (*LNG*). LNG occupies 1⁄645 the volume of natural gas. Special tankers can then be used to transport the LNG across the sea to markets. The largest conventional gas field in the world is shared by the countries of Qatar (North Dome field) and Iran (South Pars field) (fig. 24–13). It will produce 1,200 trillion ft^3 (36 trillion m^3) of natural gas. It also contains 19 billion bbl (3 billion m^3) of recoverable condensate. The trap is a broad anticline, the reservoir rock is the Khuff Formation with dolomite and limestone, the seal is overlying salt, and the source rock is a Silurian age black shale. The reservoir rock in the South Pars field averages 9% porosity and 26 md permeability. Qatar has extensive LNG facilities and is the world's largest LNG exporter.

Gas-to-liquid involves mixing natural gas and air in a reactor to form *synthesis gas* (CO and H). The synthesis gas is then put in another reactor to form synthetic crude oil. Qatar also has the world's largest gas-to-liquid facility.

Fig. 24–13. Map of North Dome (Qatar) and South Pars (Iran) gas fields

CHAPTER 15

Enhanced Oil Recovery (EOR)

Historically, water flooding and gas injection have been referred to as secondary recovery techniques and other, more exotic, techniques have been referred to as tertiary techniques. Today, the term *enhanced oil recovery (EOR)* includes both secondary and tertiary recovery techniques.

The worldwide average recovery efficiency for primary oil is on the order of 33 percent. This means that, after primary recovery, two thirds of the oil is left in the ground, principally as residual oil in water wet reservoirs. Attempts to recover this oil include:

- Secondary recovery techniques
  - —Water flooding
  - —Gas injection
- Tertiary recovery techniques
  - —Chemical flooding processes:
    - Polymer flooding
    - Surfactant-polymer flooding
    - Caustic flooding
  - —Thermal recovery processes:
    - Steam flooding
    - Cyclic injection (huff and puff)
    - Steam drive
    - In-situ combustion

Hot water
Electromagnetic (microwaves)
—Miscible recovery processes:
Miscible hydrocarbon displacement
Carbon dioxide injection
Inert gas injection (nitrogen or flue gas)
—Microbial EOR

15.1 Some EOR Principles

The amount of oil that is recovered by water flooding and by other EOR injection techniques is a function of the following:

1. The amount of oil in place
2. *Volumetric sweep efficiency*—the percentage of oil that is contacted by the flood, which is a function of:
   (a) *Areal sweep efficiency* and
   (b) *Vertical sweep efficiency*
3. *Displacement efficiency*—the percentage of contacted oil that is moved or displaced.

15.1.1 Sweep efficiency

In making estimates of volumetric sweep efficiencies for reservoir simulations, geology must be considered. The geologist, through knowledge of facies patterns, must attempt to help the engineer to define flow units within the reservoir. Flow units (defined later this chapter) are three-dimensional rock bodies in which fluids are likely to behave similarly. They are not necessarily defined by facies, but are areas of high and low permeability that are likely to behave similarly under given flow conditions.

15.1.2 Mobility ratio

One of the most important factors in determining sweep efficiency is the mobility ratio between the two fluids. If the injected fluid is more mobile than the oil, the injected fluid is very likely to finger ahead through zones of high permeability and bypass much of the oil. *Fluid mobility* is a function of relative permeability for that fluid and the reciprocal of its viscosity. The mobility ratio is the ratio between the injected fluid divided by the displaced phase. If the ratio is less than 1, the injected fluid should not bypass the displaced fluid. For untreated water the mobility ratio between normal oil and water is greater than 1, and water has a strong tendency to bypass oil.

15.1.3 Displacement efficiencies

Methods that significantly help move oil through rock are:

1. Increase the mobility of the oil relative to the water by:
   (a) Increasing the viscosity of the water. This is the principle behind polymer flooding. Polymers added to water increase the viscosity of the water, and thus, they lower the mobility of the water.
   (b) Decreasing the viscosity of the oil. This is part of the principle behind steam flooding and in-situ combustion. Viscosity of oil decreases significantly as it is heated.
2. Help the oil move through the pore throats. This can be helped by:
   (a) Changing the interfacial tension at the pore throat
   (b) Changing the wetability characteristics of the rock
   (c) Changing the relative permeability of the fluids

Surfactants can play an important role in all three of the above, and when combined with polymers, they can make a very effective (though expensive) flood.

Another important means of getting oil through the pore throats is to dissolve the oil, in a more mobile solvent or dissolve a solvent in the oil, either of which makes the oil more mobile. Both *carbon dioxide floods* and *miscible hydrocarbon displacement* methods employ this principle.

15.2 Secondary Recovery Techniques

15.2.1 Water flooding

Water flooding is used on a routine basis throughout the world to maintain reservoir pressure and to push oil in front of a water front. Injected water is normally taken from the subsurface because surface waters or seawater commonly react with formation waters to cause undesirable precipitates or expansion of clay minerals. Whatever the origin of the water, its chemistry must be checked carefully against the chemistry of the formation fluids to make certain that the fluids are chemically compatible. It can be quite embarrassing to start injecting water only to find that the formation is now impermeable because of precipitates such as

$BaSO_4$ or other insoluble minerals caused by mixing of incompatible fluids. Such insoluble precipitates can virtually shut off permeability around injection wells.

Configuration of the reservoir, depth, and cost are important factors in determining which type of injection pattern to implement in a water flood. Typically, for thin, steeply dipping reservoirs (Fig. 15–1), an edge water drive is expected. Water injectors are placed near the original water level and producing wells are placed updip. As the oil-water contact moves updip and producing wells water out, the production wells are progressively converted to water injectors.

In such a configuration (Fig. 15–1), wells are expected to water out progressively from row 6 to row 5 to row 4, and row 3 if the sweep is good. Unfortunately, in poor and inhomogeneous reservoirs it is not uncommon for an updip well (such as in row 4) to water out first. This commonly happens when injected water fingers its way up through a zone of high permeability. This situation is undesirable because oil is commonly bypassed or left behind in isolated areas. In some cases, the geologist may be able to identify a facies pattern, such as a distributary channel within a delta front sand, where such fingering or channeling is likely to occur, and designs can sometimes be adjusted to accommodate for this occurrence. For thick reservoirs in relatively flat-lying rocks, where bottom water is present, or where no water is present, other configurations, such as those shown in Figure 15–2, are commonly used.

15.2.2 Gas injection

For gas reservoir associated with oil, it is of course undesirable (illegal in some cases) to blow down the gas cap before the oil is produced. Wells that produce from near the gas-oil contact commonly produce with a high gas-oil ratio (GOR) as gas is coned downward into the oil perforations. In order to maintain reservoir pressure, solution gas is commonly compressed and injected back into the gas cap. Alternatively, the compressed gas may be injected into the annulus, where it passes through gas lift mandrels into the tubing. This injected gas helps lighten the oil column in the tubing, which in turn helps lift the oil to the surface. Gas lift, like pumping, is a primary oil recovery technique.

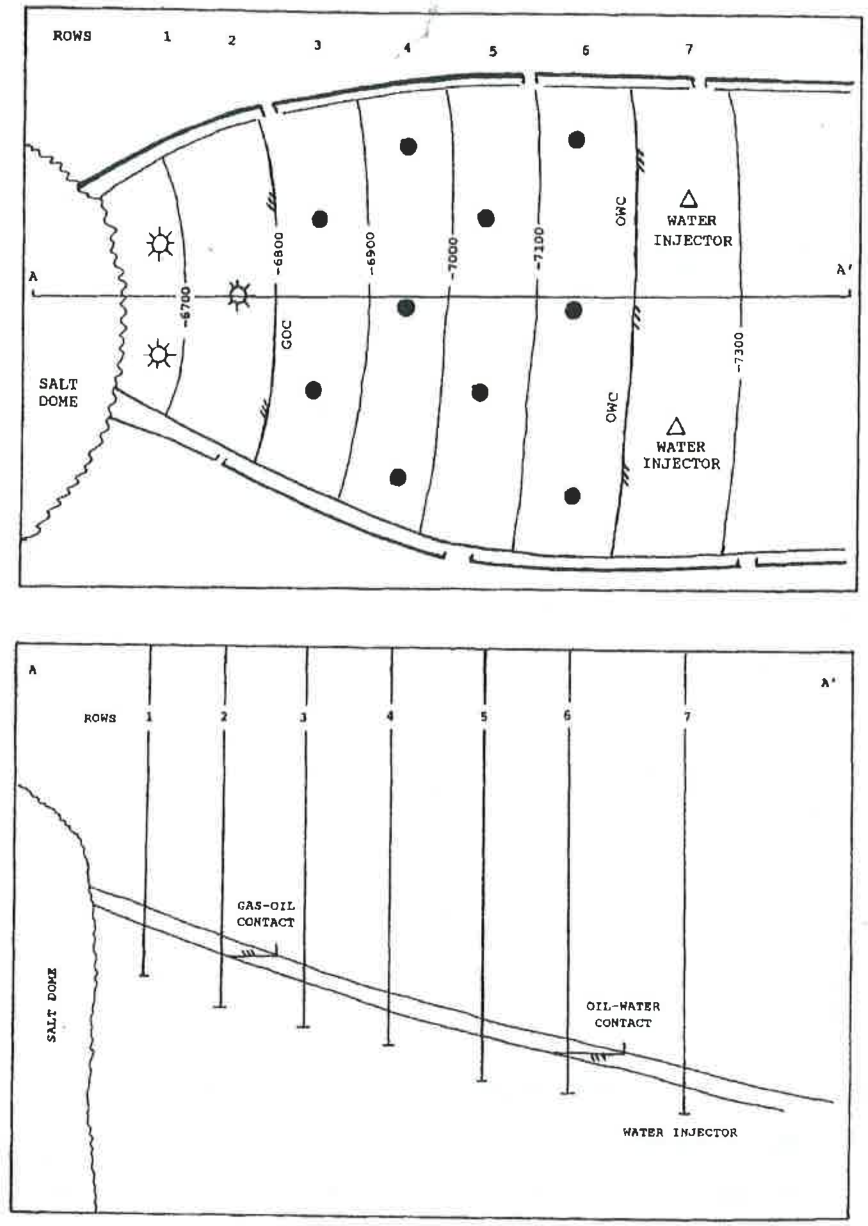


Figure 15.1
Map and cross section through highly dipping sediments showing edge water drive. Wells are expected to water out and be converted to water injectors successively from rows 6 to 5 to 4.

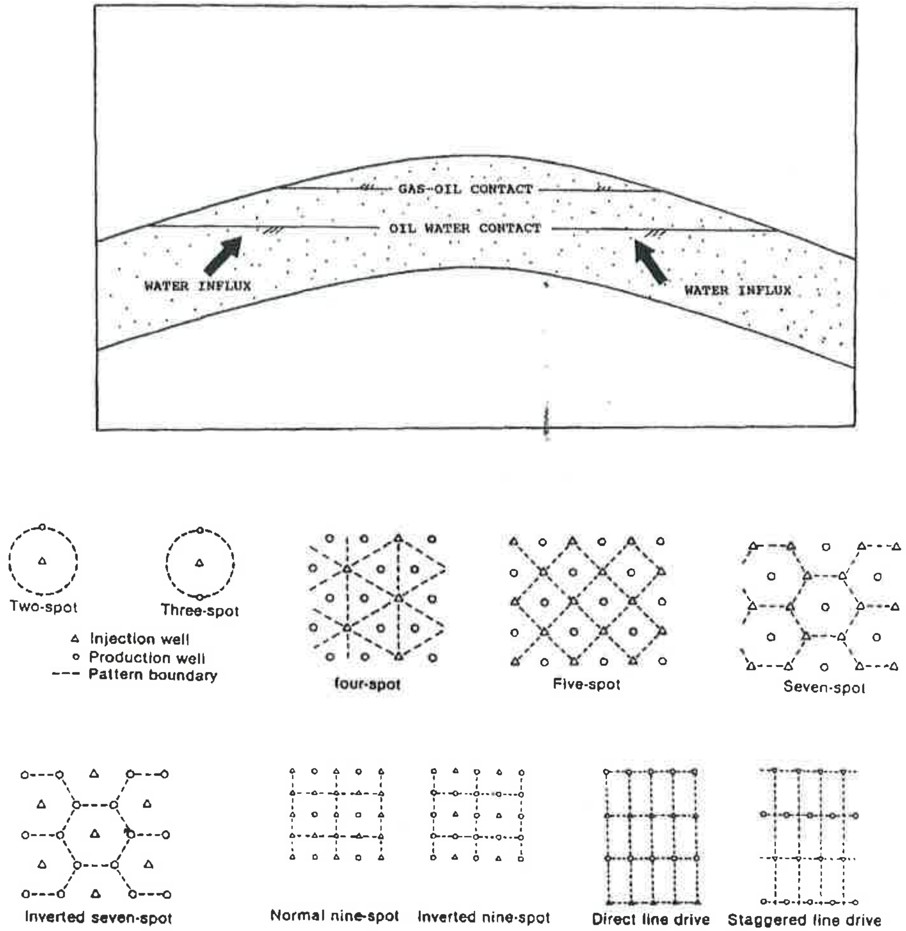


Figure 15.2
Cross section view of a bottom water drive reservoir and map view of typical well spot patterns for water flood injection design.

15.3 Tertiary Recovery Techniques

15.3.1 Chemical floods

Polymer flooding Polymers are commonly added to injection water to make the water more viscous, thus reducing the water's mobility. This tends to plug up the high-permeability zones which will normally improve sweep efficiency. Foam is another way to decrease the mobility of the displacing fluid and create a more uniform sweep efficiency.

Surfactants Oil and water are *immiscible,* meaning that they form emulsions in the subsurface that can be very difficult to break. Emulsions are caused by high surface tension between the two fluids. Surfactants such as soap or micelles are commonly added to polymer floods to break the emulsions and decrease interfacial tension between oil and water. *Caustic soda* is used to increase the pH of the reservoir, and, depending on the type of crude, react with the oil to create surfactants that help move the oil through the pore throats. Caustic flooding is normally applied to relatively acid crudes with high API gravity numbers.

15.3.2 Thermal recovery processes

Steam flooding consists of two principal types. In relatively small reservoirs or reservoirs that do not have good lateral permeability, a steam soak is commonly used. Steam is injected into the reservoir and allowed to soak into the formation for a period of time, commonly a week. The steam heats the oil and reduces its viscosity. The injection well is then produced for a period of time, also commonly a week. This procedure is referred to as a "huff and puff" process, as the well or wells are alternately used as injection wells and then as producing wells. In a conventional steam flood, steam is injected through injection wells and production occurs through production wells. Usually, this is a patterned flood such that the entire reservoir is swept. Surfactants are commonly added to help mobilize the oil. Steam floods are normally used at relatively shallow depths because, as pressure increases with depth, higher temperatures are required to keep water in vapor form.

In-situ combustion is a process whereby air or oxygen is injected into the formation where combustion of reservoir oil and gas can occur. The heat generated by the combustion creates a steam bank that drives the oil to producing wells.

Hot water injection is much like a water flood, except that the water is heated to reduce the viscosity of the oil.

Electromagnetic or heating by microwaves has been considered by a number of companies. Microwaves are very efficient at heating surfaces, but they do not penetrate more than a few centimeters past the surface. To date, no one has discovered a method to transmit the energy deep into the formation where it can do some real good in terms of mobilizing oil.

15.3.3 Miscible recovery processes

Miscible hydrocarbon displacement Oil and some natural gases, such as ethane, are *miscible,* meaning that the surface tension between the two phases is very low. Some natural gases tend to dissolve in oil, which can reduce the viscosity of the oil. Both of these processes can significantly help move relatively heavy and viscous oils through pore throats. Miscible floods tend to be quite expensive, but they can be attractive if the majority of the injected gas is ultimately recovered.

Carbon dioxide, nitrogen, and *flue gases* are the most commonly injected gases because they are cheap, they are often readily available as waste products, and they reduce the surface tension of the oil.

15.3.4 Microbial EOR

To date, no large-scale microbial projects have been attempted. There are two principal ideas behind microbial EOR. In the first method, microbes plus nutrients are injected into the formation. The microbes decompose the oil to produce detergents, CO_2, and new cells which either mechanically or chemically release oil from the reservoir pores.

In the second method, microbes and nutrients are injected into the reservoir, where they partially degrade the oil. Through this mechanism, the degraded oil and microbes block off areas of highest permeability such that further injection of other fluids causes the zones of lower permeability to be selectively flushed.

15.3.5 Comments on recovery

Finally, the injection of anything that increases a pressure gradient in the reservoir should help additional amounts of oil pop through the pore throats of the reservoir. Once oil is in discontinuous phase, it becomes very difficult to move. All of the above methods are enhanced by the injection of fluids in slugs such that the oil moves through the rock in zones of continuous phase oil.

15.4 Reservoir Modeling

When secondary and tertiary recovery techniques are being considered, reservoir engineers commonly develop computer programs that model each of the reservoirs. To work properly, such programs must consider all of the following:

1. Overall geometry of the reservoir:

   (a) External shape
   (b) Internal configuration of porosity and permeability:
      - Horizontal permeability
      - Vertical permeability
      - Distribution of low permeability zones
      - Distribution of fluid saturations
      - Internal configurations of flow units
      - Orientation and distribution of fractures
2. Location of injectors and producing wells
3. Pressure, volume, and temperature (PVT) data on the fluids to be produced
4. Type of recovery technique to be employed
5. Flow rates for injectors and producing wells

15.4.1 Reservoir characterization

Some reservoir modelers assume that the internal configuration of the reservoir is either isotropic and homogeneous, or so unpredictable that the geologist need not be consulted. The development geologist, based on correlation of well logs, petrographic data including porosity, and permeability data, plus regional data, almost always has some depositional and diagenetic models in mind for every reservoir. Rarely do those models assume an isotropic and homogeneous internal configuration. In order to model a reservoir properly the geologist and engineer must describe or characterize the reservoir in terms of all of the above characteristics. The geologist, in particular, must describe flow units.

15.4.2 Flow units

Flow units are reservoir units in the subsurface that are in hydrodynamic communication and have similar porosity and permeability characteristics. Commonly they are facies-dependent, but they need not be. For example, Figure 15–3 shows an example from the Pennsylvanian of the central U.S. where a prograding delta-front sandstone is overprinted by a meandering stream sequence. Although five general facies can be identified, only three flow units are important. From lower to upper, they are:

1. **Submarine delta front:** This facies is composed of either siltstone or thinly bedded alternating sandstone and mudstone. It is a transition zone between prodelta mudstone and delta front

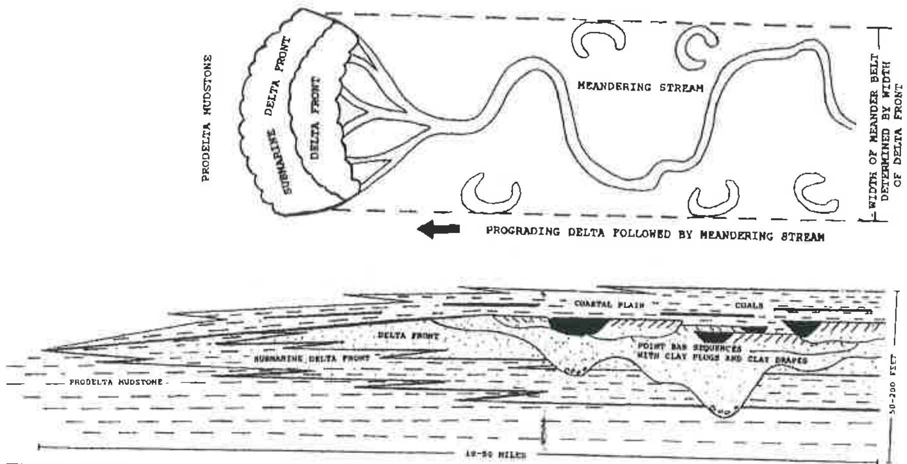


Figure 15.3
Map and cross section view of a typical Pennsylvanian river-dominated delta. The prograding delta front is overprinted by a meandering stream sequence. Flow units consist of lower, poor quality submarine delta-front siltstone or thin-bedded alternating sandstone and mudstone; high-quality delta-front sandstone and lower, point bar channel fill sequence; and upper point bar sequence which will have poor lateral continuity and highly partitioned reservoirs.

sandstone. It is composed of poor quality reservoir rock and will be very difficult to both produce and water flood.

2. **Delta-front sandstone and lower point bar sequence:** This is the best quality reservoir rock and, even though depositional environments are very different, their flow characteristics are similar for transmission of fluids.
3. **Upper point bar sequence:** Although oriented core samples of sandstone show high horizontal permeability, this area is likely to have clay plugs and clay drapes (see Chapter 12 for details) and have highly partitioned reservoirs. Horizontal permeability is likely to be highly restricted even though core data say otherwise.

15.4.3 Models

To model this reservoir as a homogeneous reservoir would certainly give incorrect results. The problem for the geologist is that, although it is known that the clay plugs and clay drapes are present, there is commonly no way of knowing exactly where they are.

A *deterministic* model is a model where the geologist is asked to make the best interpretation possible from the existing data. A deterministic model for the clay plugs may be possible if three-dimensional seismic imaging is available (Fig. 14–11), but more commonly the geologist knows that the permeability barriers are present in the reservoir, but has no way of knowing exactly where they are.

Newer *probabilistic* models (sometimes referred to as *stochastic* models) allow the geologist to assign statistical probabilities to the model. For example, in the point bar sequence example, the development geologist may be able to make the following probabilistic statements:

1. The lower part of the reservoir will have good horizontal permeability, and has an 80 percent chance of being in communication with a well located 1000 feet away.
2. A well drilled 1000 feet away has a 20 percent chance of being totally isolated from the first well by a clay plug that may cut down through the whole sequence.
3. The upper part of the reservoir, while having good horizontal permeability as determined from cores, is very likely to have extremely poor lateral continuity because of clay drapes. The upper part of the reservoir has a 90 percent chance that it will be shingled by impermeable clay drapes, and lateral continuity of the reservoir should not be expected to exceed 300 feet.
4. There is a 10 percent chance that the clay drapes have been destroyed by a chute cutoff. If this has happened, the upper part of the reservoir should have good lateral continuity.

These geologic models, coupled with the flow unit concept and reservoir simulation models, can create probabilistic (or statistical) models that are far superior to the older deterministic models. Not only are the models better, but they give full-range statistics that can be interpreted for errors.

The concept of reservoir characterization and definition of flow units within reservoirs are fundamental to all secondary recovery and EOR programs. Geologic input is one of the most important aspects of reservoir characterization, and if there is any place where the geologist, engineer, and statistician must work together, this is it.