# **Rocky Mt. Min. L. Inst. 6-1 2001**

***The Foundation for Natural Resources and Energy Law Annual and Special Institutes (formerly Rocky Mountain Mineral Law Foundation Annual and Special Institutes)*  > *Special Institutes* > *2001 March (Basic Oil & Gas Geology And Technology For Lawyers And Other Non-Technical Personnel)* > *Chapter 6 (PETROLEUM RESERVOIR ENGINEERING AND ENHANCED RECOVERY PROCESSES)***

**PETROLEUM RESERVOIR ENGINEERING AND ENHANCED RECOVERY PROCESSES**

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**6.01   Introduction**

The profession of Petroleum Engineering is currently divided into five main technical categories by the Society of Petroleum Engineers (SPE): Drilling and Completions, Production Engineering, Formation Evaluation, Reservoir Engineering and Related Technologies. Each of these groups has a large number of sub-specialties that cover virtually all areas of science and engineering that can be applied to the upstream petroleum industry. Petroleum engineers also have close links to many other disciplines. For a reservoir engineer, the most closely linked discipline is geology. It is almost impossible for someone involved in the technical aspects of reservoir engineering to effectively carry out his responsibilities without a good working knowledge of geologic fundamentals. Reservoir engineers are typically tasked with determining the following:

A. Original ***oil*** and gas in place,

B. Drive mechanism(s),

C. Recovery factor under natural depletion and enhanced recovery processes,

D. Time schedule for recovering the hydrocarbons,

E. Economic feasibility of a recovery project.

This paper will cover each of the technical tasks (A-D) as they pertain to different types of reservoirs. In addition, fundamental reservoir rock and fluid properties will be briefly described.

**6.02   Reservoir Rock and Fluid Properties**

In order to understand the various recovery processes and related calculations, it is necessary to be familiar with several of the variables that are found in reservoir engineering equations.

**Porosity (Phi)** is the pore volume (void space) in a rock that is available to store fluid divided by the bulk volume of the rock.

Porosity=Pore Volume / Bulk Volume

For example, if a piece of rock has a bulk volume of 2.5 cubic feet, and an internal pore volume of 0.5 cubic feet, the porosity is 0.2 or 20% (Phi=0.5/2.5=0.2). The higher the porosity, the greater the pore volume available to store ***oil*** and gas.

There are two types of porosity, total and effective. **Total Porosity** reflects the total pore space, while **Effective Porosity** only includes the interconnected pore space that allows for fluid flow from one pore to the next. As petroleum engineers, we are typically only concerned with fluid that can flow through the rock and be produced by a wellbore. Some formations have porosity that is isolated as small vugs and should not be included in calculations. It is important to make sure that any total porosities from certain well log and core sample measurements are modified before being reported or used in calculations. Otherwise, the **Original-*Oil*-In-Place (OOIP), Original-Gas-In-Place (OGIP)** and potential recovery will be overstated.

**Permeability (k)** is the measure of a rock's ability to transmit fluid. Pores in a rock areconnected through throats that restrict flow. The larger the throat opening, the less resistance to flow. The units are length squared (e.g., square feet, square meters, etc.). However, due to the small size of a pore throat, the standard units are millidarcies (md). For example, a small straw typically found in a cocktail would have a 50,000,000 md permeability. Tight gas sands found throughout the western United States can have permeabilities less than 0.1 md, and more permeable sands found in the California steamfloods may have over 2,000 md permeability. The higher the permeability, the easier the ***oil*** or gas in the reservoir can flow. Figure 1 has two limestone core samples from the same field. The core sample on the right has numerous small vugs and appears to have excellent flow properties. However, this vugular limestone has high total porosity that is not interconnected. The resulting permeability is low. The core sample on the left has smaller, but more uniform pore sizes. Most of the pores are in communication with one another, and the total and effective porosities are similar. The resulting permeability is higher than in the vugular sample, and this type of rock is the productive member of the field.



**Figure 1** - Limestone reservoir core samples

Reservoir engineering calculations typically include the thickness of the formation. If a formation is twenty feet thick, this is the gross thickness. **Gross Thickness (hg)** includes the full thickness from the top to the bottom of the interval. However, only the portion of the formation that contributes to flow should be used in calculations. Any shales or other non-productive intervals should be subtracted from the gross thickness to determine the **Net Thickness (hn)**. In the event that the entire formation thickness is productive, the gross and net thicknesses are equal.

**Formation Volume Factor (Bo, Bg, or Bw)** is the ratio of the volume of ***oil***, gas or water at reservoir conditions to the volume at surface conditions. In the reservoir, the fluid is at higher pressure and temperature as compared to surface conditions. As the fluid moves up the wellbore to the surface, pressure and temperature decrease, gas that is dissolved in ***oil*** and water under reservoir conditions begins to come out of solution and form a free gas phase, the liquid shrinks and the gas expands. As the reservoir pressure declines over time, the values of these formation volume factors change. An example value at original reservoir conditions for Bo is 1.3 reservoir barrels/stock tank barrel (rb/stb), and for Bg is 0.003 reservoir cubic feet/standard cubic foot (rcf/scf).

**Solution and Producing Gas/*Oil* Ratios (Rs and Rp)** are the ratios of gas to liquid ***oil***. The **Solution Gas/*Oil* Ratio** is the volume of gas dissolved in one barrel of ***oil***. As the pressure in a reservoir decreases, the solution gas/***oil*** ratio remains constant until the ***oil*** can no longer contain all the dissolved gas. At the point the first gas bubble forms out of the ***oil*** **(Bubble Point)**, the solution gas/***oil*** ratio begins to decrease. The **Producing Gas/*Oil* Ratio** is the volume of produced gas/barrel of stock tank ***oil***. Water also contains dissolved gas. However, since the amount of gas dissolved in water is so low compared to the gas dissolved in ***oil***, gas exsolution from water is usually ignored in reservoir engineering calculations.

**Viscosity (u)** of a fluid is the fluid's own internal resistance to flow. High viscosity fluids are "thick" and will not easily flow. An example is maple syrup. Low viscosity fluids are "thin" and flow easily. Water has low viscosity and gas has very low viscosity. Given a reservoir with fixed rock properties, high viscosity ***oil*** will produce much more slowly than low viscosity ***oil***.

***Oil*** reservoirs contain water, ***oil*** and the gas dissolved in the ***oil*** and water. In addition, some ***oil*** reservoirs have free gas sitting on top of the ***oil***. This gas is called a **Gas Cap**. Determining these **Gas, *Oil* and Water Saturations** is usually necessary before performing reservoir engineering calculations. The saturations are determined from well log analyses, core data and pressure/depth calculations. Figures 2 and 3 show an ***oil*** reservoir (green) with an underlying water aquifer (blue) and an overlying gas cap (red). At the interfaces between the ***oil*** and water and ***oil*** and gas, there are **Transition Zones** where both phases (***oil***/water or ***oil***/gas) are mobile. The transition zone can vary in thickness from inches to hundreds of feet, depending on the reservoir rock and fluid properties. In Figures 2 and 3, the transition zones are shown as light blue (***oil***/water transition) and yellow (gas/***oil*** transition).



**Figure 2** - Reservoir contour map with gas cap, ***oil*** zone and water aquifer



**Figure 3** - Reservoir cross-section map with gas cap, ***oil*** zone and water aquifer

When multiple saturations are present, each phase has its own effective permeability. However, the sum of these permeabilities does not add up to the single-phase effective permeability discussed above. Figure 4 shows a typical set of **Relative Permeability** curves. The curves are concave upwards since phases interfere with one another, resulting in lower effective permeability than expected.



**Figure 4** - Relative permeability curves

**6.03   Reservoir Drive Mechanisms**

Gas and ***oil*** reservoirs usually produce early in their life using their own drive energy. This energy is provided by fluid expansion as the pressure decreases or by natural water influx. The reservoir shown in Figures 2 and 3 will be modified in the following discussion to illustrate different types of reservoir behavior.

**[1]   Depletion Drive *Oil* Reservoirs**

**Depletion Drive *Oil* Reservoirs** are also called **Solution Gas Drive Reservoirs.** In this example, we have an ***oil*** reservoir at a pressure above its bubble point. This is called an **Undersaturated Reservoir**, in that all the free gas has moved into solution in the ***oil***, and the ***oil*** could actually hold more gas in solution if the gas were available. There is neither free gas nor a water aquifer in this reservoir. The well is opened at the surface and the reservoir begins to produce. The reservoir pressure begins to fall rapidly and the producing gas/***oil*** ratio is constant (Fig. 5). Above the bubble point, the only drive mechanism is the expansion of the ***oil*** and, to a lesser extent, water. Eventually, the reservoir reaches its bubble point, gas begins to come out of solution, and a free gas phase forms in the reservoir. The gas expands as the pressure continues to drop, and this expansion of highly compressible gas helps retard the pressure decrease. Unfortunately, since gas has such a low viscosity, it flows more easily than ***oil***. Therefore, the gas flow rate increases rapidly (high gas/***oil*** ratio (GOR)), and the drive energy available to help produce the ***oil*** is produced away. ***Oil*** rates then drop sharply even though a significant amount of ***oil*** remains in the reservoir. A solution gas drive reservoir typically produces between 5% and 30% of its OOIP before becoming uneconomical. In the early days of the U.S. ***oil*** industry and currently at many international locations, the absence of a gas distribution infrastructure resulted(s) in most of the produced solution gas being flared.



**Figure 5** - Typical solution gas drive ***oil*** reservoir performance

**[2]   Depletion Drive/Gas Cap Expansion Drive *Oil* Reservoirs**

In many cases, an ***oil*** reservoir has a gas cap on top of the ***oil*** zone (Fig. 6). In this case, the reservoir is at its bubble point. Any pressure decrease will cause the solution gas to immediately begin coming out of solution. If the gas cap is small, the reservoir will behave like the solution gas drive system described above. If the gas cap is large compared to the ***oil*** reservoir, the gas cap expansion will provide the drive energy. Since gas is highly compressible compared to liquid ***oil***, gas cap expansion can be a powerful drive mechanism. Gas cap expansion drive reservoirs may recover 20 % to 40% of the OOIP. The reservoir usually produces until the GOR becomes high due to coning gas into the few remaining ***oil*** wells. Regulatory bodies will typically prohibit the production of gas-cap gas until the ***oil*** has been produced. Figure 6 has a well in the ***oil*** reservoir and one in the gas cap. Figure 7 shows a comparison of the production behavior if only the ***oil*** well is produced (blue), and the detrimental effect on ***oil*** production of producing the gas cap simultaneously with the ***oil*** (green). The recoveries in this example are 21% OOIP and 87% OGIP if only the ***oil*** well is produced, and 11% OOIP and 92% OGIP if the gas cap is produced simultaneously with the ***oil*** (a 50% decrease in ***oil*** recovery).



**Figure 6** - Solution gas/gas cap drive reservoir



**Figure 7** - Production comparison - producing (green) vs not producing (blue) the gas cap

The decreased ***oil*** recovery when producing the gas cap is not just due to the loss of pressure. Figure 8 shows a cross-section for the second case where the ***oil*** has moved up into the original gas cap as the gas cap was produced (horizontal red line is the original gas/***oil*** contact). The bulk of this ***oil*** will never be recovered due to the ***oil*** creating an immobile ***oil*** saturation in the gas cap. The typical production scheme for these types of reservoirs is to produce the ***oil*** zone, recomplete the existing well higher in the reservoir or drill a new well, and then produce ("blow down") the gas cap.



**Figure 8** - ***Oil*** zone encroachment into gas cap

**[3]   Water Drive *Oil* Reservoirs**

In many cases, an ***oil*** reservoir has an associated water aquifer. There are two types of aquifers. **Bottom Water Aquifers** have the aquifer underneath the ***oil*** reservoir and **Edge Water Aquifers** (Figs. 2 and 3) have the aquifer on one or more sides of the ***oil*** reservoir. If the ratio of aquifer size to ***oil*** reservoir size is large, the expansion of the aquifer as the reservoir is produced provides the drive energy. Water moves out of the aquifer and into the ***oil*** zone. If properly balanced, ***oil*** can be withdrawn at the water influx rate. Water drive can be an efficient drive mechanism, as this influx helps maintain the reservoir pressure above the bubble point, and gas does not come out of solution and interfere with the ***oil*** production. A good water drive reservoir can produce between 35% and 75% of the OOIP. The reservoir usually produces until the **Water/*Oil* Ratio (WOR)** becomes so high that the cost of lifting the water outweighs the revenue from the ***oil***. Water drive reservoirs require more extensive facilities to handle, treat and dispose of this water.

**[4]   Depletion Drive Dry Gas Reservoirs**

**Depletion Drive Dry Gas Reservoirs** are gas reservoirs that produce solely by expansion of the gas. Gas as opposed to liquid is highly compressible. Once a well is drilled into a gas reservoir, the gas slowly expands as gas is produced. Recovery in a depletion drive gas reservoir can be over 90% of the original gas in place.

**[5]   Water Drive Dry Gas Reservoirs**

**Water Drive Dry Gas Reservoirs** have associated edge water aquifers, bottom water aquifers or a combination of the two. The water aquifer expands into the gas reservoir as the reservoir pressure is reduced. Figure 9 is an example of an edge water aquifer attached to the same gas reservoir described above. In contrast to water drive ***oil*** reservoirs, discovering that your gas reservoir has a strong aquifer attached is a disappointment. A depletion drive gas reservoir produces such a high percentage of its gas due to the low abandonment pressure of the gas. At low pressure, the gas has expanded many times over its initial volume and a small amount of low-pressure gas remains behind in the reservoir. In a water drive gas reservoir, the water influx keeps the pressure high and the gas compressed. Therefore, even though at abandonment the reservoir pore volume occupied by the gas is reduced, the surface equivalent of the remaining compressed reservoir gas is high.



**Figure 9** - Edge water drive gas reservoir

Figure 10 shows the production profiles of the depletion drive reservoir discussed above and the same reservoir with a strong water drive. The depletion drive has a 500 psia abandonment pressure and recovered 50 Bscf or 94% of the OGIP. The water drive has an 8600 psia abandonment pressure and recovered 29 Bscf or 54% of the OGIP. Once a reservoir engineer discovers that a gas reservoir has a water drive, the typical procedure is to produce the reservoir as fast as possible and attempt to "run away" from the water. While this procedure cannot be entirely successful, it is normally the best strategy. Usually, the worst option is to shut in a water drive gas field and allow the water to pressure up the reservoir. Assuming regulations and mineral interests allow, a company with both water drive and depletion drive reservoirs will normally prefer to use the water drive gas reservoirs as a "base load" into a pipeline and the depletion drive gas reservoirs as demand-based swing producers. The other disadvantage of a water drive gas reservoir is that the water must be lifted out of the well to avoid "loading up" the well with water and stopping the flow of gas. While ***oil*** reservoirs will have artificial lift equipment as part of the production equipment and produce for years after water breakthrough occurs, gas wells are many times abandoned shortly after water hits the producing well.



**Figure 10**-Production comparison-depletion vs water drive gas reservoirs

**6.04   Original Hydrocarbons-In-Place**

The methods available for predicting OOIP or OGIP, future performance and reserves change as more information about the reservoir becomes available. Figure 11 illustrates the various methods used in determining these values, the time period over which each technique has historically been used, and the relative risk in the estimates. Unfortunately, the need for accurate reserves estimates is at the beginning of a project when the least data is available.

**[1]   Analogy**

Prior to drilling the first well, engineers may attempt to estimate OOIP by applying a particular factor to the type of reservoir expected. For example, 20,000 bbls/acre. This estimate is based on fields in the area producing from the same formation.



**Figure 11**-Estimates of recovery over a field's life

**[2]   Volumetrics**

Volumetric estimations historically were carried out after one or more wells were drilled, but before significant production had occurred. Data from well logs, core samples and well tests are used to determine the net thickness, porosity, fluid properties, and radius out to a boundary. Currently, 3D seismic allows a combination volumetric/analogy calculation, since reservoir dimensions can be estimated. For the following examples, we will assume that the reservoir is 60 feet thick (net pay) with 30 feet of gas at the top, 30 feet of ***oil*** at the bottom, a 40 acre drainage area, 25% porosity, 22% water saturation, 1.35 ***oil*** formation volume factor, and 0.006 gas formation volume factor. The following equations are used to estimate the original ***oil*** and gas in place:

**OGIP**

G=43,560 A h Phi (1-Swi)/Bg

Where: G=Free gas (gas cap gas) (standard cubic feet - scf)

A=Reservoir area (acres)

H=Net thickness (feet)

Phi=Effective porosity (fraction)

Swi=Initial water saturation (fraction)

Bg=Gas formation volume factor (rcf/scf)

G=43560 (40) (30) (.25) (1-0.22)/0.006=1,698,840,000 scf

Gas is usually reported in a convenient multiple of 1,000. In this case, the OGIP is about 1.7 Bscf (billion standard cubic feet).

**OOIP**

N=7,758 A h Phi (1-Swi)/Bo

Where: N=Original ***oil*** in place (stb)

Bo=***Oil*** formation volume factor (rbbl/stb)

N=7758 (40) (30) (.25) (1-0.22)/1.35=1,344,720 stb

The ***oil*** also contains solution gas, the majority of which will come out of solution as the ***oil*** moves up the wellbore and through the facilities. To determine the amount of solution gas, multiply the OOIP by the initial solution gas/***oil*** ratio. Assuming the ***oil*** described above has an initial solution gas/***oil*** ratio of 850 scf/stb,

G=N×Rs=1,344,720 stb×850 scf/stb=1,143,012,000 scf or 1.143 Bscf

**[3]   Materials Balance**

One of the most common techniques for determining OOIP and OGIP is materials balance. Materials balance is based on the premise that as you withdraw a certain amount of ***oil*** or gas, the reservoir pressure decreases a fixed amount. By tracking the cumulative production and measuring the pressure, one can back calculate the original volume of the reservoir.

***Oil* Reservoirs**

Figure 12 illustrates this principle for an ***oil*** reservoir above the bubble point with neither a gas cap nor water influx.



**Figure 12** - ***Oil*** materials balance diagram

In this diagram, the materials balance is

Original ***Oil*** Volume=Remaining Reservoir ***Oil***+Compressibility Effects

N Boi=(N-Np)Bo+Compressibility Effects

Solving for OOIP,

N=(Np Bo)/(BoiCe (Pi-P))

Where: Np=Cumulative ***oil*** produced

Boi=Bo at initial conditions

Ce=Effective rock and fluid compressibility

Pi=Initial reservoir pressure (psia)

P=Pressure at time corresponding to Np

This is the simplest materials balance equation. For every other factor that was discussed in the drive mechanisms section above (e.g., gas cap, water influx, water production, etc.), there are other variables that must be included. In addition, operators must take care to accurately measure the reservoir rock and fluid properties, field production (including gas and water) and corresponding pressure. The most common difficulty in applying this technique is the lack of accurate data. Since the operator was not selling pressure, water, or in some cases gas, these parameters were many times only estimated, if recorded at all.

**Dry Gas Reservoirs**

Gas reservoir materials balance is similar to ***oil***, but involves fewer fluid properties variables. Since dry gas reservoirs with no water influx are produced by gas expansion, we need to know the cumulative gas produced and corresponding reservoir pressure, and gas compressibility factor (z-factor). The z-factor changes with pressure like the compressibility factor and is calculated from the gas composition. The equation is

P/z=Pi/Zi - (Pi/Zi)(Gp/G)

Typically, reservoir engineers graph this equation as a straight line by plotting the cumulative gas production (Gp) on the x-axis and the corresponding P/z on the y-axis. After enough time has passed to measure and plot several points, a best-fit line can be extrapolated to the x-axis and the OGIP determined (Fig. 13). In this case, OGIP is 48 Bscf. Water influx and over-pressured reservoirs complicate the calculation.



**Figure 13** - Gas materials balance plot

**6.05   Predicting Future Performance**

There are several techniques used to predict future performance and determine reserves. The three covered here are recovery factor, decline curves and reservoir simulation.

**[1]   Recovery Factor**

The **Recovery Factor** is the percentage or fraction of the original hydrocarbon in place that will be recovered. Several researchers and agencies have analyzed large numbers of ***oil*** and gas fields and attempted to generate equations for calculating recovery (bbls/ac-ft) or recovery factor that fit these reservoirs as well as possible[[1]](#footnote-2)1- Except for abandonment pressure, the variables in these equations can all be determined (at least locally) once data from the first well is available. Alternatively, these parameters can be estimated before drilling the well and an initial recovery estimate made. The abandonment pressure can be estimated based on experience in the area.

**[2]   Decline Curve Analysis**

Decline curve analysis is one of the most common techniques for forecasting future performance. The technique assumes that the physical processes in the reservoir and operating procedures of the operator will be the same in the future as they were in the past. If this is true, the producing ***oil*** rate can be plotted on graph paper and a curve then fit through the points (Fig. 14). To predict the future flow rates, the curve is extended out into the future and stopped at the expected abandonment rate. All wells in the field can be "rolled up" into a field total. The decline curve plots are routinely updated and analyzed for changes. The **Estimated Ultimate Recovery (EUR)** minus the current cumulative production is the well's or field's remaining reserves.



**Figure 14** - ***Oil*** well decline curve

Recovery from a gas well or field can be determined from the plot shown in Figure 13. By estimating the abandonment pressure of the gas field, a line can be drawn from the corresponding Pa/za across to the extrapolated forecast. Where these two lines intersect is the EUR of the well/field. Again, the EUR minus the current cumulative production is the well's or field's remaining reserves.

**[3]   Reservoir Simulation**

One of the most powerful tools for estimating future production and making reservoir development plans is reservoir simulation. With reservoir simulation, one can build the best possible model of the reservoir, populate the model with the same reservoir properties needed for the other recovery estimate techniques, match the past production and forecast the future performance. The color figures depicting reservoir performance and saturation changes in this paper were generated, with slight modifications, from simulation models of actual fields. Unlike other methods, simulation allows one to change the number of wells and operating conditions, and estimate the effect on reservoir performance. The field can be "produced" under several different scenarios to determine the best option. The ability to generate 2D and 3D representations of the reservoir, along with fluid saturation and pressure changes over time, also allows geologists, engineers, attorneys, judges, regulators and other interested parties to better visualize reservoirs and make informed decisions.

Currently, a reservoir characterization and simulation system is available that is inexpensive, runs on a PC and operates in the same style as most other Windows programs. As a result, reservoir models can be routinely built and used by typical reservoir engineers to determine the proper number of wells, optimum well spacing and appropriate drainage patterns.

**6.06   Improved Recovery Processes**

Recovery processes are typically classified into primary, secondary and enhanced ***oil*** recovery. Primary and secondary are chronological, and enhanced alludes to a process. These categories resulted from the historical procedure for developing most ***oil*** reservoirs. Typically, the natural drive energy is used as the primary recovery mechanism, waterflooding or immiscible gas injection are the secondary processes, and more sophisticated enhanced recovery techniques follow. Strictly speaking, however, these categories do not make sense. The steamfloods near Bakersfield, California are initiated at discovery, as the ***oil*** is too viscous to produce under its own drive energy. Therefore, the primary production comes from an EOR process. Currently, most reservoir engineers use the following definitions[[2]](#footnote-3)2- **Primary Recovery** is based on the reservoir's natural drive energy (e.g., solution gas drive, solution gas/gas cap expansion drive, natural water influx, fluid and rock expansion and gravity drainage). **Secondary Recovery** is typically the injection of gas or water to provide drive energy or prevent pressure declines in the reservoir. In this case, the gas injection is immiscible. No chemical reactions take place between the injected gas and the reservoir fluids. **Enhanced *Oil* Recovery (EOR)** includes techniques that use gases, liquid chemicals, or thermal processes to recover ***oil***. In this case, the gas injection is for a purpose other than just drive energy or pressure maintenance. The term **Improved *Oil* Recovery (IOR)** is usedfor any process that improves on the natural recovery processes and includes secondary and EOR. The target for IOR processes is high. Far more ***oil*** is left in the reservoir as a **Residual *Oil* Saturation** after primary production is complete than has been produced. The following sections discuss several of the more common IOR processes. In each of these processes, the goal is to reduce the residual ***oil*** saturation as low as possible.

**[1]   Secondary Recovery**

As discussed in Section 6.03 [1] and shown in Figure 5, depletion drive ***oil*** reservoirs have rapidly decreasing reservoir pressure, rapidly increasing gas saturation, and steeply declining ***oil*** production rates. The drive energy is depleted quickly, leaving a large fraction of the OOIP as unrecoverable. IOR techniques such as waterflooding and immiscible gas injection are used to maintain reservoir pressure and/or drive the ***oil*** to the producing well.

**[a]   Waterflooding**

Waterflooding is the most common IOR process. As stated in Section 6.03 [3], recovery from a good natural water drive reservoir can be between 35% and 75% of the OOIP. Since a solution gas drive reservoir produces between 5% and 30% of its OOIP under primary production, a good man-made waterflood should be able to recover significant amounts of ***oil***. Figure 15 illustrates the waterflood techniques for **Pattern, Line Drive**, and **Peripheral Waterfloods.**[[3]](#footnote-4)3

**Figure 15** - Typical waterflood patterns

Water is injected into one or more injection wells and drives the ***oil*** toward the producing well(s). From a technical point of view, a reservoir should be waterflooded before the reservoir pressure declines to the bubble point. At pressures at or slightly above the bubble point, the water is displacing only liquid ***oil***. No free gas is present. If properly balanced, an operator can maintain this pressure and maximize recovery. In the United States, it is common to find reservoirs that have been produced far below the bubble point and have significant low-pressure solution gas dispersed throughout the reservoir. In these cases, the injected water first repressurizes the system and, hopefully, forces the free gas back into solution. Unfortunately, one must usually raise the reservoir pressure well above the original bubble point pressure to get any significant amount of the gas back into solution. This repressurization period causes the response at the producing well to be delayed and hurts the economics of the project. To avoid these problems, some overseas regulatory bodies will not allow a reservoir to drop below its bubble point, and require the operator to have the IOR process planned prior to allowing the first production from the field.

Displacement processes like waterflooding require more accurate geology and engineering than primary recovery operations. The most important factor is to assure that the reservoir between the injector and producer allows communication. If there is a discontinuity between the two wells, the injected water will have no effect on the reservoir attached to the producer. Another problem is the heterogeneous nature of rock formations. In many cases, the permeability and porosity in one area is significantly different than in another area and affects **Sweep Efficiency.** In the waterflood shown in Figure 16, the first and third layers have high permeability, and the second, fourth and fifth layers have low permeability. Note that the water is racing through the high permeability layers but moving slowly through the low permeability layers. As a result, this pattern will produce significant amounts of water from the high permeability layers while the low permeability layers are still full of ***oil***. If the water/***oil*** ratio becomes too high, the pattern will become uneconomic.



**Figure 16** - Effect of heterogeneous layers on vertical sweep efficiency

**[b]   Immiscible Gas Injection**

The immiscible gas injection process involves injecting gas into either the ***oil*** zone itself, or the gas gap. In immiscible gas floods, the three main factors influencing the reservoir performance are sweep efficiency, mobility ratio, and gravity effects. Sweep efficiency (as discussed above) relates to the heterogeneity of the reservoir. If the reservoir has widely varying rock properties, the gas will preferentially channel into the high permeability areas. **Mobility Ratio** is the ratio of the displacing fluid mobility (gas in this case) to the displaced fluid mobility (***oil*** in this case). If the ratio is one, the fluids are equally mobile. If the ratio is greater than one, the gas is more mobile, and if less than one, the ***oil*** is more mobile. Displacement processes are generally more efficient when the mobility ratio is less than one. In a gas displacement process, unfortunately, the mobility ratio is usually greater than one and the gas tends to "finger" through instead of efficiently displacing ***oil***. **Gravity Effects** or **Gravity Segregation** refers to the fact that the gas is significantly less dense than the ***oil***, and the gas will tend to remain at or migrate to the top of the reservoir if possible. This fact is beneficial if gas is being injected into the updip gas cap, and detrimental if gas is injected into a horizontal reservoir. When gas is injected into the edge of a horizontal reservoir, instead of displacing the ***oil*** across a vertical front, the gas may rise to the top of the reservoir and bypass some of the ***oil*** bearing rock.

Another immiscible gas injection process deals with solution gas/gas cap drive reservoirs. If the gas cap cannot be produced without damaging the ***oil*** recovery potential, it is possible to inject nitrogen into the top of the gas cap and produce an equivalent volume of hydrocarbon gas out of a well lower in the gas cap. The force exerted by the gas cap remains constant and the hydrocarbon gas can be sold to cover the cost of the nitrogen plant plus profit. This technique works best when the reservoir has a thick gas cap and the sales price of the produced gas is high.

**[c]   Gas Cycling (Retrograde Condensate Reservoirs)**

For the dry gas reservoirs discussed in Section 6.03 [4], the gas is typically made up primarily of Methane. As a result, the gas stays as a gas phase in the reservoir as the pressure declines due to production. A **Retrograde Gas Condensate** or **Wet Gas Reservoir** is a gas reservoir that has a higher concentration of heavier gas components and different phase behavior characteristics. The term "wet" does not refer to water. As the reservoir pressure decreases due to production, the gas reaches its dew point. The **Dew Point** is the pressure at which liquid condensate ("***oil***") begins to drop out of the gas. The condensate builds up in the reservoir as the pressure drops further. Since the reservoir does not have an ***oil*** saturation originally, condensate becomes the residual ***oil*** saturation, is immobile, and will normally not be produced by the well. In addition, since the lowest pressure is around the producing well, the condensate forms a bank around the producing well and restricts gas flow rate. Figure 17 shows this type of condensate bank forming after 60 days of production. As the reservoir pressure drops further, the liquid region will expand.



**Figure 17** - Condensate banking

One way to avoid this problem is to maintain the reservoir pressure above the dew point. The typical pressure maintenance method is to produce the wet gas stream, separate the condensate and dry gas at the surface, reinject the dry gas and sell the condensate. If necessary, additional dry gas ("make up gas") can be purchased or diverted from other wells. As the injected dry gas mixes with the original wet gas, the phase behavior changes and the dew point decreases. As the gas continues to be recycled, the dew point decreases further. At some point, the gas will become a dry gas, the cycling effort can be stopped, and the reservoir pressure allowed to decline. Overseas, some regulatory bodies will not allow the pressure in a gas condensate reservoir to drop below the dew point pressure, as they consider the creation of an immobile condensate phase to be waste.

**[2]   Enhanced *Oil* Recovery**

Enhanced ***oil*** recovery is concerned with injecting fluids to supplement the drive energy and interact with the rock/***oil*** system to create conditions favorable for ***oil*** recovery2- The goals of the various processes are to lower the interfacial tension of the fluids, swell the ***oil***, reduce ***oil*** viscosity, modify wettability, or enhance the phase behavior. Again, the purpose of the techniques is to leave a lower residual ***oil*** saturation in the reservoir. Table 1 summarizes the techniques and recovery factors based on pilot projects and commercial operations[[4]](#footnote-5)4.

**Table 1**

**Enhanced *Oil* Recovery Processes**

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| Process | Recovery Mechanism | Issues | Typical Recovery (% OOIP) | Typical Agent Utilization |
| Immiscible | Reduces ***oil*** viscosity ***Oil*** swelling Solution gas | Stability Override Supply | 5-15 | 10 MCF solvent per bbl ***oil*** produced |
| Miscible | Same as immiscible plus development of miscible displacement | Same as immiscible | 5-10 | 10 MCF solvent per bbl ***oil*** produced |
| Polymer | Improved volumetric sweep by mobility reduction | Injectivity Stability High salinity | 5 | 0.3-0.5 bbl polymer per bbl ***oil*** produced |
| Micellar polymer | Same as polymer plus reduces capillary forces | Same as polymer plus chemical availability, retention, and high salinity | 15 | 15-25 lb surfactant per bbl ***oil*** produced |
| Alkaline polymer | Same as micellar polymer plus ***oil*** solubilization and wettability alteration | Same as micellar polymer plus ***oil*** composition | 5 | 35-45 lb chemical per bbl ***oil*** produced |
| Steam (drive and stimulation) | Reduces ***oil*** viscosityVaporization of light ends | Depth Heat lossesOverride Pollution | 50-65 | 0.5 bbl ***oil*** consumed per bbl ***oil*** produced |
| In situ combustion | Same as steam plus cracking | Same as steam plus control of combustion | 10-15 | 10 MCF air per bbl ***oil*** produced |

**[a]   Miscible Gas Injection**

**Miscibility** is the ability of two or more fluids to form a single homogeneous phase when mixed in all proportions. Gases used in miscible displacement projects are liquefiable petroleum gas (LPG), carbon dioxide (CO2), flue gas and nitrogen. In an immiscible displacement such as a waterflood, much of the ***oil*** is left behind as a residual ***oil*** saturation. At the microscopic pore level, the displacement is not 100% efficient and ***oil*** globules are dispersed throughout the reservoir. If the displacing fluid can be made miscible with the displaced fluid, these pore-level problems can be eliminated. The efficiency of the process then is based primarily on the fraction of the reservoir that can be contacted with the displacing fluid.

Figure 18 is a schematic of an LPG miscible flood. LPG is injected at pressures that cause the LPG to be a liquid. The LPG mixes with the reservoir ***oil*** and creates a new fluid that is completely miscible with both the original ***oil*** and the pure LPG slug. As the LPG slug drives the miscible bank through the reservoir, the residual ***oil*** saturation is reduced and recovery increases. Unfortunately, LPG is a hydrocarbon that has to be purchased to use in the EOR process. Therefore, a lean gas slug is typically used to drive the LPG slug. The interface between the lean gas and LPG can also form a miscible zone and help increase sweep efficiency by lowering the mobility ratio.



**Figure 18** - LPG miscible gas flood process

In an effort to decouple the cost of the injected gas from the revenues from the produced ***oil***, CO2 is used in miscible displacement projects. Numerous CO2 projects have been carried out in the western United States and West Texas due to the availability of CO2. CO2 is injected and becomes miscible with the ***oil***. Additional CO2 drives the miscible bank and ***oil*** zone toward the producing well. In order to lower the required volume (cost) of CO2 spread the CO2 cost over time and improve the displacement efficiency (lower mobility ratio), the **Water-Alternating-Gas (WAG) process** is common. Figure 19 illustrates this process. CO2 is injected in sufficient quantity to form the miscible bank, water is injected behind the CO2 for mobility control, CO2 is injected again, and water again follows CO2. CO2 also swells the ***oil***. As a result, the residual "***oil***" saturation left behind is a swollen CO2/***oil*** mix. The actual residual ***oil*** that cannot be produced is greatly reduced.



**Figure 19**-CO2 miscible gas flood process

**[b]   Chemical Flooding**

Chemical Flooding includes the processes that provide mobility control and reduce the Interfacial Tension between ***oil*** and water. Figure 20 (top) illustrates the fingering effect of a water drive with a poor mobility ratio. The displacing fluid (water) is more mobile than this particular displaced fluid (***oil***), and the water rapidly fingers through to the producing well. As a result, much of the reservoir is not even contacted by the injected water. **Polymers** (polyacrylamides and polysaccharides) and **Foam** (gas bubbles dispersed in water) can be used to modify the mobility ratio. Different types of polymers can be added to the injection water to attempt to "thicken" the water. Both techniques can lower the water mobility. With a favorable mobility ratio, the waterflood will look more like Figure 20 (bottom). In this case, the flood front is more uniform and a larger percentage of the reservoir will be swept. Polymers and foams are also used as near-wellbore treatments to divert injected water from high transmissibility thief zones into lowertransmissibility unswept zones. Some of the factors that can harm polymer floods are high salinity water, polymer retention on the rock itself and chemical, biological and mechanical degradation.



**Figure 20**-Viscous fingering in a water flood with and without mobility control

**Low Interfacial Tension (IFT)** processes attempt to lower the forces of attraction between the ***oil*** and water and reduce or eliminate the capillary forces that hold the residual ***oil*** saturation in place. These types of floods are almost always performed after waterflooding has resulted in high producing water/***oil*** ratios and high residual ***oil*** saturations. The terms chemical flooding, surfactant, detergent and others all describe essentially the same process. The most common is the Micellar-Polymer (MP) flood illustrated in Figure 21. The preflush is usually a fresher water that reduces the water hardness and salinity into the necessary range for the surfactant to work properly. The surfactant is injected to lower the IFT and reduce the residual ***oil*** saturation, and then followed by a polymer/water solution for mobility control. Fresh water with a steadily decreasing polymer concentration displaces the polymer solution to avoid damaging the polymer with salt water and for mobility control. Finally, less expensive salt water displaces the fresh water.



**Figure 21**-Micellar-Polymer flood process

**High-pH** processes use much the same process as MP flooding, but the surfactant is generated in the reservoir instead of being injected. A high pH (caustic) water is injected into the ***oil*** zone. As the water contacts the ***oil***, the negative ions in the water attract the ***oil***'s acidic hydrocarbon components and generate a surfactant. ***Oils*** differ in their properties. If an ***oil*** does not have a enough acidic hydrocarbon component, the process will not generate enough surfactant.

**[c]   Thermal Recovery**

**Thermal Recovery** is defined as the processes that enhance the producablity of ***oil*** by the addition of heat. A classic analogy is maple syrup. If one takes maple syrup (the real stuff-not diet) out of the refrigerator and tries to pour it on pancakes, the syrup flows slowly (if at all). The properties of the syrup are such that the fluid itself resists flowing. If you heat the syrup, however, it can flow almost like water. The heat causes the viscosity of the syrup to decrease dramatically. The same physical process occurs in many ***oils*** that are too viscous at reservoir temperature to produce at an economic rate, but flow quite readily when heated. Thermal recovery techniques can be highly efficient. In the U.S. (1990), over 450,000 barrels of ***oil*** per day (over 70% of the EOR production) were from thermal recovery methods. The two categories of thermal recovery are In-situ Combustion and Steam Injection.

**In-Situ Combustion** involves injecting air down a wellbore into the reservoir and igniting the air/***oil*** interface. The fire burns the air and some of the reservoir ***oil***, and the resulting heat boils the reservoir water creating steam. The hot gases and steam mix as they move through the reservoir driving heated ***oil*** toward the producer. There are three types of in-situ combustion processes; dry forward combustion, wet forward combustion, and dry reverse combustion. In **Dry Forward Combustion** (Fig. 22), the air is injected and the fire started at the injection well, much like in smoking a cigarette. Air moves into the far end, the fire generates smoke, and the hotsmoke moves through the cigarette toward your mouth. The disadvantage of this method is that the area around the producing well is cold and the ***oil*** highly viscous. Initial ***oil*** flow rates are, therefore, low.



**Figure 22** - Dry forward in-situ combustion process

**Dry Reverse Combustion** is the opposite of Dry Forward Combustion. The air is still injected in an injection well, but the fire is ignited at the producer. This way, the area around the producer is heated rapidly and ***oil*** flows more easily. The analogy of a cigarette still holds; however, in this case, you would blow through the cigarette. The end still burns, but the direction of air flow is reversed. **Wet Forward Combustion** is similar to Dry Forward Combustion, but water is periodically injected to pick up heat in the burned zone and move it through the reservoir. In-situ combustion accounts for only a few percent of the production from thermal recovery projects in the U.S.

**Steam Injection** is the most common of the two thermal categories and is broken into two sub-categories; Cyclic Steam Stimulation and Steam Displacement. **Cyclic Steam Stimulation ("Huff and Puff")** is a single-well process and is illustrated in Figure 32. Steam is injected into the well ("Huff") in order to heat the ***oil*** surrounding the well bore. The steam does not actually drive the ***oil*** away, but appears to finger through the ***oil***. The well is shut in to allow for heat transfer to the ***oil***. The well is then put on production ("Puff"), and the hotter, lower viscosity ***oil*** flows toward the wellbore. ***Oil*** rates ten times the un-stimulated rate can occur. Once the ***oil*** flow rate has decreased to an unacceptable level, the well is steam stimulated again.



**Figure 23** - Cyclic steam stimulation process

**Steam Drive or Steamflooding** is a multi-well process and is illustrated in Figure 24. Steam is injected into the reservoir, condenses and starts a hot-water flood. As more steam is injected and the temperature continues to increase, steam eventually makes its way to the producers, and ***oil***, hot water and a steam/condensate vapor mixture are produced.



**Figure 24** - Steam drive (steamflood) process

Since steam is much lighter than the ***oil***, the steam rises as high in the reservoir as possible and forms a "steam chest" (Fig. 25). At the interface between the ***oil*** and steam, the ***oil*** is significantly heated and flows toward the producers. Deeper and further away from the interface, the ***oil*** becomes warm, but not hot. As a result, the cooler ***oil*** does not flow as rapidly. Over time, the steam/***oil*** interface moves downward and most of the ***oil*** is produced.



**Figure 25** - Steam chest formation

Steamflooding is a very efficient process for ***oil*** recovery. In the ***Kern*** River Field of California, Getty (currently Texaco and soon to be Chevron) estimated that almost 70% of the OOIP would be produced by steamflooding. Heat cases the ***oil*** viscosity to drop from 2200cp down to 2.6cp, a factor of 1000. In order to enhance the ability of the injection well to take steam and the producing well to produce, most fields preparing for a steamflood undergo one or more cycles of Cyclic Steam Stimulation to preheat and clean out the formation surrounding the wells.

Two issues that have affected thermal projects are fuel costs and pollution. Historically, between one third and one half of a project's ***oil*** production was burned to generate the steam. This fact caused project economics to be poor in many cases. In addition, burning crude ***oil*** generates air pollutants such as sulfur. In the mid 1980's, these problems were solved in ***Kern*** River through the use of gas-burning cogeneration plants and the availability of gas from Western Canada. Currently, gas is burned to generate electricity using gas turbines. The heat from the turbines' exhaust passes through a heat exchanger and generates steam. The steam is piped to the steamflood and the electricity is sold to Californians. The other source of pollution is the exhaust steam/condensate vapor from the production wells. In the past, this stream was vented to the atmosphere. Currently, the flow stream is piped to a collection center where the condensate is separated out and mixed with the heavy ***oil***. The high gravity condensate helps lower the ***oil*** viscosity and allows the ***oil*** to flow more easily to the refinery.

**6.07   Drainage Patterns**

Horizontal wells or hydraulic fractures can influence the shape of the area drained. Figure 26 shows a horizontal gas well in a low permeability (0.06 md) formation. The result is an elliptical drainage pattern. A vertical well with a man-made hydraulic fracture has a similar drainage shape. These patterns are well known, and a conscious attempt is sometimes made to set up rectangular spacing patterns for these types of completions.



**Figure 26** - Drainage anisotropy due to horizontal well

Reservoirs are routinely thought of as homogeneous and isotropic. **Homogeneous** means having uniform properties, and **Isotropic** means that certain reservoir properties are the same in both directions. If a reservoir's permeability is the same in both the "x" and "y" directions, the drainage pattern will be radial until either a natural boundary is encountered or the influence of a neighboring well is felt. Regulatory bodies routinely grant a standard, square drainage area to all wells in a field. However, certain types of formations have natural characteristics that make it unlikely that ***oil*** or gas will drain in a radial pattern.

Naturally-fractured reservoirs occur throughout the world. The effect of these fractures on permeability and drainage patterns varies from negligible to dramatic. As an example, Figure 27 shows the location of several sandstone outcrops in Wyoming and the fracture patterns that are visible[[5]](#footnote-6)5-



**Figure 27** - Natural fracture patterns

As part of a naturally fractured reservoirs research project, students mapped the fractures on these outcrops and applied a mathematical transform to attempt to determine permeability anisotropy. The permeability in the direction of the fractures was calculated to be 100 to 560 times the permeability perpendicular to the fractures, depending on the formation. Figure 28 illustrates the influence of a 300-to-1 permeability anisotropy for a producing vertical gas well in a square 640 acre pattern. Note the elliptical (actually rectangular) drainage shape that develops after only one month of production. Portions of the offsetting units are being drained by this well, while much of this well's unit is not being effectively drained.



**Figure 28** - Drainage anisotropy due to natural fractures

These cases demonstrate the effect permeability anisotropy, hydraulic fractures and horizontal wells can have on drainage shape. Engineers and geoscientists should attempt to account for these effects when setting up well locations. Figure 29 (left) illustrates the worst possible choice of well locations. In this case, the wells are placed along the direction of maximum permeability. The elliptical ends overlap and the wells interfere with one another. In addition, significant gas remains undrained between the rows. If these wells have different operators or mineral interest owners, regulatory and legal problems can develop. Figure 29 (right) illustrates the effect of even a slight shift in the development plan. In an optimum development, no well unduly interferes with another, and the reservoir is adequately drained. What is required in these cases is applying technology to determine fracture orientation or other permeability anisotropy, and laying out patterns to take advantage of the natural drainage shapes that will result.



**Figure 29** - Effect of well locations on reservoir drainage

**6.08   Summary**

This paper describes the fundamental concerns of a reservoir engineer and certain concepts that may be useful to those persons that deal with ***oil*** and gas matters. Thorough coverage of these topics normally requires several full-semester courses in a petroleum engineering curriculum. In the event more details are desired on a particular topic, the Petroleum Engineering Handbook published by the Society of Petroleum Engineers is the best available general reference on the full suite of petroleum engineering topics.

**6.09   References and Acknowledgments**

Much of the information presented here is adapted from the author's reservoir engineering course notes and the Petroleum Engineering Handbook. The figures depicting the various EOR processes were originally developed by the U.S. Department of Energy and have been modified and reproduced in numerous texts and short courses. The references cited explicitly in this paper are:

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