Practical Fundamentals Of Water Injection For Increasing Oil Production

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Abstract

This paper is directed toward field operating personnel for the purpose of acquainting them with the objectives, the methods employed and the operating problems encountered in the injection of water to increase oil production. Included herein are brief discussions of the history of water flooding, why water flooding is helpful in increasing oil production, requirements of a good water flood, importance of well test information, problems encountered in water flooding, types of water handling facilities, typical production history of a water flood and the injection of water during the early years in the life of a field.

Introduction and Brief History

The injection of water into older fields where natural production has been exhausted is termed "water flooding." The injection of water into newer fields where large amounts of natural energy still exist is termed "pressure maintenance."

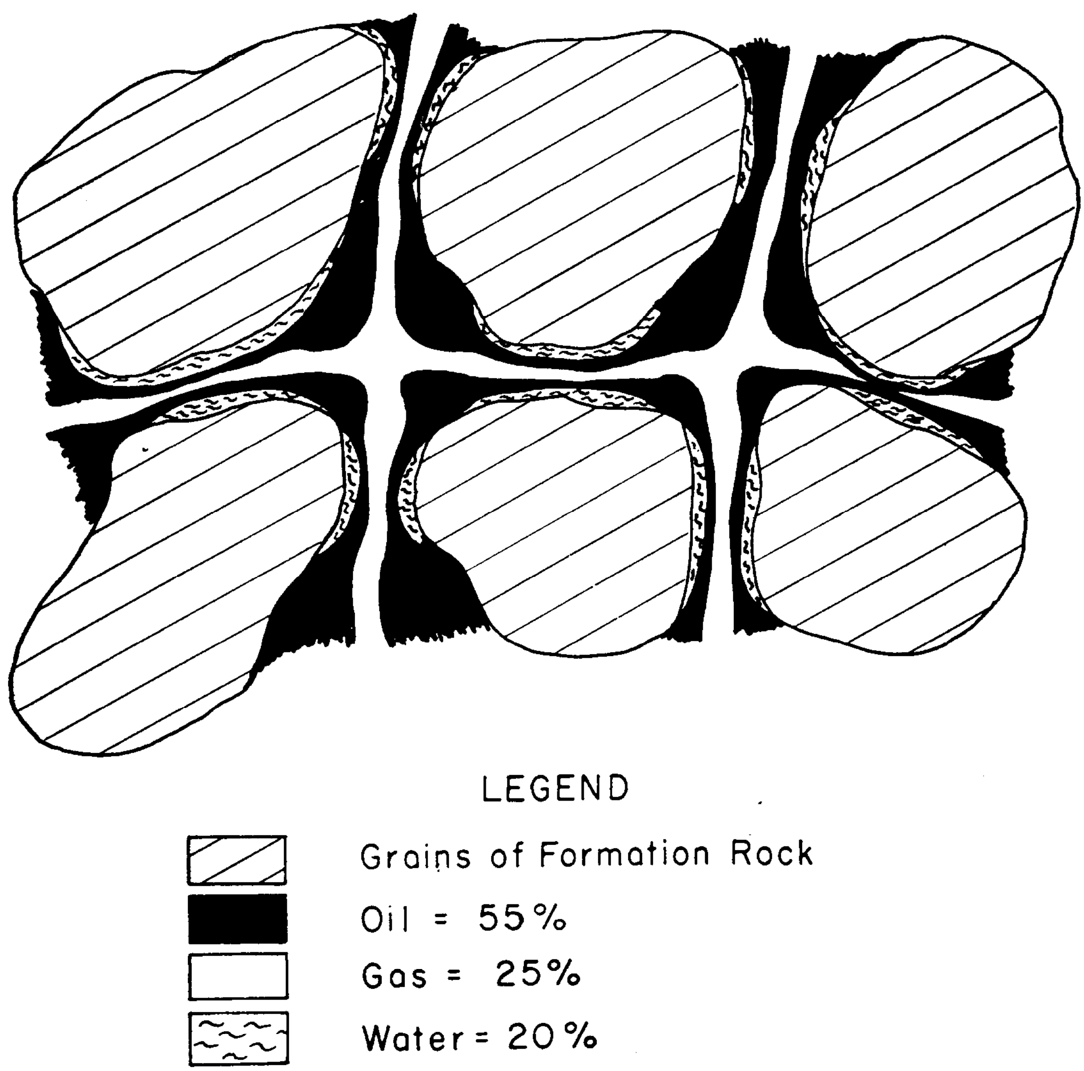
Water flooding got its start back in the early 1900's in the oil fields of Pennsylvania. As would be expected, since the earliest oil production was from the Pennsylvania fields, they were the first to exhaust their natural energy and require the application of "secondary" energy in the form of water injection. Still today, water flooding provides the major portion of oil production from the Pennsylvania fields and surrounding Appalachian area. As oil production moved into the Mid-continent areas, water flooding did so in the years following as the flush production from shallow sand fields of Oklahoma and Kansas dwindled. Likewise, as natural production declined from the shallow Yates and Queen sand fields in the Permian Basin area of West Texas, water flooding operations were undertaken and have resulted in fantastic increases in oil production from those fields. As new fields become harder and harder to find, "secondary" operations by water flooding will continue to play an ever increasingly important part in the production of oil.

Pressure maintenance operations by the injection of water during the early years in the life of a field are a comparatively recent development when compared to water flooding. Perhaps the most noteworthy of such projects are the operations in the reef fields of the Scurry County Area of West Texas. In these operations, covering an area of some 50,000 acres, the injection of water was undertaken when natural energy was partially expended and, in 1 1/2 years the energy in the fields has been increased substantially above that which existed at the start of the operation, despite the fact that several million barrels of oil were produced during that period.

Discussion:
Why Is Water Flooding Helpful In Increasing Oil Production?

In the majority of oil fields the natural energy originally present is only capable of producing from 15 to 30 percent of the oil originally contained in the fields before this energy becomes exhausted. Therefore, this means that when a field reaches the point where its wells are only capable of producing a barrel or two of

FIGURE 1—DISTRIBUTION OF OIL, GAS AND WATER IN A PRODUCING FORMATION AT NATURAL DEPLETION.

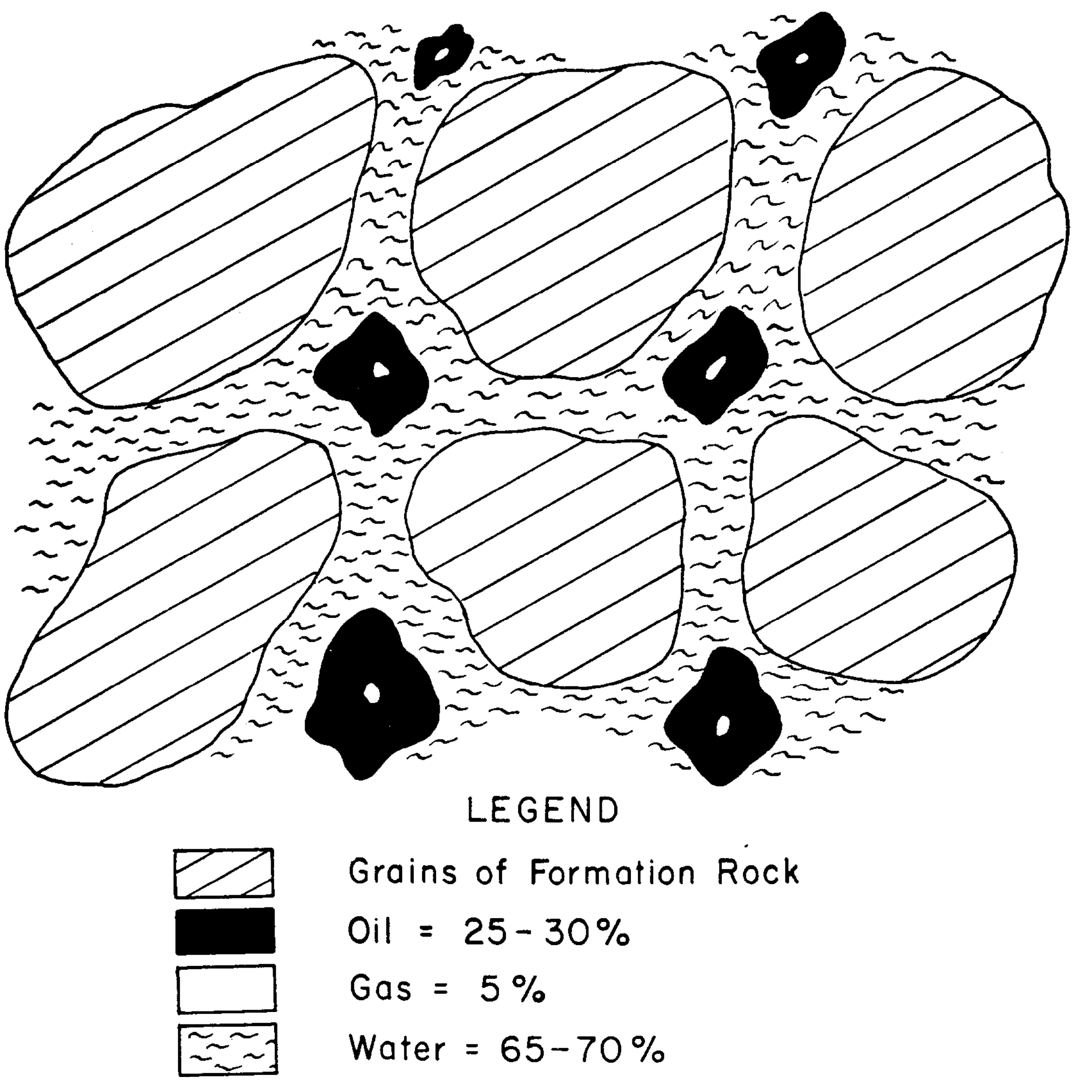


oil per day, in the majority of cases there still exists from 70 to 85 percent of the oil originally present that cannot be recovered by natural means. This remaining oil is held in the rock formation from which the field produces by what we call "capillary pressure"—much the same as coffee is drawn up and held in a lump of sugar when partially dipped in the liquid. Thus it becomes necessary to apply outside or "secondary" energy before any additional oil can be produced.

Contrary to the belief of people totally unfamiliar with oil production, oil does not exist in large underground pools or streams. Rather, it is contained in small openings between sand grains or crystals of rock material, much the same as the 1/3 bucketful of water one could pour into a bucketful of sand without running over the top. By being under hundreds or thousands of feet of rock the oil contained in a producing formation is originally under high pressure and temperature. As such there is a quantity of natural gas dissolved in the oil depending on the formation temperature and pressure and the oil composition. When oil is produced at the surface a reduction in formation pressure occurs and some of the natural gas is liberated from solution by the oil remaining in the formation; just the same as carbon dioxide is liberated from soda pop when the bottle is opened. This liberated natural gas under pressure furnishes, in most cases, the energy to expel the oil from the producing formation. When the gas energy declines to where it cannot overcome the capillary pressure and pressure needed to flow through the small openings between the formation sand grains, natural production ceases. It should be pointed out that from a practical standpoint the natural energy is almost never reduced to this point because it costs money to produce oil and when the time arrives where it costs more to produce a well than the value received for the oil produced, the well is shut in. However, for all practical purposes it can be said that the natural energy is depleted. Now then, there exists in the producing formation at this point a distribution of fluids similar to that shown on Fig. 1. This shows the remaining oil and gas and the immobile water which naturally occurs to some extent in essentially all producing formations. The percentages of the total open space between the sand grains that these fluids occupy are termed the oil, gas and water saturations. A typical producing formation at natural depletion would have an oil saturation of 55 percent, a gas saturation of 25 percent and a water saturation of 20 percent.

The injection of water into a well increases the water saturation in the formation around the well bore. Since a unit volume of the formation can only hold so much total fluids, the oil gas saturations present are shoved ahead of the increasing water saturation towards the offset producing wells. As the water is injected the pressure in the formation contacted by the advancing fluids is raised somewhat and a large portion of the free gas present in the formation at natural depletion is put back in solution in the oil. Therefore, as the water advances away from the injection well and more and more oil and dissolved gas are moved ahead, an "oil bank" is formed which moves through the formation towards the offset producing wells. When this "oil bank" reaches the offset producing wells a sharp increase in oil production takes place. As water injection is continued the advancing water eventually reaches the producing wells and oil production is accompanied by an ever increasing water cut. After the time at which injected water reaches the producing wells it will continue to bring along oil which was not moved into the "oil bank." However, not all of the oil present at natural depletion

FIGURE 2—DISTRIBUTION OF OIL, GAS AND WATER IN A PRODUCING FORMATION AT END OF WATER FLOOD.



will be recovered by water displacement. On the average about 50 percent of that oil will be recovered, thus leaving in the producing formation approximately 5 percent undissolved natural gas, 25 to 30 percent oil and 65 to 70 percent water. The approximate distribution of these fluids is shown on Fig. 2. It should be pointed out that the foregoing discussion and figures represent an extremely idealized case and that discussion later in the paper will bring out some of the practical features that alter the behavior of a water flood from that discussed above.

Requirements of A Good Water Flood Prospect

Not all naturally depleted oil fields are good water flood prospects. Expensive and disheartened experience through the years has shown that certain qualities of an oil field at natural depletion condemn the economic recovery of additional oil by water flooding.

Perhaps the most important criteria for selecting a good water flood prospect are:

1. Solution Gas Drive Primary Production—that is, the oil production by solution gas drive. This type of drive is that which was discussed under "Why is Water Helpful In Increasing Oil Production"—where oil is expelled from the formation by gas under pressure that was liberated from solution in the oil. This type of drive mechanism persists in the majority of our oil fields today, but unfortunately it usually results in the lowest percentage of natural recovery of oil originally contained in a producing formation.

There are two other main types of producing mechanisms and they are gas cap drive and water drive. Gas cap drive is such that free gas overlies the oil in a producing formation and is free to expand as oil is produced. This expanding gas cap moves oil downward toward the deeper portions of the producing formation to the wells. If properly controlled to where a minimum of this overlying gas is produced at the wells this type of natural drive can give recoveries sometimes as high as 60 to 70 percent of the oil originally in place. Therefore, since natural recovery is higher, there remains less oil in the formation to be recovered by water flooding. In addition, the presence of so much free gas in the formation tends to promote "channeling" of injected water to the producing wells without displacing much oil ahead of it.

The water drive mechanism results from the producing formation extending well beyond the oil field boundary and containing water that is free to move into the oil field as oil is produced and formation pressure is lowered. As the water moves into the oil bearing part of the formation it displaces a large portion of the oil ahead of it towards the producing wells. This, then, is actually a natural water flood process. Therefore, just as it would not be profitable to re-water-flood a field that had just been water flooded to depletion, neither would it be profitable to water flood a field which had been depleted by a natural water drive. The water-drive producing mechanism usually results in about 50 percent of oil originally in the producing formation.

In addition to the three distinct types of drive mechanisms discussed above there is oftentimes found a combination of the three furnishing the natural producing energy in a particular field. Therefore, it takes careful screening by engineering study to determine to what extent each has contributed to natural depletion before the water flooding attractiveness of a combination drive field can be decided.

2. Conductivity of The Producing Formation Be Relatively Uniform and High. In a water flood project, time is an important factor. The large initial investment is made to start the operation but any return on the investment is delayed several months or even years down the road to when the producing wells begin to show an increase in oil production due to water injection. Therefore, it is important that the conductivity or "permeability," as it is called, of the producing formation be sufficiently high to provide injection rates that will give an increase in oil production in a reasonable length of time.

Not only must the conductivity of the producing formation be sufficiently high but it is highly desirable that it be relatively uniform throughout its thickness. The presence of highly permeable "streaks" in a producing formation being water flooded promotes the rapid advance of injected water toward the producing wells with the result that these "streaks" are watered out far in advance of other portions of the formation. This in turn causes premature water production and the handling of increased flood water volumes in the injection facilities—thus raising the lifting and water treating and handling costs over the life of the project. Since the margin between profit and loss in a water flood operation is comparatively slim, such increased costs could prove fatal from an economic standpoint. Unfortunately, producing formations with fairly uniform conductivity are rarely ever found. Therefore, it oftentimes becomes necessary to selectively block or stimulate portions of a formation in an injection well in an attempt to inject water more uniformly over the thickness of the formation.

3. That The Formation To Be Flooded Be At A Reasonable Depth. As mentioned previously, after injected water reaches the producing wells oil production is accompanied by an ever increasing water cut. Inasmuch as the cost of lifting oil and water increases as the depth of the producing formation increases, it is desirable to select a field for water flooding where the formation to be flooded is not so deep that the cost of lifting the future oil and water production would be excessive as well as to cause the early abandonment of producing wells at a very low water cut. However, on the other hand there exists a happy medium in the consideration of depth to the producing formation. As the depth increases so does the maximum surface injection pressure that can be applied without rupturing or fracturing the formation being flooded — which means that higher injection rates can be obtained than if a particular formation were at a shallower depth. Therefore, the opposing effects of these two factors must be considered before it can be said that a field is too deep for flooding.

4. An Adequate And Inexpensive Water Supply. Naturally, before a field can be water flooded an adequate supply of water must be available. On the average the total volume of water required during a water flood operation is from 4 to 6 times the volume of oil to be produced. The usual sources of flood water are surface streams or lakes or underground water bearing formations. In either case the supply of water must not be too far removed from the field to be flooded or the cost of transporting the water to the injection facilities will be excessive. In addition, the supply water must not only be adequate and nearby, but it must be suitable for injection into the producing formation with a minimum of preparation or the water treating costs might also become excessive. A discussion of the problems encountered with unsuitable injection water will appear later in this writing.

5. Oil Remaining After Natural Depletion Must Not Be Too Viscous. If the viscosity, or "weight" as used in connection with motor oils, of the oil remaining in the producing formation is much higher than that of the injected water, the efficiency of oil displacement by water is drastically reduced and the total recovery from such a water flood might be so low as to make the project uneconomic. Some of the low gravity oils of California and the Rocky Mountain Region have about the consistency of thin axle grease. Water flooding formations with oils of that nature is undesirable, not only because of the low recovery efficiency, but also because of the high injection pressures required to move through the formation what little oil that is displaced.

Importance of Well Test Information In A Water Flood Operation

During the initial stages of a normal water flood operation, the producing wells are making little if any oil. It becomes important during this stage to test these wells as often as feasible so that any premature appearance of injected water will be revealed and corrective measures undertaken in the offending injection well or wells. Any delay in revealing the premature appearance of injected water means a delay in the return on investments made in establishing the flood program and an increase in water handling costs.

Individual well test information can reveal areas in a field where increases in oil production are occurring ahead of other areas. From this information, attempts can be made to stimulate the injection wells in the slower areas so that the spread in time between the first wells in the project showing increased oil production and the last wells showing a prohibitive water cut, can be brought to a minimum.

If directional trends in premature water production are indicated by individual well test information, it might be found advisable to change the injection well pattern in future expansions of a flood program or subsequent floods in the same formation in an area.

Injectivity profile tests on injection wells can be most beneficial in revealing zones within the producing formation which should be selectively stimulated or partially plugged off. In this manner the injection of water can be distributed more uniformly across the sand face and minimize the time spread between the first appearance of water and the final abondonment of producing offsets. In addition, injectivity profiles can reveal the loss of injected water around leaks in a casing seat.

Problems Encountered In The Operation of A Water Flood

Perhaps the biggest problem encountered during water flooding in some parts of the country is plugging of the formation in injection wells. This results from numerous causes. As mentioned previously, injection water must be of good quality—in most cases, better than the water we drink. If not properly treated to remove suspended matter, iron compounds, excess calcium and magnesium carbonates, barium sulfate, manganese compounds, and algae and bacteria, these substances will filter out in the formation immediately around the well-bore and severely restrict the water injection rate. Therefore, adequate surface treating and filtering facilities are very essential to a successful water flood. Inasmuch as the water injection rate at a constant surface pressure will naturally decline to a stabilized value as more and more water is injected, it can sometimes become very difficult to detect plugging of the formation during the early stages of a water flood unless the characteristics of injection wells can be accurately predicted beforehand, which is sldom the case. Therefore, formation plugging may go on undetected until severe damage has been done to the formation in the injection wells. Plugging of the formation in injection wells is also caused by the injection water being incompatible with formation water and/or clays present in the formation. From Fig. 1 it was seen that naturally occurring formation water takes up about 20 percent of the space between the sand grains in the producing formation. Quite often injection water is of such quality that when it is mixed with natural formation water the precipitation of solids takes place which tend to plug the formation and restrict the injection rate. If fresh water is used for injection and the formation to be flooded contains particular types of shales or clays, these shale or clay particles will swell when in contact with fresh water and thus plug the formation. This problem can be solved for the most part by the use of salt water for injection.

Plugging of the formation in injection wells will result from still another cause. Quite often the water used for injection in a water flood is corrosive to some extent. After months or years of injection, particles of corrosion scale will flake off the interior of the surface and subsurface injection equipment and be carried into the formation with the injection water and tend to reduce the injection capacity. Therefore, it is important that the corrosiveness of injection water be kept at a minimum at all times.

As mentioned previously, the presence of highly conductive "streaks" in a formation being flooded will promote premature water production and increase water volumes required to complete a flood. Much research has been done both in the laboratory and in field applications to develop means to selectively plug high permeability zones with the producing formation and thus utilize the injected water more efficiently in displacing oil.

Numerous operational problems arise upstream in a water flood project. These are in connection with the water supply. In projects where injection water is obtained from wells drilled to shallow water sands, a frequent problem arises from sand production, especially during periods of heavy withdrawal. This production of sand is undesirable because of its abrasive action on water supply pumps and surface equipment. Usually there is a critical water production rate from a particular supply well below which sand production ceases or is not a problem. Therefore, it becomes necessary to maintain per well water withdrawal rates below such critical values or install costly gravel packing or similar sand control features in the supply wells.

An ever-present problem in the operation of a water flood where supply water is obtained from a surface stream or lake, especially in the southwest, is the continuation of an adequate supply of water during prolonged periods of drought. Also, a water supply from a surface stream is subject to rapid change in composition which could necessitate changes in water treating facilities to keep the injected water of proper quality. For these reasons mainly, surface streams are usually termed poor sources of supply water for an extended water flood operation.

Types of Water Handling Facilities

Briefly, there are two types of flood water treating facilities — the open system and the closed system. In the open system, as the name implies, the flood water, from the source of supply to the point of injection, is open to the atmosphere. The water is aerated so that oxygen from the air will combine with certain chemicals in the water which will, upon the addition of alum, fall out as solids in settling tanks or pits. The water is then filtered and sent to injection pumps where additional chemicals such as chlorine are added to control bacteria. From the pumps the water is distributed to the various injection wells.

In a closed system, the water is pumped through a closed pipeline system directly to the injection wells. Air is excluded from the system and little or no treatment is given.

The open system is more expensive, both in initial investment and operating costs, but it is capable of handling any kind of water because of better control of the chemical components. The closed system, although lower in investment and operating costs, is difficult to keep oxygen free. With the closed system it is also difficult to return produced water to the injection system.

The brief descriptions of the two treating systems given above are very general. Each water flood project has its own distinct water treating problems which cannot, of course, be fully covered here.

Typical Production History of A Field Under Water Flood

Referring to Fig. 3, the portion of the chart from (A) to (B) represents the daily oil production in the latter stages of natural depletion. Point (B) shows the start of water injection. The interval from (B) to (C) is what is commonly referred to as "fill-up" time, or time required for the injected water to displace an oil bank ahead of itself and for the oil bank to reach the producing wells. Point (C) shows the first reaction to the water flood program when the oil bank reaches the producing offsets and causes a sharp increase in oil production from individual wells. In practice it is highly improbable that all wells in a project will realize production increases at the same time; therefore, there is usually a spread of several months or even years between the first and last wells in a project receiving production increases, although every effort is usually made to minimize this spread. The interval from (C) to (D) is marked by increased oil production up to a stabilized rate approximately equal to the water input rate and probably very little water production due to water injection to that time. Point (D) represents breakthrough of injected water to the producing wells. From this point on the oil production begins to decline while water production continually incerases until the project reaches economic abandonment (Point E).

Here again, as in the preceding section, the above discussion is very general. Any of the many problems encountered in water flooding operations as discussed previously could change the production curves shown on Fig. 3.

Water Injection To Maintain Formation Pressure

The preceding discussion has been limited to water injection in fields at or near, natural depletion. The last section of this writing will consider the injection of water in new or partially depleted fields for the purpose of maintaining formation pressure at some elevated level.

Basically, the injection of water into new or partially depleted fields is little different than that in water flooding naturally depleted fields. Perhaps the only differences would be the higher surface injection pressures required, the spacing of injection wells with respect to producing wells and the performance of producing wells during the period of injection.

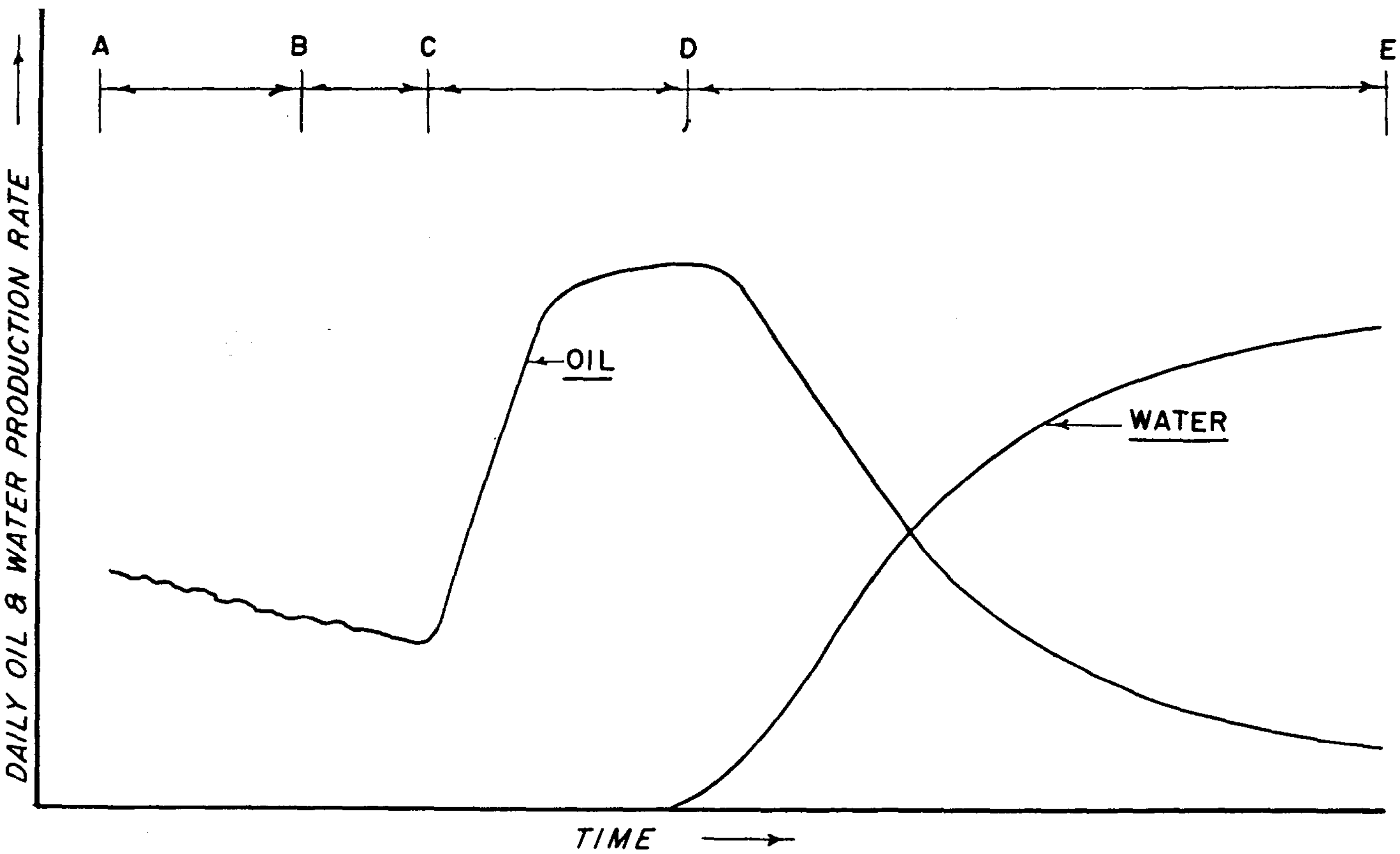
In a pressure maintenance by water injection project the ratio of injection to producing wells is usually smaller than in a water flood. If it is desired at the start of such a project to increase the formation pressure above that currently existing in the field, the water injection rate is held much higher than the oil, water and free gas production rate from the field until such time as the higher formation pressure is attained. After that the injection rate is reduced to approximately equal the production rate and the formation pressure is thus maintained fairly constant.

If the formation pressure is initially raised some significant amount, the producing wells in the project would show an improvement in capacity due to the increased pressure. However, if pressure is raised very little or merely maintained at the existing level, little effect, other than a failure to decline further in capacity, would be noted in the performance of producing wells until such time as injected water broke through. Since such a project is carried out at an elevated pressure, there is usually little if any, free gas present in the openings between the grains of the pay sand. The distribution of fluids in the formation at the start of a project would be somewhat like that shown in Fig. 1, with the exception that the gas space in Fig. 1 would be all, or mostly, occupied by oil. Therefore, in effect, there would already be an "oil bank" ahead of the injected water from the start of the project, and since this "oil bank" would extend to the producing wells, no marked change in their performance would occur. Once injected water breaks through, however, the producing wells experience an ever increasing water cut, unless remedial work can eliminate or reduce the production of injected water.

The main objectives of a pressure maintenance by water injection project are to maintain flowing conditions and resulting low lifting costs throughout most of the life of a field, minimize the production of free gas and resulting penalized production that accompanies natural pressure depletion and to create an artificial water drive that will, on the average, recover about 50 percent of the oil originally in the formation.

The preceding has been a general discussion of the fundamentals of water injection for increasing oil production, directed toward and for the benefit of those field operating personnel presently involved in such operations and those who might at some future time be confronted with the problems and operation of such projects. Every effort has been made to eliminate, or clarify, bulky technical discussion so that the subject matter could be presented in more interesting form.

FIGURE 3—TYPICAL PRODUCTION HISTORY OF A FIELD UNDER WATER FLOOD.



LEGEND

A – C = Continuation of Natural Depletion

B = Start of Water Injection

C – D = Increasing Oil Production due to Water Flood

D = Breakthrough of Injected Water to Producing Wells

D – E = Declining Oil Production accompanied by Increasing Water Production