ROLE OF CLAY IN OIL RESERVOIRS

By Norris Johnston *

Occurrence. The following observations apply to the sandstone oil pools of the United States. Carbonate reservoirs seldom, if ever, contain appreciable quantities of clay. Sandy sediments, on the other hand, frequently contain clays of many types, in quantities ranging from practically zero to a very high percentage. Hughes and Pfister (1947) have stated: "Few producing oil sections are free from clay." This is contrary to the prevailing opinion 6 or 7 years ago, when the remark was frequently heard that "California sands may be dirty (argillaceous), but east of the Rockies, clay in oil sands is a rarity." It may be true that very clean sands are more frequently found in central plains and eastern areas than in California, and even that the average condition of all sands east of the Rockies may be classified as much cleaner than that of Pacific Coast sands. But the fact remains that most oil and gas sands do contain certain quantities of many types of clay.

The types which have been found and identified include chiefly montmorillonite, illite, and kaolinite, with many less commonly mentioned forms, such as attapulgite, sericite, chlorite, anauxite, and so on. For the specific purposes of the petroleum engineer, it has been customary to group all clays as belonging to, or at least as being similar in behavior to, the three main types, montmorillonite, illite, and kaolinite. In this order, the clays show properties ranging from extreme surface activity, strong swelling tendency, and great ease of base exchange, to a set of opposite characteristics: surface inactivity, absence of swelling tendency, and lack of base-exchange activity. It is obvious from these properties that the effects on the accumulation and production of oil should be greatest in the case of the active montmorillonites, and least in the case of the comparatively inactive kaolinites. Identification of the clays is carried out by the usual means. After mechanical disintegration of the sands, finer constituent particles, which normally include most of the clays, are separated by elutriation. X-ray diffraction, differential thermal analysis, infra red analysis, microscopic examination, and other means are employed to obtain specific identification.

Clays are important in oil sands almost entirely because they occur in small particles adjacent to the sand grains, in a region which is normally occupied by the interstitial water almost always found associated with oil sands. The reason this association is so important is that clays exhibit their activity almost exclusively with respect to water and its dissolved ions. Clays dispersed in oil, or in contact with it, in the absence of water would in general behave as inert particles. So the surface-active clays would be largely indistinguishable in behavior from the inactive clays. The particles of clay normally are attached to the surfaces of the sand grains in whatever distribution chance and the forces of water or air dictated at the time of deposition of the sand grains, or during the time of formation of the clay from the sand. It is generally believed that clay particles are either deposited at the same time as the sand grains or are formed in situ, mainly from feldspars, after deposition of the sand, rather than that they migrate into position through the pore channels of a previously sedimented, clean, porous medium. Thus it is statistically likely that quite often, two adjacent sand grains may make contact only through one or more clay particles. Figure 1 is a sketch to illustrate various sand and clay configurations with reference to the oil and water content of a pore in an oil sand. Three sand grains form the pore, which is lined with interstitial water in which are submerged several clay particles. At the sand grain contact A, there are shown three clay particles in hydrated form, separating the grains by a finite and appreciable distance. At B are several clay particles which hydration has swelled and weakened to such an extent that portions have become dislodged and are free to migrate with the fluids in the pore channels. At C are shown some portions of clay particles extending farther than usual from the sand surfaces and causing some excess volume of interstitial water to be held in the pore space. At D are shown some hydrated clay particles which have attracted from the ionic atmosphere of the surrounding brine certain positive ions, which tend to neutralize the inherent negative charge of the clay particles.

Effects of Clay on Oil-Sand Behavior. The chief characteristic of clays that makes a dirty sand different in its behavior from a clean sand is the extensive hydration, which results in swelling and consequently in a partial loss of permeability of the sand. Another result of the forces that accompany swelling is the increased compressibility of a dirty sand as compared with a clean

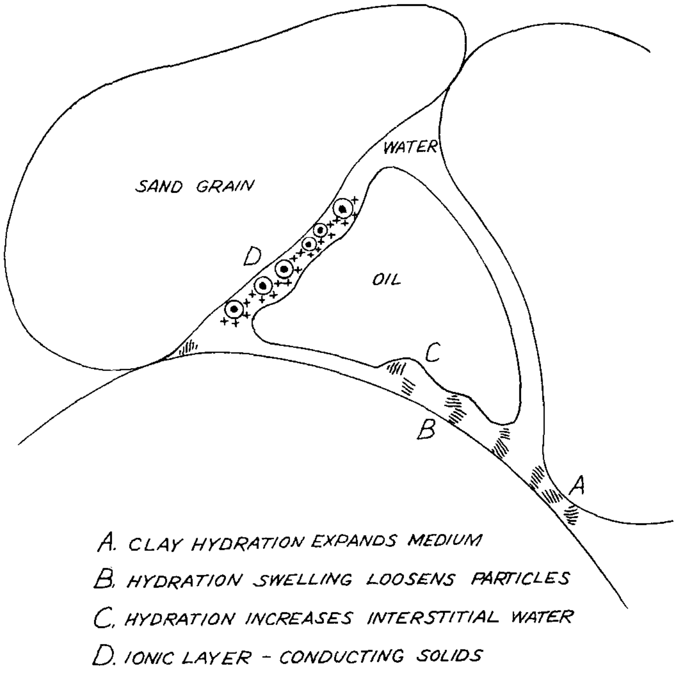

Figure 1.

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sand. Interstitial water tends to be more abundant in an argillaceous than in a clean sand. The tendency for a clayey sand to be water-wet is greater than for a clean sand, as clays are normally strongly hydrophyllic. The strong tendency for ion adsorption makes a clayey sand give quite a different electric-log resistivity curve. There are doubtless many other effects that clay may have on oil accumulation and recovery, but the above are the more important.

Hydration and Swelling. J. F. Carll (1880) was one of the earliest and most understanding of oil-reservoir engineers. In 1880 he stated clearly many of the basic principles of the recovery of oil that have stood for 72 years. "The flooding of an oil district is generally viewed as a great calamity, yet it may be questioned whether a larger amount of oil cannot be drawn from the rocks in that way than in any other, for it is certain that all the oil cannot be drawn from the reservoir without admission of something to take its place." Mr. Carll did not know all the pitfalls, but did state that the structure of the rock should be studied.

There may have been some cognizance of the presence of clay in oil sands as early as 1926, when Thom (1926) reported a possible relation between the high recovery in the First Wall Creek Sand in the Salt Creek Field, Wyoming, and the high carbonate content of the edgewater. Thom did not ascribe the high recovery of the carbonate water drive to any action of the ions on solids of the reservoir structure, but rather he ascribed the results to the removal of films of oil from the sand grains. This same hypothesis was advanced by Nutting (1926), after numerous experiments in separating oil from silica sand. In 1927, Beckstrom and Van Tuyl made a plea for more engineering data and knowledge of subsurface conditions before indiscriminate injection of either carbonate or bicarbonate water. Taylor (1928) stated that the clays and shales in oil reservoirs and their cap rocks were largely sodium-type clays in an alkaline condition. It is a tenable conclusion that the hydrated status of the clays under these circumstances would produce the low permeability necessary for a stratum to become a cap rock, though this was not explicitly stated by Taylor. During the next few years, Taylor (1928), Case (1933), and Kelley and Liebig (1934) classified clays as belonging to one of three major categories: hydrogen, calcium, or sodium base. The first is the least easily hydrated, the second intermediate, and the third the most easily and extensively hydrated.

In 1933 Case stated that calcium clays carried to the ocean would undergo a base exchange to the sodium form, which would remain stable so long as it was in contact with the ocean brine, but on later leaching with fresher water, would become impermeable. Here we have the first direct statement of the effect of clay hydration on permeability. That same year Fancher, Lewis, and Barnes (1933) stated that the discrepancy between permeabilities measured with air and those measured with brine was largely due to hydration of the clays present in the oil sand, rather than to movement of loose particles within the porous medium, which would be more noticeable with liquid than with gas flow. The author has noted a phenomenon in measuring liquid permeabilities which appears to indicate mobility of particles, but he does not quarrel with the general validity of the statement that hydration is the chief cause of plugging. After flow of water through a sample has come to equilibrium, a rapid reversal of flow at the same pressure sometimes results momentarily in an increased permeability, which soon settles back to the former equilibrium value. This could be explained by assuming that loose clay or other fine particles migrated under fluid flow to a constriction in a pore channel, through which they could not pass. On reversal of flow, these microscopic check valves could be opened, increasing the flow rate until the loose particles had become lodged in other constrictions in the opposite direction. This phenomenon is not thought to be even of the same order of importance as the major consideration of hydration swelling.

In 1934, Kelley and Liebig stated that the sodium form of clay would be stable only in the absence of other cations, such as calcium, but that base exchange from sodium to other cations is slow, because of impermeability of the clay when in the sodium form. Kelley and Jenny (1936), Kelley (1939), and Grim (1939) stated that the formation water itself, as distinguished from injected or other foreign water, may have a stronger wetting tendency, and may inhibit the swelling of the clays. Thus it may keep them in a more granular, and therefore more permeable, form. This is equivalent to saying that the clays present are normally flocculated by the formation water, and that other waters may disperse them. Muskat wrote in 1937 that the discrepancy between air and water permeabilities of oil sands was certainly caused by clays, and stated further that the final, lowest value of water permeability most nearly approaches the proper reservoir value, since only then is the hydration as complete as in the formation. A specific reference to clay in an oil reservoir came in 1938 with the statement by Waldo that the Kane field apparently contained even more clay than the Bradford field. This was followed in 1940 by the observation by Krynine that the Bradford Third Sand contained 3 to 10 percent clay. In 1941, Hindry cited the application of oil-base mud to oil-well drilling to combat the heaving shale problem, but did not mention the desirability of using oil-base mud to keep fresh-water filtrate out of the oil sand. The swelling of heaving shale is almost exactly analogous to the swelling of the hydratable clay content of oil sands, and responds to the same treatment, namely complete avoidance of fresh water. That same year, Heck (1941) started a controversy regarding theoretical aspects of using connate water for injection, and wrote that calcium chloride might be a good additive to injection water in some cases, for the purpose of maintaining a high injection rate. He was disturbed by the increased viscosity of the injection water caused by this addition, as was also Smith (1942). The author believes that for any but the lightest crudes, which seldom require artificial flooding, it may be beneficial to have a higher viscosity driving fluid, from the standpoint of greater stability of the interface, and thus less bypassing of the oil.

In 1942 Travers mentioned water block around a well bore, resulting from mud-filtrate invasion, as a condition which lowered the productivity index and thus the ultimate economic recovery. He did not mention the filtrate

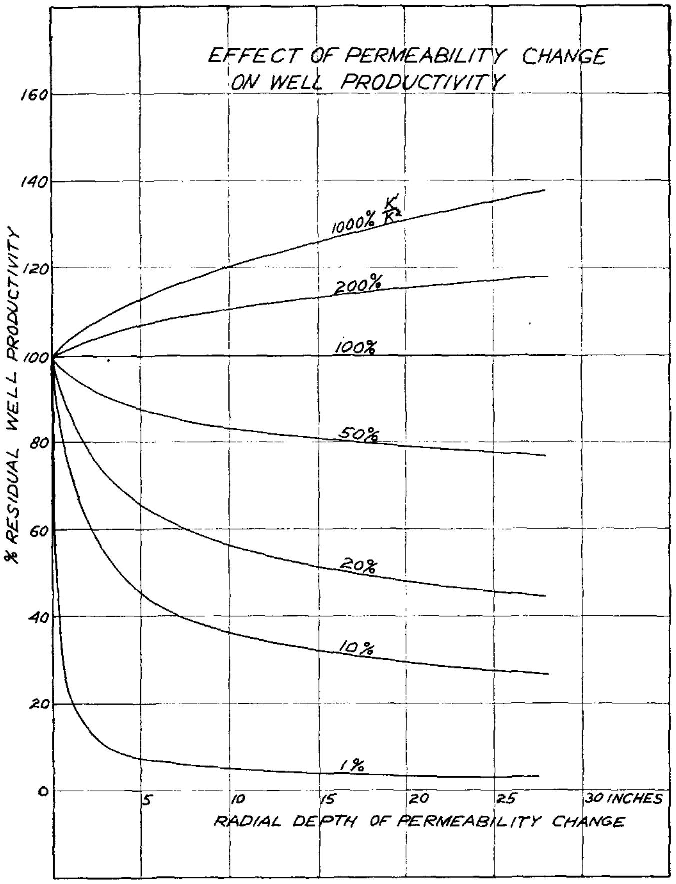

FIGURE 2.

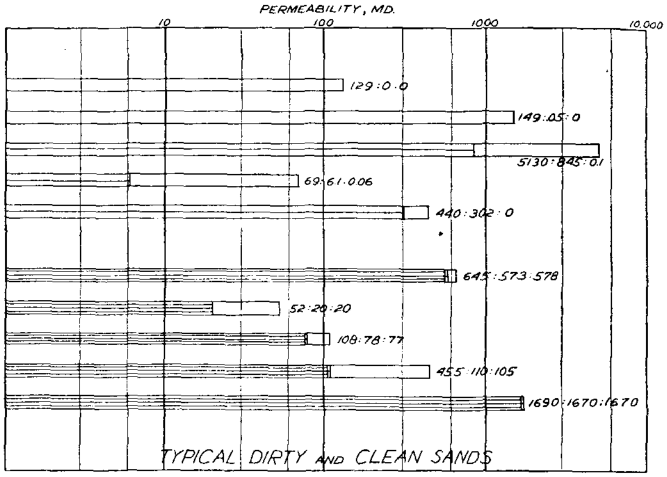

FIGURE 3.

invasion as having any effect on the clays, but only as occupying space in the pores, thus reducing permeability to oil. In 1942 Grim stated that all clays could be considered as belonging to one of the three classes, kaolinite, illite, or montmorillonite. He stated further that kaolin has little influence upon petroleum recovery, that the montmorillonites have the greatest influence, and that the illites are intermediate. Similarly, the hydrogen forms are least important, the sodium forms the most important in the processes of accumulation and recovery. In 1943 Johnston and Sherborne showed the drastic reduction of well productivity resulting from killing a well with fresh water. They discussed the fact that cores containing drilling-mud filtrate have lower permeability than the same cores after drying. It was also mentioned that the excessive deviations of well productivity from theoretical values were more a result of interaction between the connate water and certain constituents of the rock, than of the blockage caused by the mere presence of water.

In 1945 Johnston and Beeson discussed in considerable detail the permeability of more than 1200 samples of oil sands from 107 wells in 43 zones in 23 fields. This survey showed that about 70 percent of the sands studied showed distinct and serious damage to permeability, caused by influx of fresh water. Many of the sands showed much higher permeability to air than to 3 percent brine, indicating that even quite strong saline solutions contribute somewhat to hydration, or possibly to microscopic rearrangment of clay particles. It was Johnston and Beeson's view that, except for the appreciable effects of overburden pressure and formation temperature and possible adsorption of some of the oil constituents on some of the solid surfaces, the brine permeability was a closer approach to the true single-phase reservoir permeability than is the commonly

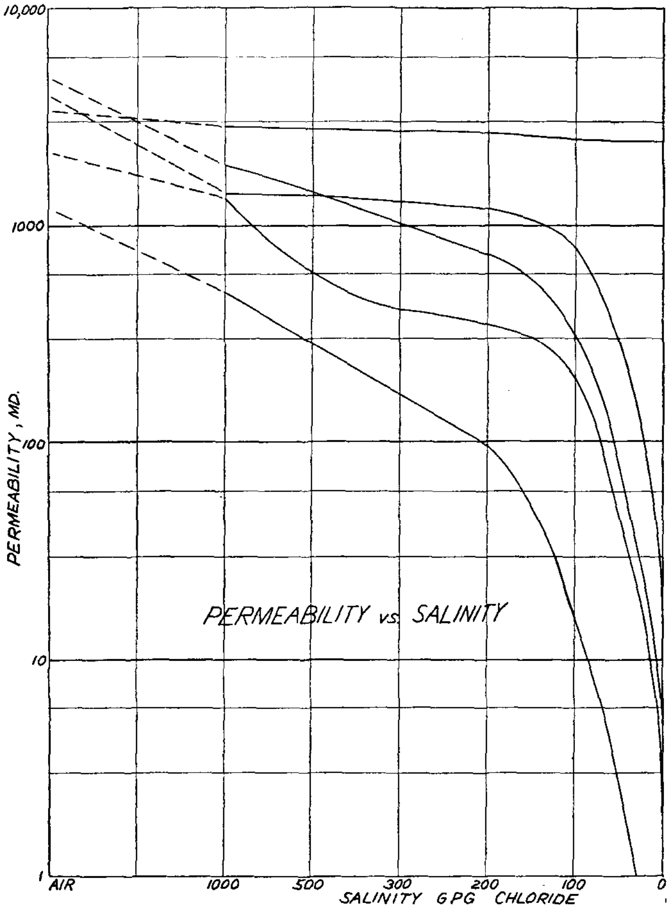

FIGURE 4.

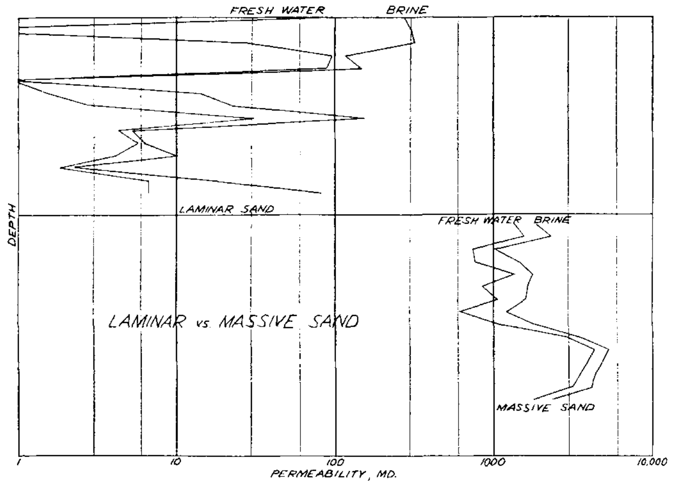

FIGURE 5.

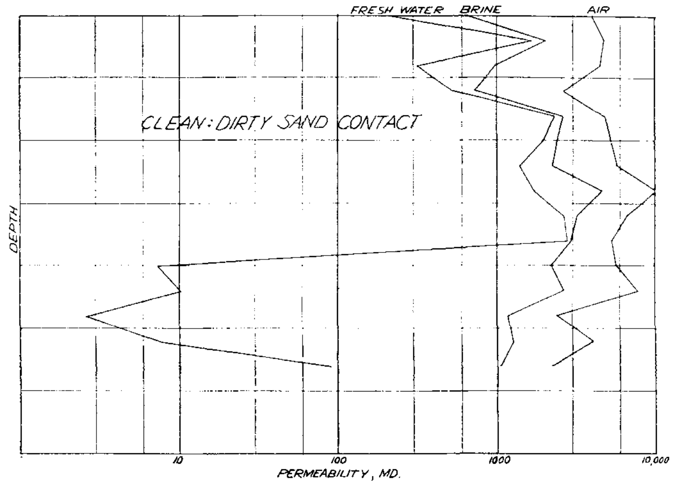

FIGURE 6.

measured air permeability. Since that time one major oil company has measured more than 15,000 brine and fresh-water permeabilities, thus learning a great deal about the distribution of hydratable clays in oilfields over a wide area.

Johnston and Beeson pointed out certain sources of error, such as the toluene extraction followed by oven drying. However, to obtain the single-phase permeability of a reservoir sand wet with its interstitial brine, there appeared to be no less damaging way than to extract the oil and vacuum saturate with the brine. They showed the effect of reduced permeability around a well bore on the resulting well productivity, in terms of both radial distance of the plugging effect of fresh water intrusion, and also the degree of susceptibility of the sand. Figure 2 shows the drastic effect on well productivity of severe hydration plugging for only a short distance into the sand, and conversely the relative difficulty of improving well productivity by increasing sand permeability, even 10-fold, for a considerable distance from the well bore. Figure 3 shows on a log scale some typical permeabilities of sand samples to air, brine, and fresh water. The upper five samples would be considered argillaceous or "dirty"; the lower five are "clean." Figure 4 shows the effect on a few samples of successively lower brine concentrations, from 3 percent to fresh water. The log scale somewhat masks the drastic nature of the reduction, but allows actual values to be shown. The differently shaped curves suggest the great variety in type, quantity, and distribution of clays in the pore spaces of oil sands. The fact that permeability declines relatively little as the salinity is reduced several-fold suggests that where necessary, fresh water may be rather freely admixed with appropriate brines, for subsurface injection, as in secondary recovery operations, in sands that would refuse to accept fresh water itself at any economic rate. Figure 5 shows how clearly fresh water can differentiate between the strata of laminar sediments as regards hydratable clay content, as contrasted with the relative constancy of permeability characteristics in a massive sediment. The ratio of fresh water to brine permeabilities varies from 0 to 100 percent for the laminar sand, and 51 to 81 percent for the massive sand. Figure 6 shows the sharpness with which fresh-water permeability can indicate a sudden change from a clean to a dirty sand, whereas air and brine were ineffective in the differentiation. The samples were taken every 18 inches over a vertical distance of 23 feet. Many other illustrations could be cited of the presence of clays as shown by water permeabilities. Clay content can be determined by quantitative measurements, and the mineralogical classification can be determined by the more elaborate physical measurements such as X-ray diffraction, infra-red, and differential thermal analyses. Frequently the result desired is a determination of the effect of the clay content on permeability, so the simplest approach is the single-phase measurement of the water permeability.

Yuster (1945) favored the use of brines over fresh water for flooding, although the Bradford operators continued to use fresh water as it was more readily available and laboratory tests showed no greater recovery with brine. In 1946 Kersten showed about a 2 to 1 improvement in initial productivity index of wells completed with oil-base mud as compared with fresh-water clay-base mud. His graphic presentation made this deduction inescapable. He stated, too, that the higher index for oil-base completions was apparently maintained through much of the well history. The same year Kelley, Ham, and Dooley (1946) arrived at several pertinent recommendations for obtaining maximum well productivity: minimize water entry into the sand, add salts to whatever water may be allowed to enter, keep the time of contact of drilling muds against the producing sand down to a minimum, use low-weight mud, and select the mud-treating agents so they will have a minimum hydration effect in the oil sand. Here we have an interesting and troublesome conflict: the chemical additions to drilling mud should disperse the mud clays thoroughly, but immediately on entering the oil sand they should change their nature to that of flocculating agents!

Wade (1947) has presented a monumental study of the contributions of many factors to the productivity of an oil well. One of his conclusions is that the productivity index of a well is higher the shorter the time the drilling mud has stood against the formation, and the less the time allowed for this action, the better, indicating that filtrate action on the sand near the well bore is unfavorable to well productivity. This action may include both water block by hydration of clays, and the intrusion of drilling-mud clays into the sand insofar as this is possible. One other conclusion of Wade is that individual pool correlations show oil-base mud to give a higher well productivity than water base, by factors varying from 1.5 to 2.0. Short time in the zone shows advantages as great as 246 percent in completion effectiveness. Further, Wade states that the average interstitial water of dirty sands at 100 md may exceed the value for clean sands by as much as 27 percent, which also contributes to lower productivity for dirty sands. At 10 md, the interstitial water values differ by 60 percent, which helps to explain the wider divergence of production effectiveness from the theoretical value at lower sand permeabilities (Johnston and Sherborne 1943).

Radford (1947) discussed the improvement in mud not only to avoid drilling trouble, but to avoid damage to the productivity of the sand. He also stressed the deleterious effect of long times of completion. One example showed the performance of two quite comparable wells, one which had been completed in 2.5 weeks, the other in 5 months. The rapidly completed well flowed 80 percent of its ultimate recovery in 12 months and was abandoned in 4.5 years. The well completed slowly did not flow at all, and in 11.5 years produced only 40 percent as much ultimate recovery per acre foot. The choice between oil and oil-base mud was inconclusive, but the choice between either of these and water-base mud was decisive. In commenting on the work of Radford, Dan Johnston (Radford 1947) showed an advantage of 2.5 to 1 in well productivity for special low-water-loss mud versus ordinary water-base mud. These observations all point to the damage to the permeability of the sand near the well bore by fresh-water filtrate, the damage being greater as more water invades the region. This is a function of time, pressure difference, mud-cake permeability (water-loss characteristic of the mud), oil viscosity, number of round trips of the bits and reamers, and of course, the argillaceous character of the sand.

Moyer (1927) discussed analytically the effect on economic ultimate recovery of a decrease in sand permeability around the well bore. He indicated that as fresh-water invasion lowered sand permeability by clay swelling, it also, and consequently, increased the interstitial or immobilized water. For an arbitrary and rather mild case of permeability damage, involving a loss from 57 md to 10 md, he showed analytically a decrease in final productivity index of 70 percent and a loss of ultimate recovery of 4 percent for an invaded zone only 15 inches deep around the well bore. Also the time required to recover the oil was greatly increased. A more drastic reduction of permeability would have been well within the limits of actual California practice in many instances, and would have resulted in still greater losses of productivity index and economic ultimate recovery, and still greater lengthening of the time required to obtain the ultimate recovery.

Hughes and Pfister (1947) made a most comprehensive study of the relation between injection well indices and laboratory data as affected by the saline content of the water. This work was carried out for the benefit of secondary-recovery operations, and specifically compared well rates using subsurface brines with well rates using fresh water or fresh water with such additives as sodium carbonate and sodium bicarbonate. Early trials in Bradford using these two additives in fresh water, supposedly to strip oil off the sand grains, were disappointing, as the high pH and prevalence of sodium ion tended to base-exchange the clays to the sodium form, which then hydrated more completely and lowered the well index. They conclude that injection water must be such as to keep any formation clays flocculated, and, in general, the best water for this purpose is the subsurface brine originating in the sand. Use of this brine at once solves the disposal problem, maintains reservoir pressure, maintains well index, and tends to increase economic ultimate recovery with a reduction in the time required for recovery. Thus the produced brines begin to take on the quality of a natural resource rather than a nuisance. Some of the observations leading to the above conclusions are rather striking. A group of 16 Bradford core samples tested in the laboratory showed subsurface brine permeability was 280 percent of fresh-water permeability through the sands. Another group, from Bartlesville, showed an average brine permeability of 400 percent of the fresh-water permeability. Well-injection rates responded immediately to brine replacing fresh water, to the extent of 20 percent, with 10 percent lower injection pressure at the sand face, and the reaction was found to be reversible. Most of the laboratory data were taken on sands containing mainly illite; where montmorillonite predominates, the effects would be more striking.

Commenting on the survey by Hughes and Pfister (1947), K. B. Nowels cited the case of the Woodson field, Throckmorton County, Texas. In 1941 the injection of clear, fresh water plugged an injection well from an intake rate of 23 barrels per day to 1 barrel per day in 13 days. Another dropped from 24 barrels per day to zero in that time, and the average of 6 wells decreased from 22 barrels to 1.6 barrels per day during the test. Because it was felt that one of the lime feeders had failed to operate correctly and had fed too much lime, the wells were treated with 50 gallons of 65 percent hydrochloric acid and the water injection continued immediately. The result was astonishing; injection rates recovered from 1.6 barrels to an average of 52 barrels per day, nearly 2.5 times their original rate. This new injection capacity was maintained, or improved in some cases. It is now felt that what actually caused the recovery of sand permeability was the result of base exchanging the clays to the relatively non-hydrating hydrogen form. The reaction of fresh water on the acid form of the clays is not serious, and as long as no appreciable quantities of sodium salts are brought into contact with the clays, future fresh-water hydration will be slight. This type of observation is what leads the present writer to believe that there may be better injection waters than the indigenous water itself, but certainly the latter is usually the most satisfactory of readily available waters.

Sherborne and Fischer (1949) showed that oil-base mud completions average about twice the productivity index provided by water-base mud completions. This gives quicker recovery and higher ultimate recovery.

They further stated that any use of water in a well is to be discouraged, but occasionally the need for reliable electric logs overshadows the importance of well productivity.

Hughes (1950) has presented a thorough summary of the many concepts relating the behavior of oil reservoirs to their clay content. He quotes Krynine (1945) as classifying sandstones as orthoquartzite, graywacke, or arkose in nature. The first is clean sand; the second contains angular grains of quartz, feldspar, and chert, set in a matrix of clay; the third comprises "ashy, light gray (or red) dirty sands with much feldspar," frequently cemented by clay. "The 'fines' of the majority of producing oil sands consist of particles of shales, silts, and clays, and impart the characteristic dirty appearance." Hughes states that clays aid compaction and shrinkage and help production by promoting subsidence on release of reservoir pressure. Though mud techniques are highly developed, the problems of keeping mud filtrate and mud particles out of the sand are less thoroughly solved, and in many ways are more serious than mud problems connected with drilling. There is an unsolved conflict between the best mud for electric logging and that for optimum well-completion effectiveness. It was pointed out that in well washing and clean-out techniques great care should be exercised to use only those chemical substances that would assure flocculation of formation clays. Somerton (1949) has suggested that the lack of an effective water drive in several California reservoirs may be attributed to the high clay content of the reservoir sands. Hughes further urges caution in the use in injection water of certain organic materials of a surface-active nature, as they may tend to disperse clays. All authors agree that, whatever is done to the oil sand around a well bore, the clays must be and must remain flocculated.

Nahin (1951) and co-workers conclude for the specific cases of the Stevens sand in Paloma and the Gatchell sand in East Coalinga that the clay content identified is in harmony with the observed sensitivity of the Stevens and insensitivity of the Gatchell to fresh-water hydration plugging. The Stevens sand contains appreciable quantities of hydratable montmorillonites, while the Gatchell sand contains clays mainly of the kaolin type. W. T. Cardwell, Jr. (Nahin et al., 1951) comments favorably on the citing by Nahin of a minimum of unsupported speculation, and agrees that "perhaps a more important factor than the amount of potentially swellable clay present is the manner in which such a clay component is interlaminated with the non-swelling minerals in the reservoir matrix." Cardwell further states that to be highly swelling, a clay must be a montmorillonite, but that even this may be insufficient, as some montmorillonites do not swell. Actual swelling tests on the fines must be made before the presence of hydratable clay can be proved.

Compressibility of Sand. Just as shale is compressible under overburden pressures, so also is sand containing an appreciable quantity of clay, more particularly when many of the clay particles occur as the bond between adjacent sand grains. Clay and shale are subject to extensive compaction, probably largely by reduction of their water of hydration by virtue of pressure. Power[1] showed experimentally imbibition pressures of shales ranged from about 3,000 to 19,000 psi. Clay particles supporting overburden pressures at sand-grain contacts would certainly be subjected to pressure intensities of this magnitude, particularly as the pressure in the fluid phases is reduced by production of the fluids. This compaction of a dirty sand reduces the pore space, and adds to the production of oil or gas per psi pressure decline over the comparable amounts recovered from a rigid sand. Also, the compaction apparently results in overburden subsidence. Subsidence of the ground level frequently takes place, as at Maracaibo and Long Beach, when extensive oil and gas withdrawals have been made from arkosic sand. In some heavy oil fields, an appreciable fraction of the entire ultimate recovery is made available by virtue of pay zone compaction.

Another evidence of compaction is the shrinking of dirty core samples when they are cleaned and dried in the laboratory. Sometimes this is so extreme that the sum of the water and oil extracted from a sample is greater than the entire pore space after drying the extracted sample, and apparent saturations exceeding 100 percent of the pore space are the result. In cases of extreme contraction, it becomes desirable to measure the pore space by the difference in weight of the dried and vacuum-saturated core samples, so as to have a measure of the "wet pore space." An alternative method is to measure the bulk volume, dry and wet, and add the difference to the falsely small dry-pore space.

Interstitial Water. The amount of interstitial water held by a sand at capillary equilibrium is dependent on the size of pore spaces and channels, the number of grain contacts, and the area of rock surface exposed to wetting by interstitial water. Obviously a fine sand will have finer pores, greater surface area, and more grain contacts, and therefore will hold more interstitial water than a coarse sand. A sand with greater distribution of sand-grain sizes will likewise hold more water. The presence of hydratable clay is not only a contributing factor to grain-size distribution, but the tendency of clays to bind water adds to the other factors to insure that a dirty sand will contain more interstitial water than a clean sand having the same characteristics of the non-swelling matrix. Figure 1 shows a possible physical picture of the way in which greater quantities of interstitial water may be held by the clay content of a dirty sand.

Hydrophilic Wettability. Because clays actively absorb or attract water, their presence in quantity on the surface of sand grains may tend to offset the oil-wet tendency of certain sand-grain surfaces and make a sand more nearly water-wet than would be the case for the same sand in the absence of the clay.

Conducting Solids. The conducting solids in surface-active clays are of special interest to those interpreting electric logs. They owe their existence to the fact that clay particles are usually negatively charged in water, so that a layer of positive charges is attracted to the surface. This layer of ionic charge is closely allied to the

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[1] Personal communication.

surface of the clay, but the charges are not immobilized as in the case of an insulating material. Thus they become available for electrical conduction. This type of conduction is ascribed to the solid itself, as it is entirely different from the electrolytic conduction in the pore channels. Also, the percentage of ions in the interstitial water that is adsorbed on the clay surfaces varies with the concentration of the electrolytes present. At low salinity, a greater fraction of the ions available is adsorbed than at high salinity. Thus there is a tendency for the formation factor to be more influenced by a given clay content of the sand when the interstitial water is of low salinity than when the brine is concentrated.

Control of Clay for Better Oil Recovery. The most successful way to combat hydration swelling of clays in oil sands is to keep extraneous water entirely out of the zone. If water must be used, it is best to use water carrying a fair concentration of soluble calcium salts, provided this is known to be compatible with the formation water. Another, usually more powerful corrective for clays that have been swelled by hydration is treatment with concentrated hydrochloric acid.

The shorter the time any mud is left against the pay sand, the higher are the resulting well-productivity indices. Damage with time is worst in the case of dirty sands and ordinary clay-water mud. Least damage occurs with oil-base mud, or oil, against a clean sand.

Those sands which show a great decrease in permeability from air to brine, and no great further decrease with fresh water, probably are showing the result of loosening of particles, rather than hydration. Not much treatment can be developed for such sands, other than to draw on them at low rates so that the loose particles will not all migrate to constrictions, which they are capable of plugging.

Subsidence may be avoided and a menacing situation turned into a promising one by replacing oil and gas withdrawals with injected water. If the injection program is carried out intelligently, a quite appreciably greater ultimate recovery is almost certain to result. A pool that has been producing great quantities of water will not necessarily yield much higher ultimate recovery with water injection, but most pools not having a sufficient natural water drive will be benefitted by secondary methods, and the tendency toward subsidence will be greatly reduced or entirely abated.

Any injection water should be carefully studied with respect to compatability with both the formation and the indigenous water. If an injected water maintains as high a sand permeability as that measured with the formation water itself, the injection water is certainly of desired quality. It is thought that some slight improvement over formation water permeability may be possible where the formation water is of low salinity, although a brief study of figure 2 will show that no extensive effort along this line is warranted, unless and until severe damage has been inflicted. The main recommendation for all cases is that the injection water should be so treated that formation clays are flocculated.

Problems for Research. A great many interesting problems exist in this field, and successful research would unearth information of untold value. The following problems are some of the more important and worthwhile:

1. Compressibility of sands under reservoir conditions for sands of varying type, amount, and clay-content distribution. This study should also encompass the effect of fluid pressure within the pore system.
2. Means of adjusting drilling-mud filtrate so that it disperses clays in the mud, yet flocculates clays in the oil sand.
3. Means of economically recuperating the sand permeability after hydration damage.
4. Measurement of true reservoir porosity.
5. Measurement of true and altered reservoir permeability.
6. Measurement of true reservoir water content.

DISCUSSION

W. T. Cardwell, Jr.:

Where are the clay particles located with respect to the sand grains as they exist in the reservoir, and is it possible that the position of the clay particles may be changed as a consequence of coring and extraction of the core sample?

Can the filtrate of a salt-water mud harm a formation by *deswelling* or flocculating clay in the formation; and could the flocculated clay particles be loosened in this action and be allowed to migrate and act as check valves in the flow channels?

If the formation permeability had been reduced only by clay swelling would it not be possible to reverse the process by injecting an electrolyte which would return the clay to its original condition? Would it not be possible that the reversal could take place during production as the contaminating electrolyte was displaced through diffusion and flow of the original interstitial water?

Ralph E. Grim:

Clay may occur as discrete particles mixed with the sand grains. It is very common, however, to find clay actually plastered on the surfaces of the sand grains; in that case it may not be observed by microscopic examination and may be particularly difficult to separate from the grains. Should a dispersing agent be used, it may become impossible to determine the cation situation in the original clay.

Norris Johnston:

In answer to Cardwell's first question, I agree with Grim that more commonly clay is attached to the sand grains, rather than being in the form of discrete particles. Therefore it would seem logical that neither the coring procedure nor the extraction would involve sufficient forces to separate any appreciable portion of the attached clay.

Cardwell's second question is more difficult to answer. If the salt-water mud filtrate carries chiefly sodium chloride, the deswelling or flocculating action may be accompanied by a base exchange that may promote more active swelling when the formation water returns after the invasion by the filtrate. This subsequent swelling might loosen particles of clay. The loosening would not seem so easily explained as the result of flocculating as it would as the result of swelling. If the filtrate contained an important quantity of calcium salts, the possible base exchange might favor deswelling or flocculation, which should retard rather than accelerate detachment of clay particles which might plug flow channels. In any case, coring, and possibly also extracting, may make some alterations in the clay status relative to the original condition in the reservoir. One way to minimize this is to use oil or oil-base mud or oil phase emulsion for the drilling fluid, in order to avoid an aqueous filtrate.

I. Barshad:

In answer to the third question it appears that this is similar to the reversibility of alkali soils. If an alkali soil high in salt is saturated with a salt solution, the permeability is relatively high. If salts are leached from the soil, particularly sodium salts which produce swelling, the permeability is reduced. This can be reversed by adding another salt such as calcium sulphate and the permeability is reversed. Essentially the same phenomenon probably occurs in reservoir sands. If the reservoir sands are contacted by a sodium salt solution, the salt will diffuse into the sands. The sodium salt can then be removed by water and the process is reversible. If a calcium salt contacts the reservoir sand, the clay present may remain flocculated and the process may not be reversible.

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