Oilfield Water-Oil-Solids Separation

A Technical Paper

by

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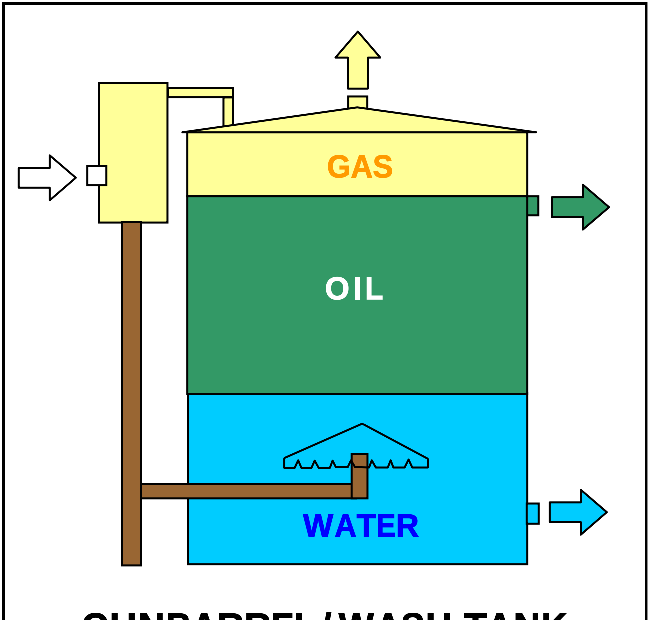
BACKGROUND

Nearly all crude oil producers must separate produced water from oil. Eventually they will also have the need to separate entrained oil from produced water too. Both of these separation processes can be accomplished with many different types of equipment, pressurized or atmospheric, and in many different ways. Some of these are more efficient than others.

When a producer selects atmospheric separation, typically in low-cost storage tanks, the first needs are to select the proper size and the right design for the appropriate separation process. Before deciding what the proper size and the right design are, it is useful to know how the more common and widely accepted designs evolved.



GUNBARREL / WASH TANK
FIGURE 1

For well over 100 years the oil producing industry has used a design which is known as the wash tank, or gun barrel to dehydrate crude oil. In this design the focus is on removing water and BS&W from produced crude oil, with no emphasis on water quality whatsoever.

The produced oil, water, gas and any solids from the well or wells first flows into a degassing chamber. Gas flows up and is equalized with the gas phase in the tank. It commingles with gas evolving from the crude and is piped off to sales, flare, or a vent stack.

Liquids flow down into the tank, and exit under a cone or spreader. The spreader typically has a serrated bottom made up of inverted "V" shaped notches like saw teeth. The v-notches were included to "meter" or distribute the flow of oil uniformly through the water phase, "washing" the water out of the crude. Thus the name "wash tank".

Later versions placed the degassing chamber on top of the tank, so when viewed from the top the concentric circles of the degassing boot and the tank appeared similar to the concentric circles one sees looking don the barrel of a gun. Thus the term "gunbarrel" tank. This design was originated in the 1860s, and is still in use today.

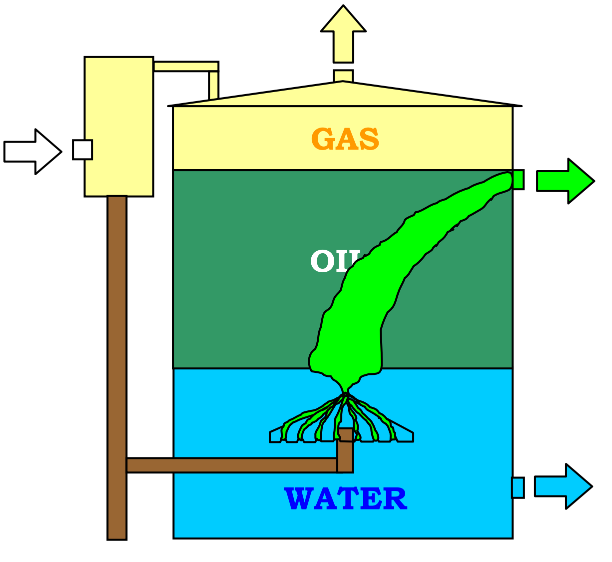
In the 1970s, and again today, the very high-value of crude oil prompted research to determine the efficiency of many oilfield "standard" processes like the old gunbarrel. Retention time studies were conducted in hundreds of gunbarrels/wash tanks and clarifiers/skim tanks. The results proved that the hydraulic efficiency of all designs in use at the time were extremely low, ranging from les than 3% to about 20%, depending on the design. More studies determined the flow characteristics leading to these very low efficiencies.

These flow studies proved that the fluids flowing in most process vessels short-circuit, flowing in a short, narrow path between the vessel inlet and outlet. This was something of a revelation since it was presumed that fluids naturally distributed uniformly in these vessels and flowed piston-like through the entire vessel.

In addition, these studies showed that flowing velocities are critical to separation on a case-by-case basis. That is, when the velocity of the bulk production exceeds the separation velocity of any fluid phase, mixing occurs which offsets or eliminates separation. This was a new level of process knowledge in the industry.

When this new level of knowledge was applied to the traditional gunbarrel (wash tank) the results were startling. Heretofore, generic sizing was based on the need for eight to 24 hours of oil retention time, depending on the API gravity of the crude, interpreted roughly linearly in a range of crude oil gravities from 15° API to 40°API.

The new flow studies showed that crude entering the tank oil wets the surfaces of the serrated spreader, and then, rather than being metered out into the water phase by the serrations where the entrained water was supposed to be "washed" out of the crude, the crude was found to really flow in rivulets



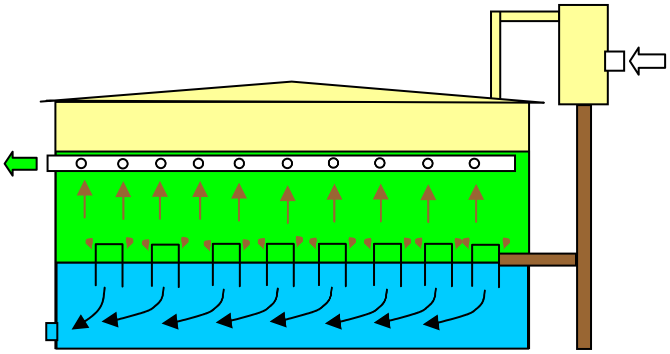
CRUDE FLOW PATH
FIGURE 2

attached to the steel spreader structure, disengaging at the highest or "sharpest" edge surface in large droplets or globules. These droplets flow rapidly and vertically into the oil phase. It was found that very little, if any, horizontal distribution occurs at the oil water interface, which serves to function like a horizontal barrier or hydraulic baffle.

Once the crude passed through the BS&W layer above the water it entered the oil phase, it flows directly to the vessel oil outlet connection. This shortened flow path bypasses the vast majority of the stored crude in the tank. The inlet crude actually only resides in the oil phase for a few minutes. This finding destroyed the old design philosophy of sizing based on enough stored oil to account for 8-24 hours of crude oil retention time. It was clear that any water in the oil phase had to separate in a matter of minutes, rather than in a matter of hours. And, since the age-old formula of 8-24 hours of retention time had worked, it became obvious that all gun barrels were horribly oversized.

At this point, design emphasis shifted away from the assumed oil retention time of the past. Most designers looked for new methods of increasing the actual distribution of oil within a smaller vertical column (volume) of stored crude to improve dehydration. This would result in smaller gunbarrel tanks, and a smaller investment in the oil stored in them

Lucite models were constructed so small scale tests of various internals could be performed. In general terms, the results were quite encouraging. Each investigator was amazed at how inefficient the old gunbarrel design actually is.



HIGH EFFICIENCY CRUDE OIL DEHYDRATOR
FIGURE 3

It became clear that when flow was uniformly distributed it would result in at least a six fold increase in actual crude retention time compared to the old wash tank/gunbarrel design. It was further discovered that truly uniform distribution of incoming crude and emulsion through the entire cross section increased retention times by a factor of 10 to 35.

It was also found that process capacity increased again when the inlet crude and emulsion is NOT washed through the water phase, but is introduced into the emulsion rich layer just above the water phase, since emulsion breaking chemicals tend to concentrate in this layer. Finally, it was observed that flow velocities needed to be carefully considered. A velocity relationship was observed, wherein a fractional oil flow rate directly proportional to API gravity accomplished the desired gravity separation of water from oil. This brought a whole new engineering dimension to the concept of "proper" design.

The conclusion of this work proved that new wash tanks/gunbarrels can be sized much smaller, reducing the capital investment for tankage. The investment of "oil-in-inventory" in smaller gunbarrels is also obviously reduced.

Further, these high-tech gunbarrels produce a very high quality oil effluent regardless of summer-winter swings in temperature and viscosity, for most oils in the 27-40° API range. However, since the separated water short circuits to the outlet, the quality of effluent water in these gunbarrels is extremely poor. It typically ranged from 1500 ppmv to 5000 ppmv oil in the effluent water, or more.

Produced water often contained too much remnant oil, and water quality became important to producers. Again, in the 1970s, several water quality improvement tank designs were tried. They contained a wide variety of internals, the best of which became known as skim tanks or clarifiers. Earlier systems evolved during the early days of secondary recovery, as produced water concentrations grew above 50% of the total production, and as producers learned that oil in water plugs injection and disposal wells, but by the 1970s it was clear that they we no more efficient than the early gunbarrel designs.

SEPARATION AND STOKES' LAW

The static separation of immiscible fluids (fluids that are not soluble in one another), and/or suspended solids, can be predicted by applying Stokes' Law of physical separation. Predicting static separation is very straight forward. An example is predicting the separation of gravel dumped into a tank of water. The tank is "static", which means there is no motion inside. By applying Stokes' Law anyone can calculate how long it will take for the gavel to reach the bottom of the tank. It is obvious that the gravel will settle to the bottom because gravel is heavier than water. It is logical that the larger, heavier pieces of gravel will settle (separate) faster, and the smaller, lighter pieces will settle (separate) slower. An understanding this simple principle is a good beginning to understanding "gravity separation" and Stokes' Law.

However, the word "static" is the key to distinguishing the merits of Stokes' Law from the dynamic separation typically demanded in oilfield separation systems.

Stokes' Law does not go far enough by itself to be applied to most process separation challenges in our industry. This is true because most oilfield process separation systems are not static. Fluids are constantly flowing all the time. There is constant if irregular motion inside process vessels. Nothing is static! So, a law that predicts the rate of static separation had to be modified for oilfield operations where almost nothing is static.

Let's review. A typical oilfield process separation system can be accurately described as those with continuously flowing conditions where all fluids are in motion. But, Stokes' Law only predicts separation in a static, non-moving environment. Nevertheless, a good understanding of the concepts set forth in Stokes' Law is critical to the understanding of separation. So, we start with it.

STOKES' LAW

Stokes Law was published in 1851. It represents the velocity of a rising or falling fluid or particle under static conditions with the following formula:

$$V_s = \frac{2}{9}\frac{r^2 g(\rho_p - \rho_f)}{\eta}$$

Where:

$F = 6\pi r\eta v$,

… and where

F is the frictional force
r is the particle radius
η is the fluid viscosity, and
v is the particles speed
V_s is the particles settling velocity,
g is the acceleration of gravity,
ρ_p is the density of the particles, and
ρ_f i
s the density of the fluid

Stokes' postulated that if the particles fall through a viscous static fluid by their own weight, then he could derive their settling velocity by equating the frictional force with gravitational force.

In order to relate Stokes' Law to the dynamic separation problems encountered in typical oilfield separation it needed to be modified. A good deal of work was necessary to accomplish this. The modified Stokes' Law can be represented in formula form as follows:

$$V = \frac{Cr^2(d_1 - d_2)}{N_1}$$

The Stokes' Law formula focuses on two immiscible phases at one time. When more than two are present, each is calculated independent of the others.

Modified Stokes' Law states that the velocity (V) of separation is equal to the density difference of the two phases (d_1 –d_2) times the square of the size of the fluid/solid particle (r^2) times the gravitational constant (C), divided by the viscosity (N) of the continuous phase.

In both versions, all of the variables have a decided impact on separation. However, <u>the greatest impact is the size of the particles</u> to be separated, since the relationship is <u>not one-to-one</u>, but instead is the <u>square</u> of the size. That is, as the particle size doubles, the separation velocity is increased by four times. As size triples, the time is nine times as fast. As size quadruples, the particle separates sixteen times as fast, and so on. The inverse it also true. A reduction in size of half results in a separation time four times longer. A reduction in size to one-fourth the original size results in a separation time sixteen times longer, and so on.

It is very important to grasp this concept in the real world, since many of the ways we handle and treat produced fluids may reduce or enlarge the size of the particles and droplets we are eventually going to separate.

Separation in the oil industry involves the separation of oil, gas, water, and solids from one another. Separating oil from water is necessary to achieve the desired oil quality so the oil can be sold and shipped to refineries. Separating oil and other contaminants from water is necessary so the water can be re-injected or disposed of without the plugging effects of entrained oils and solids on injection or disposal wells. Furthermore, whereas oil has a commercial value, any oil left in the water not only causes injection or disposal well plugging, but also reduces the income stream from the sale of the oil now lost to the water phase.

So clearly, larger particles sizes are preferable. One of the ways we grow or reduce the size of the droplets or solids we are going to try to separate is with the addition of oilfield chemicals. In most non-chemically stabilized mixtures of oil in water, the majority of the droplets of one in the other are larger than 150 microns. These droplets separate rapidly simply because of their size. However, when the droplets or particles are smaller that 150 microns, separating them becomes an ever-increasing challenge. Over treatment with oilfield chemicals is a major culprit reducing sizes, and thereby in causing chemically stable emulsions and poor separation.

Many other circumstances also cause smaller droplets. Pumping is another real world culprit. For instance, when mixtures with large droplets are moved from one place to another, the act of moving them may provide the necessary physical force necessary to divide the large droplets into smaller and smaller droplets. Imagine the impeller of a typical centrifugal pump, turning at 3550 RPM through a mixture of produced water and oil. The rapidly turning impeller shears larger droplets into smaller and smaller droplets as it turns, pumping the mixture down the line. The smaller droplets separate slower, consistent with Stokes' Law.

In most oilfield operations there are many circumstances that make separation more difficult than it could be. For instance, oil flows from the sub-terrainian reservoir at an ever-increasing velocity into the well bore. There it A) flows to the surface via its own energy, encountering a choke where large droplets are broken into tiny droplets by the forces of pressure reduction (just as in the homogenization of milk), or B) is picked up by a plunger or centrifugal pump which exhibits enormous shearing forces in the process of moving fluid through dozens of impellers, or past the ball and seat discharge check valve.

In these and most other cases the result is the same droplet size reduction. Any reduction of the size of the droplet or particle slows down the separation process. When the droplets/particles are smaller than 150 microns in the real world, the mixture is redefined as a suspension, and separation occurs at a snail's pace.

To get a grasp on the sizes we are discussing here, it may help to know that one micron is 1/1000th of a millimeter, or 1/24,400ths of an inch. While these are very tiny particles or droplets, a person with normal vision can see a 75 micron particle with the naked eye. So, while the 150 micron threshold is tiny, it is not beyond the boundaries of unaided human vision.

Before we go further, we need to understand a few more terms.

In the world of liquid or gas separation models, one or more contaminants are usually suspended in a fluid (liquid or gas) that makes up the largest percentage of the mixture or suspension. This larger, or majority fluid is called the "continuous phase". Additionally, when a mixture is made up of a continuous phase with larger than 150 micron droplets or solid particles, it is considered an unstable mixture or emulsion. When the contaminants are smaller than 150 microns, the mixture is considered a suspension. The smaller the micron size, the more stable the suspension, until finally the suspension is so stable that no Stokes' Law separation occurs.

Let's focus on suspensions that do separate. These suspensions are non-stable mixtures of the continuous and non-continuous phase. The degree of stability of the mixture depends mostly on the size of the non-continuous phase. Again, when average size of the non-continuous phase particles is larger than 150 microns separation will occur readily, usually within minutes.

When the average non-continuous droplets range from 50 to 150 microns, separation times often increase from several hours to several days. When the droplets range from 10 to 50 microns, the mixture is considered dispersion where separation may take many days or even weeks. And, when the particle size of the dispersed fluid is smaller that 10 microns, it is considered a colloidal suspension, where separation may not occur in any practical period of time.

Homogenized milk is a good example of a colloidal suspension. Milk is a mixture of butter fats (organic oils) and water. In the homogenization process, the mixture of raw milk (butterfat and water) is pumped through a tiny orifice under very high pressure. This shears the butter fat particles until they are smaller than 1 micron. The result is a stable, non-separating dispersion of two immiscible fluids. This is the kind of suspension often caused by chokes in oil/gas wells, by the shearing action of multistage downhole centrifugal pumps, by cavitating surface transfer pumps, and by leaking balls and seats in rod pumped wells.

When we look at the actual conditions typical of most oilfield operations, we find that most oil in water and water in oil have particle (droplet) sizes above 150 microns when the produced fluid reaches the surface. These are mixtures which should separate rapidly.

However, this is not always the case. When a droplet is sheared from a mixture size of 200 microns to a suspension size of 50 microns, we know that the rapid separation we might have otherwise expected will not occur. If the 200-micron droplet separated in 5 minutes, the 50-micron droplet (now one fourth the original size) will take a calculated sixteen times longer, or 625 minutes (the square of the square of the original separation time, according to Stokes' Law). This dramatic difference is the reason we will want to concentrate on the methods of fluid handling in production operations. This helps explain why it is sometimes difficult to separate very light oil from very heavy produced water.

Again, poor fluid handling techniques can cause droplet/particle shearing, lengthening the required times for separation. When this happens, producers tend to spend too much money on oversized surface facilities. This is usually a waste of money.

So, it pays to understand fluid handling. A few key examples of fluid handling mechanics that cause droplet shearing, longer than expected separation times, and larger (more costly) than necessary surface facilities, are:

The flow of produced fluids through small restrictions, like:

- the ball and seat of a rod pump, through a choke
- the flapper of a check valve
- a pinched flow control valve
- centrifugal sub-surface and surface pumps
- surface gear pumps
- trim sets in liquid level control valves on separators, free water knockouts, heater treaters, etc.

Pumping produced fluids from one vessel to another, as in:

- circulating tank bottoms
- drawing interfaces off of gunbarrels
- recirculating interfaces
- recycling sump liquids back to the separation processes

In addition, most chemical additives used in oilfield operations also have the effect of reducing particle sizes. Examples are:

Emulsion breakers when high instantaneous dosages are applied, such as:

- slugging a gunbarrel to break a difficult emulsion
- slugging a heater treater to clean up the oil pad
- overtreating the entire production steam
- overtreating a single well steam

Corrosion Inhibitors. These chemicals often depend on water wetting surface active agents to clean organic deposits from the corrosion sites. These powerful surface active agents (surfactants) promote very stable oil-water and oil-water-solids emulsions.

Scale Inhibitors. Both organic and inorganic scale inhibitors are formulated to disperse solids, preventing agglomeration. This is the exact opposite from coalescence (droplet or particle size growth). While stable dispersions are not defined as emulsions, the results are much the same, since the dispersants prevent coalescence (droplet or particle size growth).

Acids: Acids are used for well stimulation. By definition, acids have very low pH values. A low pH environment promotes dispersion. Therefore, droplet and particle coalescence will not normally occur in low pH environments. Acids applied in oilfield production operations nearly always contain surface-active chemicals used to remove the oily deposits from the reservoir rock and scale the acids are designed to attack. These surfactants promote chemically stable emulsions, and this problem is enhanced further by the presence of the very small (usually less than one micron) solids particles carried back to surface treating facilities by spent acids.

Chemically stabilized emulsions add time to the physical separation, as has been described in the preceding explanation of Stokes' Law.
This report can shed light on the causes, but only real-world experience can help predict increased separation time at the Flanagan Lease.

SURFACE FACILITIES FOR OIL-WATER SEPARATION – RETENTION TIME

It can be said that effective physical separation is a function of time. The required separation time is often referred to as "retention time", or the amount of time a fluid is allowed to reside in a process vessel before for the desired separation takes place.

A key factor contributing to oil-water separation in facility design is the prediction and determination of retention time.

From the above it is obvious that droplet or particle size is the most critical factor when attempting to predict what retention time may be needed. It is also obvious that the required retention time must be provided, or separation will not occur. If the surface facilities are too small, separation will not occur. Conversely, if the facilities are too large, money is wasted. And most commonly, if the flow through surface facilities short-circuits, separation will not occur.

Too much money has been wasted on poorly designed, oversized surface facilities throughout the history of the oil industry. Unfortunately, this trend has not slowed. This happens because of the widespread lack of information, and a general lack of knowledge. The most common oilfield approach to purchasing surface facilities has been to simply oversize everything; to throw money at the problem.

Even today, most surface facility designers copy what was done last time, particularly if it worked. This perpetuates the mistakes of the past. So, it is important that we understand it is possible to find the right balance between separation needs, retention time, surface facilities design, size, and cost.

With a basic knowledge of separation, it is possible to use available technologies and good operating practices to optimize surface facility designs. These will save money up-front and during the life of any field.

RETENTION TIME – THE FACTS AND THE FICTION

It is a common belief that if we produce 2000 barrels a day, and we believe we need one-half a day's worth (12hours) of retention time to accomplish the desired separation, we set a 1000-barrel capacity process facility. On the surface this seems to make sense, but a closer look makes us wonder …

Because of this doubt, hundreds of retention time studies are performed worldwide each year. They confirm that the fact that the actual retention time of most facilities is only a small fraction of the design goal.

We can define the optimum design as having 100% "hydraulic efficiency". That is, the fluid entering a facility designed for 12 hours of retention time leaves 12 hours after it enters.

In reality, the design goal of 100% hydraulic efficiency is unrealistic and impractical. When 100% hydraulic efficiency is achieved, flow velocities are so rapid that mixing occurs, instead of separation. Clearly, any hydraulic efficiency that is too good can cause mixing rather than separation. So, how good is too good? All the data to date points to a range of about 65 to 80% of ideal, where separation still outweighs mixing.

Hundreds of actual field tests prove that actual retention time in existing process facilities, even those with the most well known, best liked designs, are in the 0.1 to 21% hydraulic efficiency, far short of the 65 to 80% range.

The fact that the difference is so great between the design and the actual hydraulic efficiency is both enlightening and very discouraging. After all, an efficiency of 1-21% is totally unacceptable in most parts of any operation, no matter what the subject.

A better system is clearly needed, and warranted!

In order to increase the hydraulic efficiency in oil-water separation process vessels the designers have tried virtually every configuration of internal flow distribution systems. These include baffles, velocity increasing orifices, torturous matricies, vortex creating devices, parallel plates, random mass-transfer materials, coalescing tubes, and woven synthetic cloth barriers, just to mention a few.

These and many others have a positive effect on retention time and hydraulic efficiency. Most increase the actual retention time by a factor of two to three times, often increasing retention time to from 1% to 3%, 3% to 6%, or even 6% to 21%. Some even improve separation, while others simply improve mixing at the expense of separation.

The attempts that have had a negative effect on separation are very educational. If a design accelerates the fluid flow in a vessel so it is flowing faster than the Stokes' Law rise/fall rate of the separating droplets, mixing occurs. Again, mixing is the opposite of separation.

When this happens the fluids are not sufficiently exposed to the necessary dynamic flow conditions for separation to occur, even though the retention time and hydraulic efficiency may be theoretically or actually improved. From this you can see that there is more to enhancing separation than simply increasing retention time.

For instance, in any water clarifier, when the velocity of any oil droplet flowing in the mainstream water flow path exceeds its calculated oil-water separation velocity, that droplet, and all droplets that are the same size or smaller, is carried with the mainstream water flow to the water outlet.

The point to be made here is that separation is interdependent of both 1) retention time, or 2) proper fluid flow characteristics. Unless <u>both</u> are correct, separation suffers.

AN EXAMPLE CASE

To bring all of this into focus, let's look at an example case.

Assume we are using a 1500 gunbarrel of the conventional design shown in Figure 1. This gunbarrel contains 1/3rd water and 2/3^{rds} oil. Oil production is now 20 barrels per day. Therefore, the 20 B/D oil flows through 1000 barrels of stored oil in the gunbarrel.

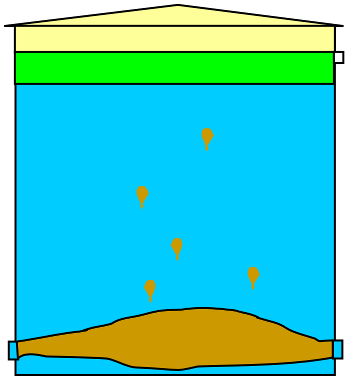
By dividing the 1000 barrel oil capacity of the gunbarrel by the 20 B/D production, it is easy to see that the ideal oil retention time is 50 hours.

In our example the ideal crude oil retention time is 50 hours based on the "tank volume versus flow per day" formula. To determine the actual retention time an oil soluble dye tracer was applied in the field. The results showed a peak concentration after 1-1/2 hours, and zero concentration of the tracer after three hours. Therefore, the 3 hour actual divided by the 50 hour calculated results in an actual 6% hydraulic efficiency.

THE FOCUS SHIFTS TO WATER QUALITY

With the advent of large scale waterfloods in late 1940s, water quality grew in importance. By 1960 water quality was in the forefront of the minds of all who dealt with water injectivity as an enhanced oil recovery mechanism, or simply for underground disposal. By 1970 the first Clean Water Act became law in the United States. Just as this Act mandated cleaner water, it also became a model for cleaner water internationally.

Water quality depended on the process efficiency of thousands of water storage, or "skim tanks". From the 1970s through the mid-1980s a great deal of thought was given to improving the inefficiencies of older skim tanks to improve water quality. Field tracer surveys showed short-circuit flow paths were typical in most skim tanks. This is shown in Figure 5, right. Retention times were documented at less than 3% of the calculated (expected) retention time, in test after test. Many new concepts were tried in an effort to improve water quality and lower costs. Additionally, internal baffle adaptations were also tried in attempts to improve effluent water quality.



TYPICAL SKIM TANK
FIGURE 5

In this time frame the industry's financial condition was unusually strong. The value of crude was high enough that every effort was made to capture every last drop and send it to the pipeline/refinery. Therefore, more testing of higher degrees of sophistication were funded. New tank internals were developed, installed, and performance tested. Practical, proven field test methods were used. These include the application of known quantities of fluorescene or urinine dyes.

In general, the results were quite dismal. More and more test results proved that most of these new designs still had unacceptably low hydraulic efficiency, and in many cases even poorer separation efficiencies. It seemed that adding baffles simply caused more mixing and re-entrainment rather than achieving the expected increases in retention time and separation efficiency.

IMPORTANT LESSONS LEARNED

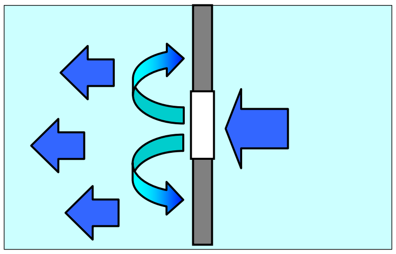
As the boom years came to an end in the mid1980s, even more exotic designs were tried. Some reached as high as 21% hydraulic efficiency. But, for the most part, they proved to be too costly, too unreliable, or simply poor separators. The poorest of these new designs were proven to have frustratingly low hydraulic efficiencies of less than 0.1%.

However, in all of this, important new lessons were learned. One of the more important lessons was, as previously stated, *that increased retention time alone does not necessarily enhance the separation of immiscible fluids*.

The reason for this is that most of the various methods of increasing retention time, such as vertical baffles that create a serpentine-like flow pattern, actually increase the horizontal flowing velocity of the fluid to a rate greater than the separation velocity of the separable fluid fraction. As previously stated, when the horizontal flow rate is greater than the vertical separation flow rate, separation ceases and mixing occurs.

Finally, the industry began to come to grips with the fact that good flow characteristics enhance separation as much as increased separation time.

Another point learned was that *eliminating acceleration points, where re-entrainment of separated fluids can occur, was even more important than vessel size.* An example of this is a fluid immersed vertical baffle or group of vertical baffles with holes drilled in it/them. The holes distribute the flow across the cross section of the baffle and prevent short circuiting by creating a usually small pressure drop. However, the result of this or any restriction is to create an accelerated velocity at the exit of each hole. The fluid flow rate must increase through each hole. As was explained above, when the horizontal flow rate due to this acceleration is greater than the vertical separation flow rate, separation ceases and mixing



Eddy Currents in Orifice Flow
FIGURE 6

occurs. Furthermore, flow path studies have proven over and over again that altering flow direction can cause re-entrainment of separable fluids. As the flow of a fluid exits any office, the pressure drop produces eddies (Figure 6) which wrap around back toward the orifice, increasing the flow velocity even more, shearing and mixing larger droplets into smaller droplets and re-entraining dissimilar fluids. Obviously, these forces are detrimental to separation.

HWSB DEVELOPED, TESTED AND PATENTED

Then in the mid-1980s, the oil boom came to an end. The price of oil fell back into the teen, and finally into single digits again. The strong financial position of the industry vanished almost overnight. Knowledge took a back seat to survival. The lessons learned, and a large portion of the knowledge gained, was lost as a result of lay-offs and early retirement programs.

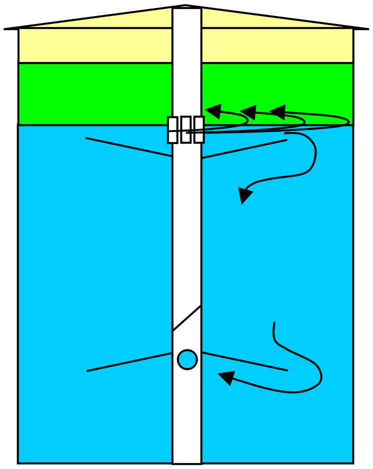
One survivor of this inevitable downturn was the desire to develop an efficient and simple gravity flow oil-water clarifier that improves performance to more reasonable levels. Work continued through this period of time, though on a scaled back level. New designs slowly evolved, were tried and fine tuned. Each gave way to the next until the design known as the HWSB™ was fully developed.

Finally, in the early 1990s Patent Number 5,073,266 was granted on a system that accomplishes the goal of clarifying produced water to injection/disposal water quality!

This patented system known as the "HWSB™".

The HWSB™ is a wide departure from all previous conventional wisdom. Its design is quite unusual. It has no moving parts. It applies concepts not found elsewhere in oilfield processing. It looks outside our industry for methods proven to be sound in other types of fluid handling. It clarifies water. It approaches the ideal condition of piston displacement, resulting in very efficient, repeatable, and forgiving separation efficiencies.

And, every HWSB™ is engineered and designed for each individual application.



HWSB™ Skim Tank
FIGURE 7

By altering the HWSB™ design slightly, it becomes a crude oil dehydrator (a modern gunbarrel/wash tank) as well as an ultra-efficient water and oil clarifier. It is the 21st century's ideal skim tank. And, where suspended solids like iron sulfide or oil coated formation fines, create interface layers or settle to bottom further proven additions to the basic design control these conditions so they no longer affect water or oil quality. When the standard HWSB™ is modified with proven solids and interface removal systems, cleaning and normal maintenance can also be prolonged indefinitely.

THE HWSB™ ENGINEERING AND DESIGN

The engineering and design process for each HWSB™ is time consuming and quite detailed. The inlet fluid velocity MUST be slowed to less than rise and fall rates of the contaminants in the water phase. This must be done carefully, and in stages, so the oil separates upward to the top of the vessel, and the solids separate downward to bottom. Changing the direction of flow is necessary in this process, so avoiding shearing and mixing velocities is critical. The annular spaces created by the tank walls and internal spreaders are carefully sized to accomplish this up to the maximum flow rating of each HWSB™.

Over 80% of the oil separation that is going to occur in a HWSB™ occurs above the inlet spreader. The remaining remnant oil exists in such small droplets that they carry over with the bulk water flow as it turns downward in the upper annulus area. The eddy current created by this properly designed annulus pulls the bulk water under the upper spreader where wit redistributes into a near-perfect plug flow (piston displacement) flow path. Here the bulk water velocity is dramatically reduced, and the smaller (20%) oil droplet separate. They are carefully collected and flowed out of the water phase and into the oil phase near the top of the vessel without traveling through the flowing water where they would surely be re-entrained.

The properly designed HWSB™ manages all fluid flows to maximize water-oil and water-solids separation. It has an overall hydraulic efficiency which approaches 72%, now considered near the real-world maximum where mixing forces take over and reverse otherwise very efficient separation efficiencies.

Today, over one hundred HWSB™ systems are in service throughout the world. Each and every one of these was designed for its specific application. And to date, every one of these has outperformed the expectations of the owner.

Please contact HTC for more information.