



Sizing Process Equipment in 2015

Sizing vs. Instantaneous Flow – Why it's Such a Big Deal

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PREFACE

With the price of oil down, and every cent more important than it was just a year ago, and getting it right means more today in terms of cash flow and profitability. In facility design sizing of oilfield process equipment should be quite straight forward, given that we have been doing it for more than 140 years. However, the basic principles used to size vessels and facilities has and continues to elude most of us, even in 2015! This paper makes an effort to resolve this issue so we can do a better job selecting the right process equipment for our surface facilities this year and beyond.

HISTORY

Historically, many people working in the oil industry were taught that successful separation is a function of “retention time”. For decades, most oilfield workers believed that if they flowed 100 barrels per day through a 100 barrel tank the result would be a one day retention time. This was such a simple concept that it was rarely challenged, and was instead accepted as a reality, taken for granted year after year. As incorrect as this is, for some of us, it still is!

The fact is that fluids do not displace fluids in a plug flow, or piston-like displacement manner. Instead, fluid flows in the path of least resistance. The difference between these two conditions, the one being hypothetical, the other being real, is the difference between perceived retention time and real retention time.

Retention time is defined as the time any fluid spends in a process vessel, or as the time it must spend in a process vessel, for the process goal to be met.

Over the 150+ years since the first oil well was brought in a rule of thumb has been established which is widely held to be valid. That rule of thumb is that “to dehydrate crude oil in an atmospheric oil-water separator, the crude oil must stay in the separation vessel for at least eight (8) hours. This concept was based on trial and error, and has therefore been quite difficult to refute.

The most common oil-water separation vessel in the oilfield today is known called a “Gunbarrel” or “Wash Tank”. Both are the same basic design. Both were developed over 100 years ago for completely

different low-water cut conditions!! In either of these the inlet fluid is degassed in a degassing section known as the “gas boot” or “degassing boot”. This boot is a small diameter short vertical “can” located on top of or beside the process tank. The idea is for most or all inlet free and solution gas to evolve from the liquid before it enters the separation vessel (Gunbarrel/wash tank). For the purpose of this paper let’s agree to use the term “Gunbarrel”.

As mentioned above, the sizing of Gunbarrels was developed by trial and error, decades before the first petroleum engineer was graduated. The trial and error method was to build a Gunbarrel for a given application, and if it didn’t work, to build a larger one. If it didn’t work, an even larger one was built to replace it, and so on until one of them actually worked, dehydrating the crude to the required quality specification. From this trial and error method the today’s industry standard “rule of thumb” evolved. Simply stated it is that building a Gunbarrel large enough to hold the equivalent of eight hours of produced crude oil dehydrate 30° API crude to pipeline quality. The tank size can be adjusted for crude in the 20° API to 40°API range so it contains more oil for lower gravity and less for higher gravity. Just how much “adjustment” is relatively undefined, but by and large this works!

There are exceptions. When the crude is particularly heavy, or the water is particularly fresh, or the crude or produced water has a natural or man-made emulsifier in it, or if the production is produced through a choke, or since the 1960s, if the produced fluid is produced by an ESP (electric submersible pump), sizing a Gunbarrel becomes much more complicated. In these cases, eight hours is often times not sufficient to achieve the desired “pipeline quality” crude even with higher gravity crudes.

The natural conclusion is to build an even larger Gunbarrel for these applications! However, bigger often result in channeling flows, where oil and water take the path of least resistance from the inlet to the outlet, by-passing the majority of the tank’s volume and potential retention time.

It wasn’t until the early 1960s that all of this came into question. Waterflooding gets the credit for raising the issue of sizing and performance. With the advent of waterflooding in the late 1940s water cuts began to rise. Production levels expanded to volumetric levels not seen in existing oilfield operations for decades. For the first time in the history of the oil patch whole fields began producing more water than oil!

While waterflooding reversed the decline rates of most of the largest oilfields, it was a two edged sword. Production equipment designed to remove small amounts of water from large amounts of oil began to fail, carrying over huge amounts of water with the oil, and vice versa. The process equipment industry responded with first vertical and then later, horizontal pressure vessels known as free water knock outs (FWKOs). These removed the bulk water from the crude, and allowed the process equipment downstream (heater treaters, gun barrels, etc.) to function more normally, at least for a time.

However, as more ESPs were installed and more water was produced, the water and oil quality coming from most oilfield process equipment began to suffer again. Larger FWKOs proved ineffective as instantaneous flow rates surged ever higher, and flows inside vessels again channeled through these vessels in the paths of least resistance.

TRYING TO SOLVE THE PROBLEM

Several large and small oil producers, having invested millions of dollars in their process equipment, began to pressure the process equipment designers and manufacturers for new and more efficient equipment designs. These requests fell mostly on deaf ears as the industry first struggled to overcome the downturn (“bust” cycle) of the middle 1950s and 60s, and then struggled to react to the boom cycle of the post Arab oil embargo years of the 1970s and early 80s. Nevertheless, some advances did take place. They included:

- *The introduction of dissolved air flotation into water cleanup system designs
 - *This trend was soon reversed by the introduction of the Wemco dispersed air flotation technology and clones of it which proved to be so ill-designed for oilfield operations that they essentially reversed the trend to use floatation altogether for the next several decades, with the exception of offshore where their smaller footprint made them the only economically viable option.**
- *The introduction of inclined and matrix plate coalescing aids for FWKOs to reduce droplet rise/fall distances and increase separation efficiency.
 - *While this technology worked very well, this trend was rapidly reversed as the plate sections plugged, often prematurely. The technology was all but discarded as causing too much downtime and as being too maintenance intensive.**
- *The introduction of sophisticated and automated heavy mineral sand and mixed media water filtration systems.
 - *These became the standard of the industry, but their use began to wane as well as the media became rapidly oil wetted and ceased to filter. Many service companies were created to work on these systems in an effort to make them pay off, but eventually many were abandoned as too maintenance intensive.**

So, by the time the next “boom to bust” cycle appeared in the early 1980s the industry as a whole had truly not advanced all that much in the advancement of better oilfield surface equipment designs.

It may not be surprising, looking back at those years, that many of the equipment failures could be traced to sizing issues. Systems sized for a given volume were found to be processing many times the rates they were sized for, and swings in production volumes were the order of the day. A field producing 50,000 b/d one day with all ESPs running could be producing 30,000 b/d the next day, and then, as larger and larger ESPs were installed to handle the ever-increasing water production, 75,000 a month or two later. It is not surprising that a surface process facility which may have functioned well at a design rate of 50,000 b/d was found to be mal-performing at 75,000 b/d. This became the order of the day, and this reality began a shift in design mindset to a harder look at sizing based on instantaneous rates, rather than on daily averages.

However, this too proved to be an inadequate approach. It was soon found that systems designed for one flow rate actually experienced a widely variation in flow rates on a minute-by-minute, or instantaneous basis. This was never more obvious than in natural gas liquids production where a gas stream may flow at one rate while liquids accumulate in lower elevation inlet piping and then, all at once, unload into the production facility all at once at a huge instantaneous rate. A closer look at most oilfield operations

proved that nearly all oilfield operations function like this to one degree or another. It was also observed that the higher the deviation in instantaneous flow rate, the greater the degree of upset in the ability of the surface process equipment to achieve the desired results.

As more and more operators observed this condition, more and more oil storage tanks were fitted with bottoms circulating pump to recycle the water that separated in the oil tanks, water carried over with the oil from the upstream separations equipment during upsets, back to the inlet to the separation equipment upstream. Sometimes, recycling made things worse! Oversized recycle systems contributed to the magnitude of each upset, increasing the flow rate during the time the recycle system was turned on.

Then, as field production declined, and upsets became less intense, less carryover occurred and the newer generations of oilfield workers abandoned the use of recycle systems, not recognizing their usefulness in the first place through lack of experience. Fewer and fewer designers installed recycle systems, and over time this valuable concept was lost.

By the turn of the century the domestic oil industry had become an industry dominated by water. It could be said the oil industry is now the “produced water industry”, since much more water is produced in most oilfields today than oil.

As oil cuts fall off and water cuts increase, today’s operators are also faced with rising costs of energy, labor, and equipment. More ESPs are installed today than ever before, and the number is on the rise. This means more and more water is being produced with less and less oil. Extreme examples exist today where hundreds of thousands of barrels are recycled through reservoirs to make less than 1000 barrel of oil. In these operations water cuts exceed 99.5%!

In the 21st century oilfield operations, when an ESP pumps off it automatically shuts down. These on-off cycles are totally random and completely unpredictable from one minute to the next. This means that tremendous variations in flow exist, making the instantaneous flow rates harder than ever to predict.

It should be obvious to almost every reader of this paper that the easiest way to process anything is in a steady state environment where nothing ever changes. Once we grasp the reality of this statement, it becomes crystal clear that when we deviate from steady-state conditions, we make it more and more difficult to achieve the desired process. From this statement it may appear that we, as an industry, are caught in a dilemma. We can’t efficiently produce and sell oil if we don’t allow our operations to deviate drastically away from a steady state operating condition. So, the question becomes, “How do we design process equipment that will actually absorb these man-made upsets?”

The answer may be more obvious than the question! The key to success is to size separation equipment based on the deviation in flow. This is not quite the same as sizing for the maximum instantaneous flow in all cases, however. Let’s see why.

PROPER SIZING

If the process equipment can be sized to buffer the highest highs and still function, then we can reduce the vessel size that would be have been based solely on the maximum instantaneous flow rate. Doing so not



only shrinks vessel size, but shrinks the cost as well. This is a more intelligent approach, but is not to be taken for granted.

To be successful in selecting the “right size”, more information is needed ... information the producer may not have. Information like:

- *The actual maximum instantaneous flow rate*
- *The duration of the slug*
- *The concentration of gas in the slug*
- *The fluid cuts (percentages of oil and water) in the slugs*
- *The effect on the receiving vessel in terms of ALL levels*
- *The effect of the slug on BS&W*
- *The effect of the slug on water-in-oil carryover*
- *The effect of the slug on oil-in-water carryover*
- *The effect of the slug on suspended solids concentrations in the water effluent stream*

In order to get realistic answers to these questions, it may be necessary to spend time actually measuring flows, observing surges, gauging tanks. This takes time, and time is a valuable commodity not all oilfield workers are willing to devote to this issue. When they are, however, the sizing solutions come into view!

For the sake of clarity, let's look at an example.

EXAMPLE

Let's assume the nominal inlet flow is 12,000 b/d of oil and water. Let's assume the water has a specific gravity of 1.02 and that the oil is 32° API, and that the total contains 200 b/d of oil. Let's assume the nominal GOR is only 10:1. (12,000 b/d = 350 GPM)

If this is all we knew we would select a 12' OD X 25' high HWSB™ to clarify the water and polish the oil to pipeline specs.

However, now let's complicate the conditions and the HWSB™ sizing by assuming that half of the daily production comes from two ESPs that cycle on and off based on FOP, and that the rest are on rod pumps that run 24/7. On average, the ESPs run about 16 hours per day each, and they start and stop independently.

This means that 6,000 b/d or the total is produced in 16 hours, while the other 6,000 b/d is produced at a rather constant rate. If we boil this down to instantaneous flow, the 6,000 barrels/16 hours from the ESPs is equivalent to 9.37 barrels per minute, or 394 GPM, assuming that both run at the same time for 16 hours straight. Let's further complicate the issue by presuming that each ESP pumps off, and cycles off, once every 30 minutes, and stay off for 30 minutes. This means that the real instantaneous rate is twice the average. So, when the two ESPs get in sync, they run for 30 minutes producing 30 X 9.37 X 2 or 562 barrels for 30 minutes, or 17.7 barrels per minute, or 786 GPM, and then shuts off. When only one

ESP runs during this same 30 minute period, when they are 180° out of phase with each other, then the ESP instantaneous rate is cut in half to 393 GPM.

When we look at the rod pumped wells the total instantaneous flow is 4.167 barrels per minute, or 175 GPM. So, when the ESPs are off the HWSB™ Gunbarrel experiences an inflow of only 50% of its capacity. When one of the ESPs kick back on, it experiences an instantaneous flow rate of 175 GPM plus 393 GPM, more than doubling the throughput for 30 minutes. This is the equivalent of 19,474 b/d ... or 62% more than the 12,000 b/d initially used to size the HWSB™.

When both pumps pump in sync, the ESP rate doubles to 786 GPM or the equivalent of 26,949 b/d plus the 6,000 b/d from the rod pumps, totaling 32,949 b/d.

*From this it may be clear that the 12' X 25' HWSB™ originally thought to be sized properly, is much too small for this application. This size vessel has a 500 bbl. storage capacity, so if it were selected its storage volume would be completely displaced during every ESP pumping sequence. It would not have sufficient storage capacity to buffer the condition where both ESPs pump simultaneously, so it **MUST** be sized larger ... and **ONLY** because of the instantaneous flow rate.*

CONCLUSIONS

Instantaneous flow rates are elusive and hard to determine accurately. Nevertheless, the effort to properly determine the actual maximum instantaneous flow rate is critical to the proper sizing of all oilfield process equipment. When sized properly, most oilfield process equipment will function as desired. For more information call HTC at 918-298-6841 or visit www.hitec1.com on the web.

ABOUT THE AUTHOR AND HTC



Bill Ball is the founder and owner of HTC, Inc. He has a long history of oilfield separation system design experience, which when coupled with his hands-on oilfield experience and career portfolio, make him one of the industry's leading separation authorities today. After his university studies he launched his career in a 1,000,000 b/d waterflood operation where he was responsible for the evaluation and performance improvement all surface facilities. Through this hands-on effort, he learned the modifications necessary to improve process efficiency; what works and what doesn't! In the decades since Bill has accumulated a lifetime of knowledge and experience in the fields of real-world oilfield separation and facilities design. Bill's many patents speak for themselves.

The culmination of Bill's efforts to improve processing in oil field operations is the Pro-Fit® System with its DFSD™ De-sanding, Flow Splitting, and De-gassing tank, the HWSB™ Skim Tank, a Gunbarrel replacement for all high water cut applications, and the "HEGB™ High Efficiency Gunbarrel". These unique designs achieve the highest level of hydraulic and separation efficiency known to exist in any design. In combination they form the foundation of HTC's ProFit™ SWD Plant Design Package currently considered to be the most cost effective SWD Plant Design available. In overview, each produces results that achieve unparalleled quality in the effluent streams.



Today in 2015, HTC, Inc. is one of the industry's leading low-cost surface facilities design firms. HTC specializes in salt water disposal (aka SWD) plant, flowback water treatment plants, two and three phase separation systems, and crude oil processing and dehydration/desalting plant designs worldwide. 3D Cad augments 2D designs and gives clients and construction firms another 21st century tool to use in shrinking costs and installation times.

In 2015 more HTC facilities blanket every sector of the oil and gas industry than ever before, adding to HTC's already strong reputation as a competent and capable full service engineering and design provider to meet your every need.

