

Sizing Process Equipment

Instantaneous Flow – Why it's such a big deal

Author: Bill Ball

President, HTC, Inc.

PREFACE

The sizing of oilfield process equipment should be quite straight forward, given that as an industry we have been doing it for more than 140 years. However, this basic principle has and continues to elude most of us. This paper makes an effort to resolve this issue.

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 typical oil-water separation vessel is known today by the names "Gunbarrel" or "Wash Tank". Both are the same basic design. The inlet fluid is degassed in an atmospheric pressure degassing section known as the "gas boot" or "degassing boot". This boot is a smallish vertical two phase separation vessel operated at atmospheric pressure so most or all solution gas has an opportunity 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 eight hours' worth of crude oil will render it successful.

By and large this works!

Unless 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). In these cases, eight hours is often times not sufficient to achieve the desired "pipeline quality" crude.

The natural conclusion is to build an even larger gunbarrel for these applications!

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.

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 it essentially reversed the trend to use floatation altogether for the next several decades.
- The introduction of matrix plate coalescing add-ons for FWKOs to increase separation efficiency.
 - While this technology worked very well, this trend was rapidly reversed as the matrix plates plugged 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 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 $30 \times 9.37 \times 2$ 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 since the real instantaneous flow rate is the rate at which each vessel will need to perform its tasks. When average hourly or daily rates are used for sizing, vessels are typically undersized and the separation efficiencies are quite low as a result. When instantaneous rates are overestimated, equipment is often oversized... In this case fluid distribution efficiencies suffer as does overall performance. The window of opportunity, where proper sizing is based on real instantaneous rate, is relatively small. Every effort should be made to discover and apply it.

ABOUT THE AUTHOR



Bill Ball began his oilfield career in the Mechanical Engineering department of a one million barrel per day oilfield waterflood operation where he was in charge of surface facilities performance and design. He then worked as a product development and applications engineer for Diversified Chemicals Corp. (later Amoco Chemicals), an oilfield and industrial water chemical treating company. Bill then joined CE Natco and went on to manage one of its West Texas branches in Hobbs, NM. There, Bill promoted a local fab shop to better satisfy the needs of Natco's clients. Bill accepted a promotion and moved to Natco's headquarters in Tulsa. When Natco relocated to Houston, Bill left Natco and joined IT McGill Environmental where he served as director of McGill's Marine Vapor Control Group. IT-McGill was later purchased by Koch Industries and absorbed by its John Zink Division, where Bill served as director of business development for Latin American and later as a manager in Zink's vapor control group. He formed High-Tech Consultants, Inc. in 1992 and has served as its president ever since.