

VAPOR CONTROL SOLUTIONS FOR UPSTREAM OIL AND GAS PRODUCTION

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ABSTRACT

Volatile organic compound (VOC) vapors are generated in a variety of upstream oil and gas production operations. Proper management of VOC vapors is important for safety, environmental, and economic reasons. While there is no “one size fits all” solution, Trimeric has worked with upstream oil and gas producers over the past 10 years to identify and develop a variety of VOC control solutions that can be tailored to customer and site-specific requirements. Current and future production rates, the number of sites, availability of power, regulations, capital and operating costs, maintenance requirements, operator attention, cold climate impacts, and several other factors are taken into consideration for selection of VOC control methods at these sites. A variety of thermal oxidizers including open and enclosed flares with different methods for staging burners and providing combustion air will be presented. Different types of vapor recovery unit (VRU) systems will be reviewed including those based on reciprocating, screw, and centrifugal compressors. Use of slug catchers, surge bottles, and vapor recovery towers (VRTs) to maximize flash gas recovery and to minimize flashing of the liquid in the storage tanks will be discussed.

Introduction

Volatile organic compound (VOC) vapors are generated in a variety of upstream oil and gas production operations. Control of vapors generated during production is a critical part of these operations for safety, environmental, economic, and other reasons. This has become more important in recent years due to increasingly stringent environmental regulations and as the number of domestic oil and gas production sites has increased, sometimes in close proximity to nearby communities or in areas with strict environmental requirements such as ozone non-attainment areas.

Vapors formed are predominantly hydrocarbon streams that contain species regulated as VOCs resulting in permitting, reporting, and other administrative requirements in addition to emissions control requirements. The vapor streams are flammable and may have a detectable odor. Combustion-based control devices like flares generate secondary pollutants including NO_x and CO, as well as some unburned hydrocarbons (VOC). In addition to managing these issues, there is an economic benefit to reducing the formation of the vapors and reducing the emissions associated with their control as this usually results in additional oil and gas production coupled with lower costs for emissions controls.

The sheer number of oil and gas production sites, which can number in the hundreds or even thousands for a single operator in a large field, is a key factor in development of a successful vapor control program. Many sites lack access to electrical power and other utilities and control equipment is often required to operate with only produced gas for a fuel source and a driver for pneumatic devices. Sites are typically unattended and may be visited by production personnel once or twice a day and for no more than a few minutes per site due to the number of sites that each “pumper” must cover on their route. Management of water and hydrocarbon condensation, solids formation, and related cold climate impacts are addressed throughout the paper. Taken together, these factors drive the need for a low-cost, reliable, and simple approach for reducing the formation of these vapors and the emissions they can generate. As one might expect, there is no “one-size fits all” solution to this problem, but this paper will present many lessons learned in the field from more than 10 years of working on this problem at over 100 production sites.

Site Description, Common Equipment, and Vapor Sources

The typical oil and gas production site will have process equipment for separating oil, natural gas, and produced water. Each site will serve one or more wells. The oil and produced water are typically stored in separate tanks and the flash gas that forms when produced oil or condensate pressure is reduced is either flared or sent to a pipeline. While the specific configuration can vary from site to site in terms of the type and number of separators, storage tanks, and control devices, there are some commonalities that can be used to describe a typical site for the purposes of this paper. Usually the site will have multiples of each device and there has been a trend to have higher multiples consolidated in larger common pads that has been facilitated by the increase in horizontal (or directional) drilling.

Wells can have continuous, free-flow production or cyclic on/off operations. Wells can be pumped or supported by gas lift, while others rely on reservoir pressure and are turned on and off by actuated valves on automatic timers. Some wells, such as older vertical wells, sometimes use

a plunger-lift in the production tubing that helps to sweep accumulated fluids to the surface. Several of these production operations result in discreet surges in fluid production that can generate high peak flow rates of vapor that must then be controlled. Trimeric has observed peak flash gas rates up to about 30 times the daily average values.

Figure 1 shows a typical flow schematic for a production separator, which is also sometimes referred to as a heater treater. Figure 2 is a picture of one of these separators. The production tubing transfers the produced fluids from the wellhead to a flowline that often flows through the heated part of the production separator before passing through an orifice (or choke). Heating before the fluids go through the choke helps to manage the temperature drop as pressure of the fluids is reduced across the choke. The three-phase mixture of oil, gas, and water is flashed into the separator. Sales gas comes off the top of the vessel and liquids are heated via a submerged fire-tube. Hot exhaust gases from a burner that uses some of the gas produced at the site pass through the inside of the fire-tube. The temperature set point for this heating is chosen to break oil-water emulsions and to facilitate oil/water separation, so that the oil meets BS&W requirements. Heating can also prevent wax or paraffin buildup. A weir separates oil and water into separate sumps called the oil box and the water box. A weir separates oil and water into separate sumps called the oil box and the water box.

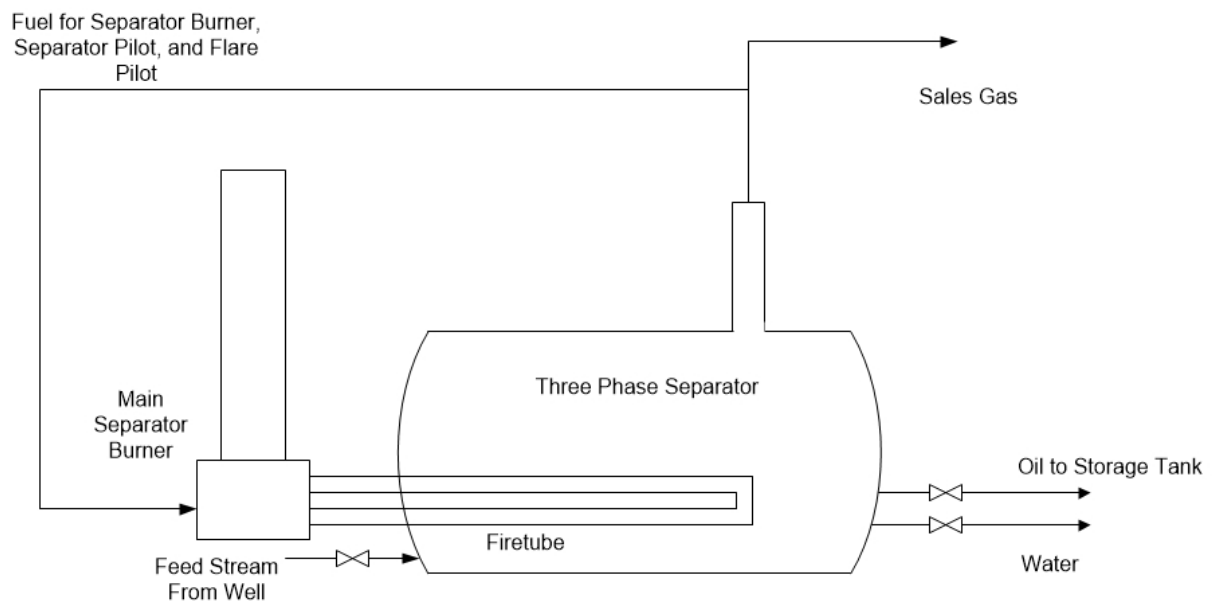


Figure 1 – Single Stage Production Separator Schematic



Figure 2 – Picture of Single Stage Production Separator

A typical separator will have simple, pneumatically actuated, snap-acting controls. For example, when the oil level reaches the high set point, a valve dumps the fluid to an atmospheric pressure oil storage tank. Some oil flashes to vapor due to the lower pressure downstream of this valve and this is typically the largest generator of vapor at these sites. Water is dumped from the water box in a similar manner, but this is not typically a significant generator of vapors and is not part of the focus of this paper. Dump valves automatically close when the low liquid level is reached, resulting in discreet slugs of oil going to the storage tanks with a commensurate production of flash gas. When production from the well(s) is at its highest rate, the oil dump valve can open very frequently (e.g. every 15 to 30 seconds), generating a significant amount of flash gas that needs to be controlled.

There are also some vapors generated in the storage tank due to liquid level changes. Withdrawing oil from the tank lowers the level in the tank and some liquid evaporates to fill the additional head space. When more liquid is added to the tank, these vapors are compressed due to the rising liquid level and the vapor will go to a control device once the pressure in the tank exceeds a set point (typically a fraction of one psi described in ounces (oz./in²)). There are also breathing (or standing) losses that occur when diurnal or other temperature increases heat the vapors already in the head space of the storage tanks. These working and breathing losses are also part of the vapors to be controlled at the site, but typically these are secondary to the vapors generated by flashing the oil to atmospheric pressure.

Separators can have multiple stages of pressure reduction (typically two stages), which can reduce generation of vapors and slightly increase oil production. It also creates additional options to recover or treat vapors at an intermediate pressure between the high pressure separator vessel that rides the sales gas pipeline pressure and the atmospheric pressure storage tanks. Reducing the amount of vapor generated and recovering some of it instead of flaring it all

generally results in higher revenue and also reduces the amount of vapor that needs to be controlled, which is clearly a win-win scenario. However, it is important to have proper pressure and temperature settings in each stage of the separator to realize these benefits. This is discussed in more detail later in this paper.

Vapor control equipment is typically an open or enclosed flare (thermal oxidizer) or a compressor-based vapor recovery unit (VRU), and many sites have both. At many sites, each flare is referred to as an emission control device (ECD), whereas VRUs and related components upstream of the ECD are usually considered production equipment. A flare typically combusts (oxidizes) the vapors with 98% or better efficiency. A VRU with sufficient capacity captures nominally all of the vapors and returns them to the sales gas line. However, if the VRU is powered by burning some of the sales gas produced at the site, this results in some secondary emissions and a reduction in sales gas revenue.

Many sites will use a VRU to capture vapors available at intermediate pressure and one or more flares to treat atmospheric pressure vapors coming off the storage tanks. Another key advantage to this approach is that the flares serve as backup control devices for all vapors to be treated at the site when the VRU is out of service. VRUs can also be used to treat vapors from atmospheric pressure oil storage tanks, but a gas blanketing system, catalytic oxidation unit, or other measures may be needed to prevent oxygen (air) ingress into the storage tanks from leading to issues with sales gas exceeding the oxygen pipeline spec, which is typically on the order of 10 ppmv. These control devices and related approaches for vapor control are discussed in more detail later in this paper.

Several strategies to dampen the peak vapor generation rate have been tested and/or used in production. These include slug catchers upstream of the separators and interstage pressure vessels sometimes referred to as surge bottles or buffer tanks. Some producers use another heater treater downstream of the production separator for the intermediate pressure vessel. Changing the timing and/or duration the wells are on-line may also be an option to reduce the peak generation rate (such as staggering wells instead of having multiple wells on-line at the same time), but many producers prefer to avoid changing production operations in favor of adjusting the downstream vapor control operations. As one customer explained to Trimeric, “They don’t want the tail wagging the dog.” Approaches to reduce the peak vapor generation rate are also described in more detail later in this paper.

A related approach, the vapor recovery tower (VRT) located between the separator and the storage tank uses hydrostatic head pressure to drain oil from the VRT to the storage tank at very low pressure (~ 3 psig), while vapors from the top of the VRT go to a control device. The VRT doesn’t lower the peak vapor generation rate to the extent that a surge bottle does, but routing these vapors from the VRT to a VRU instead of from the storage tank to a VRU eliminates the potential for air (oxygen) ingress that can be an issue for recovered gas sent to the sales gas line. Also, the vapor generation rate is significantly reduced in the oil storage tank due to the much lower upstream pressure in the VRT as compared to the production separator or surge bottle.

Pressure relief valves are installed on separator vessels and oil storage tanks. If vapors are generated at an instantaneous rate that exceeds the capacity of the control device(s), they are vented to the atmosphere to prevent excessive pressure in the vessels or tanks. In some

locations, regulations only allow tank venting in emergency situations. Preventing this from happening is a major objective of vapor control systems at these sites.

A common issue throughout these sites and most of the equipment previously described in this section is management of condensation and/or solid formation. The produced gas is typically rich in hydrocarbon content and saturated with water vapor. Many sites in cold climates run into issues with undesired condensation of water or hydrocarbons and/or formation of solids that can include ice, paraffins, and hydrates. Management of these issues on a case-specific basis is discussed in the remainder of this paper.

Impact of Separators (Heater Treaters) on Vapor Generation and Control

Single Stage Separator

A simple, single stage production separator (or heater treater) was described and shown in the previous section. Vapor control is simple, but not necessarily optimal, in this scenario. Gas in the separator goes into the sales gas pipeline, water goes to a water storage tank (or vault / sump), and oil dumps to the storage tank. When the oil dumps to the storage tank, some of the liquid flashes to vapor and all of the vapors to be controlled end up in the storage tank. In addition to the flash gas, this also includes the working and breathing losses described in the previous section. The control device is typically one or more flares, but a VRU can be used in this application. Oxygen can be present in the storage tank due to air ingress and this can complicate VRU operations fed from storage tanks unless a gas blanketing or catalytic oxidation system is added. The control devices themselves are described in more detail later in this report, but some key details with this approach are described in this section.

First, all of the vapor to be controlled will be near atmospheric pressure (< 1 psig). Without any equipment between the single stage production separator and the storage tanks, there is no means of moderating the vapor generation rate. Every time the dump valve opens, more oil flashes and more vapors enter the storage tank with the oil. The control device(s) must be sized to handle this peak rate or the pressure relief valve on top of the storage tank (typically set around 12 ounces or 0.75 psig) will vent excess vapor to the atmosphere. A thief hatch is used for gauging the oil level in the storage tank and collecting oil samples. The thief hatch has a two-way “breather” valve to keep the pressure in storage tanks designed for near atmospheric pressure operation from reaching a pressure too low or too high. Pressure can be too low when the tanks cool for diurnal or other reasons, which could collapse the tank. Pressure can be too high when temperatures rise or more typically when a lot of flash gas is being formed, which could potentially rupture the tank. Usually, the thief hatch vents at pressures ranging from 12 to 16 ounces (0.75 to 1 psig). It can be very costly to size control devices to handle all possible peak generation rates in this scenario in order to avoid all venting of vapors to the atmosphere. This leads to some more interesting (and more complicated) options.

Two Stage Separator

A diagram for a two stage production separator is shown in Figure 3. A picture of a two stage production separator is shown in Figure 4. A key operational advantage a two stage separator has over a single stage is that the overall amount of flash gas formed is reduced and some of it is

now available at an intermediate pressure. The intermediate pressure flash gas is easier to recover with a VRU, while the amount of atmospheric pressure flash gas that needs to be controlled from the storage tanks is reduced. The intermediate pressure flash gas can have heating values as high as 2,500 Btu/scf as it is much richer than the sales gas, which results in higher revenue if the recovered gas is sold on a heating value basis.

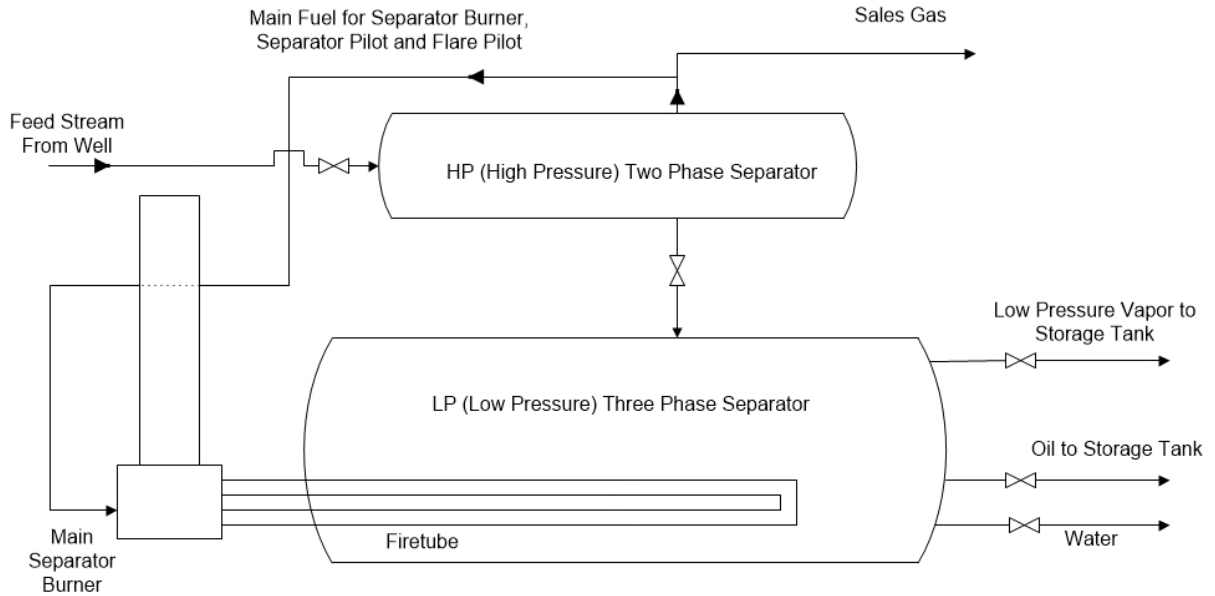


Figure 3 – Two Stage Production Separator Schematic



Figure 4 – Picture of Two Stage Production Separator

Sales gas is now taken from the top of the high pressure (HP) separator and oil flashes across a dump valve into a low pressure (LP) separator. Water is also concurrently dumped to the LP separator. More hydrocarbons stay in the liquid phase with this step, since the downstream pressure is now an intermediate pressure, perhaps around 40 psig, instead of near atmospheric pressure. An intermediate pressure gas stream is also formed that needs to be removed from the LP separator.

Temperature settings are important in the HP separator. Higher temperatures cause more of the valuable hydrocarbons to end up in the sales gas line, and lower temperatures cause more of the lighter hydrocarbons to dump to the LP separator with the oil and the water. The light hydrocarbons will then flash out in the LP separator, stripping along with them some of the heavier hydrocarbons that would have otherwise ended up in the oil storage tank. The HP separator typically rides the sales gas pipeline pressure, so this is not usually a variable that can be controlled. Temperature control methods in the HP separator vary depending on the separator design and manufacturer.

Routing the intermediate pressure gas from the LP separator to the storage tank is one option, but then the gas drops to atmospheric pressure with the same associated vapor control challenges as described for the single stage separator. This gas can be routed from the LP separator to a VRU that compresses the flash gas to sales gas pressure and combines with the sales gas in or downstream of the high stage separator before going through a flow meter and to the pipeline. The challenge here is specifying a VRU with sufficient capacity for the peak gas generation rate and that is also suited for intermittent operation and variable suction flow rates. A backup vapor vent line from the LP separator to the storage tank or to a separate flare (ECD) is typically provided for times when the VRU is down or when it is not able to keep up with the peak vapor generation rate in the LP separator.

Management of temperature and pressure in the LP separator (to the extent possible) is also important for stable operations and maximizing oil production. Heating is needed primarily to prevent formation or buildup of paraffins and is often done only in the winter months. It also helps break oil-water emulsions and facilitates oil / water separation, so that the oil meets BS&W requirements. A temperature higher than needed will result in more light and intermediate hydrocarbons in the intermediate pressure gas formed in the LP separator, when they could have otherwise ended up with the sales oil. A temperature too low or a pressure too high in the LP separator will cause more of the light hydrocarbons to dump with the oil to the storage tank. These will readily flash to vapor across the dump valve, which will strip intermediate hydrocarbons in the process, resulting in more vapor to be controlled and lower oil production. A pressure too low in LP separator results in more hydrocarbons in the LP separator gas and could also result in problems with draining the oil to the storage tanks.

It is clear from this discussion that management of temperatures and pressures (to the extent possible) in each stage of the separator is a balancing act that impacts operations, revenue, and the amount of vapors that need to be controlled. Making sure that each pumper understands this can lead to benefits across all of the production sites. Adjustments may be needed seasonally, when production changes, or for other reasons.

Flares

Flares are the most common type of control equipment at upstream oil and gas production sites. They are also called burners or thermal oxidizers as well as ECDs (emission control devices) at many locations. Flares come in all shapes and sizes. Designs range from simple open flares with a visible flame on top to enclosed thermal oxidizers with multiple burner stages that cycle on and off based on load (pressure). Regardless of the specific flare type, low cost is crucial in this application due to the number of units that are required, which can number in the thousands for a single producer in a large field. This means that sophisticated flares designed for refineries and similar applications will likely be cost prohibitive for upstream oil and gas production sites. Companies that make separators and related oilfield production equipment have developed flares for this application and some more traditional flare manufacturers have worked with oil and gas producers to develop flares that are tailor made to this application and cost effective in this market. This can require a partnership between the oil and gas producer and the flare manufacturer that assures that the number of orders will be sufficient to offset costs for development and production of flares specifically for this application.

Figure 5 shows a simple open flare at an oil and gas production site. Low cost and simplicity are the main benefits of open flares in this application. They have essentially no moving parts, resulting in high availability and low maintenance costs. They are easy to move from one site to another. The visible flame can be a concern with the use of open flares, particularly in instances where communities have grown closer to the oil and gas production sites. The use of open flares may also be limited by regulatory agencies. If there are upset conditions that result in a higher flow rate and supply pressure of gas to the flare, the flame can grow larger than intended with the design. Proper mixing of air with rich gas at low pressure can be a challenge in this application, but it is easier with the open flare design than in an enclosed flare. Nonetheless, visible smoke can sometimes be an issue with open flares, particularly as the production cycle is tapering off and pressure of the gas delivered to the flare is dropping to zero. In some areas, only non-smoking flares are allowed.

In contrast, Figure 6 shows an enclosed flare or thermal oxidizer. The obvious difference with this design is that the flame will no longer be visible. The enclosed design also allows for better control of combustion temperatures resulting in more complete conversion of the hydrocarbons to CO₂ and water. Performance testing can be simpler for enclosed flares. Ensuring proper mixing of air is more of a challenge than with open flares, especially if there is no electricity at these locations to drive an air blower. Instead, special designs with multiple air intakes, adjustable dampers, and proprietary designs to mix air and hydrocarbon gases in the burner section have been developed. It is also important to make the enclosure able to withstand the high heat release and temperatures associated with rich gas combustion. As part of our work in this area, Trimeric worked with an oil and gas producer and a flare manufacturer to develop a high capacity enclosed flare for this application. The remainder of this section provides some more details regarding key points from that effort.



Figure 5 – Picture of Simple Open Flare

Due to the number of flares required, a cost increase of even \$ 100 per unit can be significant for an oil and gas producer operating in a large field. Each part is selected carefully to limit overall system costs. Custom burner assemblies with simple orifices drilled into horizontal pipe sections can be favored over commercially manufactured burner tips. Field testing of developmental prototypes showed that the simpler orifice design could lead to flame instability at certain parts of the production cycle, which resulted in severe pulsation and vibration of the unit. A lot of trial and error, coupled with further design improvements in the overall burner assemblies and air mixing systems, was needed to eliminate problems with pulsation and vibration.

Visible smoke, particularly at the very beginning or very end of production cycles, can be a challenge with flares in this application. Pressure of the gas upstream of the orifices is lowest at these times, which exacerbates the challenges of getting a stable flame and good air / fuel mixing. Even intermittent, faint traces of smoke are generally unacceptable. The enclosed flare shown in Figure 6 included a burner system designed to operate in stages. Pressure actuated valves with increasing pressure-to-open set points were installed upstream of separate parts of the burner manifold. At the lowest pressures, only one manifold was in service and as pressure increased in the cycle, a second and then a third manifold was on-line. The reverse occurred as the pressure dropped when the cycle tapered off. It was important to specify valve actuator internals and their orientation in such a way that any condensed liquids did not accumulate on soft materials (rubber) and lead to premature deterioration.



Figure 6 – Picture of Enclosed Flare

Finally, a check valve was added between the storage tanks and the flare that required a couple of ounces of pressure to open. This prevented flow from the storage tanks to the flare until the minimum pressure needed to open the check valve was exceeded, ensuring the minimum required pressure for a stable flame and good air / fuel mixing was delivered to the burner orifices. Again, it was important to select and orient the check valve in a way to make it tolerant to condensation of liquids.

A refractory blanket lining was installed to permit the use of low cost enclosure materials. The first enclosures were made of galvanized metal and then subsequent units were made of carbon steel after a low enough cost solution from both a materials and a fabrication standpoint was developed. Even so, the operation of the first hundred or so units revealed the need to identify and use a heat-resistant paint that was suitable for this application. In the end, a robust flare was developed and the oil and gas producer ordered several hundred units. The flare manufacturer

was also able to sell this flare to other oil and gas producers. The development of this flare produced very good results for all participants.

There are other aspects of flare use that need to be considered. There is typically a requirement for a flame arrestor device that prevents a flashback from the flare to the oil storage tanks. There are offset requirements that typically require a minimum distance between the flare and other fired units and the oil storage tanks. This can be an issue that requires careful planning for locations in tight spaces. Some regulatory agencies require infrared detection to ensure the pilot flame remains lit, along with solar-powered telemetry devices to shut in production and notify producers if the pilot flame goes out. Some installations may have a knockout pot that collects condensed liquids upstream of the flare, which will require periodic emptying.

Performance testing may be required to demonstrate the VOC destruction efficiency. Flares also create secondary pollutants including criteria pollutants such as NO_x, CO, and PM (particulate matter). Sour fields will also have sulfur oxide emissions. CO₂ is also a product of the combustion process and since it is considered a greenhouse gas (GHG), this may lead to requirements for estimating and reporting GHG emissions.

Despite these items, a flare-only control approach is the simplest vapor control option. However, it becomes less economical with increasing production rates, since valuable rich hydrocarbon vapors are not recovered. Use of flares-only can also be constrained by environmental regulations. Regulators typically assume 98% VOC destruction with flares (performance testing may be required), but even assuming that only 2% of the VOC is emitted at high production sites can bump the sites up against permit limits that operators prefer to avoid. All other things being equal, it is preferable to recover the gas as product than to flare it.

The trick of course is to integrate the operation of vapor recovery unit (VRU) and associated equipment into the site with low enough capital and operating costs and sufficient reliability such that the revenue from the recovered vapors justifies the additional expenditures. Operations including a VRU will invariably be more complex than a site that uses only flares for vapor control. The design must be such that operations staff can tolerate the requirements to support the additional equipment. The remainder of this paper focuses on strategies that have been used to progress toward and achieve these results.

Vapor Recovery Units

Using a VRU to recover hydrocarbon vapors as a revenue-generating product is generally preferred over oxidizing them in a flare, which offers no opportunity for revenue to offset the costs of vapor control. Incorporating a VRU into the vapor control strategy can reduce the overall site emissions. However, it can be quite challenging to integrate VRU systems into upstream oil and gas production sites with satisfactory results from an economic and operational standpoint. Some of the main reasons for this are as follows:

- VRU and related equipment is more capital intensive than a flare
- Maintenance costs are usually higher with a VRU than a flare
- Downtime is usually higher with a VRU than a flare

- Water and hydrocarbon condensation can create operational issues and can lead to equipment damage
- Oxygen contamination in the sales gas can be an issue when VRUs are collecting vapors from atmospheric pressure storage tanks
- Revenue recognition for the oil and gas producer and allocation to royalty owners can be complicated

Despite these and other challenges, VRUs can be part of an effective vapor control solution in this application. This section will describe some approaches that have been used to manage these challenges in order to succeed with VRUs in this application. Figure 7 shows a picture for a two stage reciprocating compressor VRU system that was used in over 100 installations for one producer in one field. There are several ways that the VRU can be configured within the location. The VRU can treat all the vapors formed at the site from the storage tanks with near atmospheric pressure suction conditions. However, a large, expensive VRU can be needed for 100% capture using this approach. Furthermore, a gas blanketing system, catalytic oxidation unit, or other approach may be needed to prevent oxygen (air) from entering the storage tanks and leading to issues with meeting the sales gas specification for oxygen (typically on the order of 10 ppmv). The VRU can take gas only from an intermediate pressure source such as the low stage of a two stage separator, a surge bottle, and/or a VRT. In these cases, one or more flares can then be used to control the vapor formed in the storage tanks. This approach has a key advantage in that the flares are a backup control device in instances when the VRU is out of service.



Figure 7 – Picture of Two Stage Reciprocating Compressor VRU

Figure 8 shows a process flow diagram with a surge bottle between the separator and the storage tanks. The surge bottle feeds a VRU and a flare treats the vapors from the storage tanks. The arrangement is similar if the VRU is fed from the low pressure separator in a two stage separator or from a VRT. These approaches are described in more detail elsewhere in this paper. In most cases, the gas compressed in the VRU is returned to the highest pressure stage of the separator where it combines with the sales gas. An exception would be if there are local requirements that can consume the gas recovered by the VRU at a pressure lower than the pipeline. These might include feed to lift gas compressors or local fuel use, although the gas recovered by the VRU is typically more valuable on a heating value basis and this rich gas may not burn well in engines designed to run on much leaner natural gas.

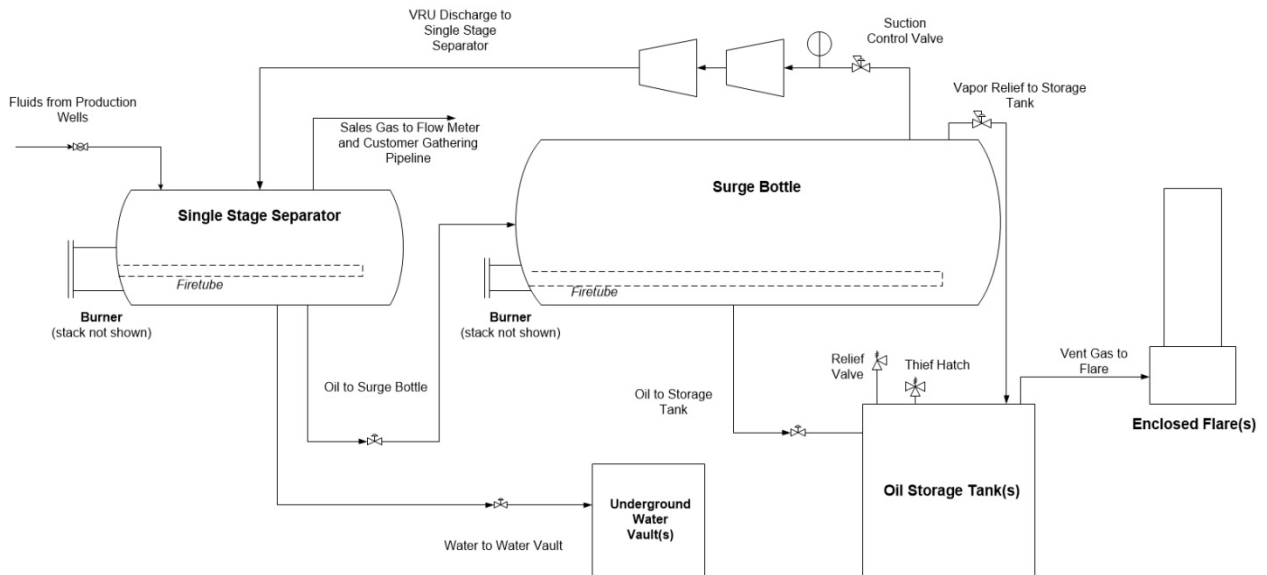


Figure 8 – Process Flow Diagram for Site with Surge Bottle

Not much can be done about the fact that a VRU is going to cost more than a flare in this application. Flares are essentially passive equipment, with very few moving parts. VRUs on the other hand, are engine or electric motor driven compressor systems, which are oil lubricated (usually), and typically have more moving parts than flares. It is also more of a challenge for a VRU to handle the on/off and variable loads at these sites than it is for a flare, which only needs to have a pilot flame to be ready to treat vapors. However, there are ways to increase the throughput / capacity and reliability of the VRU in order to make operation of more expensive control equipment more economical in upstream oil and gas production.

A common way to increase the throughput capacity of a VRU is by increasing the suction pressure to the VRU. Surge bottles (also called buffer tanks) and vapor recovery towers (VRTs) are commonly used to increase suction pressure and throughput capacities of VRUs in this application. Some operators also use another heater treaters like the three-phase production separator to act as a surge bottle. These items are discussed in more detail elsewhere in this paper. There are several types of compressors that can be used in this VRU application, but they will all generally be smaller in size and lower in cost with higher suction pressure as this results in a lower actual volumetric flow rate of gas to be processed and a lower compression ratio for the same sales gas / pipeline pressure. Smaller equipment results in more revenue generation per unit cost of control equipment and can reduce the size of additional control equipment.

Several types of VRU compressor systems have been considered for or used in this application. These include reciprocating compressors, rotary screw compressors, rotary sliding vane compressors, and scroll compressors. A detailed description of these compressor types is beyond the scope of this paper. However, selection of compressor type is very important and should be given careful consideration when specifying or selecting a compressor for a VRU system in this application. Some other VRU systems use high pressure gas a motive force instead of a fuel burning engine. These can include eductor and booster compressor systems. Their usefulness in this application is limited because the highest pressure gas at the site is usually the sales gas and using some of this gas to drive this kind of VRU results in an intermediate pressure gas stream that lacks the pressure needed to get into the sales gas pipeline. This results in a need for more compression equipment to get the drive gas and/or recovered gas into the pipeline unless there is an on-site requirement that can always consume all of the intermediate pressure gas.

Regardless of the compressor type, a commonly noted drawback in this service is oil-thinning. Rich gas compression, particularly in cold weather, can result in some water or hydrocarbon species condensing into a liquid phase that mixes with the compressor lubricating oil. Over time, oil thinning can lead to significant damage to the VRU compressor such as bearing failures. The oil thinning problem is exacerbated by the start-stop nature of this application, as gases trapped in the VRU system will cool after the VRU cycles off. A two stage, reciprocating compressor used at over 100 sites had to be modified several times to address this issue. First the interstage cooler was disabled and then some sales gas was blended in at stage 1 discharge / stage 2 suction to try to keep the gas from getting too rich in order to keep all hydrocarbon species in the vapor state. Insulation on suction and discharge lines is recommended as are adjustable enclosures which can retain heat in cold weather and be opened to provide avenues for cooling in hot weather. Adjustable timed warm-up cycles can give the VRU a minute or two to warm up before it needs to be ready to process gas. These can be actuated via a pressure transmitter that detects a slight increase in pressure in the source of the suction gas. A similar cool down or purge for a minute or two after the cycle is complete can also help, provided that the compressor can be run at this unloaded condition.

Using a VRU can sometimes also result in some headaches with royalty payments to mineral rights owners as it can be a bit complicated to allocate the revenues generated by the VRU to a particular well, particularly when the VRU serves multiple separators or other vessels that can process feed from multiple wells at the same time. Oil and gas producers may also want to offset operating and maintenance costs for VRU systems against the revenue generated by the VRU, which adds another step in the process in allocating net royalties to mineral rights owners. An additional complication with VRU use in this application that can be overlooked is that the gas recovered by the VRU typically has a much higher heating value than the sales gas, but it is difficult to generate additional revenue based on the higher heating value. A grab sample to determine the composition of the sales gas is typically measured only on an intermittent basis (maybe one to four times a year). Samples are often taken when the VRU is not running, so in essence the vapors recovered by the VRU are treated as having the same heating value as the sales gas. A separate meter and separate sampling can be done for the gas recovered by the VRU, but this complicates coordination with the sales gas meter and composition. Flow-

weighted sampling using a composite sampler can resolve these issues where the production rate is sufficient to justify the expense of using a composite sampler. Gases recovered by the VRU are proportional to the oil production, so this is one option for allocating revenues from gases recovered by the VRU.

Peak Management and Related Strategies

Trimeric has observed that some wells can generate peak vapor flow rates as high as about 30 times the daily average. Clearly then, there is an incentive to reduce the peak gas flow rate in order to reduce the capacity requirements for vapor control equipment. Trimeric assisted one oil and gas producer with the testing of several peak management strategies including slug catchers and surge bottles. Some operators also use another heater treater like the three-phase production separator to act as a surge bottle. The VRT also lowers the peak vapor generation rate, but typically to a lower extent than a surge bottle due to the lower operating pressure in the vapor space of the VRT. Routing vapors from the surge bottle or VRT to a VRU instead of from the storage tank to a VRU eliminates the potential for air (oxygen) ingress that can be an issue for gas recovered from storage tanks. The VRT also reduces the vapor generation rate in the oil storage tanks due to the lower upstream pressure in the VRT as compared to the separator or surge bottle.

Slug Catchers

Slug catchers are commonly used in other segments of the oil and gas industry. The slug catcher is a simple device that operates more or less as “wide spot in the line”. Figure 9 shows a prototype slug catcher developed for one upstream oil and gas producer. Figure 10 is a picture of the unit in the field. In the upstream oil and gas production application, the slug catcher needs to be sized to handle the entire volume of liquid produced without the liquid level reaching the gas outlet before the production cycle ends. A larger size requirement for higher production rates increases the cost of the slug catcher in this application more than other options because the vessel must be rated for the maximum pressure upstream of the choke. A flange is also required for access and cleaning. Lastly, there is no means of heating the slug catcher to prevent accumulation of paraffins or freezing of liquids as they are slowly drained from the slug catcher to the separator. Due to these limitations, one Trimeric client opted to pursue other solutions for peak management in this application.

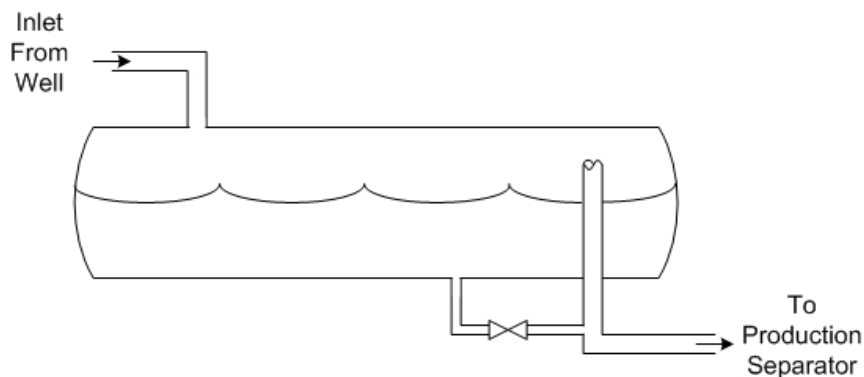


Figure 9 – Prototype Slug Catcher Schematic



Figure 10 – Picture of Prototype Slug Catcher

Surge Bottles

Similar to the difference between a one-stage separator and a two-stage separator, adding a surge bottle (buffer tank) downstream of the separator (whether a one-stage or a two-stage) brings some key advantages for peak vapor reduction. Some operators also use another heater treater like the three-phase production separator to act as a surge bottle as it turns out that heating this vessel is quite useful in preventing buildup of paraffins or freezing. Adding an extra stage of pressure drop reduces the overall amount of flash gas formed and some of it is now available at an intermediate pressure. The intermediate pressure flash gas is easier to recover with a VRU, while the amount of atmospheric pressure flash gas that needs to be controlled from the storage tanks is reduced. The intermediate pressure flash gas can have heating values as high as 2,500 Btu/scf as it is much richer than the sales gas, which results in higher revenue if the recovered gas is sold on a heating value basis.

Trimeric worked with one oil and gas producer to develop a surge bottle. The program was quite useful and the surge bottle became a part of the standard setup at many sites. Figure 11 shows an early version of the surge bottle concept and related control functions. As liquids flash into the surge bottle, the pressure builds and when it reaches a high set point, vapor exits the surge bottle and goes to a VRU or to a storage tank and then a flare. This reduces the pressure in the surge bottle. If the pressure in the surge bottle reaches a high-high set point, vapors are vented from the surge bottle regardless of other conditions. Once the control device lowers the pressure in the surge bottle to a predetermined set point, the drain valve opens for oil at a reduced pressure to drain to the storage tank. However, it is important that the pressure that remains in the surge bottle is sufficient to move the oil to the storage tank. If the oil level reaches a high-high set point, the oil drains to the storage tank regardless of other conditions in the surge bottle.

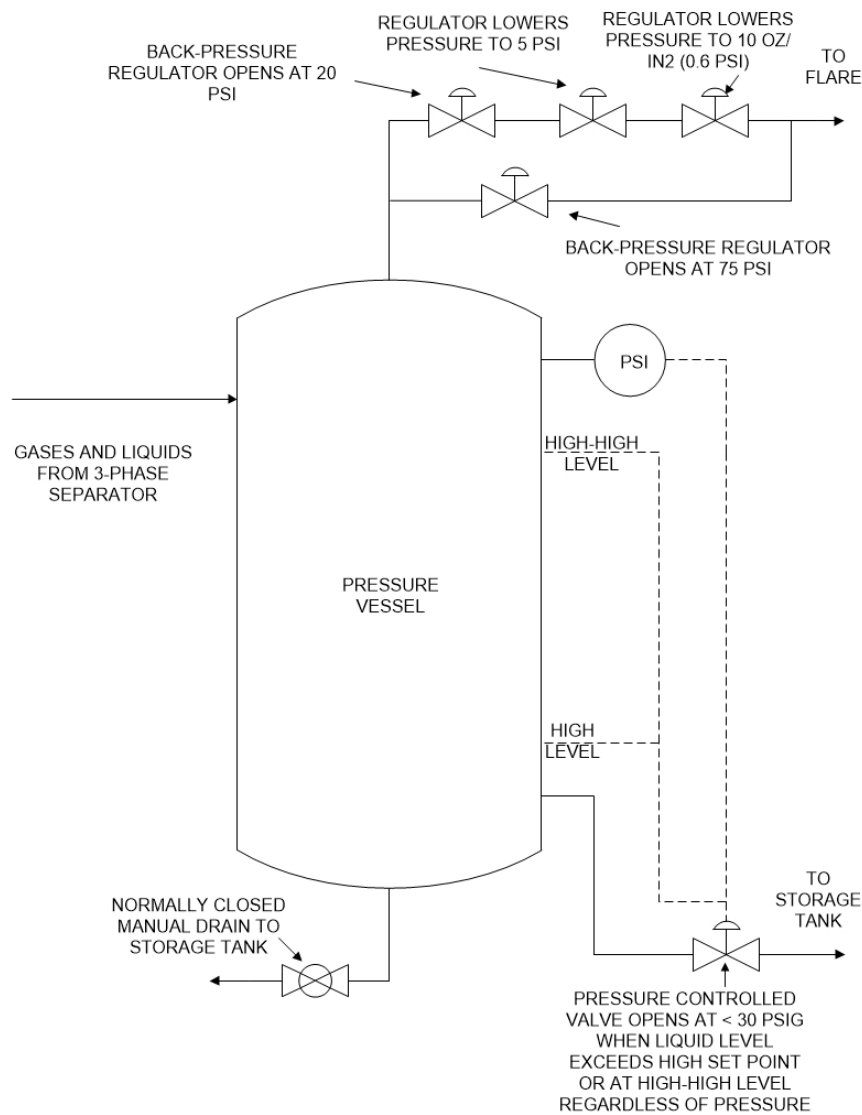


Figure 11 – Surge Bottle Controls Schematic

The control philosophy evolved over the course of development. For example, a higher pressure to vent gas from the surge bottle set point was used on systems where this gas fed a VRU in order to increase the capacity of the VRU and a gas regulator was added on a vapor line from the separator to the surge bottle to keep a minimum pressure in the surge bottle needed to ensure oil would drain from the surge bottle to the storage tank. Sites that have electricity may use a pump to move the oil from the surge bottle to the storage tank at lower operating pressures in the surge bottle.

A key lesson learned early on is that the surge bottle had to hold all of the oil produced in one cycle before getting so full that oil had to be drained to the storage tank before the vapor control device had enough time to reduce the pressure in the surge bottle. If not, oil drained to the storage tank when the oil level reached a safe upper limit in the surge bottle regardless of pressure and this resulted in a high vapor generation rate in the storage tanks. Similarly, gas would vent (either to a VRU or to a storage tank and then to a flare) if the pressure increased to the safe upper limit. These events often resulted in the capacity of the control device being

exceeded and some gas venting occurred. Both experiences reinforced the concept that the best benefits to be had from using the surge bottle came when it had the capacity to contain the entire slug of oil produced from a well.

This, coupled with increasing peak production rates at many sites, led to larger and larger surge bottles as the concept evolved. The first test used an existing 2 ft. diameter, 6 ft. vertical vessel, next a 3 ft. diameter, 8 ft. vertical vessel was built for purpose and 10 of these units were put through a test campaign lasting several months. At about half of the sites test, issues with paraffins or freezing in cold weather were encountered. This led to the final form of the surge bottle developed on this project. The vessel was changed to horizontal to accommodate a firetube for heating in the same fashion as done in the three-phase separators and to lower the profile of the vessel. The diameter was increased to 6 ft. and the length was increased to 20 ft. A photograph of one of these units is shown in Figure 12.



Figure 12 – Picture of Surge Bottle

As previously mentioned, several benefits were documented with the surge bottle. As peak oil production rates at individual sites trended up over the years as a result of horizontal or directional drilling and improved fracturing techniques, the surge bottle to VRU and storage tank

to flare became one of two preferred approaches. Again this approach also allows flares on the storage tanks to serve as a backup when there were issues with the VRU, surge bottle, or related equipment. The other preferred approach swaps a VRT for the surge bottle and will be discussed next.

Vapor Recovery Towers

A VRT is usually installed between the separator and the storage tanks in a similar arrangement to the one previously described for the surge bottle. Oil dumps from the separator to the VRT and then from the VRT to the storage tanks. The VRT is a small diameter (2 ft. to 4 ft.), tall (35 ft. to 40 ft.) vertical vessel. It operates at very low pressure at the top of the tower (on the order of 3 psig). Figure 13 shows a VRT at an upstream oil and gas production site. The height of the liquid level in the VRT provides a hydrostatic head for moving the oil to the storage tank. Since the oil in the VRT is at very low pressure, there is a minimal amount of flash gas formed when the oil goes to the storage tank. This is an operational advantage the VRT has over the surge bottle as a lower flare capacity is needed for the storage tank vapors generated when oil goes from the VRT to the storage tank. Controls for the VRT are also generally a lot simpler than the surge bottle.



Figure 13 – Picture of Vapor Recovery Tower. Photograph courtesy of Reset Energy.

The low pressure in the VRT, coupled with the residence time in the VRT allows most of the light ends to evolve as vapor and go to the control device. A VRU is used to recover vapors from the VRT at many sites. One disadvantage compared to the surge bottle is a lower suction pressure that the VRT provides to the VRU. This requires a VRU with larger volumetric capacity (all other things being equal). Furthermore, due to the lower operating pressure in the VRT, it does not reduce the peak vapor formation rate to the extent that the surge bottle can. Oil dumps from the upstream separator to the VRT at its normal rate and flash gas is formed at peak rates similar to those of a separator dumping directly to a storage tank.

The geometry of the VRT does not lend itself well to heat input and issues with paraffins, plugging, and freezing have been encountered with VRTs. VRT systems are typically designed for 30 minute residence time, which can increase to 60 or 90 minutes as production declines. The increased residence time exacerbates paraffin, plugging, and freezing issues and some operators therefore take some of their VRTs out of service as production declines. The VRT also needs to be tall enough to ensure the oil will drain to the storage tanks under all conditions. This adds to the height profile of the site, which can be a concern in some installations. Clearly there are some tradeoffs between the surge bottle and VRT concepts, but the arrangement of vapor control centered around a VRT feeding a VRU is used at hundreds of production sites.

Conclusions

Control of vapors formed in upstream oil and gas production can be a complex topic. Site specific factors such as regulations, pipeline pressure, availability of electricity, and frequency that operating personnel are at the site can significantly impact the optimal approach for vapor control. Severe weather conditions such as cold climates must be taken into consideration to reduce or eliminate impacts on production and vapor control equipment due to issues with paraffin buildup, condensation, plugging, and freezing.

Peak vapor formation rates can be on the order of 30 times higher than daily average rates. Strategies to reduce the peak vapor formation rate can reduce the size and cost of vapor control equipment and they can also reduce vapor control costs or even generate additional revenue in some cases. Peak management strategies can include slug catchers, surge bottles (or buffer tanks), and vapor recovery towers (VRTs). Development of a surge bottle (or buffer tank) for one oil and gas producer led to deployment of surge bottles at numerous production sites and some key lessons learned along the way were the need for a vessel large enough to hold the entire volume of oil produced in one cycle, the need to optimize operating pressure in order to have sufficient vapor control capacity to lower the pressure in the vessel in a short time, and the need to heat the vessel to manage paraffin and freezing issues.

Vapors from atmospheric pressure storage tanks are most often controlled by flares. This eliminates concerns with air (oxygen) ingress when oil storage tanks feed VRUs. However gas blanketing systems can be used to keep positive pressure on the storage tanks at all times and production is high enough at some sites to mitigate oxygen contamination concerns without adding a gas blanketing system or catalytic oxidation unit. At sites with electricity, roots blowers have been used to combine storage tank vapors with higher pressure vapors generated upstream in surge bottles and/or VRTs and send all of these vapors to a VRU. This approach nearly eliminates VOC emissions due to flash gas formed during oil and gas production.

Several vapor control strategies were presented and compared in this paper. There are likely numerous variations on these concepts that have been developed by other companies and there is no “one size fits all” solution due to different production characteristics, regulations, and operating company goals. Nonetheless, this paper presents a few “one size fits most” options for consideration. Flares would likely be the most practical option in terms of operations and cost for sites with low production rates (~ 100 bbl/day, but this will vary based on well cycles, flash gas to oil ratio, and other factors). Flares are a low cost and low maintenance option that is technically feasible even for higher production rates, but they generally only get credit for 98% VOC destruction, they generate secondary emissions, and do not offer any opportunity to generate revenue to offset cost of control.

For larger sites, addition of either a surge bottle or a vapor recovery tower (VRT) can make sense. The surge bottle or VRT can feed a vapor recovery unit (VRU) and one or more flares can control vapors from the storage tanks. Flares can also serve as a backup when the VRU is out of service. Control equipment costs will likely be higher and operations are more complex with these approaches than with flares alone, but under the right circumstances they can generate revenue that offsets the cost of control and reduce emissions compared with use of flares only.

All of these approaches are continually evolving, particularly the design of flares. Manufacturers are continually upgrading their units to make them more reliable, with a wider range of capacities with smoke free operation, higher capacity, and lower cost per volume of gas treated. Some operators combine multiple approaches such as a surge bottle feeding a VRT and even sending storage tank vapors to a VRU instead of a flare, nearly eliminating VOC emissions from flash gas. Mechanical refrigeration units can be used to recover some rich flash gas as NGL in some locations. Sites with electricity and higher production rates make these more advanced control approaches more feasible. Upstream oil and gas producers can use some of the insights and experiences shared in this paper to help select a vapor control strategy that best suits their objectives for production operations, vapor control, and regulatory compliance.