Installing Vapor Recovery Units on Storage Tanks

Executive Summary

There are about 500,000 crude oil storage tanks in the United States. These tanks are used to hold oil for brief periods of time in order to stabilize flow between production wells and pipeline or trucking transportation sites. In addition, the condensate liquids contained in produced gas that are captured by a mist eliminator filter/ coalescer ahead of the first compressor station in transmission pipelines are often directed to a storage tank as well. During storage, light hydrocarbons dissolved in the crude oil or condensate—including methane and other volatile organic compounds (VOC), natural gas liquids (NGLs), hazardous air pollutants (HAP), and some inert gases—vaporize or "flash out" and collect in the space between the liquid and the fixed roof of the tank. As the liquid level in the tank fluctuates, these vapors are often vented to the atmosphere.

One way to prevent emissions of these light hydrocarbon vapors and yield significant economic savings is to install vapor recovery units (VRUs) on storage tanks. VRUs are relatively simple systems that can capture about 95 percent of the Btu-rich vapors for sale or for use onsite as fuel. Currently, between 7,000 and 9,000 VRUs are installed in the oil production sector, with an average of four tanks connected to each VRU.

Natural Gas STAR partners have generated significant savings from recovering and marketing these vapors while at the same time substantially reducing methane and HAP emissions. Partners have found that when the volume of vapors is sufficient, installing a VRU on one or multiple storage tanks can save up to $606,800 per year and payback in as little as two months. This Lessons Learned study describes how partners can identify when and where VRUs should be installed to realize these economic and environmental benefits.

Technology Background

Underground crude oil contains many lighter hydrocarbons in solution. When the oil is brought to the surface and processed, many of the dissolved lighter hydrocarbons (as well as water) are removed through a series of high-pressure and low-pressure separators. The crude oil is then injected into a storage tank to await sale and transportation off site; the remaining hydrocarbons in the oil are emitted as vapors into the tank. The same principles apply for condensate, which accumulates as a result of the conditions within the pipelines and is removed ahead of the first compressor station. The recovered condensate, which contains dissolved light hydrocarbons, is routed to a storage tank where the dissolved light hydrocarbons are emitted as vapors. These vapors are either vented, flared, or recovered by vapor recovery units (VRUs). Losses of the remaining lighter hydrocarbons are categorized in three ways:

- Flash losses occur when the separator or heater treater, operating at approximately 35 pounds per square inch (psi), dumps oil into the storage tanks, which are at atmospheric pressure.

- Working losses refer to the vapor released from the

Economic and Environmental Benefits

Method for Reducing Natural Gas Losses	Volume of Natural Gas Savings (Mcf/yr)	Value of Natural Gas Savings ($/yr) [1] $3 per Mcf	$5 per Mcf	$7 per Mcf	Implementation Cost ($)	Other Costs ($)	Payback (Months) $3 per Mcf	$5 per Mcf	$7 per Mcf
Installing Vapor Recovery Units (VRUs) on Oil Production Storage Tanks	4,900—96,000	$13,965—$273,600	$23,275—$456,000	$32,585—$638,400	$35,738—$103,959	$7,367—$16,839	6 — 37	4 — 23	3 — 16

[1] Assumes 95% of the annual volume of gas lost can be recovered using a VRU.

changing fluid levels and agitation of tank contents associated with the circulation of fresh oil through the storage tanks.

- Standing losses occur with daily and seasonal temperature changes.

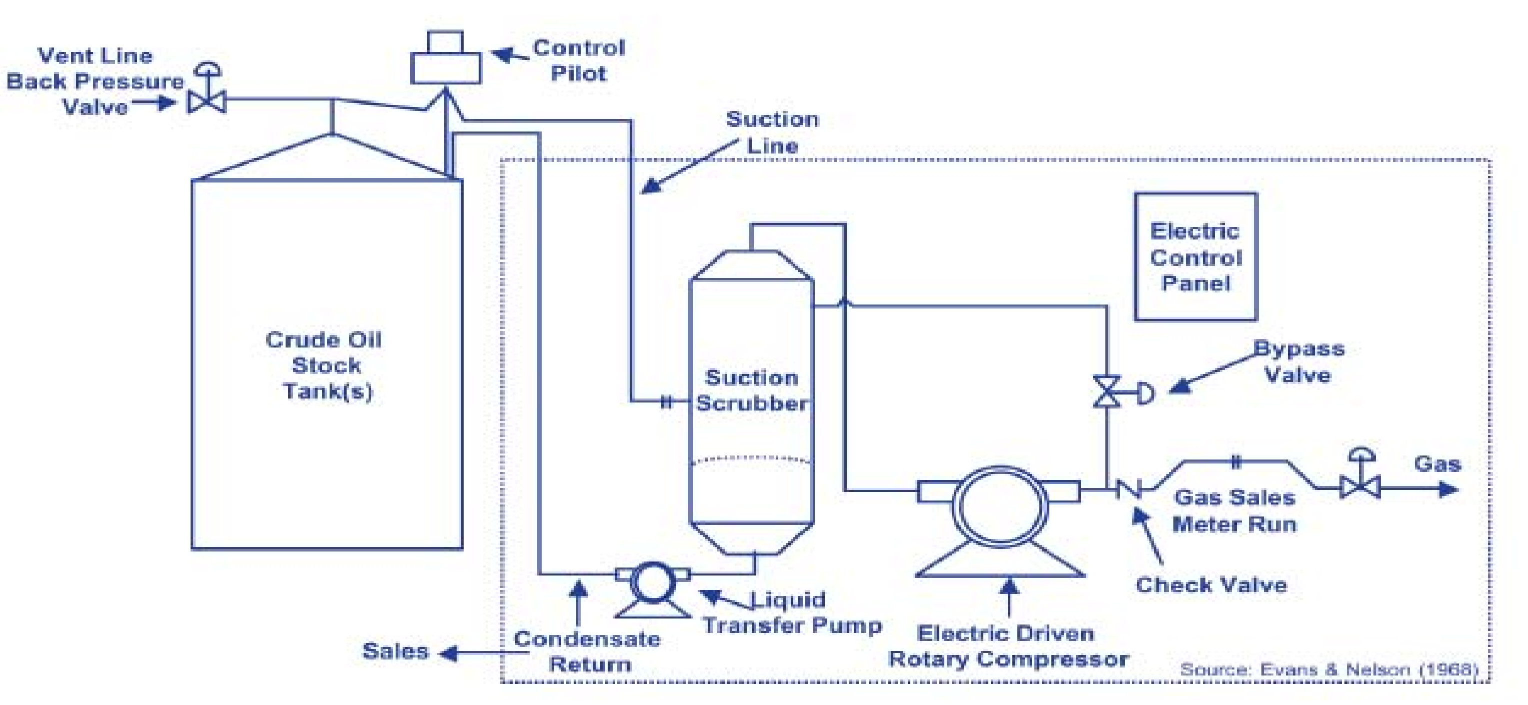
The volume of gas vapor coming off a storage tank depends on many factors. Lighter crude oils (API gravity>36°) flash more hydrocarbon vapors than heavier crudes (API gravity<36°). In storage tanks where the oil is frequently cycled and the overall throughput is high, more "working vapors" will be released than in tanks with low throughput and where the oil is held for longer periods and allowed to "weather." Finally, the operating temperature and pressure of oil in the vessel dumping into the tank will affect the volume of flashed gases coming out of the oil.

The makeup of these vapors varies, but the largest component is methane (between 40 and 60 percent). Other components include more complex hydrocarbon compounds such as propane, butane, and ethane; natural inert gases such as nitrogen and carbon dioxide; and HAP like benzene, toluene, ethyl-benzene, and xylene (collectively these four HAP are referred to as BTEX).

VRUs can recover over 95 percent of the hydrocarbon emissions that accumulate in storage tanks. Because recovered vapors contain natural gas liquids (even after condensates have been captured by the suction scrubber), they have a Btu content that is higher than that of pipeline quality natural gas (between 950 and 1,100 Btu per standard cubic foot [scf]). Depending on the volume of NGLs in the vapors, the Btu content can reach as high as 2,000 Btu per scf. Therefore, on a volumetric basis, the recovered vapors can be more valuable than methane alone.

Exhibit 1 illustrates a VRU installed on a single crude oil storage tank (multiple tank installations are also common). Hydrocarbon vapors are drawn out of the storage (stock) tank under low-pressure, typically between four ounces and two psi, and are first piped to a separator (suction scrubber) to collect any liquids that condense out. The liquids are usually recycled back to the storage tank. From the separator, the vapors flow through a compressor that provides the low-pressure suction for the VRU system. (To prevent the creation of a vacuum in the top of a tank when oil is withdrawn and the oil level drops, VRUs are equipped with a control pilot to shut down the compressor and permit the back flow of vapors into the tank.) The vapors are then metered and removed from the VRU system for pipeline sale or onsite fuel supply.

Exhibit 1: Standard Stock Tank Vapor Recovery System



Economic and Environmental Benefits

VRUs can provide significant environmental and economic benefits for oil and gas producers. The gases flashed from crude oil or condensate and captured by VRUs can be sold at a profit or used in facility operations. These recovered vapors can be:

- ★ Piped to natural gas gathering pipelines for sale at a premium as high Btu natural gas.
- ★ Used as a fuel for onsite operations.
- ★ Piped to a stripper unit to separate NGLs and methane when the volume and price for NGLs are attractive.

VRUs also capture HAPs and can reduce operator emissions below actionable levels specified in Title V of the Clean Air Act. By capturing methane, VRUs also reduce the emissions of a potent greenhouse gas.

Decision Process

Companies using fixed roof storage tanks can assess the economics of VRUs by following five easy steps.

Step 1: Identify possible locations for VRU installation.

Virtually any tank battery is a potential site for a VRU. The keys to successful VRU projects are a steady source and adequate quantity of crude oil or condensate vapors along with an economic outlet for the collected product. The potential volume of vapors will depend on the makeup of the oil or condensate and the rate of flow through the tanks. Pipeline connection costs for routing vapors off site must be considered in selecting sites for VRU installation.

Step 2: Quantify the volume of vapor emissions.

Emissions can either be measured or estimated. An orifice well tester and recording manometer (pressure gauge) can be used to measure maximum emissions rates since it is the maximum rate that is used to size a VRU. Orifice meters, however, might not be suitable for measuring total volumes over time due to the low pressures at tanks. Calculating total vapor emissions from oil tanks can be complicated because many factors affect the amount of gas that will be released from a crude oil tank, including:

1. Operating pressure and temperature of the separator dumping the oil to the tank and the pressure in the tank;
2. Oil composition and API gravity;
3. Tank operating characteristics (e.g., sales flow rates, size of tank); and
4. Ambient temperatures.

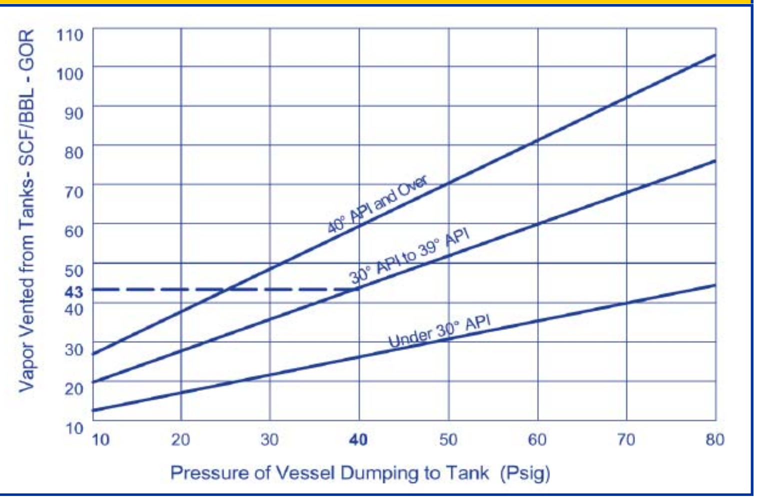
There are two approaches to estimating the quantity of vapor emissions from crude oil tanks. Both use the gas-oil ratio (GOR) at a given pressure and temperature and are expressed in standard cubic feet per barrel of oil (scf per bbl).

This process is applicable to all compressor designs. The less common overhung compressors have a single seal, and switching from wet to dry seals would yield half the savings of doing the same for a beam type compressor.

The first approach analyzes API gravity and separator pressure to determine GOR (Exhibit 2). These curves were constructed using empirical flash data from laboratory studies and field measurements. As illustrated, this graph can be used to approximate total potential vapor emissions from a barrel of oil. For example, given a certain oil API

Five Steps for Assessing VRU Economics:
1. Identify possible locations for VRU installation;
2. Quantify the volume of vapor emissions;
3. Determine the value of the recovered emissions;
4. Determine the cost of a VRU project; and
5. Evaluate VRU project economics.

Exhibit 2: Estimated Volume of Storage Tank Vapors



gravity (e.g., 38°) and vessel dumping pressure (e.g., 40 psi), the total volume of vapors can be estimated per barrel of oil (e.g., 43 scf per bbl). Once the emissions rate per barrel is estimated, the total quantity of emissions from the tank can be determined by multiplying the per barrel estimate by the total amount of oil cycled through the tank. To continue the example above, assuming an average throughput of 1,000 barrels per day (bbl per day), total emissions would be estimated at 43 Mcfd (Exhibit 3).

Exhibit 3: Quantity (Q) of Hydrocarbon Vapor Emissions

Given:
API Gravity = 38°
Separator Pressure = 40 psi
Oil Cycled = 1,000 bbl/day
Vapor Emissions rate = 43 scf/bbl (from Exhibit 2)

Q = 43 scf/bbl x 1,000 bbls/day = 43 Mcfd

The shortcoming of this approach is that it does not generate information about the composition of the vapors emitted. In particular, it cannot distinguish between VOC and HAP, which can be significant for air quality monitoring, as well as determining the value of the emitted vapors.

The second approach is to use the software package E&P Tank version 2.0. This is the modified version of the previous software; the American Petroleum Institute (API) introduced several changes in this model which made it more user-friendly. Partners in the Natural Gas STAR Program have recommended E&P Tank as the best available tool for estimating tank battery emissions. Developed by API and the Gas Research Institute (now the Gas Technology Institute), this software estimates emissions from all three sources—flashing, working, and standing—using thermodynamic flash calculations for flash losses and a fixed roof tank simulation model for working and standing losses. An operator must have several pieces of information before using E&P Tank, including:

1. Separator pressure and temperature.
2. Separator oil composition.
3. Reference pressure.
4. Reid vapor pressure of sales oil.
5. Sales oil production rate.
6. API gravity of sales oil.

E&P Tank also allows operators to input more detailed information about operating conditions, which helps refine emissions estimates. With additional data about tank size, shape, internal temperatures, and ambient temperatures, the software can produce more precise estimates. This flexibility in model design allows users to employ the model to match available information. Since separator oil composition is a key input in the model, E&P Tank includes a detailed sampling and analysis protocol for separator oil. Future versions of the software are being developed to estimate emissions losses from production water tanks as well.

Step 3: Determine the value of the recovered emissions.

The value of the vapors recovered from VRUs and realized by producers depends on how they are used:

1. Using the recovered vapors onsite as fuel yields a value equivalent to the purchased fuel that is displaced–typically natural gas.
2. Piping the vapors (NGL—enriched methane) to a natural gas gathering pipeline yield a price that reflects the higher Btu content per Mcf of vapor.
3. Piping the vapors to a processing plant that will strip the NGLs from the gas stream and resell the NGLs and methane separately should also capture the full Btu content value of the vapors. Exhibit 4 illustrates a method of calculating the value of the recovered vapors using an average price of $7.00 per Mcf (for pipeline quality natural gas at 1,000 Btu per scf). Where the

Exhibit 4: Value of Recovered Vapors

R = Q x P
R = The gross revenue
Q = The rate of vapor recovery (Mcf/day)
P = The price of natural gas

Calculate:
Q = 41 Mcfd (95% of 43 from Exhibit 3)
P = $7.00/Mcf
R = 41 Mcfd x $7/Mcf =
$287/day
$8,800/month
$105,600/year

Methane Content of Natural Gas

The average methane content of natural gas varies by natural gas industry sector. The Natural Gas STAR Program assumes the following methane content of natural gas when estimating methane savings for Partner Reported Opportunities.

Production	79 %
Processing	87 %
Transmission and Distribution	94 %

Btu content of the vapors is higher, the price per Mcf would be higher.

Step 4: Determining the cost of a VRU project.

The major cost elements of VRUs are the initial capital equipment and installation costs and operating costs.

VRU systems are made by several manufacturers. Equipment costs are determined largely by the volume handling capacity of the unit; the sales line pressure; the number of tanks in the battery; the size and type of compressor; and the degree of automation. The main components of VRUs are the suction scrubber, the compressor, and the automated control unit. Gas measurement is an add-on expense for most units. Prices for typical VRUs and related costs are shown in Exhibit 5.

When sizing a VRU, the industry rule-of-thumb is to double the average daily volume to estimate the maximum emissions rate. Thus, in order to handle 43 Mcfd of vapor (Exhibit 3), a unit capable of handling at least 86 Mcfd should be selected.

Nelson Price Indexes

In order to account for inflation in equipment and operating & maintenance costs, Nelson-Farrar Quarterly Cost Indexes (available in the first issue of each quarter in the *Oil and Gas Journal*) are used to update costs in the Lessons Learned documents.

The "Refinery Operation Index" is used to revise operating costs while the "Machinery: Oilfield Itemized Refining Cost Index" is used to update equipment costs.

To use these indexes in the future, simply look up the most current Nelson-Farrar index number, divide by the February 2006 Nelson-Farrar index number, and, finally multiply by the appropriate costs in the Lessons Learned.

Partners who have installed VRUs and VRU manufacturers report that installation costs can add as much as 50 to 100 percent to the initial unit cost. Installation costs can vary greatly depending on location (remote sites will likely result in higher installation costs) and the number of tanks (larger VRU systems will be required for multiple tanks). Expenses for shipping, site preparation, VRU housing construction (for cold weather protection), and supplemental equipment (for remote, unmanned operations) must also be factored in when estimating installation costs.

Operations and maintenance (O&M) expenses vary with the location of the VRU (sites in extreme climates experience more wear), electricity costs, and the type of oil

Exhibit 5: Vapor Recovery Unit Sizes and Costs

Design Capacity[1] (Mcfd)	Compressor Horsepower[2]	Capital Costs[3] ($)	Installation Costs[3]	O&M Costs ($/year)
25	5—10	20,421	10,207—20,421	7,367
50	10—15	26,327	13,164—26,327	8,419
100	15—25	31,728	15,864—31,728	10,103
200	30—50	42,529	21, 264—42,529	11,787
500	60—80	59,405	29,703—59,405	16,839

[1] Assumes design capacity is double average vapor recovery rate.
[2] Assumes compressor discharge to a 100 psi or less sales line or fuel gas system.
[3] Cost information provided by Natural Gas STAR partners and VRU manufacturers.

produced. For instance, paraffin based oils can clog the VRUs and require more maintenance.

Step 5: Evaluate VRU Project Economics.

Installing a VRU can be very profitable, depending on the value of the recovered vapors in the local market. Exhibit 6 calculates the simple payback and Internal Rate of Return (IRR) for VRU sizes and costs listed in Exhibit 5. Using an estimate of the value of recovered vapors of $7.00 per Mcf, the potential returns are attractive, particularly for the larger units.

When assessing VRU economics, gas price may influence the decision making process; therefore, it is important to re-examine the economics of installing vapor recovery units as natural gas prices change. Exhibit 7 shows an economic analysis of installing a 100 Mcfd vapor recovery unit at different gas prices.

Lessons Learned

The use of VRUs can profitably reduce methane emissions from crude oil storage tanks. Partners offer the following lessons learned:

★ E&P software can be an effective tool for estimating the amount and composition of vapors from crude oil tanks.

★ Vapor recovery can provide generous returns due to the relatively low cost of the technology and in the cases where there are market outlets for the high BTU vapors.

★ VRUs should be installed whenever they are economic, taking into consideration all of the benefits—environmental and economic.

★ Because of the very low pressure differential between

Exhibit 6: Financial Analysis for VRU Project

Design Capacity (Mcfd)	Installation & Capital Costs[1] ($)	O&M ($/Year)	Value of Gas[2] ($/Yr)	Payback[3] (months)	Internal Rate of Return[4] (%)
25	35,738	7,367	30,300	19	58
50	46,073	8,419	60,600	11	111
100	55,524	10,103	121,360	6	200
200	74,425	11,787	242,725	4	310
500	103,959	16,839	606,810	3	567

[1] Unit cost plus estimated installation cost of 75% of unit cost. Actual costs might be greater depending on expenses for shipping, site preparation, supplemental equipment, etc.
[2] 95% of total gas recovered at $7 per Mcf x 1/2 design capacity x 365 days
[3] Based on 10 percent discount rate.
[4] Calculated for 5 years.

Exhibit 7: Gas Price Impact on Economic Analysis

	$3/Mcf	$5/Mcf	$7/Mcf	$8/Mcf	$10/Mcf
Value of Gas Saved	$52,011	$86,686	$121,360	$138,697	$173,371
Payback Period (Months)	16	9	6	6	5
Internal Rate of Return (IRR)	70%	136%	200%	231%	294%
NPV (i=10%)	$93,947	$213,440	$332,934	$392,681	$512,174

the storage tank and the compressor, large diameter pipe is recommended to provide less resistance to the gas flow.

★ A VRU should be sized to handle the maximum volume of vapors expected from the storage tanks (a rule-of-thumb is double the average daily volume).

★ Rotary vane compressors are recommended for VRUs to move the low volume of gas to low pressures.

★ It is very important to choose reliable, sensitive control systems, because the automated gas flow valves must be opened and closed on very low pressure differences.

★ Include methane emissions reductions from installing VRUs in annual reports submitted as part of the Natural Gas STAR program.

One Partner's Experience

Chevron USA Production Company installed eight vapor recovery units in 1996 at crude oil stock tanks. As a result, Chevron has realized an estimated reduction in methane emissions of 21,900 Mcf per year from each unit. At today's gas price of $7 per Mcf, this corresponds to approximately $153,300 in savings per unit, or $1,226,400 for all eight units. The capital and installation costs were estimated to be $240,000 ($30,000 per unit) in 1996 or the equivalent of $324,000 ($40,500 per unit) in 2006 dollars. This particular project would have realized a payback in just over 3 months in 2006.

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