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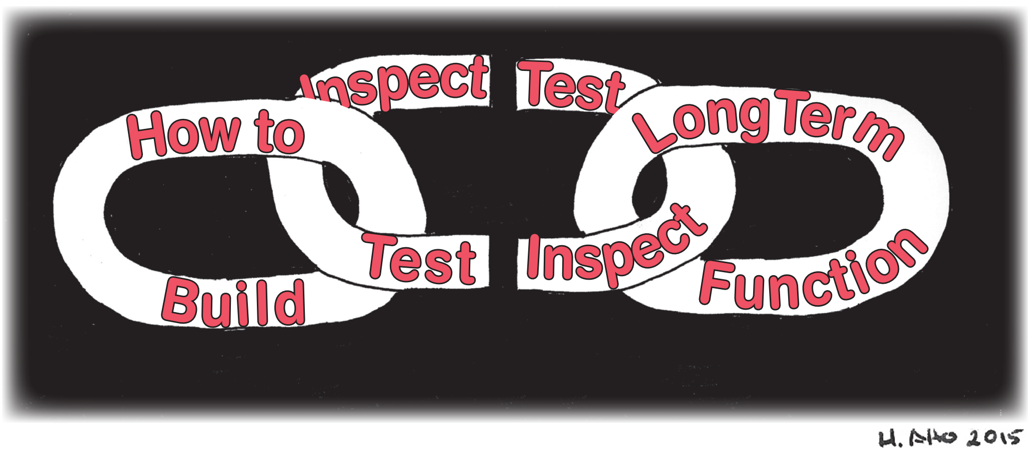
L.U.S.T.LINE

A Report On Federal & State Programs To Control Leaking Underground Storage Tanks

The Missing Link

How Well Is UST Equipment Working?

by Kevin Henderson



Thirty years ago, the U.S. Environmental Protection Agency (USEPA) began the process of promulgating regulations relative to underground storage tanks (USTs). The resulting regulation requires that tanks and piping be installed in accordance with a code of practice developed by a nationally recognized association or independent testing laboratory. While the original UST regulation did a very good job of describing the kinds of equipment required and the performance standards that must be met, it fell short with regard to ensuring that much of that fancy equipment performed as originally intended years after it was installed.

Recognizing this missing link between describing how something must be built and ensuring it actually functions as intended, USEPA proposed several periodic testing and inspection requirements in its November 2011 draft rule changes. If promulgated, these proposed changes, among other things, would require that UST system components, including spill, overfill prevention, secondary containment, and leak detection equipment, be periodically inspected and tested. These requirements would serve to identify weaknesses and help improve the long-term performance of the UST components, completing an important missing link in the federal UST regulatory schema.

As was the case, for example, with UST tank and piping in the original rule, one of the options in the proposed rule changes would require that periodic functionality testing be conducted in accordance with a code of practice developed by a nationally recognized association or independent testing laboratory. Anticipating the need for this type of code of practice, the Petroleum Equipment Institute (PEI) developed RP1200 *Testing and Verification of Spill, Overfill, Leak Detection and Secondary Containment Equipment of UST Facilities*. This document is intended to serve as an industry standard and authoritative source for the testing of UST system components.

■ *continued on page 2*

Inside

6 Stage I Vapor Recovery and ATGs
11 Rules Are Just Fine for Some Tank Owners
12 Petroleum Remediation Using Activated Carbon
14 Remediation Technologies on the Info Highway
16 Innovative Site Characterization
19 "Pig" Chews Over Meeting UST Regulatory Goals – Part 3
22 Backlog of UST Releases on Tribal Land

■ **The Missing Link** *from page 1*

RP1200 has two broad objectives with respect to the effective operation and maintenance of UST systems. The first objective is to ensure that various devices and equipment intended to prevent and detect leaks in the UST system are functioning properly. The second objective is to ensure that if a leak or spill does occur, secondary and spill containment components of the UST system are capable of containing the leak or spill so that the operator has enough time to detect it and respond before the leak or spill reaches the environment. Given the many different ways UST systems are designed, installed, operated, and maintained makes the task of developing the procedures and protocols needed to accomplish these two goals much more difficult than one would initially think.

Finding Consensus

The 2012 edition of PEI RP1200 represents the first attempt to create an industry standard for many of the testing procedures that have evolved in a rather ad hoc manner since the inception of the UST rules. Given the broad range of topics and differences of opinion among the RP1200 committee members relative to the existing procedures, it was necessary to reconcile many different issues.

While some industry and manufacturer procedures existed, there were many conflicting aspects of these documents, and in some cases, there was little specific guidance that could be referenced. RP1200 represents a synthesis of existing industry procedures and manufacturers' recommendations and, where there were no existing sources or significant conflicts existed between documents, the RP1200 committee produced its own consensus recommendations based on the practical experience of committee members.

To provide a sense of the issues addressed by the committee and the rationale for the final product, what follows is a summary of the pertinent sections of the recommended practice.

Secondary Containment—Tanks

Double-walled tanks are designed to have either fluid-filled or dry interstitial spaces. Tanks with fluid-filled interstices are said to be hydrostatically monitored. Tanks that have a dry interstice can be monitored atmospherically or by vacuum. Therefore, two general procedures for testing the integrity of tanks with secondary containment have been developed—hydrostatic and vacuum testing.

The vacuum-testing procedure described in RP1200 is general in nature and is intended to establish that the tank secondary containment will contain leaked product until it can be discovered and removed before it reaches the environment. Vacuum testing involves the establishment of a relatively small vacuum in the interstitial space. The vacuum is monitored for a period of time that is dependent on the site conditions and volume of the tank. The amount of vacuum drawn depends on whether the tank is of steel or fiberglass-reinforced-plastic (FRP) construction.

In the case of steel tanks, the testing procedure is also dependent upon whether the tank has "110 percent containment" or a "tight-wrap" design. A 110 percent containment tank is defined as a tank with secondary containment where the interstitial space volume is 10 percent of the total primary containment volume. A tight-wrap tank is one whereby the primary tank structurally supports the secondary containment. If the tank is a 110 percent containment design, the procedure for testing must adhere to that established by the Steel Tank Institute. Tight-wrap steel tanks may follow the testing procedure established in RP1200.

FRP tanks with an atmospheric (dry) interstice, whether 110 percent containment or a tight-wrap design, may utilize the vacuum test procedure described in RP1200 to establish the general integrity of the secondary tank. In addition to the test procedure described in RP1200, the Fiberglass Tank & Pipe Institute has published FTPI RP 2007-2 *Field Test Protocol for Testing the Annular Space of Installed Underground Fiberglass Double and Triple-Wall Tanks with Dry Annular Space* that may also be utilized.

Hydrostatic testing tank secondary containment involves several variables that complicate the development of a generalized test procedure. Therefore, RP1200 adopts by reference the test protocols that have been established by tank manufacturers. The checklists/data logs for these manufacturer-developed test protocols are included in Appendix 1 of RP 1200.

Secondary Containment—Piping

This section of RP1200 describes how to test the outer wall of double-walled piping. Although most double-walled piping systems terminate in containment sumps, an integral part of the secondary containment, testing the sumps is addressed separately. While there are several different ways that secondary containment of double-walled piping systems may be evaluated for integrity, pressurization of the interstice is the most common. Therefore, RP1200 only describes a test protocol utilizing an inert gas (e.g., nitrogen or helium) to pressurize the interstitial space.

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The generally accepted practice within the industry has been to apply a pressure of 3–5 pounds per square inch gauge (psig) to the piping interstice and monitor this for a period of time. Since this has been a well established protocol for many years, the RP1200 committee decided to incorporate this simple test procedure and established a minimum test pressure of 5 psig and duration of 1 hour. If there is any loss of pressure, the piping secondary containment does not pass the integrity test.

Further complicating the testing of double-walled piping systems is the varied ways in which the secondary containment may end within the piping containment sumps. In order to simplify the discussion, it is assumed that piping system secondary containment is capable of being sealed at the ends such that pressure can be applied to the interstice. If the interstice cannot be sealed at the terminations, testing cannot be accomplished utilizing the procedures described in RP1200.

Testing can be conducted in sections or as one continuous pipe, depending on the characteristics of the installation and the desired result of the testing. For instance, when troubleshooting to narrow down the location of a problem it may be desirable to test each section of the pipe independently.

Spill Buckets and Containment Sumps

Spill buckets and containment sumps may be of single- or double-walled construction. The integrity of single-walled spill buckets may be evaluated utilizing either hydrostatic or vacuum test methods. Testing double-walled spill buckets is accomplished by establishing a low level of vacuum within the interstice. Although the integrity of containment sumps may be tested either hydrostatically or by vacuum, only hydrostatic testing is described in RP1200. In addition, only test procedures that evaluate the integrity of single-walled sumps or the primary of double-walled sumps are described. Testing the interstitial space of double-walled sumps may be accomplished by utilizing manufacturer-developed procedures.

Hydrostatic spill buckets testing is general in nature and intended to demonstrate that the spill bucket is capable of containing small quantities of spilled product for short periods of time until it can be removed properly. Hydrostatic testing consists of filling the spill bucket with water; a pass/fail determination is made based on changes in the water level over time. Hydrostatic testing may be accomplished by manually measuring the fluid level or by using precision measurement methods available from manufacturers capable of significantly shortening the test time.

An important aspect of hydrostatic testing is the visual examination conducted before the spill bucket is filled with water. The visual examination is conducted to help ascertain whether or not the tank fill riser cap and the spill bucket drain (if present) are liquid tight. Adding water to the spill bucket would likely cause water to enter the tank if these components are not tight. With the widespread use of ethanol-blended fuels, this is a particularly important concern. Therefore, as an alternative, the tank fill riser cap may be removed and a plumbers' plug installed in the riser pipe to eliminate the possibility of water entering the tank because of a faulty cap. Similarly, the drain valve may be removed and a plug installed (either temporarily or permanently) if local regulations allow. In some cases, it may be preferable to test the spill bucket with both the tank fill riser cap and drain valve in place, since doing so will also determine whether or not the cap and drain valve are functional.

Vacuum testing may be used to test the integrity of both single-walled spill buckets and secondary containment of double-walled spill buckets. Vacuum testing the single-walled spill bucket and double-walled spill bucket primary containment is accomplished with the use of a special test cover that allows the spill bucket to be sealed. The vacuum level within the sealed spill bucket is measured over time, and a pass/fail determination is made based on the rate at which the vacuum level decays. The integrity of double-walled spill buckets may be tested by drawing a vacuum on the interstitial space using a dedicated test port. When the interstice of a double-walled spill bucket is tested, the integrity of both the primary and secondary containment is evaluated simultaneously.

Testing of containment sumps is described utilizing hydrostatic procedures whereby the sump is filled with water to an appropriate height and then monitored for a period of time. This testing is general in nature and intended to establish that the sump is capable of containing leaked product until it can be discovered and removed. As with spill bucket hydrostatic testing, monitoring the test fluid within the containment sump may be accomplished manually or by the use of precision monitoring equipment. When conducting hydrostatic testing, it is important to ensure that all monitoring equipment and electrical components installed in the sump are either removed or made safe prior to submergence.

Overfill Prevention Equipment

Although overfill prevention devices could be tested by intentionally overfilling the tank, this approach is not recommended by the RP1200 Committee. Since there is no other practical way to test most overfill prevention equipment, the recommended practice describes a procedure that is intended to verify that the equipment is installed correctly and determine that the equipment is functioning as designed.

Three types of overfill prevention equipment are commonly installed in UST systems: drop-tube devices (commonly referred to as "flapper valves"), vent-restriction devices (ball float valves), and electronic high-level alarms.

The federal UST rule requires that overfill prevention equipment automatically restrict flow or alert the transfer operator when either the tank is no more than 90 percent full or shut off flow into the tank when it is no more than 95 percent full. The federal rule also allows other alternatives that will restrict flow 30 minutes prior to overfilling, alert the operator one minute before overfilling, or shut off flow before any of the tank-top fittings are wetted. Although these alternatives are allowed in the federal rule, the RP1200 committee chose to develop procedures for overfill

■ continued on page 4

■ **The Missing Link** *from page 3*

prevention equipment reflective of the more conservative application of the rule (i.e., shut off at 95%, restrict, or alarm at 90%).

The verification/inspection of automatic shut-off devices involves removing the device from the tank and conducting both an operability and visual confirmation that the device is installed properly and mechanically functional. The procedure requires confirmation that the device is installed to cause complete shut off of product flow when the tank is no more than 95 percent full. It also requires that the device be visually inspected and the working mechanism manually activated to ensure that all of the components necessary for the device to function as designed are present and in good working order.

Although the committee recommends that ball float valves be removed from tanks and that an alternative method of overfill prevention be installed, procedures for inspection/verification of these devices are provided. The procedure for ball float valves requires removal of the device from the tank and verification that the device is installed such that it will restrict flow when the tank is no more than 90 percent full. It also involves a visual examination to ensure that all of the components necessary for the device to function, as intended, are present and in good working order.

Procedures for electronic overfill alarms are limited to automatic tank gauging systems (ATGs) in which the product float that measures the fluid level is an integral part of magnetostrictive ATG probe assemblies. The ATG probe assembly is removed from the tank and all of the components necessary for proper function are visually inspected. Additionally, the float is manually moved along the ATG probe to confirm that an alarm condition that provides an audible and/or visual warning to the delivery driver occurs when the tank is no more than 90 percent full.

Automatic Tank Gauging

The term "automatic tank gauge" is a general industry term that refers to all electronic systems that function to monitor the product level in a tank or to detect leaks. These systems include those that have in-tank probes designed to measure fluid levels and those that have sensors installed within the interstitial space of double-walled tanks. Systems that monitor the interstice may do so in a number of different ways. However, since electronic sensors that operate on a simple float switch principal are by far the most common type, this is the only test procedure developed in the recommended practice.

In-tank probes are tested by removing the ATG probe from the tank. A visual examination is conducted to ensure that all of the ATG system components appear to be in good working order. The probe floats are manually moved on the shaft to verify that the fluid level indicated on the ATG console corresponds with the actual fluid level in the tank when the system is operating. In addition, the ATG console is checked to verify that the site setup parameters are correct and that everything is labeled properly.

Electronic sensor testing involves placing the sensor in the appropriate test fluid and verifying that the expected response (e.g., alarm) is observed. A vital part of the test also involves ensuring that the sensor is installed properly in accordance with the manufacturer's requirements so that a leak will be detected before it reaches the environment.

Automatic Line Leak Detectors

Automatic line leak detectors (ALLDs) are mechanical or electronic devices designed to detect a leak in a pressurized product line that is equivalent to 3 gallons per hour (gph) at 10 psig within one hour. Therefore, it is necessary to simulate a leak equivalent to 3 gph at 10 psig when testing these devices. This is typically done with some type of test apparatus that is capable of accurately simulating a leak in the piping that would allow 3 gph to flow if the line pressure were 10 psig. The exact size of the hole may vary since different fuels may have different flow characteristics (i.e., viscosity). Because of differences in fuel viscosity, the test apparatus must have an orifice that can be adjusted to achieve a flow rate equivalent to 3 gph at 10 psig. Once the correctly calibrated simulated leak is established, the test procedure confirms that the ALLD is capable of detecting a leak equivalent to 3 gph at 10 psig.

The procedure for testing mechanical ALLDs requires that the simulated leak occur at the dispenser at the highest elevation above the submersible turbine pump.

With this kind of crud becoming more and more common in our tanks, it is easy to understand why automatic tank gauging systems need to be looked at periodically.

This verifies that there is not excess head pressure in the piping system that could potentially prevent the mechanical ALLD from functioning correctly. If there is no change in elevation or if the dispensers are lower than the STP, the simulated leak must occur at the dispenser that is farthest away. This confirms that all of the piping (including that to any satellite dispensers) is monitored by the mechanical ALLD.

Testing electronic ALLDs also involves the creation of a simulated leak in the piping and confirms that the ALLD is capable of detecting a leak in the piping equivalent to 3 gph at 10 psig. The proper alarm condition and STP shutdown (if required by code) must occur in order for the electronic ALLD to pass the test. Another important part of the test procedure for electronic ALLDs is verifying that the system-setup parameters are correct. If the setup parameters are not correct, a leak in the piping could potentially go undetected.

An important step in the test procedure for both mechanical and electronic ALLDs is confirming that the STP contactors ("relays") operate properly. This allows the STP to cycle on/off and is critical for the proper operation of ALLDs. In addition to verifying that the STP cycles on/off properly, RP1200 recommends that a visual inspection of the STP contactors be made to verify that the relay switches appear to be in good condition.

Shear Valves

Although the testing of shear valves is a relatively simple matter and has been required by fire codes for many years, it is rarely performed. Because shear valves are usually excluded from UST regulations, testing does not usually occur. This is very unfortunate since properly installed and operating shear valves are a very important aspect of protecting human health and the environment at a typical UST retail facility for reasons that should be apparent. If the dispenser is accidently knocked down or a fire occurs, the potential for a substantial release of highly flammable fuel with potentially catastrophic consequences exists in very close proximity to the public.

Recognizing the very real threat posed by an improperly functioning shear valve, the Mississippi Department of Environmental Quality chose to include testing of shear valves in its UST regulations. Doing so provides the regulatory authority most commonly associated with UST systems with the ability to ensure shear valves are properly installed, maintained, and tested.

The test procedure described in RP1200 involves manually closing the shear valve poppet and verifying that no product flow occurs through the dispenser nozzle. In addition to verifying that the flow is shut off, the test procedure also requires evaluation of the anchoring of the shear valve to the dispenser island. Secure anchoring at the correct height relative to the dispenser island is necessary for the shear valve to function as designed in the event of an impact to the dispenser cabinet.

Emergency Stop Switches

The procedure for testing emergency stop switches verifies that all power is disconnected to the dispensers, submersible turbine pumps, and all signal/control circuits associated with these UST system components. The purpose is to ensure that in the event of activation of the emergency stop switch, the fuel-dispensing and pumping system is completely disabled. The test also confirms that power to all other non-intrinsically safe electrical equipment in the classified areas surrounding fuel-dispensing devices is disconnected when the emergency stop switch is activated.

Is This the Link?

While RP1200 describes and provides procedures for the testing, verification, and inspection of many UST system components, it does not attempt to interpret any regulatory requirements. Let's be clear, nothing in RP1200 should be construed as mandating or requiring any kind of testing. RP1200 is simply a document that describes procedures for how testing should be done if one desires to conduct testing or if it is required by some regulatory statute, code, or ordinance.

As is the case with similar issues, the effectiveness of all this testing will depend in large part on establishing the rule and, more importantly, enforcing and implementing the rule in an effective manner. After all these years of effort and expenditure of resources to design, build, operate, and maintain UST systems that do not leak, isn't it time we took the issue of proper operation and maintenance seriously? Let's be sure that we understand not only how the testing should be performed but that it is actually done in accordance with all of the requirements so that we can hopefully say one day in the not too distant future: "We found the missing link!" ■

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Tank-nically Speaking

by Marcel Moreau

*Marcel Moreau is a nationally recognized petroleum storage specialist whose column, **Tank-nically Speaking**, is a regular feature of* LUSTLine. *As always, we welcome your comments and questions. If there are technical issues that you would like to have Marcel discuss, let him know at* **marcel.moreau@juno.com.**

What Does Stage I Vapor Recovery Have to Do with ATGs?

The tank owner was perplexed. He had been doing leak detection conscientiously for years. His single-walled tanks were only a dozen years old. His ATG had been conducting continuous leak detection since his tanks were installed and he had never had an issue with failed tests. In the last few years, however, he'd been getting frequent failed test results, especially on his regular tank. To track down the problem he'd had numerous tightness tests conducted, using a number of different testing technologies, but all the tests indicated that his tanks were tight. His inventory records showed nothing amiss.

He brought in the company that had installed the ATG. The service tech that came checked all the ATG settings and could find nothing wrong. The tech then called the ATG manufacturer, who asked the technician if the failed tests had appeared after Stage I vapor recovery had been installed. The service tech relayed the question to the tank owner. Reviewing his records, the tank owner realized that the problem had indeed arisen not long after he installed Stage I vapor recovery. The puzzled service tech scratched his chin as both men asked aloud: "What does Stage I have to do with ATGs?"

NOTE:: I last wrote about Stage I vapor recovery and its effects on UST systems back in *LUSTline* #62 in August 2009 (available in the *LUSTLine* archives at *www.neiwpcc.org*). In that article, I focused on two issues: 1) the relationship between Stage I and inventory measurements made with a gauge stick, and 2) the conflict between co-axial Stage I vapor recovery and ball float valves installed for overfill prevention. The widespread implementation of Stage I as a result of the *National Emission Standards for Hazardous Air Pollutants* (NESHAP) regulations has brought to light a different issue: the interactions of Stage I and ATGs. Thanks to Heather Peters of the Missouri Department of Natural Resources for educating me on this issue.

Some Hardware Basics

There are three aspects of Stage I vapor recovery that need to be understood to get to the bottom of how Stage I affects ATGs: pressure/vacuum (P/V) vent valves, drop tubes, and tank vapor tightness.

Pressure/Vacuum (P/V) Vent Valves

Stage I vapor recovery rules require the installation of P/V vent valves on tank vent openings. Although many models of P/V vent valves look somewhat similar to standard vent caps on the outside, P/V vent valves do not allow air and vapors to freely enter and exit the tank as standard vent caps do. P/V vent valves incorporate mechanisms that prevent vapors from leaving the tank until the pressure inside the tank is in the range of 2.5 to 6 inches of water, and air from entering the tank until the vacuum in the tank is in the range of 6 to 10 inches of water. These pressure and vacuum levels are quite small. You can generate a similar pressure when you blow bubbles through a straw that is submerged 2.5 to 6 inches deep into a glass of water, or when you drink water through a straw where the top of the straw is 6 to 10 inches above the liquid level in the glass.

Why Are P/V Vent Valves Necessary?

If we're trying to prevent the escape of gasoline vapors from a tank into the environment, why isn't a vent cap that keeps vapors in the tank by maintaining pressure in the tank enough? Why do we also need a mechanism that prevents air from entering the tank? There are two reasons.

One role of P/V vent valves is to increase the efficiency of balance Stage II vapor recovery systems. Almost all of the early Stage II vapor recovery systems were balance systems, which relied on the flow of fuel into the automobile gas tank to drive the vapors back to the underground tank. By preventing the ingress of air through the tank vent line as liquid was pumped from the tank, the vacuum portion of the P/V vent valve created a small vacuum in the tank ullage that also helped draw the vapors from the automobile gas tank back to the UST.

Balance Stage II systems were largely replaced by vacuum-assist Stage II systems some 20 years ago. In today's world, carbon canisters in vehicles in most states are supplanting Stage II, so this role of P/V vent valves is not so important as it once was.

A second role of the vacuum valve is to make sure that no fresh air enters the tank during fuel deliveries. Tank trucks equipped for Stage I fuel deliveries also have P/V vent valves. Though different in design, they serve the same function as P/V vent valves on the UST. The tank on the truck must also be vapor tight, so that when fuel flows from the truck into the UST, the P/V vent valve in the truck tank maintains a vacuum that helps draw the vapors from the UST into the truck. The P/V vent valve in the UST, meanwhile, prevents the ingress of fresh air into the UST so that only the vapors in the UST and not fresh air from the atmosphere flow back to the truck.

Drop Tubes

Another requirement of Stage I vapor recovery regulation is that drop tubes be installed in fill risers. Drop tubes are typically aluminum tubes that slide down inside fill risers and extend from the top of the fill riser to within six inches of the bottom of the tank.

Why Do We Need Drop Tubes?

During a delivery, product flows through the drop tube and enters the tank below the liquid level. In the absence of the drop tube, fuel free-falls from the top of the tank where the fill riser ends to the level of the fuel in the tank. The fuel falling through the air together with the splashing of the fuel as it hits the surface of the liquid in the tank substantially increases the amount of fuel vapor in the tank ullage. The more vapors present in the tank ullage, the greater the quantity of gasoline vented to the atmosphere (if Stage I vapor recovery is not present) or transferred back into the delivery truck (if Stage I vapor recovery is present). Remember that NESHAP rules specify that gas stations pumping between 10,000 and 100,000 gallons per month are required to have drop tubes but not Stage I vapor recovery.

As a side benefit, the drop tube also increases the velocity of the fuel flowing into the tank, thus decreasing the time required to deliver a load of fuel.

Vapor-Tight Tanks

The third requirement of Stage I regulations that we need to understand is that UST systems should be vapor tight. To enforce this requirement, UST systems must be tested periodically. The test involves applying a slight pressure to the tank ullage using nitrogen. The pressure level is then monitored for a period of time to see if it decreases. A certain amount of pressure loss is allowed, but if too much pressure is lost, the UST fails the test and the vapor leaks must be found and corrected.

One element of this pressure-decay test protocol is that the fill cap must be removed while the test is conducted. This requirement is designed to ensure that minimal amounts of vapors are released when the fill cap is removed during the fuel-delivery process. What this means for drop tubes, however, is that no vapors must be able to flow between the tank ullage and the inside of the drop tube.

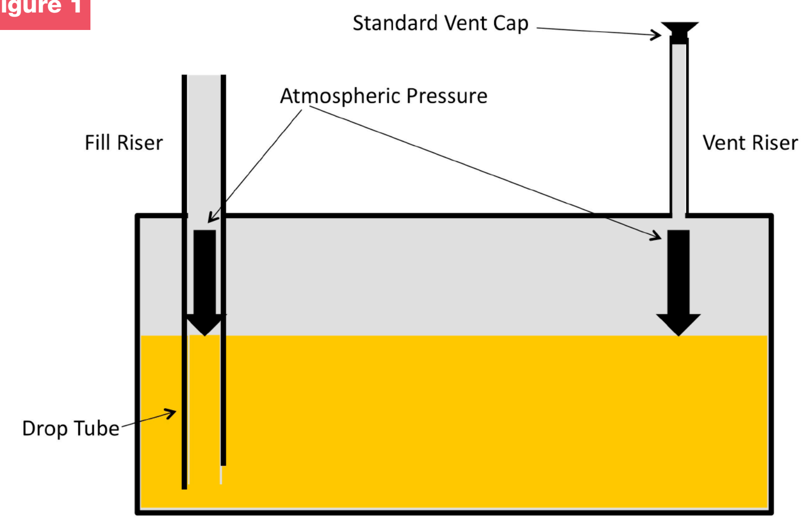
Okay, So Now What?

The combination of P/V vent valve, drop tube, and a vapor-tight tank creates a scenario where the ullage of the tank and the space above the fuel inside the drop tube are likely to be at different pressures. And because the bottom of the drop tube is open, gasoline flows from the area of higher pressure to the area of lower pressure. As a result, gasoline will likely be at a different level inside the drop tube than outside in the main body of the tank.

There are a number of variables that complicate this scenario, so let's start simple. Imagine there is a vapor-tight tank with a standard vent cap,

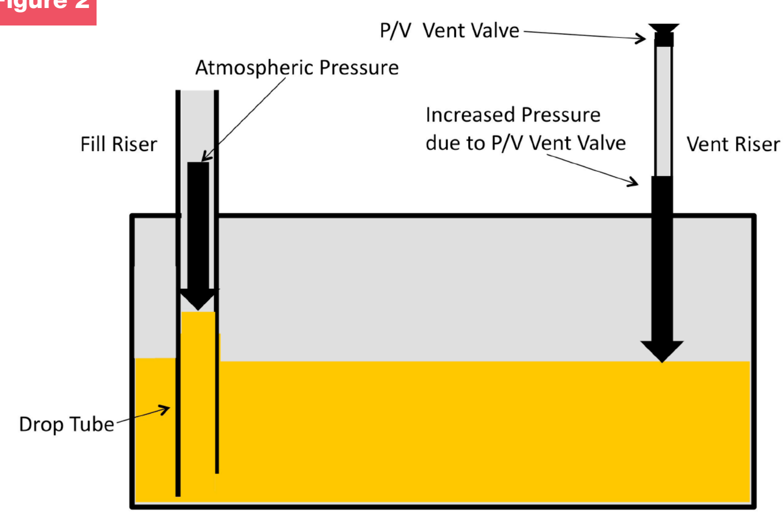
■ continued on page 8

Figure 1



When the pressure inside both the tank and the drop tube are equal, the liquid level inside the drop tube and the tank will be equal.

Figure 2



When the pressure inside the tank is greater than the pressure inside the drop tube, the liquid level inside the drop tube will be higher than the liquid level in the tank.

■ **Tank-nically Speaking**
from page 7

a drop tube, and the cap on the fill pipe is off. There are no fuel deliveries or pumping activity going on. In this scenario, both the fuel in the drop tube and the fuel in the tank are under atmospheric pressure. Because the pressures are equal, the level of fuel in the drop tube and the level of fuel in the tank are exactly equal. This is the scenario in Figure 1.

Now let's replace the standard vent cap with a P/V vent valve. The fuel in the drop tube is still subject to atmospheric pressure, but let's say the P/V vent valve is maintaining a small pressure inside the tank. The result is what we see in Figure 2: The pressure in the main body of the tank is greater than the pressure in the drop tube, so the fuel level is higher in the drop tube than inside the tank. The fuel in the drop tube rises up to a level where the weight per square inch of the column of fuel inside the drop tube, plus the pressure of the atmosphere above the liquid in the drop tube equal the weight per square inch of the fuel in the main body of the tank, plus the air pressing down on the surface of the fuel.

The situation is reversed if the P/V vent valve is maintaining a slight vacuum in the tank (Figure 3). The fuel level in the drop tube is lower than the fuel level in the main body of the tank.

How Pressure and Vacuum Are Produced in Tanks

In the examples just described, the tank was inactive. But in the real world, tanks are having fuel added and withdrawn on a regular basis. This is how pressures and vacuums are generated inside the tank.

In the days of vacuum-assist Stage II vapor recovery, where in many cases the amount of vapor returned to the UST was greater than the volume of liquid pumped out, it was common to generate pressure inside the ullage of USTs.

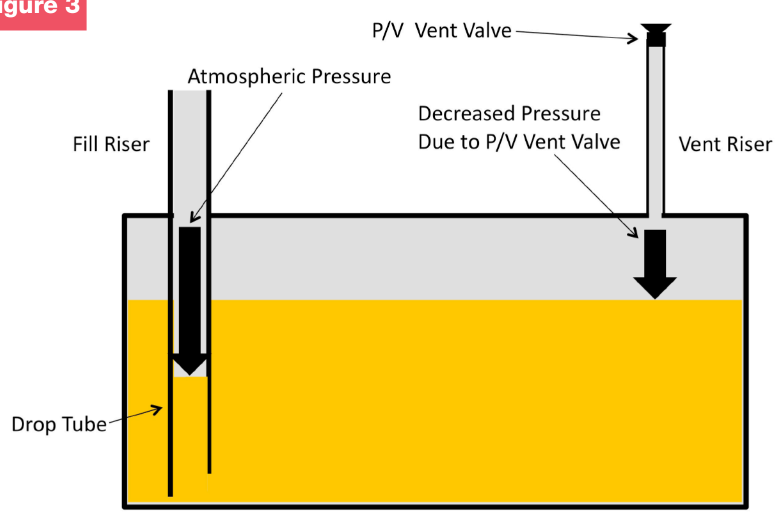
In the absence of Stage II, the result of withdrawing liquid without adding any vapors or allowing any air to enter the tank is to create a vacuum in the UST that increases until the set point of the P/V vent valve is reached and the valve opens to allow some air into the tank.

The examples I just discussed also left the fill cap off the fill riser. The picture gets a bit more complicated when we place the cap on the fill opening of the tank. Now the space inside the drop tube is closed. If the pressure in the body of the tank increases, the liquid level inside the drop tube rises, compressing the vapors inside the drop tube. If that pressure is released by removing the fill cap, then the sudden change in pressure inside the drop tube causes the liquid in the drop tube to rise up and then oscillate up and down for a bit until equilibrium is reached. When equilibrium is reached we will have the scenario in Figure 2, where the level of fuel in the drop tube is significantly higher than the level of fuel in the tank.

Likewise, if a vacuum develops in the tank, the liquid level inside the drop tube drops and a vacuum also develops inside the drop tube as long as the fill cap is vapor tight. This may make the fill cap a bit difficult to remove because the difference between the atmospheric pressure pressing on the top of the fill cap and the reduced pressure inside the drop tube must be overcome. When the cap is removed, the fuel level in the drop tube falls because of the increased pressure on the surface of the fuel in the drop tube. Here again, the liquid level in the drop tube oscillates up and down for a bit until equilibrium is reached. When equilibrium is reached, we have the scenario in Figure 3, where the level of fuel in the drop tube can be significantly less than the level of fuel in the tank.

If you are a fuel delivery driver sticking the tank to determine the amount of fuel that can be delivered, the stick measurement in this scenario will lead you to believe that there is more room available in the tank than is actually present. This is not a good thing.

Figure 3



When the pressure inside the tank is less than the pressure inside the drop tube, the liquid level inside the drop tube will be lower than the liquid level in the tank.

And What About ATGs?

So right about now you're probably asking, "So when is he going to get to the failed ATG tests?" I'm almost there, but there is one more element that must be added to the picture, and that is that most tanks are not truly vapor tight. The pressure-decay testing that is done identifies substantial vapor leaks, but a tank does not have to be absolutely vapor tight in order to pass the test. Studies in New Hampshire indicate that true vapor tightness of a tank is very difficult to achieve, and that even brand new fittings such as fill caps, ATG caps, and vapor adaptors frequently leak. (*Impact of Inspection and Vapor Mitigation Technologies on Vapor Leak Rates and MtBE Concentrations in Groundwater, Environmental Research Group*, University of New Hampshire, November 22, 2010.)

Finally!

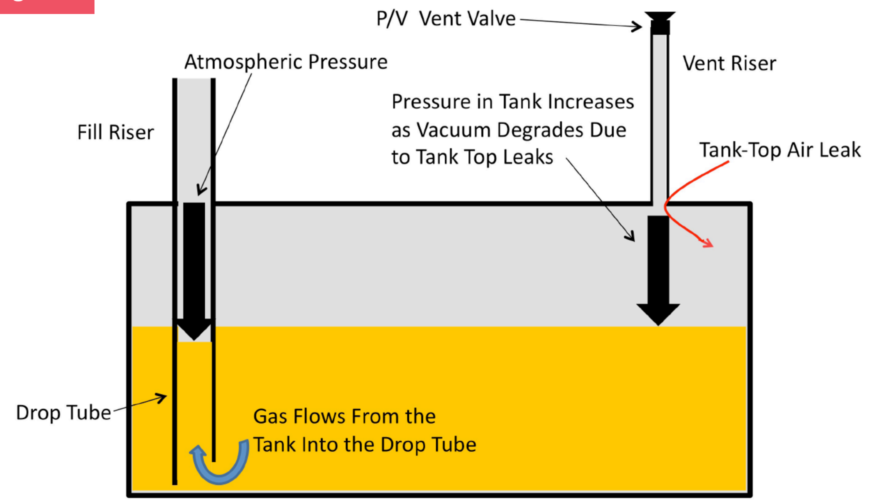
What does all of this mean for a tank with Stage I vapor recovery using an ATG for periodic tank testing? During the day, when fuel sales are brisk, a vacuum develops in the tank as liquid is removed and the P/V vent valve prevents air from entering the tank. There are vapor leaks in the system, but they are reasonably small relative to the rate at which fuel is being sold, so the vacuum is maintained at the set point of the P/V vent valve. As we get to the wee hours of the morning and pumping activity is quite infrequent, the rate at which air leaks into the tank is greater than the rate at which liquid is removed, so the level of vacuum in the tank decreases slowly.

To simplify the picture a bit, let's assume that the fill cap on the UST is not vapor tight, so the pressure inside the drop tube is at atmospheric pressure. During the busy part of the day, the vacuum in the tank lowers the fuel level inside the drop tube relative to the fuel level in the tank (the situation in Figure 3). As night arrives and fuel pumping activity slows down, the vacuum level inside the tank decreases (i.e., the pressure increases) as air leaks into the tank. As the vacuum in the tank decreases, fuel slowly flows from the tank into the drop tube (Figure 4).

Now let's add that ATG to this picture. Let's say it's late at night and the ATG is in test mode and watching the fuel level in the tank very closely. As the vacuum level in the tank decreases, fuel flows from the tank to the inside of the drop tube, and the fuel level in the tank decreases. To the ATG, a decrease in the fuel level that is not due to changing temperature is a leak. Of course, this is not a leak to the environment. Fuel is merely being transferred from one part of the tank to another, but the result is still a failed test and a perplexed tank owner.

The scenario would be the same if the fill cap were vapor tight. In this case there would be a vacuum in the drop tube that would help draw fuel into the drop tube from the main part of the tank. If the rate of fuel transfer exceeded the threshold leak rate for the ATG, the result would be a failed test.

Figure 4



During periods when the tank is relatively inactive, tank-top leaks allow air to enter the tank, the vacuum decreases (i.e., the pressure in the tank increases), and product flows from the tank to the drop tube. The ATG monitoring the liquid level in the tank sees the drop in liquid level as a leak.

What's to Be Done?

P/V vent valves have been around for some 40 years now, so this is not a new problem. The American Petroleum Institute (API) identified the issue back in the 1990s in their publication on inventory control (API Recommended Practice 1621, *Bulk Liquid Stock Control at Retail Outlets*, Fifth Edition, May 1993). The API was focusing on the issue of incorrect stick readings produced because the fuel level in the drop tube was substantially different from the fuel level in the tank. The solution provided in that document was to drill a ¼-inch hole in the drop tube near the level of the top of the tank. This would allow the pressures in the tank and inside the drop tube to equalize, thus equalizing the level of the fuel inside and outside the drop tube.

This was only a partial solution, however, because if the fill cap and tank top were reasonably vapor tight the inside of the tank would not be at atmospheric pressure when the fill cap was removed. Removing the fill cap would suddenly bring the liquid in the drop tube to atmospheric pressure, but the pressure or vacuum in the tank would take longer to get to atmospheric pressure because of the much larger volume of air in the tank and the small opening in the drop tube available for air to flow. The liquid level in the drop tube would not accurately reflect the liquid level in the tank until the pressure in the tank reached atmospheric pressure.

Even this solution became unworkable, however, when the California Air Resources Board (CARB) modified the pressure-decay-test protocol by requiring the removal of the fill cap during the test. The ¼-inch hole in the drop tube now produced failed pressure-decay tests and was no longer an acceptable solution.

Would a Hole in the Drop Tube Solve the Failed ATG Test Problem?

Please note that I am not advocating drilling holes in drop tubes as the solution to the failed ATG test problem. This may not be a legal measure under current NESHAP requirements for a vapor-tight tank. But let's set those issues aside for a moment and imagine that we did drill a hole in the drop tube. Would that solve the failed ATG test problem? Because the pressures (and therefore liquid levels) inside and outside the drop tube are the same, there is no reason for the liquid level in the tank to change and you would think that the ATG failed test problem would go away. However, Heather Peters in Missouri tells me that some folks who have tried the small-hole-in-the-drop-tube solution have found that failed ATG tests, though less frequent, still occur.

■ continued on page 10

■ Tank-nically Speaking

from page 9

How can this be? It's because the USTs that we think of as rigid are actually quite flexible. If you look up the criteria for a tightness test in the federal rule, you will find that one of the things a tightness test must compensate for is tank deformation. At the time the rule was written, the issue was that where tightness tests needed to overfill the tank to conduct the test, the tank tended to bulge out, essentially increasing the tank volume. In some cases the bulging would happen slowly during the course of the test, causing the liquid level to fall and the test to fail.

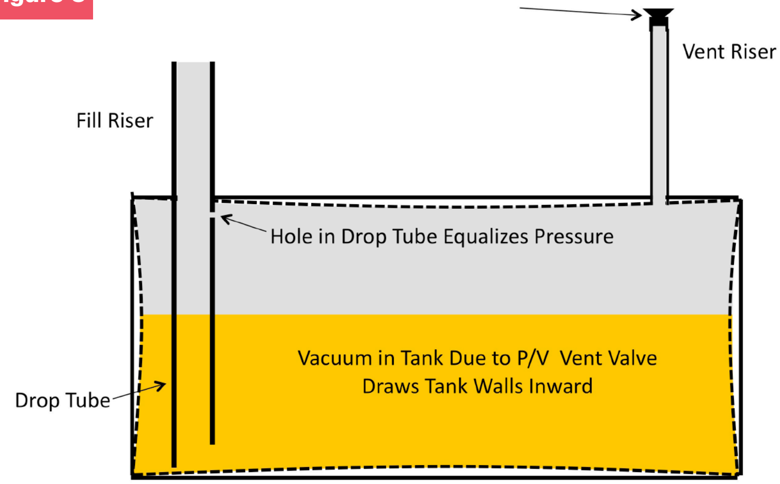
I believe a similar tank deformation scenario may be occurring when a tank is subject to a slowly decreasing vacuum. While I do not have any field data, my hypothesis is that when the tank is under vacuum, the sides and ends of the tank are "drawn in," (Figure 5) thus decreasing the tank volume. As the vacuum level slowly declines, the tank relaxes a bit (Figure 6), causing the liquid level to decrease slightly, producing a failed test. So the issue of ATGs and P/V vent valves is not just limited to liquid flow into the drop tube. It appears that just the vacuum itself is sufficient to cause leak detection problems with ATGs.

Something's Gotta Give

Because failed ATG tests, especially ones that cannot be easily explained, have the potential to raise a lot of eyebrows (especially among UST regulators), tank owner solutions to this issue have been practical but not necessarily legal. Finding ways to defeat the offending P/V vent valve by creating a less than vapor-tight UST seems an obvious solution. Loosening the P/V vent valve so it does not seal to the vent riser will do the trick nicely without being obvious. But solutions such as this could seriously compromise the effectiveness of the air rules. Are we okay with that?

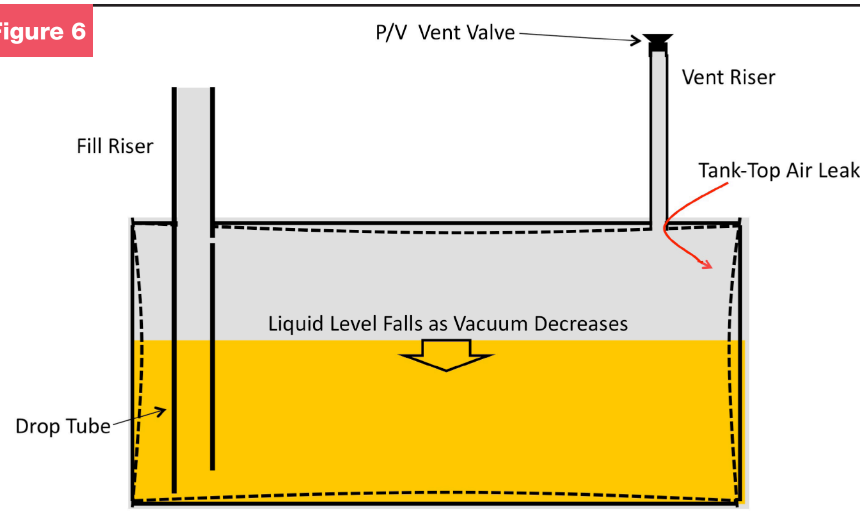
The status quo is not calculated to make anyone happy. Tank owners are faced with explaining failed tank tests to the UST regulator or circumventing the air regulations. UST regulators who understand the problem have no legal solution to offer

Figure 5



If we drill a hole in the drop tube, the pressure and liquid level inside and outside the drop tube are equal. Liquid flowing from the tank into the drop tube will no longer cause failed ATG tests. However, the presence of a vacuum in the tank may draw the sides and ends of the tank inward slightly.

Figure 6



As the vacuum decreases due to a small air leak, the walls of the tank straighten out and the liquid level drops slightly. If an ATG is in test mode when this happens, the falling liquid level may produce a failed test result.

to their tank owners. Air regulators are likely not aware that the effectiveness of their regulations is being compromised because of the unforeseen interactions of ATGs and P/V vent valves.

I Say It's Time to Reconvene

Perhaps it's time to revisit the issue of the role of P/V vent valves in limiting vapor emissions from UST systems. Is the "V" part of P/V really necessary in the absence of balance Stage II vapor recovery systems? While the vacuum may play a role in helping the transfer of vapors from the tank to the delivery vehicle, how significant a role is this? If the delivery vehicle is vapor tight and the vacuum vent valve on the truck is doing its job, shouldn't that be doing most of the work in transferring the vapors to the truck? If the goal is to keep vapors in the tank, isn't a "pressure" vent valve that requires a small pressure to build up before vapors are allowed to escape all you really need?

Is it time to convene a meeting of knowledgeable air regulators, UST regulators, petroleum equipment manufacturers, tank owners, and any other stakeholders out there to figure out a solution to this issue that does not make outlaws out of tank owners by forcing them to choose between compliance with UST regulations and air regulations?

How Widespread Is This Problem?

I don't know. Do you? I would appreciate any reports regarding failed ATG tests that may be associated with P/V vent valves. Send your data and/or thoughts to: marcel.moreau@juno.com. ■

Field Notes

from Robert N. Renkes, Executive Vice President, Petroleum Equipment Institute (PEI)

Realistic, Fair, and Evenly Applied Tank Rules Are Just Fine for Some Tank Owners

If you read the trade press on a regular basis, you might get the impression that tank owners are against regulations like those proposed by USEPA on November 11, 2011. But just like anything else, there are always two sides to every story. Let me share with you some candid observations from a tank owner who welcomes realistic, fair, and evenly applied tank rules.

First, a little background. I was fortunate to spend an hour alone with the owner of a medium-size (100-200 USTs) convenience store chain. The conversation skipped around from the price of crude to industry mergers to alternative fuels to electronic payment systems. When it turned to government regulation, I asked him this question: "If the final UST regulation looks anything like the rule proposed by EPA in 2011, how bad will it hurt your company?" I'll paraphrase his response:

I don't think the new UST rule will hurt my company. In fact, I think it will actually help it. Let me give you four reasons why.

1. To begin with, EPA's proposed rule mandates UST best practices that my company has followed for years. We want our spill buckets and overfill protection systems to work—it costs us money and gives us a corporate black eye if they don't. We feel the same way about our tanks. We want them to contain the product they are designed to hold. So our company already performs most of the inspections and tests proposed in the proposed regulation. We figure it's not going to cost us the $7,000 per site annual expenditure that you read about every so often in the press—for us it will run $200–$250 more per year, which we can absorb. We find it interesting that our figure is even below the $900 per site in annual compliance costs that EPA estimated in their proposed rule.

2. Second, we have some competitors out there that have been hanging on by a thread for years. They spend no money on their UST systems. They fight NOVs every chance they get. They transfer ownership of their store when something bad happens. They are the rotten apples in our industry, and they make all of us look bad. If and when this proposed rule becomes law, one of two things will happen. One, those tank owners will spend the money that our company already spends, which is good for the entire industry because it levels the playing field. Or two, they will fold up their tents and leave the industry, which is also good for us—we'd have one less bad actor in the competition.

3. Third, more and more states already require that we test overfill devices, spill buckets, and the integrity of secondary containment systems. Anyone in the industry will tell you that the USTs in use today are most prone to problems at these three specific locations and, overall, are the least tested portion of the UST system. Testing these components will reduce releases and reduce the drain on the state funds, which our company relies on in event of a catastrophic release.

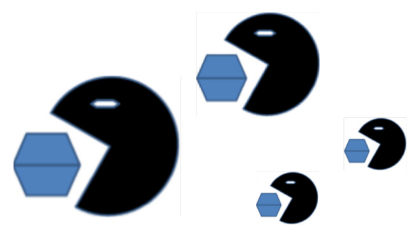
4. And last but not least—and call me corny and old-fashioned—we believe that keeping our water and soil clean is part of our corporate responsibility to our customers and/or neighbors. It's simply the right thing to do. ■

A Thoughtful Column Engineered by Mahesh Albuquerque

Mahesh Albuquerque, Director of the Colorado Division of Oil and Public Safety, is on the lookout for articles from creative thinkers and experts willing to share ideas, insights, and stories on a wide variety of issues related to underground storage tanks. Topics include policy, strategy, successes, failures, and lessons learned. "Now that we have been regulating USTs for 30 years," says Mahesh, "my hope is that this column will help stimulate readers to 'think outside the tank,' to ponder why we do what we do, and to consider and share creative ways to improve our effectiveness—as we strive toward environmental protection." Mahesh can be reached at mahesh.albuquerque@state.co.us.

Hello Carbon, My Old Friend

Petroleum Remediation Using Activated Carbon



by Tom Fox

Many readers may recall the early days of petroleum storage tank remediation when pump-and-treat (P&T) systems were commonly employed to move contaminated groundwater through above-ground treatment systems. Activated carbon (AC) filtration vessels were often used as a final treatment step prior to water discharge. As P&T systems fell out of favor due to their ineffectiveness in reaching the cleanup goals required for closure, likewise, AC seemed to fall out of favor as a remedial tool. But the beneficial properties of AC have not changed and still have a place in petroleum remediation.

Over the past decade, a new market has developed for AC; it involves direct injection into the subsurface to treat dissolved-phase contamination. This in-situ remediation technique uses AC in a two-step process—sequestration and then biodegradation. During this process organic compounds are sorbed to AC so strongly that it is almost certain that the contamination will be stable and unavailable for leaching for at least 50 to 100 years (Norwegian Research Council, 2011), an ample time for natural anaerobic biodegradation processes to occur. The Colorado Division of Oil and Public Safety (OPS) refers to this process as "carbon-based injection" (CBI).

To our knowledge, four AC products currently on the market can be used specifically for remediating petroleum hydrocarbons via injection: pure powdered AC; Trap & Treat BOS 200 by Remediation Products, Inc. (RPI); COGAC by Remington Technologies, LLC; and PlumeStop Colloidal Biomatrix by Regenesis. (OPS does not endorse any particular product.) The brand name products have patented or patent-pending additives that are intended to promote hydrocarbon degradation after injection. Some of these products are also available in granular form.

OPS has approved CBI at more than 200 LUST sites. The success we have noted in sequestering and immobilizing dissolved hydrocarbon contamination to reduce environmental and health risks makes AC an option to consider as part of our remediation toolbox.

How successful has CBI been? If success is defined as achieving site closure, approximately 15 percent of the CBI sites have satisfied OPS criteria to achieve site closure conditions (full disclosure: we have not evaluated the "success" of other remedial technologies with this criteria, but typically sites that require remediation have multiple remedial technologies employed to achieve closure). Furthermore, if success is defined as achieving a significant reduction in dissolved-phase contaminant concentrations, then we are glad to report that the vast majority of injection sites experienced >95 percent reduction in BTEX within six months.

As with any remedial technology, observations may take years to make themselves apparent. The purpose of this article is to share our observations with you. With that, we will present you with the three C's of our observations as they relate to the implementation of a successful CBI application—characterization, contact, and confirmation.

Step 1: Characterization

As with any remedial project, success is due in large part to good site characterization. OPS typically requires a thorough characterization of the proposed treatment area prior to full-scale design to precisely target the horizontal extent and vertical zones of contamination. We recommend the use of continuous soil sampling and/or Membrane Interface Probe (MIP) technologies. The effort expended in this site characterization improves the effectiveness of the design, and often reduces the total project cost as assumptions associated with the contaminant-bearing zone are reduced.

Estimations of the masses of hydrocarbon by phase (LNAPL, dissolved, and adsorbed) allow us to target an adequate amount of AC where needed. If we suspect that significant LNAPL is present, the cost-effectiveness of AC versus alternative technologies is weighed. The dissolved mass represents the immediate and direct demand that will be placed on the AC; the sorbed mass represents a longer-term demand that occurs as hydrocarbons desorb into treated groundwater (T. Lewis, 2012).

Pilot testing should be undertaken before employing full-scale injection. A test batch of AC slurry (not water, which will behave differently) over several vertical zones should be used to gauge likely pressures and flows during injection, thereby ensuring that the proper equipment is used during full-scale implementation. Installing a set of two-to-four monitoring points at varying distances and directions from the injection point allows for an estimation of the radius of influence (ROI) in order to plan reasonable injection point spacing. Watch for groundwater mounding and the appearance of AC in monitoring points. Beware that surfacing is not indicative of ROI, and ROI is not necessarily indicative of uniform and complete distribution between the injection and monitoring points.

Step 2: Contact!

Once you have completed a thorough assessment of the treatment area, estimated the contaminant mass as a basis of design, and completed a pilot test, it's time for implementation. Whether it is AC, a chemical oxidant, or an air bubble, the media we use for in-situ treatment must come into contact with hydrocarbon molecules to effectively clean up. In the case of CBI, direct contact of AC with the contaminant is necessary to effect sequestration and enhance the likelihood of biodegradation.

The entire vertical interval of the contaminated zone should be treated. Injecting over short (one- to two-foot) intervals provides the best control of where the AC goes. Most injection contractors use a top-down injection process, and tend to use high flows (and sometimes high pressures to sustain those flows) to fluidize or fracture soils for better results. (Note: Fracturing the soil without knowing where the fractures are going, particularly if close to the well bore, could cause AC to be injected into the well bore.)

Injection points are typically laid out on a closely spaced (eight to ten feet, center-on-center) grid. Access to the full plume area should be relatively unhindered by utilities and surface structures/traffic, to increase the probability of contact, unless some form of directional drilling is contemplated.

The exact geometry of AC distribution after injection is not fully known, especially in differing lithologies. The resultant treatment area is uniquely and unpredictably asymmetrical at each of the vertical injection levels. The amount, dispersion, and length of carbon distribution are not uniform. In fine-grained soil, CBI seems to propagate in veins that follow paths of least resistance that tend to be concave upward (see Figure 1). Individual veins may travel far (creating a larger apparent ROI) and surface tens of feet away from an injection point, but have a more uneven distribution than in coarser materials. Conversely, AC may "clump" in coarse-grained soil, resulting in uniform distribution over the injection interval, but with limited areal extent (T. Lewis, 2014, unpub. data).

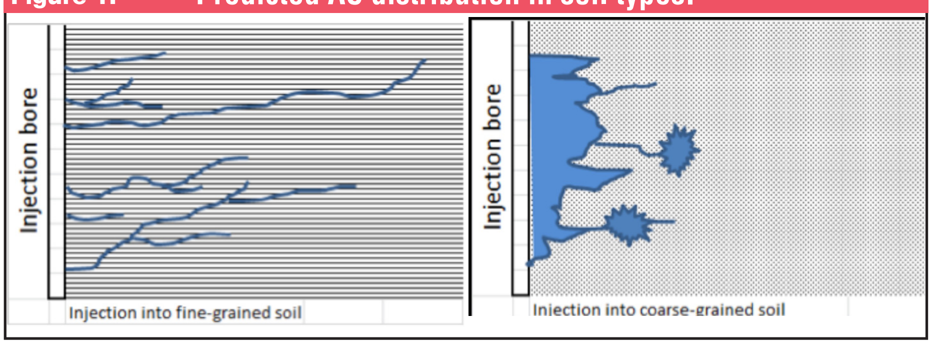
been thoroughly treated. However, and as previously noted, organic compounds adsorb strongly to the AC and unless overloaded with contaminant mass there should be enough AC to adsorb the dissolved-phase mass. Once the AC has entered the well and filter pack it is pretty much there to stay.

For years we addressed this issue by attempting to rehabilitate AC-impacted monitoring wells using vacuum extraction and aggressive redevelopment procedures. But we cannot say with any degree of certainty that the monitoring wells are free of AC and no longer consider this to be good practice.

In LUST remediation, groundwater monitoring wells are used to be representative of an area. We implement technologies to treat the area and use the wells to give us an indication of how effective the treatment is. The question is, are wells impacted with AC still representative of the area? Simply collecting groundwater from the monitoring wells does not answer this question.

Given this uncertainty, OPS has begun a new post-remediation performance-monitoring program to evaluate the effectiveness and distribution of the CBI. Confirmation sample locations are advanced throughout the treatment area to assess distribution and collect groundwater samples. Continuous soil coring is undertaken at CBI sites to observe the AC distribution, and confirmation soil samples should be collected, as appropriate, based on previous characterization efforts. Temporary or permanent groundwater monitoring points are installed to evaluate the effectiveness of dissolved-phase mass reduction.

Figure 1. Predicted AC distribution in soil types.



Step 3: Confirmation

As OPS has gained experience with CBI, it has become apparent that several assumptions inherent in the process need confirmation. CBI presents a rather unique challenge to post remediation monitoring as the AC often directly connects with monitoring wells in the treatment area. At first glance, the appearance of AC in wells may be interpreted as confirmation of a well-done CBI project, documenting that the aquifer has

■ continued on page 24

Wander LUST

a walkabout with Jeff Kuhn...

Jeff Kuhn is with the Montana Department of Environmental Quality (MDEQ) and a venerable veteran of petroleum remediation at the state and national levels. Through this column he takes us on "walkabouts" across the fascinating world of underground storage tanks. Jeff welcomes your comments and suggestions and can be reached at jkuhn@mt.gov.

Searching for (and Sharing) Remediation Technologies on the Information Highway

With the exponential growth of the information highway it is wise to streamline the way we share information on remediation technologies to avoid duplicating efforts. Most states are aware of how entities such as USEPA (OUST, TIFSD, ORD), ASTSWMO, ITRC, NEIWPCC, NGWA, and API work to encourage the use of remediation technologies through outreach and a multitude of training efforts for the regulatory and consulting communities.

These bodies foster the sharing of remediation technology information through technical meetings, websites, and publications focused on educating states, tribes, territories, local governments, and environmental consultants. While all of these groups share common ground and overlap in their level of information distribution, API and USEPA's ORD are unique in supporting scientific research on specific petroleum-contaminant issues. The detailed research they complete is an important and fundamental part of understanding what must be done from a public policy standpoint for petroleum cleanup.

In some cases these groups share work efforts and funding, and co-sponsor meetings, such as the long-standing partnership between USEPA and NEIWPCC in co-sponsoring the National Tanks Conference. That's a good model for how to share limited resources and staff to accomplish the common goal of benefiting a large number of people.

THE ACRONYMS

USEPA – United States Environmental Protection Agency
- OUST – Office of Underground Storage Tanks
- ORD – Office of Research and Development
- TIFSD – Technology Innovation and Field Services Division

ASTSWMO – Association of State and Territorial Waste Management Officials

ITRC – Interstate Technology & Regulatory Council

NEIWPCC – New England Interstate Water Pollution Control Commission

NGWA – National Groundwater Association

API – American Petroleum Institute

There are many examples of how all of these groups respond to specific issues identified by state regulators. For example, ITRC focuses a significant amount of its efforts on topics such as Remedial Process Optimization[1], Petroleum Vapor Intrusion[2], and Evaluating LNAPL Technologies[3], all of which are titles of specific ITRC Technical Regulatory documents representing the culmination of a three-year lifecycle effort from individual technical teams. Each of these teams was created to respond to a specific technical hurdle, and each team included extensive involvement from state and federal regulatory agencies and other stakeholders. The resulting documents function as an extremely valuable resource tool used by regulators to respond to project management issues.

At ASTSWMO's 2014 Annual Meeting in Reston, Virginia, a panel session on information sharing discussed some of the challenges of how to share remediation technology information[4]. I participated in the session as an ITRC board member and framed the need to find new ways to share remediation technology information across organizations. I admit, it is easy to identify needs, and much harder to arrive at concrete alternatives that could save time and money for entities with a stake in the technology game. ASTSWMO and ITRC accomplish this is in different and complementary ways.

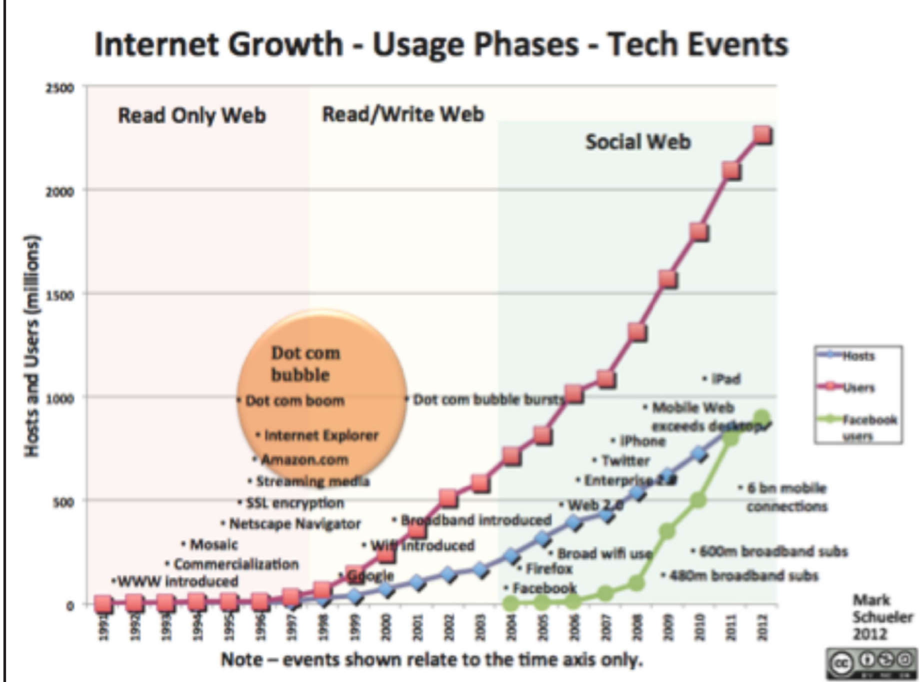
Having been involved with both organizations I believe opportunity exists for such groups to work together more closely. Each has a unique role. For example, ASTSWMO is focused on identifying, building consensus, and providing options for resolving environmental policy issues, while ITRC is squarely vested in developing and providing information resources designed to help break down barriers to the acceptance and use of technically sound innovative solutions to environmental challenges. ITRC's mission statement specifically reflects this commitment.

Ahhh, the Internet

The internet has greatly heightened our ability to quickly find information. But it still has not solved the overall problem of determining the track record and regulatory acceptance for specific technologies. In fact, there are only a few places on the internet where case-incident information appears to be warehoused in a searchable, consolidated format. CLU-IN and the TRIAD Resource Center[5] are among the most widely known sources. Otherwise case-incident studies appear to be scattered, out-of date, or are present in multiple, non-searchable formats. As a result, project managers are looking more closely at technical forums and workgroups available through various forms of social media, where they can find case-incident information.

The phenomenal growth of social media (Figure 1) is a good indicator of the availability of information pipelines with which we are all becoming more familiar. Many states, including my own agency, maintain Facebook and Twitter accounts. Given the rapid growth of the social web, the immediate transfer of files via mobile-web, and the advent of technical forums within professional networks such as LinkedIn, it is hard to believe that we still lack good sources of reliable, up-to-date, remediation technology information.

Figure 1. Internet Growth 1991–2012



Source: Mark Schueler Southampton University 2012
http://webscience.org/web-observatory/about/tracking-explosive-growth/

Crashing and Burning on the Information Highway

The advance and use of new remediation technologies is occurring very rapidly. All of the organizations mentioned here have an important role to play in sharing remediation technology information. But how can they do this more effectively and ensure access to *good, reliable* information—information that is useful to project managers? Most importantly, can we use older tools (e.g., case-incident databases such as CLU-IN) and newer tools (e.g., social media) in a way that saves time and money?

While computer technology has vastly expanded our capacity to collaborate, it's ironically left us with less time to devote to the business of understanding and thoughtfully resolving challenging remediation project hurdles. Critical challenges, such as thoroughly evaluating remediation technologies to ensure they are well matched to site-specific conditions and developing effective remedial process optimization designs, are often not given the time they deserve. Why? One answer is that we may simply be spending more time tracking the status of projects on databases than ever before, leaving us less time to really think about how we're managing our projects.

Groups like those mentioned above can help by first identifying the areas where their involvement with remediation technologies overlap, by sharing technology information where possible, and by using conferences, webinars, and social media tools to collaborate in ways that could save time and money. It's the brave new world of technology. My computer-savvy kids tell me it's time to embrace the information highway. My mirrors are adjusted, my seatbelt is buckled, my foot is on the accelerator. But given the overwhelming amount of information available, and the time involved in tracking it all, how do I even know if I am on the right highway? ■

References

1 *Remedial Process Optimization: Identifying Opportunities for Enhanced and More Efficient Site Remediation*, September 2004, ITRC Technical Regulatory Guidance.

2 *Petroleum Vapor Intrusion, Fundamental of Screening, Investigation, and Management*, October 2014, ITRC Guidance Document.

3 *Evaluating LNAPL Remedial Technologies for Achieving Project Goals*, December 2009, ITRC Technical Regulatory Guidance.

4 ASTSWMO Annual Meeting, October 29–30, 2014, Reston, VA., session entitled "UST Training and Partnership Opportunities."

5 CLU-IN (*http://clu-in.org/products/combinedremedies/*) and the Triad Resource Center (*http://www.triadcentral.org/*).

Innovative Site Characterization

Breaking Out of the Mold

by Richard Spiese

When I was asked to write about innovative sampling at LUST sites I thought, "hmm, most of this stuff isn't that new; it's been around for a number of years." But then I thought about it some more and I realized that even in a small state like Vermont that embraces and approves innovative sampling approaches, the majority of our site investigations follow that same old site characterization approach—a release is identified, a work plan is submitted and approved, the work is performed (using a drill rig, monitoring wells, and a fixed lab), a report is written, comments are provided outlining unknowns, a new work plan is submitted and approved, work is performed (using a drill rig, monitoring wells, and a fixed lab), the report is written, the comments are provided outlining unknowns, a work plan…and on, and on, and on. I think we all realize this process is inefficient, not cost effective, often does not completely assess the degree and extent of the contamination, and is not in the best interest of the public we all serve. My co-worker, Michael Smith, has joined me in this effort.

What Is "Innovative Site Characterization"?

Although I don't really know of a formal definition for this term, I will define the term innovative site characterization as "any sampling approach, technology, or tool that is only recently being utilized by the environmental site-investigation community and that is not commonly used in the investigation of LUST sites." Innovative site characterization includes things like USEPA's Triad Approach (*http://www.triadcentral.org/index.cfm*).

Innovative sampling technologies are similar to innovative sampling tools, but more technical in nature, and include high-resolution site-characterization tools such as membrane interface probes, laser-induced fluorescence, electrical conductivity/resistivity, and cone penetrometer testing. This could also include field labs and immunoassays. Innovative sampling tools include passive or no-purge samplers (e.g., thief samplers, diffusion samplers, integrating samplers). All of these innovative sampling approaches are not, to the best of my knowledge, being used at the majority of LUST sites.

Innovative site characterization also includes the use of dynamic work plans as envisioned in the USEPA Triad process (see Figure 1). It requires frequent communication among the stakeholders, consultants, and regulators, which is necessary to assess data as they are generated to allow necessary changes to the work plan and conceptual site model during the work. This focuses the site investigation and allows a generally more accurate site-specific assessment of contaminant fate and transport.

Plugging in the Triad Approach

The most important tool in the innovative site characterization toolbox is the innovative sampling approach. To use this tool appropriately it takes brainpower. Let's face it: all sampling tools have limitations, advantages, and disadvantages. It's using the right tool for the right job that is important. You don't use a hammer to drive a screw, and you don't use a screwdriver to drive a nail.

For carpenters it's easy to know which tool to use for which job. In our industry, however, we often don't know if a site is small and simple and can be easily characterized using borings, monitoring wells, and sample analysis; or if the site is large and complicated—having several sources, migrating into a number of geologic strata, a diving plume, and sensitive receptors at risk. We may not know this until well after several site investigations have been performed.

So, what does it take to use the Triad approach to investigate LUST sites? It takes a regulatory regime that allows for decision making in the field (many state funds require preapproval, which often doesn't give the consultant the flexibility in the field to make instantaneous decisions and modify the work plan), responsible parties that trust their consultants to do the right thing, consultants with the knowledge to write dynamic work plans that anticipate flexibility during the site investigation, and all parties working in good faith to get the site as fully characterized as possible in the least amount of time for the least amount of money. By using the Triad approach correctly, consultants can get LUST sites more fully characterized in less time for less money.

How does USEPA define the Triad Approach? According to USEPA's Technology Innovation and Field Services Division document *Key Optimization Components: Triad Approach,* "The Triad Approach is used during site characterization and remediation to manage decision uncertainty. It enables team members to make project decisions regarding contaminant presence, location, fate, exposure, and risk reduction—and ultimately design the remediation correctly and cost effectively.

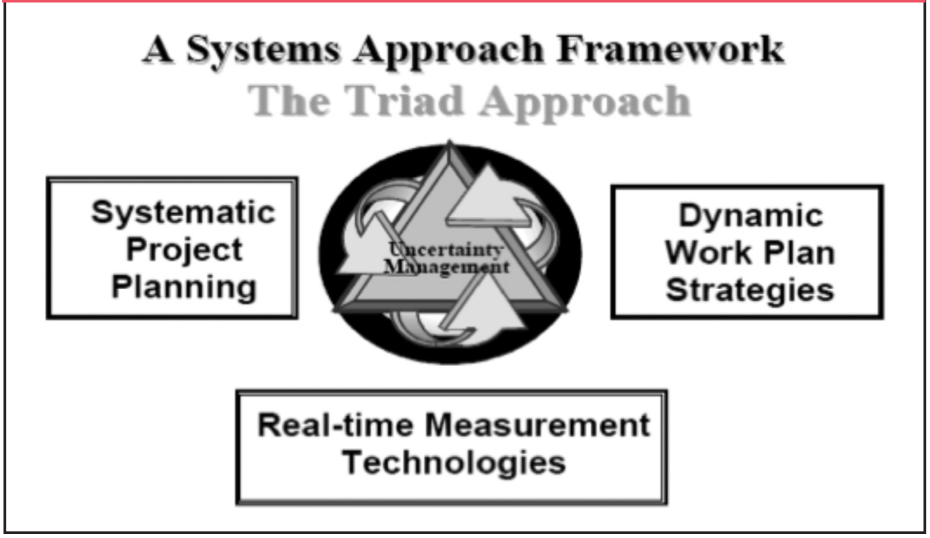
There are three elements of the Triad Approach: systematic project planning (SPP), dynamic work strategies (DWS), and use of real-time measurement technologies."

This work is performed in order to complete a thorough conceptual site model in the shortest time frame for the least amount of money. The money is saved in three key ways:

1. fewer mobilizations to the site;
2. development of site characterization strategies that can be tailored to the site, based on site-specific conditions encountered during the characterization; and
3. fewer reports written, reviewed, and re-written.

In essence the site should be more thoroughly characterized and bet-

Figure 1 THE TRIAD APPROACH



ter understood, supporting a more appropriate remedial strategy, shortening the time needed to operate the remedial system, saving operation and maintenance costs, site visits, and getting the right remedial technology implemented the first time.

The systematic project planning is the up-front time needed to agree upon what is known and how the work plan will be prepared to allow for dynamic work plan strategy implementation. These strategies include taking the real-time measurements obtained during the site investigation, and using real-time measurement technologies, plugging this information into the systematic project planning agreements. This information can then be used to decide what additional information is needed right now to more completely understand site conditions and more thoroughly complete the conceptual site model. Real-time measurement technologies are used in the field to get the data needed. These technologies include the ones mentioned above where I refer to innovative sampling technologies and tools.

Allowing consultants to use the Triad Approach can be scary for regulators, but lacking additional resources to hire additional staff to "hand hold" every project, it is the only way to expedite site investigations that are "faster, cheaper, better" (those that have been around for a long time will remember that the USEPA Office of Underground Storage Tanks used this phrase back in the 1990s in expedited site characterization). There will be difficulties and growing pains in allowing for this process (e.g., consultants who misuse or even abuse the flexibility allowed for in the Triad Approach), but with these frustrations will come learning opportunities that can further allow state LUST Programs to refine their process and more fully characterize their LUST sites to everyone's benefit.

Innovative Site Characterization Technologies

Innovative sampling technologies incorporate innovative sampling tools needed to conduct the site characterization using strategies designed to accurately assess the contaminant issues. These are very technical in nature, and include high-resolution site-characterization tools such as membrane interface probes, laser-induced fluorescence, electrical conductivity/resistivity, and cone penetrometer testing. They also often include field labs and the use of immunoassay technologies.

• Membrane Interface Probe (MIP)
The MIP is a tool used to log the position and relative concentration of VOCs in unconsolidated soils. It is usually pushed into the soils using a direct-push tool (Geoprobe) and can be coupled with an electrical conductive/resistivity probe and/or a hydraulic profiling tool. The MIP is coupled with a heater block that heats the soils in front of the probe, promoting contaminant volatilization and allowing for diffusion of the volatile organic compounds across the membrane.

The sample is then brought to the surface via an inert carrier gas (usually nitrogen) where it can be analyzed by a photoionization detector, flame-ionization detector, or electron capture detector. The sample could also be analyzed using a gas chromatograph (USEPA Method 8260) or a direct sampling ion trap mass spectrometer (the field lab analysis will be discussed further in that section). The MIP will characterize both the dissolved and non-dissolved phases of contamination, making it ideal for quickly characterizing groundwater plumes.

A major drawback to MIP is that it does not differentiate between NAPL and non-NAPL phases of contamination. This can be a major problem with regard to issues associated with high analytical detection limits; however, this problem is being addressed as we gain more experience with using the tool.

• Laser-Induced Fluorescence (LIF)
LIF can be used to characterize fuel types. The probe is placed on a direct-push tool, much like the MIP probe. LIF relies on the fact that all polycyclic aromatic hydrocarbons (PAHs) will fluoresce when exposed to ultraviolet light. The probe face will emit an ultraviolet light on a window on the probe. As the probe comes into contact with contaminated soils while being driven down into the soils, the PAHs give off different and distinct wavelength times. This response is compared to references indicating the type of fuel and relative amounts in the soils. It may also be field calibrated using cores that contain the site-specific NAPL. This helps assess NAPL saturation and potential NAPL mobility. (See *LUSTLine* Bulletin #68, June 2011, for more information on LIF.)

• Hydraulic Profiling Tool (HPT)
The HTP is a logging tool that measures the amount of water injected into a formation over time to help estimate the relative conductivity of the soils through which it is pushed. The tool measures the change in pressure of injected water to provide an estimate of the conductivity of soil formations at very small scales. The HPT is often coupled with MIP or any of the other direct-push technologies to assist in more thoroughly

■ *continued on page 18*

■ **Innvovative Site Characterization** *from page 17*

understanding the nature of the geologic formation. Hydraulic profiling tools such as the Waterloo Profiler also allow for the collection of groundwater samples from very small vertical portions of the aquifer, allowing a more accurate profile of contaminant concentrations over a vertical profile. This, in concert with relative conductivity, can be used to help determine where and how to inject remedial fluids efficiently based on site-specific geology.

• Electrical Conductivity/Resistivity (EC/ER)
EC/ER uses direct-current resistivity and conductivity sensors to measure the apparent ability of soils to conduct current. The response of these sensors relates to the varying properties of the soils, with higher conductivities corresponding with smaller grain size. The exact measurements of this technology are a combination of the porosity, conductivity, and degree of clay in a formation. One major drawback to this technology is the interference of the readings caused by high residual-phase contamination.

• Cone Penetrometer Testing
This technology uses sensors on the cone tip to measure the change in lithostatic pressure (i.e., the change in tip resistance and sleeve friction) as an indicator of the lithology of a formation. Fine-grained soils like silts and clays exert lower tip resistance on the probe than coarser-grained soils like sands and gravels. Greater sleeve friction indicates that the soils are more consolidated or cohesive. This technology is used to further characterize the nature of the soils at a site, including allowing the identification of small lithologic features such as thin clay lenses or layers of highly transmissive sands and gravels, giving one an estimate of soil hydraulic conductivity in that part of the formation.

When groundwater or soil samples are taken at a site for analysis, they can be analyzed on-site, providing essentially "real-time" data that can assist in further directing the nature of future field work. On-site analysis can be performed in a more qualitative nature using direct observations or photoionization detectors; or in a more semi-quantitative or quantitative manner, using immunoassays, field x-ray diffraction, or on-site field laboratories.

• Immunoassays
Immunoassays can be used to detect all of the various petroleum products (e.g., gasoline, diesel, jet fuel, BTEX, PAHs, TPH). They are semi-quantitative, having detection limits in the part per million to part per billion range. They can provide analytical results at a rapid rate (i.e., each analysis can be performed in 30 minutes to two hours), they are fairly simple to use (requiring minimal training to use), and have a low relative cost ($20–$50 per sample).

Immunoassays work by having antibodies selectively bind to the structure of the analyte of concern. The relative concentration of the compound of concern is determined by observing a sensitive colorimetric change linked to the amount of antibody bound up by the amount of the contaminant. The color change is compared to a known standard on a color/concentration chart or a spectrophotometer. Water samples, after filtration, may be tested directly with the immunoassay sample kit; soil samples must go through an extraction process with a solvent, usually methanol, before analysis using the immunoassay sample kit.

When using immunoassays confirmatory samples must be taken and sent to fixed or quantitative field laboratories for analysis to determine the accuracy of the immunoassay results. I worked on an Advisory Opinion about 15 years ago with the New England Waste Management Officials' Association (NEWMOA) that outlines the use of this technology. It can be found at: *http://www.newmoa.org/cleanup/advisory/immunoassayweb.htm.*

One of the recommendations in this document is that the field results obtained using this technology be confirmed by a fix laboratory at a 10% to 20% rate. More recently, the Interstate Technology Regulatory Council (ITRC) issued guidance on using immunoassay kits in their guidance documents covering Triad, Site Conceptual Model, and Incremental Sampling Methodology. These can be found on the web at the ITRC website.

Immunoassys do have some limitations. For example:

- They are contaminant-specific—you must know which contaminant you are looking for so that you order the correct immunoassay kit.
- There are interferences with the analysis, cross reactivity between analytes (e.g., BTEX is sensitive to naphthalene), and matrix interferences (e.g., clays can prevent extraction of contaminants from soil samples).
- The immunoassay is sensitive to direct sunlight.
- Soil samples may have higher detection limits due to extraction limitations.
- Petroleum test kits have problems with heavy or weathered petroleum products.

Field labs use the same technologies as fixed labs; that being GC/MS to give more qualitative results. Field labs can quickly and in real time give groundwater, soil, or vapor results to assist in directing additional site characterization to further refine the project manager's understanding of the site (refining the conceptual site model for the site).

With both current technologies and an experienced chemist running the field lab, field lab results can be just as accurate as those from a fixed lab. If the regulator or project manager has any concerns with the accuracy of the field lab, they may require that split samples be sent to a fixed lab for confirmatory sampling, although I would argue that this level of accuracy is not needed at most sites given the current improvements in field lab technologies.

Why Use Innovative Site Technologies?

You might ask, "So why use these innovative site technologies since they are expensive and new to LUST investigations? What if mistakes are made?" Maybe, but certainly we all have sites we manage that were inadequately characterized. We have likely thrown multiple technologies at very high costs to our state fund's or to the responsible party's pocketbook. Making sure we have a very clear conceptual site model and knowing where the contamination is

■ *continued on page 23*

A "Pig" Chews Over Meeting Federal UST Regulatory Goals

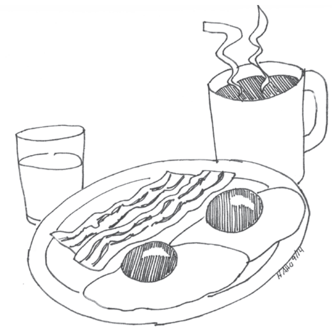
Part 3 – The Energy Policy Act

by Patrick Rounds

I am the pig at the bacon and eggs table. My company provides financial responsibility coverage for thousands of our customers' UST facilities. As insurers, we are the fully committed pig that is all in—if an insured tank leaks, we pay. Unlike the chicken we don't get to lay another egg. So, although we don't write the regulations, we need the regulations to achieve their intended goals so we can achieve ours. This is the third in a three-part series of articles in which I focus on how well our regulatory goals are being met.

In a breakfast of bacon and eggs, the chicken is involved, but the pig is committed.

Attributed to Fred Shero



Twenty-one years after the enactment of RCRA Subtitle I, the Energy Policy Act (EPAct) of 2005 created additional requirements to support and enhance the goals of the original law. The requirements include UST system inspections; operator training; delivery prohibition; evidence of either financial responsibility and installer certification, or secondary containment and under-dispenser containment for new and replaced UST systems; and public records documenting the number, sources, and causes of UST releases, the state's record of compliance with Subtitle I or an approved state program, and data on equipment failures.

With nine years of these new requirements under our belt, it's as good a time as any to evaluate their impact from an insurer's perspective. (Note: the data used in this article comes from *http://www.epa.gov/swerust1/fedlaws/epact_05.htm.*)

Inspections

The Energy Policy Act required that the USEPA Administrator or a state that receives funding under RCRA Subtitle I must conduct an on-site inspection to determine compliance with 40 CFR 280 (or requirements or standards of an approved state) within two years, and every three years thereafter. States were allowed up to a one-year extension of the first three-year interval if it could document that it had insufficient resources to complete the inspections within the first three-year period. To comply with this requirement, every regulated UST facility in the country was supposed to have had an on-site inspection by 2007; another on-site inspection by 2010 or in extreme cases, 2011; and another inspection within another three years—no exceptions. By 2014, every operating UST facility should have had an on-site inspection at least three times.

The Good

In the past three fiscal years, the USEPA tracked 287,945 inspections, which is 140 percent (may include duplicate inspectio sns or enforcement follow-ups) of the total number of regulated UST facilities in the U.S. (99,235 in FY 2012, 95,827 in FY 13, and 92,883 in FY 14).

Areas for Improvement

Inspection protocols vary by state. Many states do not inspect dispensers because the federal definition of a UST does not extend above the shear valve. However, most petroleum leaks originate from the dispenser. So whether or not the dispenser is considered part of the UST system, if it is the source of a leak, it should be inspected and all leaks should be addressed.

Some inspections do not require that every manway be opened and all components be inspected. But inspecting just one tank top only tells you about that manway. It stands to reason that every tank top, manway, and dispenser should be inspected.

A three-year inspection cycle is too long. Rounds & Associates conducts more than 3,000 UST, third-party compliance inspections every year, many of them are part of an annual inspection process. We have documented that more than 20 percent of all inspected facilities have an ongoing leak at the time of the inspection; 90 percent of these leaks occur in a portion of the system where the leak may not be detected by the leak detection system. As a result of the inspection, these leaks are immediately stopped and most of them never become "releases."

Most of the leaks that we find would become releases if the leak was allowed to continue. A quality inspection program will pay for itself based upon the leaks discovered, stopped, and addressed before the leak becomes a release. High quality, photo-documented inspections can be conducted for under $300 per site. If the average release response (using the AST-WMO state-fund survey response) is $144,000, and an inspection costs $500, finding and stopping just one leak will save $144,000 and fund 288 inspections—and 288 inspections will identify an average of 57 or more facilities with leaks, more than offsetting the inspection cost.

■ continued on page 20

Meeting Regulatory Goals

from page 19

In the original 1988 UST regulations, non-sudden releases were a major concern. However, leaks from the dispenser or leak detector itself are the probable source of many non-sudden releases. These leaks will continue to cause releases until they are addressed by a comprehensive, quality, on-site inspection.

Some states allow third-party inspection programs. USEPA's inspection grant guidelines provide a list of acceptable entities that may conduct the three-year inspections. Inspectors performing third-party inspections must meet conflict-of-interest requirements developed by the state. UST system owners or operators are not allowed to conduct inspections by themselves to meet the three-year inspection requirement. While conducting regular inspections of your tank system is a good business decision, self-inspections must be coupled with inspections performed by an entity listed by USEPA in the inspection grant guidelines. They are not acceptable by themselves.

Operator Training

The Energy Policy Act requires that all facilities have a trained Class A, Class B, and Class C operator.

The Good

Currently, 46 states and four territories have implemented an operator-training program; five states and three territories are working toward implementation. South Dakota has documented 100 percent operator compliance with the training requirements. As a result of the EPAct, training is now part of the UST regulation discussion. This is a success.

Areas for Improvement

Training is a good concept. We are trying to effect behavior in a positive manner. The question we need to ask is whether the training is improving UST operations and reducing UST releases. Most states allow web-based training. Most training is a one-time thing with no continuing education requirement. But is simply attending a training "event" our definition of success? What should define success?

Web-based training is a cost-effective method of making training available to operators, but is it the best method to ensure that operators are gaining the knowledge necessary to properly manage UST facilities? As one professional educator explained, "web-based programs provide everyone an opportunity to obtain low-cost training, and provides an opportunity to learn, if the student wants to learn. However, it is also the easy way out for those who are just trying to comply." Compliance with the training requirement does not mean that all operators have gained the knowledge necessary to be good system operators.

So, how should we measure success? Should we use the number of identified compliance issues as the metric to evaluate success, or the number of discovered leaks, or reported releases? Whatever the metric, success should not be defined only by the number of operators who have met the training requirement. Shouldn't increasing the percentage of knowledgeable owners able to properly operate and manage their UST systems be one metric of success?

Limiting the training requirements to the tank operator may have inadvertently discouraged owners from obtaining training. Facility owners are the key player in tank management requirements. Operators may change multiple times in a year and their education and knowledge go with them. Owners can become responsible for bad operator behavior. Both owner and operator should meet the training requirements and understand the UST regulations.

One and done training is not as effective as training that requires continuing education with additional contact hours on an annual or bi-annual basis. The real issue is whether tank operators (and owners) are doing a better job of managing their tank systems. Annual or biennial training should be considered.

Delivery Prohibition

The Energy Act requires that it is unlawful to deliver to, deposit into, or accept a regulated substance into a UST that has been identified by USEPA or a state to be ineligible for such delivery; USEPA was directed to issue guidelines to implement delivery prohibition.

The Good

Forty-two states, Guam, Puerto Rico, and the Virgin Islands have implemented a "red-tag" program while seven states and the District of Columbia have implemented a "green-tag" program. Only Nebraska and the remaining territories have not implemented a delivery prohibition program. Since 2009, more than 35,000 delivery prohibitions for regulatory violations have been issued.

More than 10,000 releases were reported annually between 2005 and 2009. Since 2009, the average is down to about 6,000 releases per year. The percent of facilities in Significant Operational Compliance with UST Release Detection and Release Prevention requirements has increased from 66.4 percent to 72.5 percent during this same time. Across the U.S., there are over 10,000 more facilities in compliance with technical operational requirements today than in 2009.

In FY 2013 and 2014, for every 10 sites inspected, there was one site subject to delivery prohibition. Although there are many factors involved, it appears as if delivery prohibition is having its intended effect of reducing violations and decreasing releases nationwide.

Areas for Improvement

Nebraska and three territories do not have a red-tag program. Some jurisdictions do not report delivery prohibition. In the last two fiscal years, 11 states, D.C., all territories, and all Indian country reports indicate there were no delivery prohibition actions, while one state reported that nearly as many sites were subject to delivery prohibition as were inspected (97%). There are significant variations among jurisdictions. This may be due to reporting issues or how delivery prohibition is implemented.

Nebraska, which does not have a red-tag program, has a release detection and release prevention compliance rate of 59 percent, while the national average in 2014 was 72.5 percent. Does red-tag authority account for the difference? Massachusetts has a red-tag program but has only a 29 percent release-detection and release-prevention compliance rate; however, after 677 inspections there were no delivery prohibitions in 2014. Without better data on how delivery prohibition is managed and its relationship to both the inspection process and the delivery prohibition decision, it is difficult to evaluate the effectiveness of red- and green-tag programs.

Consistent use of the red-tag authority will increase compliance nationally. Every participating jurisdiction has its own standard for when to use its red-tag authority. Some use it primarily for registration violations. It stands to reason that red tag should be used consistently throughout the country so all tank owners know exactly what to expect. Red tag should not be employed at the discretion of the field inspector. Owners need to have clear expectations. (Self-certification is not an effective use of a red-tag or a green-tag program.) Consistently applied requirements will result in better compliance and better environmental results.

Secondary Containment

In the EPAct, under the heading "Additional Measures to Protect Groundwater from Contamination," states are to require:

(1) *secondary containment for new or replacement tanks and piping, and under-dispenser containment for new motor fuel dispenser systems, if located within 1,000 feet of any existing community water system or existing potable drinking water well; or*

(2) *evidence of financial responsibility by tank and piping manufactures for the costs of corrective action related to releases caused by improper manufacturing; and evidence of financial responsibility by installers for the costs of corrective action related to release caused by improper installation, and licensing and certification for installers of tanks and piping, after the effective date of the act.*

The Good

All states and territories have either implemented a secondary containment requirement or are in the process of implementing the requirement. Secondary containment of all new tank systems, including under-dispenser containment with continuous electronic monitoring, will greatly reduce releases from UST systems.

Requiring adequate financial responsibility for all manufacturers and installers of tank systems provides an incentive for the industry to utilize practices that reduce or eliminate leaks caused by improper manufacturing and installation procedures. Most states have implemented installer licensing or certification criteria.

Areas for improvement

The EPAct allows either secondary containment OR financial responsibility and licensing or certification of manufacturers and installers. These options address separate issues and neither should be optional. Both options should become the business standard for all future installations.

Based on the industry's knowledge of non-sudden, non-detected leaks, and limitations with other leak-detection options, all new tank systems should have secondary containment with continuous electronic containment monitoring. Tank owners should expect accountability by manufacturers and installers when requesting proposals for new installations. Even if not required by regulation, owners should require that manufacturers and installers be licensed, certified, and have adequate insurance coverage. Quality installation is a business issue.

Public Records

States are required to maintain, update at least annually, and make available to the public, a record of regulated USTs; the number, sources, and causes of UST releases; a record of UST system regulatory compliance, and data on the number of UST equipment failures in the state.

The Good

There are two sources of information available related to these requirements:

(1) The USEPA collects data from states and territories regarding UST performance measures. These data include information such as the number of active and closed tanks, releases confirmed, cleanups initiated and completed, facilities in compliance with UST requirements, facilities inspected and delivery prohibition actions. This data is compiled twice each year and published on the USEPA website.

(2) States (most of them) publish public records on their UST regulatory agency websites with information on the sources and causes of UST releases.

Areas for improvement

The USEPA data does not include information on the sources and causes of UST releases or any information on equipment failures. It also does not provide any information on the age of a release when discovered. The state public records generally rely on "unknown" or "other" as both the primary cause and source of reported releases. Most state reports do not provide data on tank equipment failures.

The EPAct requirement to maintain and update data necessarily includes the requirement to obtain those data. States must develop the means to determine the sources and causes of UST releases and to identify and track tank equipment failures. The data provided by most states doesn't even distinguish releases at abandoned sites from releases at operational sites. In most instances there does not appear to be any attempt to determine the cause of loss. All suspected releases should be investigated, and if a release is confirmed, its source and cause should be investigated. Without emphasis on obtaining the sources and causes of releases and tracking these metrics, we cannot determine the effectiveness of loss control strategies to reduce releases.

■ continued on page 23

A Message from Carolyn Hoskinson

Director, USEPA's Office of Underground Storage Tanks

Studying the Backlog of UST Releases on Tribal Lands

Surely you've heard the idiom, "What's good for the goose is good for the gander." Our recently completed tribal backlog study shows that USEPA is committed to that concept.

Our 2011 national backlog study (*www.epa.gov/oust/cat/backlog.html*) provided us with significant insights and valuable information about releases remaining to be cleaned up in the 14 states we examined. The national study, which comprised 66 percent of our country's backlog at that time, helped us identify strategies those states, other states, and USEPA could use to continue reducing the national backlog of releases remaining to be cleaned up.

Because USEPA has direct implementation responsibility on tribal lands, we thought it appropriate for us to take a look in our own backyard. And so we set off to study the tribal backlog. We applied the same analytical, data-driven approach used in the national backlog study to the 312 releases in Indian country.

What Was Our Goal?

Our goal for studying the releases that remain to be cleaned up in Indian country was to gain insight into the characteristics of the releases on tribal lands in order to help us identify strategies to continue progress in cleaning up these releases.

What Did We Learn?

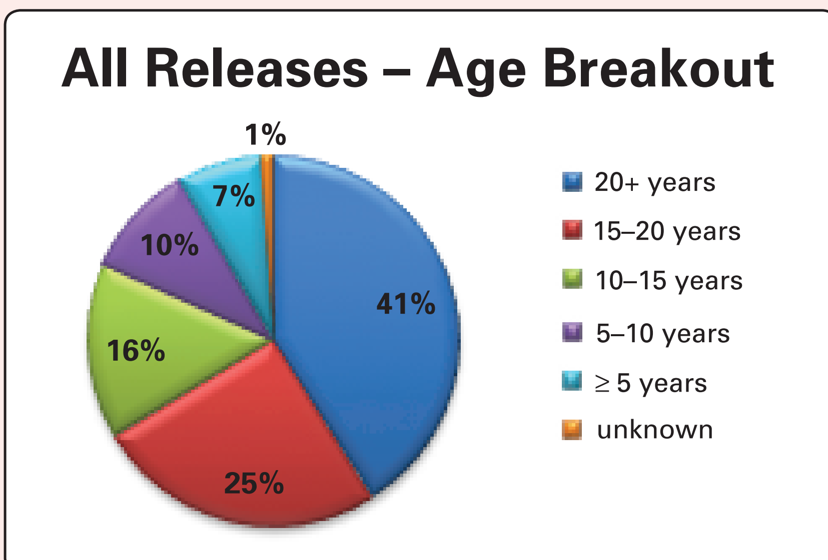
We categorized the 312 Indian country releases, which helped us more clearly see the trends.

- Many sites in the tribal backlog are old; 66 percent of the tribal backlog is 15 years old or older. Most of the releases are moving forward with cleanups; 57 percent of releases are in the remediation stage or further along.
- Money to pay for cleaning up releases in Indian country comes from multiples sources: responsible parties, state funds, Leaking Underground Storage Tank (LUST) Trust Fund for high priority releases, and Navajo Nation Fund on Navajo lands.
- Most releases are located at non-operating UST facilities; only 31 percent are at active UST facilities.

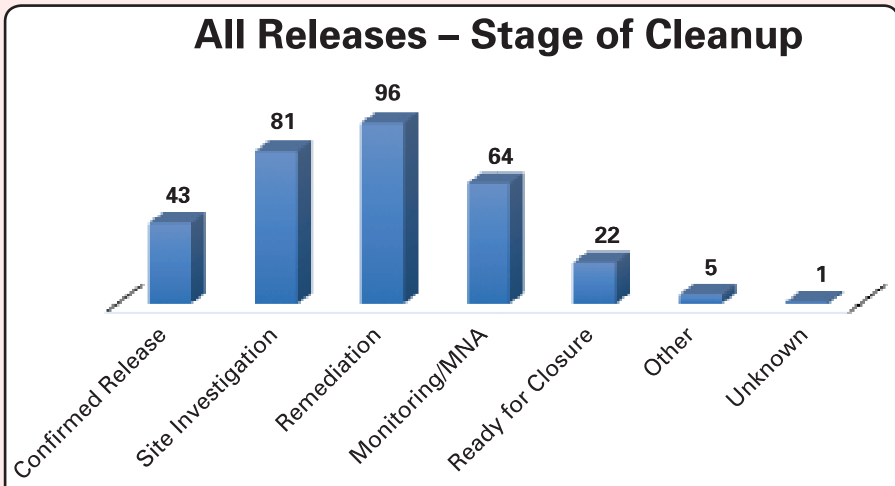
There are a number of complex cleanups, which will require significant time and money in order to reach completion.

As you might expect, the tribal backlog is a microcosm of the larger national backlog. Our 2011 national backlog study showed us that each state has its own unique makeup and set of issues. We found the same for USEPA regional offices directly implementing the UST program in Indian country—each has a different set of factors that determine which strategies will work best to make progress on the tribal backlog.

- Some USEPA regional offices have large numbers of releases remaining in their backlogs; others have only a few releases remaining.
- Some USEPA regional offices have the majority of cleanups paid for by state funds; some have none.
- Some USEPA regional offices have tribes that actively oversee cleanups; others have only a few.
- Some USEPA regional offices have most of their releases in later stages of cleanup; others are mostly in the early stages.



A Message from Carolyn Hoskinson continued... continued from page 22



Note: Stage of cleanup data is unavailable for six sites.

What Are Our Next Steps?

USEPA plans to use these data to develop creative, innovative ways to address the sites. We hope to follow a similar approach to what many states did following the 2011 national backlog study. Many states used that study as a springboard to take an in-depth look at releases remaining to be cleaned up and pursue strategies to address sites that have similar characteristics.

Through the tribal study, we identified releases where cleanup is potentially stalled; we will investigate those releases to find opportunities for making cleanup progress. USEPA regions will continue to work with tribes as we identify opportunities and implement backlog reduction strategies. We will recommit to search for responsible parties. Because Congress appropriates limited money from the LUST Trust Fund to pay for cleaning up abandoned sites, we must prioritize which tribal backlog releases are to be cleaned up with Fund money. It is important for us to work together to identify efficiencies and use innovative approaches as we do the important work of cleaning up UST releases and protecting human health and the environment. ■

■ Innovative Site Characterization *from page 18*

on a site will provide the right cleanup technology to the right location.

Using the correct and most efficient remedial technologies the first time can save much more money than re-characterizing a site and installing a new remedial technology because the first system failed to remediate the site due to incomplete characterization. Furthermore, field laboratories are becoming cost-competitive with fixed labs, and in many cases are less expensive since they usually charge per day rather than per sample. A mobile lab can usually perform between 30 to 40 GC/MS EPA 8260 analyses in a day.

These innovative site technologies may not be needed at every site. Many sites are characterized thoroughly enough in the tank removal report to determine that with several years of monitoring or with soil excavation the site can be brought to a satisfactory closure. However, for any sites that may require an in-situ remedial technology, using these innovative site technologies, coupled with innovative site characterization (the Triad approach), will assist us in getting the site characterized correctly the first time. Let's unlock the talents of our consulting community to help us correctly characterize our sites quickly and thereby bring our sites to closure more quickly and save money in the long run. Come on, we can do it! ■

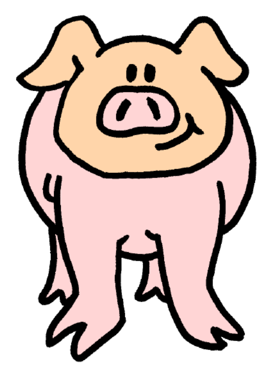
Richard Spiese is Site Project Manager with the Vermont Department of Environmental Conservation (VDEC). He also serves on the ASTSWMO LUST Task Force. Richard can be reached at richard.spiese@state.vt.us. Michael Smith is also Site Project Manager with VDEC and serves on the ITRC. He can be reached at michael.smith@state.vt.us.

■ Meeting Regulatory Goals *from page 21*

USEPA should post the state public records created to comply with the EPAct on the USEPA website, in the same manner as performance measures.

Just My Opinion

The EPAct added potentially effective regulatory tools to the original RCRA Subtitle I mandates. Delivery prohibition, inspections, training, secondary-containment, and public record requirements can all have a positive impact when developing a comprehensive UST regulatory program. Each of these requirements either direct that better metrics be obtained or require better metrics to determine success.



The many "shoulds" articulated in this series of articles reflect a tank facility insurer's business of observing, obtaining, and tracking key metrics, critical for the success of my work and I would think any UST regulatory program. We need to place much greater emphasis on obtaining quality data and sharing those data. The UST and LUST industry needs access to better data. Source and cause of losses and documentation of equipment failures are critical metrics. Better data will support better accountability. It is hard to improve the score if you don't know the score. ■

Patrick Rounds is President and CEO of PMMIC Insurance. He can be reached at pjr@roundsassociates.com. Your comments are welcome.

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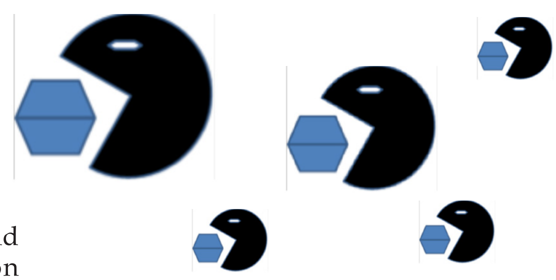
■ THINK TANK *from page 13*

Another point to ponder is the rate of biodegradation and the role biodegradation plays in the effectiveness of CBI. OPS has been requesting baseline and periodic measurement of inorganic parameters that are likely to change due to CBI, including pH, conductivity, DO, ORP, nitrate, sulfate, and COD. Documenting actual bacterial growth in relation to nutrient and contaminant reduction will be done when possible.

On the Continuous-Improvement Track

The ability of AC to adsorb contaminants and remove them from a waste stream is not in question, as evidenced by the wide usage of AC throughout multiple industries. OPS has approved CBI at over 200 LUST sites over the past decade and has observed successful reductions in contaminant mass. Thorough characterization, knowledgeable design, and proper implementation are critical components that lead to increasing the likelihood of achieving regulatory closure. Our research and understanding of CBI has led us to reevaluate our confirmation-sampling program. We look forward to reviewing the results of this new confirmation-sampling program to better understand the distribution, mass reduction mechanisms, and overall efficacy of CBI. ■



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