New England Interstate Water Pollution Control Commission
neiwpcc.org/lustline

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Bulletin 83
December
2017

# L.U.S.T.LINE

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

## Testing Containment Sumps

*by Marcel Moreau*


Not so long ago in a land near at hand, there were no underground storage tank sumps. They did not exist. There was no need for them because the soil around a submersible pump or beneath the dispenser was a wonderful absorbent for any spilled product. Even large leaks most often disappeared into the earth and so were not a problem (unless they found their way into storm sewers, utility vaults, basements, or water wells). The openings at grade along the top of a tank were called manholes, though most were far too small to allow a man (or a woman) to enter. Removing the manhole cover revealed a fill pipe or a submersible pump manifold. Both were surrounded by dirt…often smelly dirt.

But things have changed over the last 30 years, and all but a few diehards would say for the better. Since that time not so long ago, containment sumps have come to be recognized as essential elements in secondarily contained piping systems, and critical elements in leak detection and leak-containment strategies for UST pressurized piping. Today containment sumps are common in most states and ubiquitous in some states where secondary containment has been the rule for a quarter century or more.

While containment sumps have been a common component of secondarily contained piping systems since the early 1990s, they have been slow to achieve explicit mention in the regulations. The 2005 Energy Act specifically required under-dispenser sumps for new installations and certain dispenser replacement scenarios, but it did

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not include any installation, testing, or maintenance requirements for these sumps. The 2015 revisions to the federal UST rule provide the first regulatory requirements specifically targeting containment sumps.

This issue of *LUSTLine* focuses on several aspects of containment sumps. Jill Williams-Hall writes about water disposal issues associated with containment sump testing (page 11), and Kevin Henderson asks some snaky questions about containment sump inspections (page 10). In addition, Rick Long clues us in to why the PEI RP1200 Committee decided to stick with high-level testing as the industry recommended practice (page 18).

In this article I'll be providing a brief history of sumps for those of you who may be more recent arrivals to the UST scene. Then I'll focus on issues surrounding what the water level should be in a containment sump when it is tested to see if it is really liquid-tight.

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*LUSTLine* is a product of the New England Interstate Water Pollution Control Commission (NEIWPCC). It is produced through cooperative agreements (US-83555901 and US-83556001) between NEIWPCC and the U.S. Environmental Protection Agency.

*LUSTLine* is issued as a communication service for the Subtitle I RCRA Hazardous & Solid Waste Amendments rule promulgation process.

*LUSTLine* is produced to promote information exchange on UST/LUST issues. The opinions and information stated herein are those of the authors and do not necessarily reflect the opinions of NEIWPCC.



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## First, The Definition

Here's the formal definition of containment sump from PEI RP1200, *Recommended Practices for the Testing and Verification of Spill, Overfill, Leak Detection and Secondary Containment Equipment at UST Facilities:*

> *A liquid-tight container that protects the environment by containing leaks and spills from piping, dispensers, pumps, and related components. Containment sumps may be single-walled or double-walled. Typical locations include the top of a tank (fill sump or submersible turbine pump sump), underneath the dispenser (under dispenser sump), or at other points in the piping run (transition or intermediate sump).*

The RP1200 definition is very similar to the regulatory definition (see Kevin Henderson's article on page 10 for the regulatory wording). The definition is consistent with the traditional dictionary definition of "sump," which is a low spot where liquids collect. The term "uncontained sump" was introduced into the regulatory world in 2005 by the USEPA's sump inspection and maintenance document to refer to what has traditionally been called a manhole. I have never liked the term "uncontained sump" because it is an oxymoron—sumps by definition collect liquids, but liquids don't collect in an "uncontained" sump. In this article, I'm going to use the terms I believe are most often used by UST industry professionals, namely,"manhole" and "containment sump."

Note: don't confuse "manhole," a grade-level opening over a tank, with "manway," which is an opening in a tank itself that is specifically designed so a person can enter a tank.

## A Brief History of Containment Sumps

In the early days of secondary containment piping, the secondary containment was limited to just that—the piping. Double-walled pipe first emerged in the UST world as a fiberglass-piping concept where different diameters of pipe could be

**Figure** *1.* ***Early versions of double-walled piping were only concerned with containing the pipe.*** *In the photograph above, 2-inch diameter primary piping was installed inside 4-inch diameter secondary piping. A 4 x 2-inch reducing fitting was used to seal off the interstitial space of the pipe. There was an opening in the bottom half of the reducing-fitting (not visible in the photo above) where a sensor could be installed. On this tank, the opening on the bottom of the reducing-fitting was left open, and leak detection consisted of an external leak sensor located under the white cap at the upper left. Note the primitive penetration fitting where the piping comes through the wall of the manhole.*

nested within one another to create a double-walled system. But because the creators were piping people, the secondary containment did not include anything that was not a pipe. The outer wall of the pipe ended just beneath the crash valve at the dispenser and just downstream of the union at the submersible pump (see Figure 1).

As we now know, most leaks are not in the piping itself but at the ends—in the dispenser and near the submersible pump. It was the development of flexible piping systems, specifically the first generation of Total Containment secondary containment pipe, that introduced the concept of a containment sump at the submersible end of the pipe. The containment sump served as the collection point for any liquid that might flow down along the secondary pipe, as well as containment for the submersible pump itself.

The engineering for the first STP sumps was minimal, failing to take into consideration the challenges posed in building an underground liquid-tight container with numerous penetrations. First generation sumps left much to be desired in terms of effectiveness. But the concept was born and the idea of containment sumps around submersible pumps took hold. Dispenser sumps soon followed.

Problems with containment sump design and installation continued through the 1990s. The bottom line issue was that although sumps were supposedly liquid tight, the fact was that many were not. Problems stemmed from inadequate design (especially the earlier sumps) and failure to test containment sumps to confirm that they were liquid tight. Through the 1990s, neither PEI RP100, the industry standard UST installation document, nor many containment sump manufacturers' installation instructions included a test at installation to see if the sump could actually hold water.

By May 2005, the USEPA recognized some aspects of the sump problem and published a document on inspecting and maintaining sumps. But this document was purely advisory in nature as there were no regulatory requirements relative to sump maintenance or inspection. But at least this publication showed that there was high-level awareness of the problems with sumps and the importance of maintaining their integrity.

## The 2015 UST Rule Amendments & Containment Sumps

The 2015 UST rule revisions finally brought containment sumps into the regulatory fold. The 2015 rule amendments require both annual visual inspection and triannual testing of containment sumps. *While ALL containment sumps are subject to the annual inspection requirements of the rule, ONLY containment sumps that are part of a piping interstitial monitoring system are subject to the triannual testing requirements.*

Testing is not required if the sump is double-walled and periodically monitored.

Sticking to the precedent set in the 1988 rule, the 2015 amendments did not specify exactly how sumps were to be tested, deferring instead to one of the following:

- Manufacturer requirements
- A code of practice developed by a nationally recognized organization
- Requirements determined by the implementing agency to be no less protective of human health and the environment than manufacturer or industry code of practice requirements.

The 2015 rule specifically references PEI RP1200, *Recommended Practices for the Testing and Verification of Spill, Overfill, Leak Detection and Secondary Containment Equipment at UST Facilities* as a code of practice that can be followed for testing sumps. Not everyone is happy with the PEI approach, however.

## The Basics of Sump Testing

The generally accepted containment-sump testing procedure is straightforward. As described in PEI RP1200, water is added to the sump and the water level is measured to the nearest 1/16 of an inch using a measuring stick. An hour later the water level measurement is repeated. If the water level has changed by less than 1/8 of an inch, the test passes.

Given the technology available to us in this day and age, relying on a yardstick and an eyeball to determine sump integrity seems a bit Stone Age to me. An 1/8-inch change in water level in a 4-foot diameter sump comes out to be about a gallon of liquid. So the size leak we are looking for with this test is about a gallon an hour. This makes our sump testing about ten times less sensitive than our typical tank- and line-tightness test. This seems like an unacceptably crude test to me, but I'm in the minority.

It seems to me we could shorten test times and increase test consistency and precision by using our ATG technology to test sumps. At least one ATG manufacturer markets what is essentially a portable ATG with shortened probes for use in testing sumps. While the ATG approach is an officially acceptable methodology for testing sumps per RP1200, it is only an option and not a requirement.

So, with that off my chest, let's get into the nitty gritty of water-level issues.

## High-Water-Level Issues

The test procedure described in PEI RP1200 specifies that the sump is filled with water to a level that is 4 inches above the highest penetration or joint in the sump sidewall. In a typical sump, this means the water level will likely be a few feet deep. This does pose some practical issues:

### ■ The Volume of Water Required

The volume of water involved in testing a single sump will be on the order of 150 to 200 gallons for a typical sump (48-inch diameter, water depth of about 24 inches). A site with three sumps would be looking at using about 450 to 600 gallons of water, assuming the sumps are tested at the same time. And this doesn't count the water used for the dispenser-sump testing, which could easily add hundreds of gallons more. This is a substantial amount of water to handle, both in terms of getting it to and from the site and transferring it in and out of containment sumps.

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What to do with the water after the test is also problematic. Is the water contaminated with petroleum? If so, what is the level of contamination? Is the water a waste? Or can the water be considered to be a test fluid and so reused to test other sumps at other sites? What if the sumps at the other site leak, and so some of the (potentially) contaminated water is released to the environment? The thorny issue of test water reuse/disposal is discussed by Jill Williams-Hall in her article on page 11 of this issue.

### ■ Some Sump Equipment Was Not Meant to be Submerged

Not everything in the sump is intended to be submerged in water. Specifically, I'm thinking of electrical junction boxes, which could end up below the water level for the test. Electrical codes require that these junction boxes be explosion proof, but this does not make them waterproof. The possibility of water entry into junction boxes containing 110- or 220-volt wiring does not seem like a good scenario to me.

### ■ Isolating Dispenser Sumps Can Be a Challenge

Testing dispenser sumps becomes particularly burdensome because many secondary-contained piping systems have a single sensor in the STP sump that monitors the entire piping run, including the dispenser. In these systems the secondary piping is open to the dispenser sump so that fuel leakage into the dispenser sump will flow to the STP sump where the sensor is located.

Testing the dispenser sump to a level above the piping entry fittings means that the secondary piping entry into the dispenser sump must be sealed off for the test. In most cases it will be difficult for an average size person to reach past the dispenser and deep enough into the sump to do this work. In some cases, it might be necessary to remove the dispenser to have adequate access to the penetration fittings to be able to seal them off. Even with the dispenser removed, sealing the penetration fittings will be inconvenient at best and nearly impossible at worst.

### ■ STP Sump Penetrations Must Be Sealed as Well

Sealing off the secondary piping from the STP containment sump will also be required for a high-level water test. While access to most STP sumps is a good deal easier than dispenser sumps, it is still not exactly convenient. As for sumps that have not been tested since installation (if then), sealing off the secondary pipe could be a challenge.

### ■ The More Sump Penetrations Tested, the More Likely the Test Will Fail

The more sump penetration fittings submerged below the water level during the test, the more you increase the odds that one of them will be leaking and thus cause the test to fail. Alternatively, several fittings leaking at smaller rates (say, two penetration fittings each leaking at 0.3 gph and one penetration fitting leaking at 0.4 gph), could produce a gallon an hour leak rate which would result in a failed test.

### ■ How Do You Find the Leak?

What if the sump fails the test? How do you find the leak? Unless there are obvious defects (which should have been identified and fixed before the test was conducted) determining which penetration fitting(s) is leaking is a nearly impossible task. You could wait for a while to see where the water level stabilizes, repair whatever fitting is at this level, and then repeat the test.

But if there is another leaky penetration fitting located higher than the first one, the repair and retest process would need to be repeated again. This all takes time and money, such that it might be more efficient to just apply a repair technique to all penetrations at once. Either path to remedying a failed test will likely be expensive.

## So, Why Do High-Level Testing?

Sump penetrations and sump sidewall joints are the most likely places where leaks occur in sumps. The

| High-Level Testing | |
|---|---|
| **Pros** | **Cons** |
| This is the industry recommended practice, based on the knowledge and experience of industry professionals. | Need to isolate dispenser sumps from secondary piping to conduct the test. Hard to do in most cases and may require dispenser removal in some cases. |
| Maximizes the volume of leaked fuel that can be contained without a release to the environment. This allows for more time between when the sensor sounds the alarm and the leak is stopped. | Need to isolate STP sumps from secondary piping to conduct the test. In many cases this will lengthen the time (i.e., money) required to prepare a sump for the test. |
| Sensor need not be positioned at the absolute bottom of the sump to be effective (though lower is definitely better). NOTE: I'm not recommending here that sensors be located anywhere else than the bottom of the sump. I'm acknowledging that sensors get raised but as long as they remain within the sump and functional they can still prevent releases to the environment as long as the entire sump is liquid-tight. | More sumps will fail the test and need potentially expensive repairs. |
| | Potential for harm to electrical components not intended to be submerged in water. |
| | More water to handle/dispose of. |

**Table 1.** ***The pros and cons of high-level sump testing.*** *In general, high-level testing will require more work to prepare the sumps for testing, produce a greater number of failed tests, and require more sump repair activity. In other words, the average high-level sump test will cost more than the average low-level test.*

obvious argument in favor of including all of these in a tightness test is that you are then reasonably assured that the containment sump will hold a substantial amount of product should there be a leak (assuming the sump is not full of water when the release begins). Unless the leak is a gusher, this buys the tank operator time to respond to the leak before any environmental contamination occurs.

Also, should the sensor in the containment sump be raised off the bottom of the sump but remain in a vertical (operational) orientation, then the sensor is more likely to eventually trigger an alarm because fuel is less likely to leak out of a leaky penetration fitting before it reaches the elevated sensor.

The PEI RP1200 Committee considered comments submitted regarding lower level testing for the 2017 edition of the recommended practice, but opted to stay with the high-level test described in the 2012 edition of RP1200. See Rick Long's article on page 8 for a discussion of why the Committee chose to keep high-level testing as the industry recommended practice.

## Low-Water-Level Issues

An alternative sump testing method has been proposed by the Petroleum Marketers Association of America (PMAA). This methodology was officially recognized by the USEPA as equally protective of human health and the environment in a May 2017 entry in the UST technical compendium. Though not completely described, I believe this method is similar to the PEI RP1200 test except that the water level during the test is equal to the minimum water level required to activate the sensor in the sump. For commonly used float-based sensors, the water level during the test will likely be on the order of a few inches.

From an economic standpoint, this test method has several advantages:

- Because most sump penetrations will not be evaluated by the test, there will be no need to seal off the secondary piping from the sump, greatly simplifying and shortening the preparations for the test. This shortens the test technician's time on site and so reduces costs.
- Penetration fittings that are severely torn or completely deteriorated may not need to be repaired as long as the liquid level during the test is below the fitting. (See Kevin Henderson's article in this issue of *LUSTLine*, page 10 for more discussion on this point.)
- Because fewer fittings will be tested, more containment sumps will pass the test (see Figure 2). There will be many fewer repairs, so more money will be saved on repair costs.
- The volume of water required to test all the sumps at a site will be reduced from hundreds of gallons to tens of gallons. This reduces the amount of equipment required to transport and handle the water, and greatly reduces the magnitude of the water reuse/disposal issues.

But, from an environmental standpoint, the picture is not so rosy. Because of the limited volume of liquid that the sump can reliably contain, the response to a sensor alarm signal must be quick and effective. But "quick" and "effective" are not terms that are often used to describe

■ continued on page 6

| Low-Level Testing | |
|---|---|
| **Pros** | **Cons** |
| Fewer sumps will fail the test, so fewer repairs will be necessary and this will save tank owners money. | This is not the industry recommended practice. |
| Less water to handle/dispose of. | Minimizes the volume of leaked fuel that can reliably be contained before a release to the environment occurs. |
| Less potential for harm to electrical components because they will likely be above the water level during the test. | Response to leak alarms must be quick and effective if environmental contamination is to be avoided. Historically, "quick" and "effective" response to alarms has been the exception rather than the rule. |
| In many cases, there would be no need to isolate dispenser sumps from secondary piping. | Raising sensors above the level of a leaky sump penetration or seam can result in an undetected release to the environment. |
| In many cases, there would be no need to isolate STP sumps from secondary piping. | |

**Table 2.** ***The pros and cons of low-level sump testing.*** *In general, low-level sump testing will require less work to prepare the sumps for testing, produce a greater number of passing tests, and require less sump repair activity. In other words, the average low-level sump test will cost less than the average high-level test.*

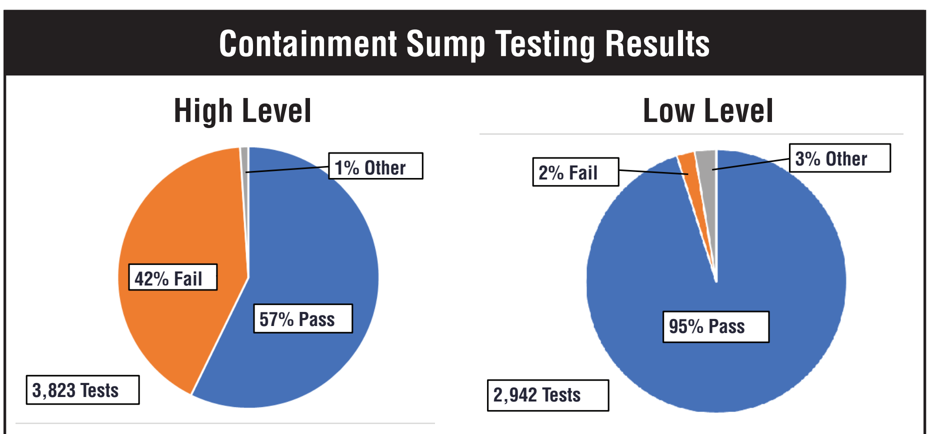


**Figure 2.** ***Comparison of high-level versus low-level containment-sump testing results.*** *Data are for both dispenser and STP sumps. High-level test data are from Maryland in 2005, early in Maryland's sump testing program. Low-level test data are from Massachusetts in 2016, early in Massachusetts' sump-testing program. Test data courtesy of Crompco.*

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UST operator responses to annoying alarms.

## Can Additional Requirements Increase the Effectiveness of Low-Level Tests?

In their technical compendium entry, USEPA recognized that testing sumps at lower levels is not as protective of human health and the environment as testing at higher levels. However, the document stated that if additional measures are used in conjunction with low-level testing, protection equivalent to high-level testing may be achieved.

One additional measure that USEPA describes in the technical compendium is to have the sensor shut down the submersible pump or the dispenser rather than just sound an alarm. The USEPA example also states that in the case of the dispenser being shut down, there must always be an attendant present when fuel is being dispensed.

Presumably, the requirement for an attendant is because dispenser sump monitoring systems often just cut power to the dispenser. This prevents the dispenser from dispensing fuel and is more likely to get someone's attention than a blinking light. But if the source of the leak is at the crash valve, the union at the base of the dispenser, or perhaps a filter, the release itself will not be stopped because the submersible pump is still allowed to operate.

However, having an attendant present to respond to a dispenser shutdown is not going to solve the problem. There are multiple reasons why a dispenser may not pump fuel, many of them due to electronic issues. Unless the attendant is specifically trained to understand that a dispenser shutting down is potentially a sign of an ongoing leak, the response is likely to be to place a bag over the nozzle(s) when, in fact, the situation may require an emergency response.

According to the USEPA example, if a facility wants to dispense fuel while it is unattended, then shutting down the submersible is the only option. But if the sensor in a dispenser sump detects liquid, which STP do you shut down? Because the sensor will not know which product is leaking, the only environmentally protective answer is to shut down all the STPs. This would cause liquid detection in a single dispenser sump to shut down an entire site. While this is protective from an environmental standpoint, it is not good for business and would likely be unpopular with UST owners.

## A Few More Things to Consider

Although not explicitly stated in USEPA's description of this alternative, it is clearly implied that for this testing option to be used, there must be a sensor in the sump where the low-level test is to be conducted. While sensors are present in most STP sumps, there are a great many existing dispenser sumps that do not contain sensors. Stand-alone sensor systems are available that shut down a dispenser if liquid is detected in the dispenser sump. These do not require wires to be run from the dispensers to the ATG and so are relatively easy to retrofit. Sump testers and UST owners should be clearly informed that every sump that utilizes a low-level test must be equipped with a leak detection sensor.

Another issue arises for certain discriminating sensors that are able to detect fuel even when a few inches of water are present in the sump. These sensors have the usual float switch at the base of the sensor to detect water, but also include a polymer strip mounted vertically inside the sensor. If a few inches of water are present, but then there is a fuel leak, the polymer strip will react and signal the presence of fuel.

For this type of sensor, the containment sump must be liquid-tight up to the top of the sensor, which is often about 12 inches high. Otherwise, if there were a hole in the side of the sump at a depth of say, four inches, water might accumulate to this level and then flow out of the sump. If fuel is released into the sump at this point, the fuel might well flow out into the environment through the hole without ever accumulating to the point where the fuel sensor would be activated. Containment sump testers will need to become keenly aware of the characteristics of the various sensors that are present at UST facilities in order to test sumps at the appropriate level.

## USEPA Provided an Example, Not a New Regulation

Note that what USEPA described in its technical compendium served only as an example of what an implementing agency might deem as protective of human health and the environment as the high-level sump test described in PEI RP1200. Implementing agencies may come up with

**High-Level Versus Low-Level Sump Test Requirements**

| High Level – Industry Recommended Practice | Low Level – USEPA Example of Equally Protective Test |
|---|---|
| Water level 4 inches above highest penetration or joint in the sump sidewall. | Water level only high enough to trigger the sensor. |
| Hold water level for one hour. | Hold water level for one hour. |
| 1/8-inch level change or greater is a failed test. | 18-inch level change or greater is a failed test. |
| Sensor activation need only sound an alarm. | Sensor activation must shut down a submersible pump or a dispenser. |
| | If the sensor shuts down a dispenser, unattended fueling is not allowed. |

**Table 3.** ***Comparison of high- and low-level containment sump test requirements.*** *The high-level test is described in PEI RP1200. The low-level test is described in USEPA's technical compendium associated with the 2015 rule amendments. What the USEPA describes in the technical compendium is presented as an example of the types of additional conditions that may be placed on a low-level test to have the low-level test provide protection equivalent to the high-level test. Implementing agencies may make their own decisions regarding additional requirements to impose on low-level testing.*

other combinations of requirements that the agency might judge to be equally protective. I would caution those pursuing this route to consider carefully as many different sump scenarios and sensor types as practicable in arriving at the package of alternative requirements.

My own short list of requirements to increase the effectiveness of a low-level containment sump test is as follows:

- Incorporate both high-level and low-level tests into the regulatory scheme. For example, require that the first test and every third test be a high-level test. Test data show that sump integrity improves substantially after the initial testing. This indicates that once a sump has passed a high-level test, the sump can reasonably be expected to remain tight for a while, so subsequent testing can be less rigorous. But nothing lasts forever, so high-level testing would need to be repeated, say at nine-year intervals (assuming a three-year testing frequency). Records of three previous tests would need to be retained so that the appropriate level for the next test could be determined.
- Require a sensor in every sump at the site (STP, dispenser, and intermediate).
- Require sensors in STP sumps to shut down all of the STPs in the sump they are monitoring.
- Require sensors in dispenser sumps to shut down all STPs serving the dispenser. NOTE: I personally don't think that attendants (e.g., Class C operators) can be counted on to respond to a shut-down dispenser as an indication of a leak, let alone identify the source of the leak and figure out how to stop the leak.
- Require all sensors to be position-sensing sensors that alarm if the sensor is not sitting on the bottom of the sump. Positioning the sensor at the very bottom of the sump is a fundamental assumption of this approach to sump testing. Position-sensing sensors can provide some assurance that the sensor is correctly positioned.
- Require sumps containing discriminating sensors designed to detect product floating on water to be tested to a level that is higher than the maximum level at which the sensor can detect product.
- Include a visual inspection of the sump as part of the low-level test. If any damage is detected that might affect the integrity of the sump (e.g., torn entry boot or crack in the sump wall), the test result is "fail" and the damage must be repaired. A test must then be conducted to a level that is at least four inches higher than the repair to show that the repair has been effective.
- Require that the annual verification of sensor operation document that sensors not only trigger alarms but also shut down the appropriate equipment.
- Make erroneous sensor installation (i.e., positioning it in any way that will prevent its proper operation) a red-tag offense, thus prohibiting fuel deliveries to the site. The red tag would only be removed when all the sumps at the site have successfully passed a high-level test per RP1200 requirements.

***While the low-level sump-testing scenario will be attractive to many UST owners and operators, regulators must be sure to understand and communicate the full scope of requirements for using this low-level test method to the regulated community. Low-level test requirements will need to be carefully and completely described so that sump testers will have clear instructions to follow and tank owners will know exactly what they have to do.***

## Communication is Key

While the low-level sump-testing scenario will be attractive to many UST owners and operators, regulators must be sure to understand and communicate the full scope of requirements for using this low-level test method to the regulated community. Low-level test requirements will need to be carefully and completely described so that sump testers will have clear instructions to follow, and tank owners will know exactly what they have to do.

So which sump-testing method will you choose? What additional requirements would you impose on sumps that want to use low-level testing? ■

*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.*

### Endnotes

1. *UST Systems: Inspecting and Maintaining Sumps and Spill Buckets - Practical Help and Checklist,* (EPA 510-R-05-001), May 2005, https://www.epa.gov/ust/ust-systems-inspecting-and-maintaining-sumps-and-spill-buckets-practical-help-and-checklist
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4. *https://www.epa.gov/ust/underground-storage-tank-ust-technical-compendium-about-2015-ust-regulations#spillbuckets*
5. For a refresher on sensor types, see "Making Sense of Sensors," *LUSTLine* #58, September 2008, available in the *LUSTLine* archives at *http://neiwpcc.org/our-programs/underground-storage-tanks/l-u-s-t-line/l-u-s-t-line-archive/*

# Field Notes

*from Rick Long, Executive Vice President, Petroleum Equipment Institute (PEI)*

# Recommended—Though Perhaps Not Perfect—Practices
## *What Current Discussions on Sump Testing Reveal*

The U.S. Environmental Protection Agency (USEPA) has long recognized that state and local governments are best positioned to oversee the underground storage tanks (USTs) within their borders. The regulated tank community is just too large and too diverse for federal authorities to develop a deep understanding of each state's situation, must less craft a coherent, state-by-state regulatory framework that would take the myriad variables into account.

That principle is enshrined in the USEPA's UST state program approval (SPA) process. Through SPA, states can develop tank regulations that precisely fit their individual priorities—as long as the state-authored regulations are at least as stringent as federal UST requirements.

Since July 15, 2015 (the effective date of the 2015 federal tank regulations), the SPA process has been put to a major test, with 38 SPA states plus the District of Columbia working to update their UST regulations. To be in compliance, these jurisdictions must amend their existing state plans and reapply for SPA status by Oct. 18, 2018.

As the amendment process unfolds across the country, no single question is receiving more attention than the how best to test containment sumps used for interstitial monitoring of piping. And as mentioned in Marcel Moreau's lead story in this issue of *LUSTLine*, PEI's recommended practices are at the center of these discussions.

### RP1200

At present, the federal regulations accept only one code of practice for containment sump testing: PEI's RP1200: *Recommended Practices for the Testing and Verification of Spill, Overfill, Leak Detection and Secondary Containment Equipment at UST Facilities.* The RP1200 hydrostatic testing method is described in Marcel's article.

Any SPA state that, for one reason or another, is uncomfortable with the RP1200 hydrostatic test may adopt an equally protective alternative test method. In the technical compendium accompanying its 2015 federal regulations, USEPA has even given an example of a package of test requirements it would consider sufficient for a low-level test to provide protection equivalent to a high-level test. Again, see Marcel's article for details of the USEPA's example.

No containment sump testing method is perfect. Both the RP1200 test referenced in the federal regulation and the low-level sump-test package referenced in USEPA's technical compendium have pros and cons. However, the committee that drafted RP1200 continues to believe its recommended procedure offers the best, most balanced and most environmentally protective approach to this important task.

The composition of the RP1200 committee was carefully selected to reflect the diversity of the industry. Experts from large fuel marketers, small fuel marketers, environmental firms, fiberglass and steel tank manufacturer associations, distributors, contractors, testing companies, state regulators, and the USEPA were all represented.

This diversity ensured that the consensus recommendations (i.e., not completely unanimous) in the document—including the hydrostatic containment sump-testing procedure—took into account the perspectives of all major UST stakeholders. By contrast, the stakeholders advancing alternative test methods typically represent a much more narrow range of interests.

### Public Comments

Before reaching its final decisions, the RP1200 committee also actively solicited input from the industry. As with all PEI recommended practices, RP1200 went through a lengthy public comment period. Many of the commenters offered suggestions on containment sump testing. Here's a sampling of actual public comments submitted to the committee:

- Water level should be six inches above the highest penetration fitting.
- Water level should be four inches above the lowest penetration fitting.
- Water level should be three inches above the bottom of the sump.
- The test should be three hours long, not one hour.
- Test failure should be based on "a measurable change in water level" rather than a drop of 1/8 inch.
- The water level should only reach the height that would activate the liquid sensor.
- The test should require precision monitoring so that a sump

## Field Notes continued

with a water level change of 0.01 inch would fail.

- A pressurized line-leak detector should be used to identify piping leaks of 0.2 gallons per hour or greater.

Each of these ideas—and others, as well—were reviewed, discussed, and voted on by the committee. Some were rejected as being impractical; others relied too heavily on a given company's proprietary, patented technology; others were not sufficiently protective of the environment.

### Why High-Level Hydrostatic Sump Testing?

In the end, three fundamental factors led the committee to the high-level hydrostatic sump test it recommended.

- First, any meaningful test must ensure that the sides, bottom, and penetration points of the sump are all liquid-tight. In fact, penetration points and side seams are the most likely points of failure in sumps. RP1200's hydrostatic test protocol directly addresses these problem areas. Low-water-level tests do not.
- Second, in a busy fueling station environment, containment-sump sensors can be and often are jostled, damaged, or moved from their designated location. A test that relies on the accuracy and precise placement of a sensor is inherently risky. Faulty calibration, inadequate anchoring, equipment malfunction, or a sensor placed too high in the sump can easily nullify the effectiveness of a low-water-level test. The RP1200 protocol is much more robust and much less prone to error.
- Finally, alternative sump-testing procedures that appear to be more convenient and less expensive may not be so over the long term. Comparative data from major testing organizations show that the RP1200 hydrostatic test uncovers many more sump failures than low-level tests. For owners and operators who truly are interested in protecting the environment in which they work, spending a little more now to reduce the risk of an undiscovered leak or catastrophic failure later is a small price to pay.

More information can be found at *www.pei.org/rp*. ■

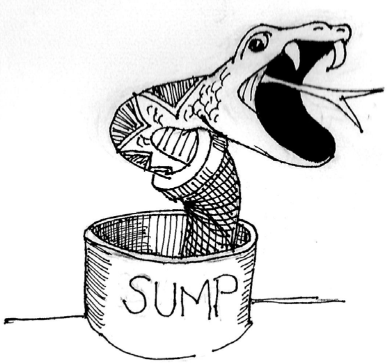
**We take care of the future best by taking care of the present now.**

-Jon Kabat-Zinn

## WHAT'S WRONG WITH THIS PICTURE?

**Follow the yellow fiberglass pipe as it exits the sump and you'll notice... no penetration fitting. Any liquid accumulation drains right out the sump.**

Courtesy of Ben Thomas




## Watch Out for Them Snakes

# Thoughts on Annual Containment-Sump Inspections

by Kevin Henderson

*Since the passage of the 2015 federal UST rule there has been much discussion and consternation about the triennial containment sump integrity-testing requirement. However, little thought has been given to the annual containment-sump inspection that is part of the walkthrough inspection requirement. What should UST regulators know about the containment-sump inspection requirement and how will it potentially impact the regulated community?*

*At first glance, the inspection requirement seems simple and of no significant consequence. However, a closer examination of what the rule actually says and how it could be interpreted reveals a potentially major headache for all parties involved. First, we must understand that the rule found at 40 CFR 280.36 applies to all containment sumps. It does not matter if the containment sump was installed before secondary containment was required or if it is used for interstitial monitoring—all containment sumps must be inspected. To help simplify the discussion, I will refer to those containment sumps installed before secondary containment was required as "old." Sumps installed after secondary containment was required and "old" sumps that are actually used for interstitial monitoring will be referred to as "new."*

### What Is a "Containment Sump"?

The definition found in 40 CFR 280 reads as follows:

> *Containment Sump means a liquid-tight container that protects the environment by containing leaks and spills of regulated substances from piping, dispensers, pumps, and related components in the containment area. Containment sumps may be single-walled or secondarily contained and located at the top of tank (tank top or submersible turbine pump sump), underneath the dispenser (under-dispenser containment sump), or at other points in the piping run (transition or intermediate sump).*

And what about those old containment sumps that were installed before secondary containment was required? Many of these have suffered from taking on water (see figure 1) and have subsequently been abandoned. Because they were installed before secondary containment was required, they are simply single-walled systems and the containment sumps serve no real purpose.

These old containment sumps may stay full or water, the walls and/or floors of the sumps may have collapsed or ruptured, and the penetration fittings may have deteriorated. Since the tank owner/operator usually gave up trying to keep the water out of these systems long ago, there has been no attempt to conduct interstitial monitoring. Although these old sumps do not serve as secondary containment, they must also be inspected annually in accordance with the rule.

### What Does the Annual Containment Sump Inspection Require?

The USEPA rule states that you must "visually check for damage, leaks to the containment area, or releases to the environment; remove liquid (in contained sumps) or debris."

**Figure 1.** *Typical "old" containment sump that stays full of water and does not serve as secondary containment.*

In addition to looking for leaks, the purpose of inspecting new containment sumps for damage is to make a visual assessment of whether or not the sump is liquid tight during the annual testing period.

While owners/operators may understand the reasoning, and it makes perfect sense to check new sumps for damage, some may question the purpose in checking old containment sumps for damage. The astute owner/operator may be asking a number of reasonable questions:

- Okay, if I find damage, must I then repair these old containment sumps just as I would a new containment sump?
- Must I then conduct an integrity test to ensure that the repair fixed the "damage"?
- What about the "remove liquid" part of the rule? It is simply not possible to pump the water out of some old containment sumps, since groundwater enters the sump as fast as you can pump it out.
- Although I understand that an argument can be made that you must remove the liquid to conduct a damage assessment, is there any real purpose to removing the liquid if it is in all likelihood going to return at some point anyway?

### A Matter of Interpretation

If damage or some kind of defect is discovered in a new sump during an annual inspection, what action must be taken? More specifically, what if a torn entry boot is found in a sump

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# Test Water, Test Water…Oh My!

*by Jill Hall-Williams*

The 2015 Federal UST regulations require that spill-containment equipment and containment sumps used for interstitial monitoring of piping be tested at least once every three years to ensure the equipment is liquid-tight. Testing can be done by vacuum, pressure, or liquid methods. The use of liquid methods for testing has raised questions regarding the requirements for re-use of the water and subsequent disposal. The UST statute and regulations do not address liquids used for testing spill buckets or containment sumps. The Resource Conservation and Recovery Act (RCRA), Subtitle C, governs the re-use and disposal options for the test water.

States, tribes, or local municipalities may have requirements that are more stringent than the federal RCRA C regulations. Always check with these entities to determine the appropriate requirements.

The following step-by-step approach will help determine the options for re-use and disposal.

### 1. Is the containment-sump test water considered a waste under RCRA C?

The test water is not a waste until it is no longer being used. Therefore, if the water is transferred from one facility to another and continues to be used for testing containment devices it is not a waste. Once the determination is made that the water will no longer be used for testing and it must be disposed of, then some RCRA determinations must be made.

### 2. What kind of waste is test water – solid waste, hazardous waste, non-hazardous waste?

Once the water is no longer being used it becomes a solid waste. It may also be a hazardous waste. If the water is a hazardous waste there are specific disposal requirements.

### 3. How do you determine if the test water is a hazardous waste?

Once the sump test water must be disposed of, it will be a hazardous waste if it exhibits any of the characteristics of hazardous waste described in 40 CFR 261.21-24. With the containment-sump test water, the most likely characteristics that would apply are the toxicity characteristic (TC) in 40 CFR 261.24 and ignitability characteristic in 40 CFR 261.21.

- **Toxicity characteristic:** The chemical benzene, often found in petroleum products, is the constituent most likely to be found in UST-sump test water in concentrations equal to or greater than the TC regulatory value, which for benzene is 0.5 mg/l. Thus approximately 0.007 ounces of benzene in 100 gallons of test water would exceed the TC limit. (Note: The water solubility of benzene at 23.5 degrees C is 0.188 percent, or 1880 ppm. While gasoline has typically contained approximately 1 percent benzene, in 2011 USEPA required benzene to be limited to 0.62 percent; see entry 1094 of the Merck Index, 12th Ed., 1996, and Gasoline Mobile Source Air Toxics.)
- **Ignitability characteristic:** If a representative sample of the sump test water exhibits a flash point below 140 degrees F at the point of generation or during the course of its management, it is considered an ignitable hazardous waste. (Note: Pure benzene has a closed-cup flash point of 12 degrees F; see entry 1094 of the Merck Index, 12th Ed., 1996.)

  Gasoline is more likely than diesel fuel, kerosene, or heating oil to be hazardous for benzene or flash point. Kerosene has a flash point of 150-185 degrees F; see entry 5305, Merck Index, 12th Ed, 1996.

### 4. What procedures can I use to determine if the sump test water meets the criteria in #3?

40 CFR Section 262.11, Standards Applicable to Generators of Hazardous Waste, requires generators to employ one of two procedures to determine whether or not a solid waste is a hazardous waste:

- **Analytical testing:** With respect to the sump test water, the relevant tests for benzene are: EPA Method 1311/8260 or 1311/5030/8015 or 1311/5030/8021 to determine if there is enough benzene in the test water that it fails for toxicity, and EPA Methods 1010A or 1020B to determine if the test water fails for ignitability. The toxicity characteristic leaching procedure, or TCLP, is the method used for determining whether a waste exhibits the toxicity characteristic (see 40 CFR 262.11). Note the TCLP test considers the solids content of the test water. More information about these laboratory test methods is available in USEPA's SW-846 Compendium.
- **Generator knowledge:** Generators may apply knowledge of the hazard characteristics of the waste in light of the materials or the process used to generate the waste. The key to using a "knowledge of" process is that it should be scientifically defensible and capable of reliably and accurately determining whether or not the waste is hazardous, particularly for non-hazardous determinations.

Because only a very small amount of benzene needs to be present in order for the test water to be TC hazardous (approximately 0.007 ounces of benzene in 100 gallons of water), a knowledge of process evaluation is in all likelihood incapable of ascertaining that the test water is non-hazardous. But it certainly could be used to determine the water to be hazardous (based on the water solubility of benzene and its presence in gasoline). Appropriate knowledge of materials and process for a waste stream like the test water could include information such as:

– The process that generated the waste (i.e., the fact that this process brings water into contact with gasoline, which contains benzene).

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■ **Test Water…Oh My** *from page 11*

- Observation of visible free petroleum in the test water, since the test water is likely to fail analytical testing if visible petroleum is present.
- Past sampling results of prior test water generated under similar conditions.
- Basic physical and chemical knowledge about likely waste constituents.

### 5. Is the test water exempt from the hazardous waste requirements via the exemption in 40 CFR 261.4 (b)(10)?

**This exemption states that the following solid wastes are not hazardous wastes (40 CFR 261.4(b)(10): "Petroleum-contaminated media and debris that fail the test for the Toxicity Characteristic of §261.24 (Hazardous Waste Codes D018 through D043 only) and are subject to the corrective action regulations under part 280 of this chapter.**

The test water does not qualify for this exemption from the hazardous waste requirement for several reasons. First, the test water is not consistent with the terms media or debris as defined in 40 CFR 261 and 40 CFR 268.2(g). That is, the water being discarded has been used as a product for testing sump integrity and is not ambient media that has been contaminated by an outside source. Second, even if it were media or debris that fails the toxicity characteristics of § 261.24, the test water is not subject to the corrective action regulations under 40 CFR 280. Water used to test multiple sumps may pick up petroleum constituents but would not generally require reporting under the UST regulations, unless there is an indication of a release from the UST system. Therefore, sump test water does not meet the requirements for the exemption. *Federal Register*, Vol 58, No 28 (332 pp, 83 MB, About PDF).

### 6. If the test water is characterized as a hazardous waste what are the disposal options?

Possible disposal options include:

**a.** If the test water is not ignitable, it may be acceptable to dispose of it via the sanitary sewer. Approval from the local sewer authority is generally required and it is highly recommended that you check with your state, tribal, and local authorities for rules or other restrictions regarding such a disposal method.

**b.** You may drum and store the test water properly until a hazardous waste hauler picks it up according to the hazardous waste generator regulations that specify accumulation time and management standards depending on how much hazardous waste is generated in a calendar month (see USEPA's hazardous waste generator website).

Check with your state, tribal, and local authorities for the applicable requirements for hazardous waste stored on site by generators and also to determine if there are licensing requirements for hazardous waste haulers in your jurisdiction.

**c.** You may filter the test water through an oil-water separator and properly dispose of the oil and water. Check with your state, tribal, and local authorities for requirements regarding disposal of the oil and water from the oil-water separator. It is possible that even after the water is filtered, it may contain enough benzene to be considered hazardous waste.

### 7. If the water is characterized as hazardous what are the reclamation options as opposed to disposal in #6?

The regulation at 40 CFR 261.2(c)(3) exempts from regulation off-specification commercial chemical products that are legitimately reclaimed to produce fuels. USEPA has interpreted this exemption to include off-specification fuel materials such as fuel and water mixtures. This exemption could apply to the test water if the test water contains enough fuel such that the fuel could be legitimately reclaimed if the test water is sent to a fuel recycling facility for recovery.

### 8. If the test water is not characterized as being a hazardous waste, how can it be properly disposed of?

Even in cases where the water is non-hazardous under the RCRA regulations, the testing contractor or UST facility owner and operator should check with state, tribal, and local authorities regarding applicable requirements for disposal, including disposal to the sanitary sewer or other safe waste management practice.

### 9. Who becomes the generator for the test water when it is no longer usable and becomes a waste?

This depends on when and where the test water becomes a waste. If the test water is used just once prior to being disposed, then the facility where the test is conducted is the generation site. Under the RCRA hazardous waste generator requirements, where more than one party's actions contribute to a waste being generated, all parties are subject to joint and several liability as generators—they are co-generators. For example, the testing contractor is a generator under 40 CFR 262.10 because his actions produce the waste test water; the owner/operator of the facility is a generator because he/she owns the equipment from which the waste is generated.

Joint and several liability dictates that both generators are responsible for ensuring compliance with applicable hazardous waste requirements. However, USEPA prefers and even encourages one party to assume and perform the duties and responsibilities of generator on behalf of all parties, as appropriate. USEPA recommends that co-generators specify via a contract that states who is responsible for compliance with hazardous waste and disposal requirements. ■

*Jill Williams-Hall, a Sr. Planner with the Delaware DNREC, is on assignment to USEPA's, Office of Underground Storage Tanks, Washington DC. She can be reached at: williams-hall.jill@epa.gov.*

**For additional information, see USEPA's *Waste Analysis at Facilities that Generate, Treat, Store and Dispose of Hazardous Waste – Final: A Guidance Manual.***

**https://www.epa.gov/sites/production/files/2015-04/documents/tsdf-wap-guide-final.pdf**

**A Message from Carolyn Hoskinson**

*Director, USEPA's Office of Underground Storage Tanks*

# On the UST Front: Countdown to October 2018 Compliance

As a mother of two sons, I've done my best to give equal airtime to each child, and I carry that approach to equality into my work life. So, it is appropriate that my article in this issue of *LUSTLine* focuses on the prevention side of the underground storage tank (UST) program, since my last article talked about the UST cleanup program.

Actually, the timing is perfect for me to write about prevention, given there are compliance deadlines coming due less than one year from now. We have also produced numerous resources and are working on more to help our co-regulators and the regulated community achieve, and remain, in compliance with the 2015 federal UST requirements.

Below I provide information about the October 2018 UST deadlines; explain whether federal or state UST regulations apply; and discuss the deadline for re-applying for state program approval (SPA). Plus, I share with you resources—already developed and still being developed—to help in complying with the 2015 UST regulation.

## 2015 UST Regulation Emphasizes Proper Operation and Maintenance

As you know, USEPA's revised UST regulation, which affects owners and operators in Indian country and in states and territories (referred to as states) without state program approval, took effect on October 13, 2015. The revisions established federal requirements that are similar to key portions of the Energy Policy Act of 2005, and they strengthened the 1988 federal underground storage tank regulation by increasing emphasis on properly operating and maintaining UST equipment.

Some requirements—such as testing following a repair, notifying implementing agencies about ownership changes, and demonstrating compatibility—were effective immediately. Still other requirements—such as secondary containment and interstitial monitoring for new and replaced tanks and piping, and under-dispenser containment for new dispenser systems—became effective on April 11, 2016. USEPA's website at *www.epa.gov/ust/revising-underground-storage-tank-regulations-revisions-existing-requirements-and-new* provides more details about the 2015 revised UST regulation, as does my cover article in *LUSTLine* #78, published August 2015.

## Remaining UST Requirements Effective in October 2018

Less than one year from now, on October 13, 2018, the remaining significant UST requirements become effective for owners and operators in Indian country and in states without state program approval. Our September 2015 tri-fold describes the significant changes from the 1988 UST regulation and their implementation timeframes; see *www.epa.gov/sites/production/files/2015-07/documents/regs2015-crosswalk.pdf.* In brief, the major deadlines coming in October 2018 are:

- All designated operators must be trained. Existing class A, B, and C operators must be trained by October 13, 2018. Class A and B operators hired after October 13, 2018 must be trained within 30 days of assuming duties. Class C operators hired after October 13, 2018 must be trained before assuming duties. Training can either be formal training or evaluation, or it can be passing an examination.
- Owners and operators must conduct periodic walkthrough inspections and maintain records about the inspections.
- Owners and operators must test and inspect spill and overfill prevention equipment every three years.
- If owners and operators use containment sumps for interstitial monitoring of piping, that equipment must be tested at least once every three years.
- Owners and operators must test electronic and mechanical components of their release detection equipment for proper operation at least annually.
- Owners must meet requirements for certain previously deferred UST systems, such as emergency power generator tanks, field-constructed tanks, and airport hydrant systems.
- Owners must maintain site assessment records when using groundwater and vapor monitoring.

## Do Federal or State UST Regulations Apply?

We continue to hear comments that some in the UST regulated community are uncertain as to when and

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## A Message from Carolyn Hoskinson*...continued from page 13*

| DO FEDERAL OR STATE UST REGULATIONS APPLY? | |
|---|---|
| **If USTs are located in:** | **Then:** |
| A state **with** an approved state program | The regulation of the state where the USTs are located applies. Note that a state's requirements may be different from the federal UST requirements.<br><br>Owners must comply with the state regulation, which operates in lieu of the federal regulation. |
| A state **without** state program approval | Both the requirements of the state where the USTs are located and the federal UST requirements apply.<br><br>Owners must comply with both federal and state regulations. |
| Indian country | The federal regulation applies to the USTs. |

where the federal UST regulation applies. To help in that regard, we developed the table below. To determine which states have approved programs, see the map and list of states on USEPA's website *www.epa.gov/ust/state-underground-storage-tank-ust-programs#which.*

**October 2018 Is the Deadline for SPA States to Apply for Approval of Their Revised Regulatory Requirements**

With less than one year until October 2018, states are doing an amazing job of updating their own regulations. We encourage states to continue their ongoing work to achieve state program approval by adopting and applying for approval of their updated regulatory requirements. So far, more than 30 states are already working with USEPA, and we welcome other states' and territories' requests for assistance in reviewing their draft UST regulations and their SPA applications.

Our review helps states as they prepare to implement the 2015 UST regulation and ensures that their regulations are as stringent as the federal UST regulation, which is a requirement in order for states to achieve SPA. States and territories can access more information about applying or re-applying for SPA on USEPA's website *www.epa.gov/ust/state-underground-storage-tank-ust-programs#apply.*

**Congratulations to Oklahoma, the first state to complete the revised state program approval process under the 2015 federal UST regulation.**

The 2015 SPA revision requires that current SPA states have until October 13, 2018 to re-apply to USEPA in order to maintain their SPA status; this includes incorporating the 2015 revisions to the federal UST regulation into their state final regulations. Re-applying for SPA applies to the 38 states, along with Puerto Rico and the District of Columbia, all of which already have SPA. The remaining 16 states may apply for SPA—which also requires incorporating the 2015 federal UST regulation into their regulations—irrespective of the October 2018 deadline. Once USEPA approves a state's program, that state's requirements apply and the state has the lead role in UST program enforcement.

When establishing compliance deadlines in their regulations, states applying or re-applying for SPA may allow additional time beyond the deadlines in the 2015 UST regulation. However, the timeframe for compliance with states' regulations must be less than or equal to the timeframes in the 2015 UST regulation. As an example, a state may allow up to three years after issuing its state UST regulations before requiring UST owners and operators conduct walk-through inspections. That means if a state issues its final UST regulation in May 2018, the allowable effective date can be May 2021.

### Resources To Help With Compliance

In addition to reviewing states' UST regulations and SPA applications, we have developed—and are developing more—resources to provide compliance assistance.

#### What's Already Available?

- Our UST technical compendium about the 2015 UST regulation (formerly referred to as Questions and Answers About the 2015 Regulation), *www.epa.gov/ust/underground-storage-tank-ust-technical-compendium-about-2015-ust-regulations,* contains USEPA's interpretations and guidance about the 2015 UST regulation. We recently added questions and answers about sump water disposal; secondary containment and corrosion protection requirements for remote-fill pipes; tank technologies placed within existing UST systems; and airport hydrant systems related to Department of Defense facilities. We will continue to add questions and answers as they arise.
- Re-applying or applying for SPA, *www.epa.gov/ust/state-underground-storage-tank-ust-programs#apply,* provides a flowchart and table, which describe the process for states to apply and re-apply for SPA under the 2015 UST regulation, as well as samples of the six components in a state's SPA application.
- Plain language documents, *www.epa.gov/ust/publications-about-2015-ust-regulation,* help states, tribes, and the regulated commu-

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**A Message from Carolyn Hoskinson** ...continued from page 14

nity meet the 2015 UST requirements.

- Our 2015 UST regulation web page, *www.epa.gov/ust/revising-underground-storage-tank-regulations-revisions-existing-requirements-and-new*, provides a wealth of information about the rule, such as a summary and history of the rulemaking; additional resources (e.g., notification forms, regulatory impact analysis, publications, response to comments, technical compendium); and links to 40 Code of Federal Regulations (CFR) 280 and 281.

### What's New?

Our revised UST inspector training now covers requirements and information from the 2015 federal UST regulation is available as of December 19, 2017. The training includes two modules: introduction to the UST program and basic UST inspector training. You can access both modules of the training via USEPA's website, *https://www.epa.gov/ust/underground-storage-tank-ust-inspector-training*. Inspectors who have or are seeking USEPA inspector credentials may prefer to access the training through our inspector Wiki site, *https://ssoprod.epa.gov/sso/jsp/inspectorlogin.jsp*.

This training is primarily for USEPA regional UST inspectors, as well as Indian country and state UST inspectors who currently have or are seeking USEPA inspector credentials. UST inspectors with current credentials must take the training in order to be up to date with current requirements. I request that USEPA regional UST programs share this training with their credentialed inspectors. Note that UST inspectors must take this online training to meet the UST program-specific training requirements for UST credentialed compliance inspector or field investigator under USEPA Order 3500.1.

Although intended for UST inspectors, the training is available to anyone. We think others, such as Indian country compliance officers and stakeholders in the UST industry, will find the training is effective and useful. Specifically, the training covers:

- the federal UST regulation
- differences between the UST and leaking UST program
- financial responsibility
- components of an UST system
- how to prepare for and conduct compliance inspections at a typical UST facility
- periodic testing of spill prevention and overfill prevention equipment
- walkthrough inspections
- release detection equipment testing
- operator training
- tailored requirements for airport hydrant fuel-distribution systems and field-constructed tanks.

If you have questions about this revised UST inspector training, contact Tony Raia (raia.anthony@epa.gov) of my staff.

### Designated Class A & B Operator Exam

- USEPA is developing free operator exams to help class A and class B designated UST operators meet the 2015 federal UST requirement requiring that designated operators demonstrate knowledge and pass an exam
- USEPA will provide two types of exams:
  - Comprehensive
  - Topic-specific, for operators to complete re-examination due to UST system non-compliance
- Available in January 2018 and accessible through USEPA's website, *www.epa.gov/ust*, or CD from USEPA regional UST programs

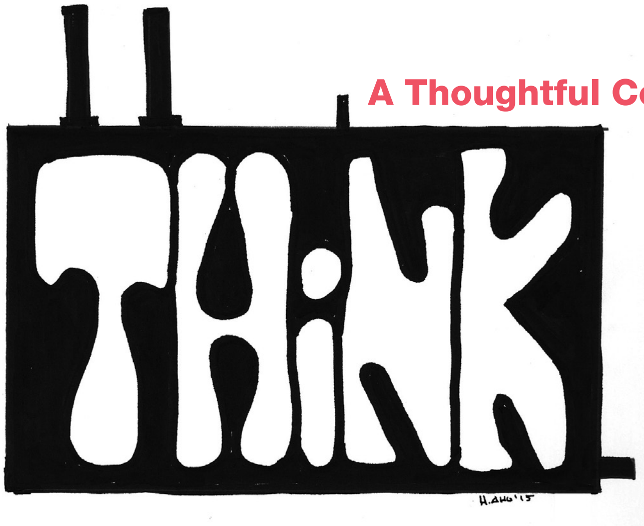
### What's Coming?

- Class A and class B designated UST operator exam. We are developing an online exam for class A and class B designed UST operators. The exam is based on the 2015 federal UST regulation, and users will be able to print a certificate demonstrating knowledge of and compliance with the requirements. USEPA developed this primarily for owners and operators in Indian country, and we are keeping our commitment to tribes by developing these exams. States may use this exam to develop their own programs; operators in non-SPA states can also use this exam to comply with the federal requirements, though they may also need to meet state-specific requirements.

### Onward

As I look at the upcoming remaining deadlines for the 2015 UST regulation, I am proud of the tremendous progress we've already made—even though we have more work to do. As always, if you have thoughts on how we can better assist states, tribes, and the regulated community to achieve compliance, please contact me or Tony Raia of my staff at raia.anthony@epa.gov or 202-566-1021 with your feedback and ideas.

I continue to believe wholeheartedly that the work we do in preventing, detecting, and cleaning up UST system releases makes a real difference in protecting the health of the people in our country and in keeping our environment safe from releases. ■



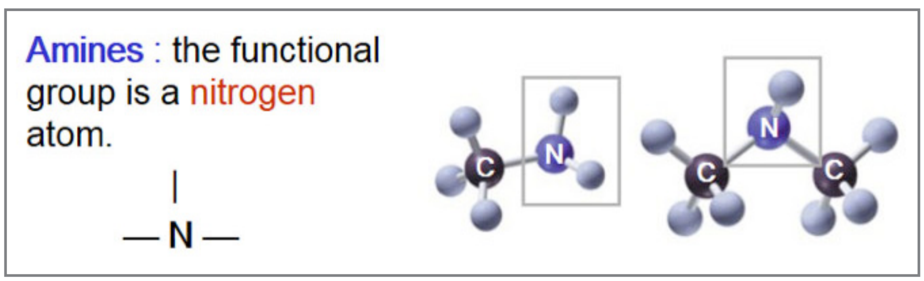

**A Thoughtful Column Engineered by Mahesh Albuquerque**

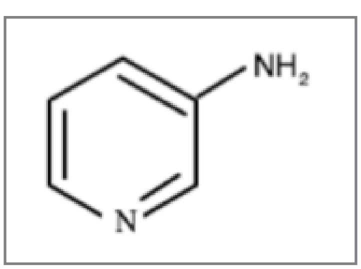
*Mahesh Albuquerque, Director of the Colorado Division of Oil and Public Safety, is on the lookout for articles from creative thinkers and experts willing to share ideas, insights, and stories on a wide variety of issues related to underground storage tanks. Topics include policy, strategy, successes, 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.*

# Filming Amines
## *An Elixir for UST System Corrosion?*

*As underground storage tank (UST) inspections have become more frequent and thorough across the country, we have seen increasing evidence of corrosion in UST systems storing a variety of fuels. A decade ago, most of this evidence was observed on external tank components, such as submersible turbine pump (STP) heads, and was often associated with ethanol-blended fuel. However, within the last decade, we have also started finding corrosion on metal components inside tanks, especially those associated with Ultra Low Sulfur Diesel (ULSD).*

*This is not surprising, as corrosion is a naturally occurring process that causes the deterioration of a metal because of chemical reactions between it and the surrounding environment. Corrosion is a time-based phenomenon complicated by design characteristics, environment, and operational usage, among other factors. As we learned in school, all metals can corrode, though certain types (e.g., pure iron) corrode quicker than alloys like stainless steel. The least corrosive are the noble metals, like silver, platinum, and gold.*




### Controlling Corrosion

The type of metal and the environmental conditions (particularly the atmosphere in contact with the metal) determine the form and rate of corrosion.

The noble metals are the most expensive and are usually not used to fabricate UST system materials. So, controlling the type of metal alone is not a practically feasible method of corrosion protection. That means we need to look at controlling the other factor that contributes to metal corrosion—the environment around the UST system.

Since the inception of the UST regulations, I think we have done a good job of addressing the effects from one of the environmental factors—the soil in which the UST system is buried. We have been protecting buried metallic UST systems from corrosion by using galvanic or impressed current systems, or by wrapping them with electrically insulated coatings. While these methods have proven to be effective, they primarily protect external metallic surfaces and not the interior of these UST systems. This is obvious as the corrosion issues we have seen in STP containment sumps and inside tanks are not related to metal being in contact with soil.

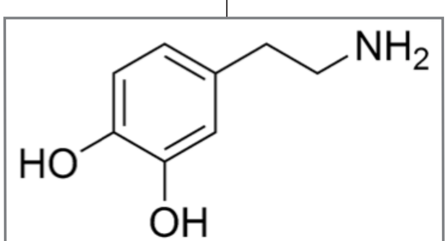
So what are these issues related to? What else is in contact with the UST system components? Well, there's the fuel that's stored inside the UST system, the atmosphere, and yes, water. Most motor fuels in their pure form do not contain much water, are not very corrosive, and are usually compatible with the metals to which they are exposed. So it is probably not just the fuel that's causing the corrosion.

The atmosphere is composed of gases (primarily oxygen and nitrogen) along with other gaseous compounds and pollutants, like carbon dioxide, sulfur dioxide, nitrogen oxides, aerosol particulates, and moisture, all of which can cause corrosion. The most important factor in atmospheric corrosion, however, is moisture—in the form of rain, dew, condensation, or high relative humidity. In the absence of moisture, most contaminants would have very little or no corrosive effect.

So the presence of air (oxygen) and water/moisture seems to be the common factor that enables corrosion. Water can enter UST systems through a variety of mechanisms—condensation of humid air, surface water or groundwater ingress through loose or damaged tank fittings, upstream sources via a fuel delivery. The Steel Tank Institute's publication *Keeping Water out of Your Storage System* provides great practical guidance on this subject.

Even if we did a fantastic job of keeping water out, we still have to contend with the atmosphere. Air displacement technologies, such as nitrogen blanketing, can help control the atmosphere and prevent corrosion. Other technologies include the use of protective coatings to isolate vulnerable materials from the environment. These coatings can range from sacrificial coatings (e.g., galvanizing) to surface modification (e.g., electro-plating) to sprayed-on liners or sealants (e.g., internal lining). Coatings are most effective when applied to bare metal, usually on new equipment before corrosion sets in.

Another mechanism for inhibiting corrosion involves formation of a coating (often a passivation layer) that prevents access of the corrosive substance to the metal. A corrosion inhibitor is a chemical compound that, when added to a liquid or gas, decreases the corrosion rate of a material, which is typically a metal or an alloy. Liquid corrosion inhibitors are fuel additives or spray-on coatings that impart anti-rust properties and provide excellent corrosion protection to fuel distribution systems. The inhibitors are surface-active "polar" molecules that attach themselves to metal surfaces. Once attached, the molecule's oil-soluble tail forms a water-repellent layer over the metal.



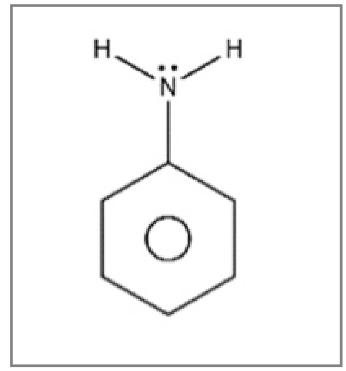

*Filming amines have been developed in a number of formulations over the years, and they are available as corrosion inhibitors specific for almost all fuels in today's marketplace. I wonder if filming amines are an elixir for the corrosion seen in UST systems—that elusive pot of gold at the end of the rainbow.*

## Filming Amines

In USEPA's July 2016 report *Investigation of Corrosion-Influencing Factors in Underground Storage Tanks with Diesel Service*, they included several approaches that may be helpful with limiting corrosion. One approach was the use of liquid corrosion inhibitor additives or other corrosion inhibitors, including filming amines.

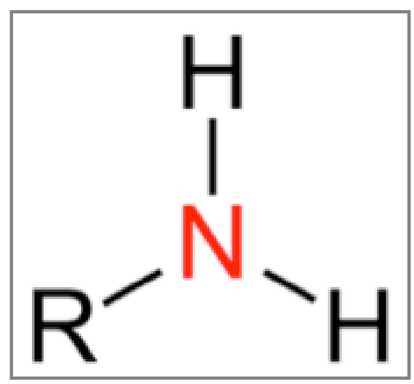
I was not familiar with filming amines, so they piqued my interest and I did what I usually do to find out more—I Googled it. I found out that filming amines have been used as corrosion inhibitors for decades to control corrosion, particularly in boiler condensate systems. Filming amines are fed continuously into boiler feedwater to protect metal surfaces from corrosion caused by dissolved oxygen and carbon dioxide in condensate water. The amine forms a thin film on the surfaces that repels the potentially corrosive water.

They are also added to coolants, fuels, hydraulic fluids, boiler water, engine oil and many other fluids used in industry to control corrosion. Most notably, corrosion inhibitors have been used for decades in fuel storage, pipeline, and aviation applications.




## What Are These Amines?

In organic chemistry, amines are compounds and functional groups that contain a basic nitrogen atom with a lone pair of hydrogen atoms. Amines are formally derivatives of ammonia, wherein one or more hydrogen atoms have been replaced by a substituent, such as an alkyl or aryl group. Important amines include amino acids, biogenic amines, trimethylamine, and aniline. Inorganic derivatives of ammonia are also called amines, such as chloramine. The amine group of the molecule is hydrophilic, so it will attach to wetted surfaces, while the "tail" is hydrophobic, providing protection of the metal surfaces from corrosive condensates.




Filming amines have been developed in a number of formulations over the years, and they are available as corrosion inhibitors specific for almost all fuels in today's marketplace. I wonder if filming amines are an elixir for the corrosion seen in UST systems—that elusive pot of gold at the end of the rainbow. ■

# Being Sure Cathodic Protection Protects

*by Lorri Grainawi*

Cathodic protection (CP) has been around a long time. It was used in the late 1800s to protect the exterior of boats from exposure to the water. While there are many different methods of assuring that liquids remain safely contained in a vessel, such as a steel underground storage tank, CP is the only method of corrosion protection that can be tested to verify if it's working.

To put it simply, cathodic protection takes the forces that Mother Nature has provided and makes them work for us. All metals have a different amount of energy. By connecting them together, one metal will always provide energy to the other. The metal providing the energy corrodes, while the metal receiving energy is protected. The key to protecting the steel is making sure the CP system is functioning properly.

## What Equipment Is Used for Testing?

The energy of the metal can be measured using a voltmeter. Because all soils have different properties (some are very wet, for example, while others are dry) we always use a reference cell. The reference cell is just that, a reference point that can be used to negate the differences in the soils. All we need to do is connect the tank, the reference cell, and the voltmeter together with wire, and voila! Like magic you can see the level of cathodic protection on the tank! The magic number we want is -850 mV or more negative.

## Correct Measurements Are a Must!

There are a few potential difficulties for which the tester must be on the look out. For one, the number we are trying to measure is really small, less than one volt. Compare that with the electricity voltage used in your home—110 volts (more than 100 times greater!). That's why the tester needs to be careful about errors in the measurements he/she records.

Errors can be caused by such things as placement of the reference cell, problems with equipment (e.g., the voltmeter not being calibrated), and even sunlight shining on the reference cell. One of the most common causes of errors is associated with being out in the field—it can be difficult to get a good, tight connection to structures. A good electrical connection is necessary for accurate readings.

Testers also need to think about *what* they are connecting to *where*. For example, are they above or below any isolation fittings that are installed? Sti-P3 tanks are always shipped with isolation devices on every fitting.

In order to test the tank, the tester needs to connect to the tank itself, not the pipe that rises up to grade. It's easy to overlook this when testing an impressed current system where it may not be known that the tanks are Sti-P3 tanks. This is why it's important to verify continuity between all structures when testing impressed current systems.

## Galvanic Cathodic Protection Systems

The energy levels associated with galvanic cathodic protection can be measured in terms of potential or voltage. Metals with higher energy levels, when measured with a voltmeter, have a more negative reading than the metals they are protecting. For example, magnesium often measures around -1500 mV while steel measures around -500 mV. When magnesium is connected to steel, magnesium is the anode, and corrodes to protect the steel.

### How many readings should be taken and from where when testing a galvanic system?

CP testing is easy—one end of the voltmeter is connected to the tank and the other end to the reference cell. Then you take your readings. Where you connect to the tank makes no difference. On the other hand, reference cell placement is everything!

STI's Recommended Practice for testing the cathodic protection of Sti-P3 tanks was updated this year. A committee was used consisting of a balanced mix of regulators, contractors, CP experts and testers, and tank manufacturers. In a nutshell, the RP requires three readings to be taken on all tanks—two remote and one local. STI also recommends a minimum of two readings on flex connectors.

For pipelines, the National Association of Corrosion Engineers (NACE) recommends a minimum of two readings, at either end of the pipeline for galvanically protected steel pipelines that are less than 100 feet long. Pipelines longer than this need an additional reading near the center of the pipeline run.

As always, state regulations may, and do, vary. For example, Mississippi allows for three possible results, Pass, Fail, or Inconclusive. Mississippi is also unique in that they only require two readings to be taken, one local and one remote. Testers in Mississippi are allowed to state Inconclusive if the tank passes the remote reading, but fails the local, or vice versa. The reason for this has to do with what a tank owner is required to do when a CP system fails. Of course, the tank system must be further investigated to determine if the system is protected or not.

The UST inspector should always look for a site drawing. The drawing should clearly indicate where all readings were taken, and each tank should be identified by product and/or number.

### What is a remote reading?

Quite simply, a remote reading is taken at a location where the reference cell is placed so it is away from the influence of other metals and structures. To find true remote earth, the tester places the reference cell in soil or backfill material at least 30 feet away from the tank. After recording the number on the voltmeter, the reference cell is moved at least 10 feet in any direction. If the first location was "true remote earth" the reading on the tank will be within 10 mV of the first reading. The tester may use these two readings as part of the three readings needed for every tank.

In the November, 2004 issue #48 of *LUSTLine*, Kevin Henderson (former Compliance and Enforcement Manager for the UST Branch at the Mississippi DEQ) wrote about using remote readings when testing cathodic protection. At the time, this was a relatively new concept.

### What's the big deal about remote readings? Why even bother?

Readings directly over the tank can vary significantly. Buried metals and electrical equipment influence CP readings. Given all the equipment, and the variety of metals involved, readings can jump significantly simply by moving the reference cell a few inches. Remote readings remove that variability, giving a more accurate reading on the entire tank. Once again, it's important to minimize errors when testing CP!

### What is a local reading?

A local reading is when the reference cell is placed directly over the structure being tested. It's important that the reference cell be placed directly in the soil, or in backfill. Tanks are usually covered up with concrete or asphalt. In cases where there is no access to the soil or backfill material over the tank, an access port will need to be created by drilling. Both concrete and asphalt will cause errors in the measurements and that's why the reference cell must not be placed on top of either to obtain a CP reading.

The inspector should be looking to verify that at least three readings were taken on all tanks and that both remote and local readings were taken. Of course, in order to pass, all readings must be more negative than -850 mV. If they aren't, a CP expert may be called in to determine if the system is adequately protected.

### What about flex connectors?

Testing flex connectors can be tricky because they are often located in sumps. If the flex connector is in a dry sump, meaning the flex connector is not in contact with either soil or water, you won't be able to test the CP. By removing the soil and/or water, it's like removing the wire in an electrical connection. No current can flow, and therefore there is no voltage to measure.

If the flex connector is in an enclosed sump but is in contact with the soil, a CP reading can be measured. However, the sump will isolate the flex connector from the outside soil. That means you can't get a remote reading. If you'd like more information on testing flex connectors, STI will soon have a published procedure specifically for testing flex connectors.

The inspector should look for notes to see what type of installation the flex connector is in and then determine the number of readings required and where they should have been taken.

> ***Given all the equipment, and the variety of metals involved, readings can jump significantly simply by moving the reference cell a few inches. Remote readings remove that variability, giving a more accurate reading on the entire tank.***

## Impressed Current Systems

Impressed current cathodic protection systems are similar to galvanic systems. However, instead of deriving their power from metals, they use an outside source for their power. A rectifier converts the AC electricity coming in to DC (direct current). This does a couple of things. First and foremost, it can provide much more power to protect a system. This is useful when you have lots of metal to protect. Impressed current systems are routinely used on cross-country pipelines and large-diameter aboveground tank bottoms sitting on soil. For underground tanks, it's most often used on older, bare steel tanks and attached metallic pipelines.

These systems are tested by cycling the power on and off. The inspector should look for "instant off" readings taken with the reference cell located directly over the tank. Because the power to the system can be turned on and off, the tester has two options to obtain the pass/fail criteria. They can use either a -850 instant-off potential (or more negative) to pass the system, or they can use a 100 mV shift in polarization. That second option sounds a lot more complicated, but it's really not.

The 100 mV polarization criteria is used when tanks don't meet the -850 instant-off criteria. Now when I first heard that, I thought it meant the tanks weren't as well protected and somehow able to "cheat" the system, but that's not true at all. The -850 mV criteria actually has a large safety factor built in. Steel only needs 100 mV of protective current to protect it. Steel in the ground, without CP, typically measures around -500 to -600 mV. So if the tank with CP, measures -850 mV, it has more protection than it needs.

With galvanic systems, because we can't turn the CP off, we never really know what the steel reads without the anodes. But with an impressed current system, we can, and in fact, must, cycle the power on and off to take a valid reading. That's why it makes sense to use the 100 mV polarization criteria for impressed current systems.

The key to using the 100 mV criteria is taking the correct readings. The tester needs to take the instant off readings first. If that doesn't meet -850 mV, then, when all the other testing is done, they need to re-test, with the reference cell in the same place, with the power turned off. The tester should see the readings start to drop immediately. The reading should continue to decline the longer the power stays off. If the reading drops more than 100 mV from the instant-off reading, the reading passes!

To summarize, the tester needs to use both the instant off, and the depolarized reading for the tank. Sometimes the depolarized reading is referred to as the native reading.

## Any Questions?

I'd love to hear from you! After reading this, if you think your group would benefit from training, STI offers classes and we would be happy to come to your area. ■

*Lorri Grainawi is Director of Technical Services with the Steel Tank Institute. She can be reached at lgrainawi@steeltank.com.*

# FAQs from the NWGLDE

*…All you ever wanted to know about leak detection, but were afraid to ask.*

## Statistical Inventory Reconciliation (SIR)

### *The Rules, the Listing, the Site Report*

*The recently updated USEPA underground storage tank (UST) rules included changes for statistical inventory reconciliation (SIR). What does this mean for sites where SIR is used as their leak detection method?*

### What Are the Rules SIR Must Follow?

The new regulation included SIR as a specific release-detection method for the first time. Under the previous 1988 UST regulations, SIR was regulated under the general "other methods" option at 40 CFR 280.43(h).

The revised federal UST regulation established the following:

- The performance standard of SIR methods must detect a leak rate of at least 0.2 gallon per hour (gph) with a 95 percent probability of detection and no more than a 5 percent probability of false alarm.
- SIR methods are similar to inventory control and those associated rule requirements apply.
- Each SIR method must perform a quantitative analysis. This means that the SIR method must calculate the leak rate for the facility, specifically for the data set, not simply indicate a result of Pass or Fail.
- To meet the performance standard, the SIR method must "use a threshold that does not exceed one-half the minimum detectible leak rate" in determining whether a release has occurred or not. This last requirement is often confusing and is explained as follows.

### How Do I Read and Use the NWGLDE Listing for SIR?

In order to meet listing requirements for the National Work Group on Leak Detection Evaluations (NWGLDE), SIR release-detection-method vendors must document that their method meets the required performance standard (i.e., can detect a 0.2 gph leak with a 95 percent probability of detection and no more than a 5 percent probability of false alarm) by having their method or equipment evaluated by a third-party.

NWGLDE maintains a list of the equipment and methods that have been submitted to the workgroup that have verified through a third-party that the equipment or method has met this performance standard. The listing for each method summarizes the third-party evaluation, the method, the threshold, performance parameters, and limiting criteria, as applicable. For many SIR methods, to prove that they meet the federal performance standard of 0.2 gph with the accuracy required in the rule, data must be analyzed at the leak declaration threshold/leak threshold of 0.1 gph.

### How Do You Read Your SIR Site Report?

When you look at your site report, you see multiple leak thresholds and rates…did you pass? The report may include the NWGLDE-listed leak threshold (not data specific). But for SIR, the method must also analyze the inventory and related data collected to determine the data set's minimum detectable leak rate (MDL) for that tank system and that time period. This is accomplished for every period of performance—every 30-days (i.e., monthly monitoring), in accordance with the federal UST regulations. This (MDL) can be affected by the throughput, the accuracy of the data, and the consistency or range of the data, among other factors. The following three sections describe how to read the report.

**1)** Look at the NWGLDE listing for the method you are using. To meet the regulatory performance standard (0.2 gph), you need to look **here** for the third-party-evaluated listed leak threshold.

| | STATISTICAL INVENTORY RECONCILIATION TEST METHOD (QUANTITATIVE) |
|---|---|
| **Certification** | Leak rate of 0.2 gph with PD > 99.9% and PFA = 0.0%. |
| | Leak rate of 0.1 gph with PD > 99.0% and PFA < 1.0%. |
| **Leak Threshold** | 0.1 gph for leak rate of 0.2 gph. |
| | 0.05 gph for leak arate of 0.1 gph. |
| | A tank system should not be declared tight if the test result indicates a loss or gain that equals or exceeds this threshold. |
| | Gains (water ingress) are analyzed and evaluated on an individual basis. |
| | |

**2)** What is your "pass" threshold?

The **third-party** **listed leak threshold** may appear on your site report. The **data set leak threshold** **must** be calculated for each specific data set (each month, each tank) and is the maximum leak rate for the data set to be considered passing. It **cannot** exceed half the **minimum detectable leak rate.**

| Summary of test results from monthly SIR reports. Complete for all 12 months. | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Month / Year** | **Listing Leak Threshold** | **Data Set Calculated Leak Threshold** | **Minimum Detectable Leak** | **Calculated Leak Rate** | **Pass, Fail, Inconclusive** | | |
| | gph | gph | gph | gph | P | F | I |
| Oct/ 2015 | 0.10 | .085 | 0.17 | -0.08 | * | | |
| Nov 2015 | 0.10 | .095 | 0.19 | -0.09 | * | | |
| Dec/ 2015 | 0.10 | .085 | 0.17 | -0.09 | * | | |
| Jan/ 2016 | 0.10 | .065 | 0.13 | -0.09 | * | | |
| Feb/ 2016 | 0.10 | .065 | 0.13 | -0.09 | * | | |
| Mar/ 2016 | 0.10 | .085 | 0.17 | -0.09 | * | | |
| Apr/ 2016 | 0.10 | .09 | 0.18 | -0.09 | * | | |
| May/ 2016 | 0.10 | .095 | 0.19 | -0.01 | * | | |
| Jun/ 2016 | 0.10 | .085 | 0.17 | -0.09 | * | | |
| Jul/ 2016 | 0.10 | .01 | 0.02 | 0.06 | * | | |
| Aug/ 2016 | 0.10 | .09 | 0.18 | -0.08 | * | | |
| Sep/ 2016 | 0.10 | .09 | 0.18 | -0.08 | * | | |

The regulation requires the vendor to calculate the data set's minimum detectable leak rate **and** the leak threshold specifically for the set of data analyzed. The data set's *calculated leak threshold* cannot exceed half the minimum detectable leak rate NOR can it exceed the NWGLDE-listed threshold.

**Data Set Calculated Leak Threshold ≤ half the Minimum Detectable Leak Rate**

**AND**

**Data Set Calculated Leak Threshold ≤ Third party evaluated, NWGLDE-listed leak threshold**

If the **data set calculated leak threshold** meets these two criteria, it is the maximum leak threshold for a "pass" for this data set.

**3)** You now know what your maximum passing leak threshold is. SIR provides your tank system's calculated leak rate. Did your tank system pass?

The data set calculated leak threshold established your "pass" maximum for each data set. Compare this maximum value to your tank system's calculated leak rate. If the calculated leak rate is lower than the data set calculated leak threshold, the tank system passes monthly monitoring!

| **Month / Year** | **Listing Leak Threshold** | **Data Set Calculated Leak Threshold** | **Minimum Detectable Leak** | **Calculated Leak Rate** | **Pass, Fail, Inconclusive** | | |
|---|---|---|---|---|---|---|---|
| | gph | gph | gph | gph | P | F | I |
| Oct/ 2015 | 0.10 | .085 | 0.17 | -0.08 | * | | |
| Nov 2015 | 0.10 | .095 | 0.19 | -0.09 | * | | |
| Dec/ 2015 | 0.10 | .085 | 0.17 | -0.09 | | * | |
| Jan/ 2016 | 0.10 | .065 | 0.13 | -0.09 | | * | |
| Feb/ 2016 | 0.10 | .065 | 0.13 | -0.09 | | * | |
| Mar/ 2016 | 0.10 | .085 | 0.17 | -0.09 | | * | |
| Apr/ 2016 | 0.10 | .09 | 0.18 | -0.09 | * | | |
| May/ 2016 | 0.10 | .095 | 0.19 | -0.01 | * | | |
| Jun/ 2016 | 0.10 | .085 | 0.17 | -0.09 | | * | |
| Jul/ 2016 | 0.10 | .01 | 0.02 | 0.06 | | * | |
| Aug/ 2016 | 0.10 | .09 | 0.18 | -0.08 | * | | |
| Sep/ 2016 | 0.10 | .09 | 0.18 | -0.08 | * | | |

In other words: If the **Data Set Calculated Leak Threshold** > **Calculated Leak Rate**, then it's a PASS! Remove equal from the equation.

■ continued on page 27

# Aggressive Fluid Vapor Recovery (AFVR)... Reinvented

by Read Miner

*Through the years, the presence of Light Non-Aqueous Phase Liquid (LNAPL) (aka free-phase product) has plagued the cleanup progress of petroleum-impacted sites across this nation. Despite the challenges of LNAPL removal, it is an important step toward reducing the residual petroleum in the ground, reducing or preventing potential petroleum migration, mitigating vapor intrusion concerns, and expediting the natural attenuation of petroleum. The purpose of this article is to document changes made here in South Carolina that have significantly improved the efficiency of LNAPL removal.*

## Stinging and Slurping

Beginning in 2007, the South Carolina Underground Storage Tank Management Division (SCUSTMD) increased the use of Aggressive Fluid Vapor Recovery (AFVR) for removal of LNAPL from the subsurface. The process that we call AFVR is also called Enhanced Fluid Recovery (EFR) and Mobile Multi-Phase Extraction (MMPE).

In simplistic terms, the process involves the simultaneous extraction of fluids and vapors from the subsurface using high-capacity pumps (usually liquid ring pumps) commonly mounted on mobile trucks or trailers with large-capacity tanks. The fluids are removed from the ground through pipes called "stingers" that are lowered into pre-existing recovery wells. The stingers are not slotted and their bottoms are commonly cut off at an angle. The stingers are slowly lowered into recovery well(s) below the free product/water table interface, and the fluids are extracted through the stingers under high vacuum.

The tops of all wells remain sealed to generate a high vacuum (up to 25-inches Hg). As the water is extracted, the water table is progressively lowered around each recovery well until it is lowered to the bottom of the stinger. Once that occurs, a "slurping" action is generated to collect a combination of air and water. The air moves through the formation at a high velocity, picking up petroleum vapors released through volatilization from the trapped residual petroleum. The stinger is progressively lowered to expand the radius of influence and expose more of the formation containing trapped residual petroleum.

In South Carolina, the recovered fluids are transported to a permitted wastewater treatment facility. The recovered vapor stream is monitored throughout the duration of the event for air velocity, temperature, moisture content, and vapor concentrations. The resulting data are used to calculate the pounds of petroleum removed from the ground in the vapor phase. The vapor stream is then treated in real time, on-site using carbon filters, catalytic converters, or thermal oxidizers. Vapor treatment is designed to minimize exposing people to the volatilized petroleum and odors.

Prior to 2013, AFVR events in South Carolina were typically limited to durations of eight to twelve hours. The stinger pipes were typically set at six-inches below the bottom of the LNAPL to recover the LNAPL and at the same time minimize the production of water. Although this process did recover LNAPL, the LNAPL would repeatedly re-enter the recovery wells once the aquifer had time to re-equilibrate.

## LNAPL Research

Over the years we have benefited from great strides in our understanding the behavior and distribution of LNAPL in the sub-surface. In recent years, the Interstate Technology & Regulatory Council (ITRC) has compiled the results of this research into several publications and training opportunities. I encourage anyone that is not already familiar with ITRC's resources to go to their website at *www.itrc.org*.

The ITRC resources have provided us with valuable insight regarding how LNAPL is distributed in the subsurface. For example, we know that LNAPL does not form a continuous homogeneous pancake of fuel that saturates 100 percent of the pore spaces at the watertable interface. Because the subsurface is heterogeneous with differing sand/silt/clay percentages in three dimensions, the LNAPL distributes unevenly both horizontally and vertically.

This uneven distribution is further complicated by seasonal changes in rainfall and infiltration that cause the watertable interface to fluctuate vertically, smearing the LNAPL into different stratigraphic horizons. The resulting distribution of LNAPL in the subsurface commonly forms a "shark-fin"-shaped distribution as described in the ITRC documents. The peak of the "shark-fin" represents the stratigraphic interval where the ratio of LNAPL to water is the greatest in the soil pore spaces. In many cases, the highest LNAPL/water ratio is trapped below the watertable interface.

## Application

During 2012, the SCUSTMD used this understanding regarding LNAPL distribution to propose changes to improve the effectiveness of LNAPL recovery efforts. These changes were incorporated into a revised state-lead AFVR bid solicitation in early 2013. The results were so remarkable that the changes were approved for full-scale implementation. Some of the most important changes follow.

- **Increased Stinger Placement Depth:** Prior to 2013, stingers were lowered and maintained at a depth of six-inches below the measured LNAPL elevation in each recovery well. This was intended to capture the LNAPL that was floating on the water table interface. However, this approach does not capture the LNAPL that is trapped below the watertable interface discussed above.

Starting in 2013, South Carolina required that the stinger be progressively lowered at six-inch intervals, and the resulting vapor concentrations measured at each interval. Once a vapor recovery profile has been generated through a cross-section of the well, the stinger is adjusted to the stratigraphic interval resulting in the greatest petroleum recovery. These intervals with the highest vapor recovery crudely conform to the same intervals containing the highest LNAPL/water ratios and the peak of the "shark-fin," as discussed above. Periodic re-adjustments are made as necessary throughout the duration of the AFVR events to maximize petroleum recovery.

- **Increased Duration:** Prior to 2013, traditional AFVR events lasted 8 to 12 hours. That limited duration did not allow enough time for the formation to be de-watered. Starting in 2013, the duration of events was increased up to 96 continuous hours. On very rare instances, environmental firms in South Carolina have implemented back-to-back 96-hour events resulting in a 192-hour event. To date, we have not pushed events longer than 96-hours due to complications with worker overtime and weekend employment issues. Through personal communication with the Utah Department of Environmental Quality's John Menatti, I am aware that Utah has overseen 30-day duration events.

  As discussed above, LNAPL is commonly trapped in the formation below the watertable interface. A longer duration event allows more time for water to drain from the soil pore spaces. LNAPL has a greater interfacial tension than water and does not drain from the pore spaces readily. Air progressively enters the pore spaces to replace the space vacated by the water. As air enters more pore spaces, the flow of air between pores increases as it is pulled under high vacuum toward the recovery wells. LNAPL is very volatile and has a relatively low vapor pressure. Therefore, the negative pressure enhances the volatilization of the LNAPL out of the soil pores and the resulting vapors flow quickly toward the recovery wells.

- **Minimum Vacuum and Air Flow Rates Established:** AFVR equipment comes in many different designs. Starting in 2013, South Carolina established standards that equipment must have a minimum capacity of pulling a vacuum of 25 inches Hg pressure and a minimum air flow rate of 250 CFM under open-flow conditions. This ensured that the state cleanup fund was not paying for the use of equipment that was under-designed for the required task, and that the recovery of both water and vapors is completed as efficiently as possible.

## Cost

For each petroleum-impacted facility, our project manager evaluates the potential risk of the petroleum release with regard to the potential risk to the environment, property, and health. Some facilities may be of little concern and are candidates for monitored natural attenuation (MNA). For releases that are not already candidates for MNA, a determination is made as to whether AFVR has the potential to remove enough petroleum to mitigate the risk and make the release a candidate for MNA at a lower cost than the anticipated cost for a comprehensive corrective action strategy. If yes, AFVR may be used at that facility.

Current published turnkey rates (including all equipment, personnel, mobilization, off-gas treatment, report preparation, and mark-up) for 48-hour and 96-hour events, are approximately $8,049 and $15,615, respectively, plus wastewater disposal cost.

## Results

From 2014 to November 2017, the SCUSTMD has overseen the implementation of more than 1,760 extended duration AFVR events under the new standards. During these events, more than 85,000 gallons of petroleum were removed from the sub-surface. The quantity of petroleum removed is calculated by adding the quantity of LNAPL captured in the holding tank to the pounds of petroleum (converted to gallons) recovered as vapor during the event(s).

More than 14 million gallons of wastewater have been generated during the same time period. Forty-eight and 96-hour events are the most efficient with average LNAPL recoveries of more than three-quarter gallon per hour of operation. Twenty-four-hour AFVR events average a lower average petroleum recovery of about a half gallon per hour, while even shorter duration AFVR events only averaged about a quarter gallon petroleum recovered per hour. The higher petroleum recovery efficiency of the longer events is proportional to the improved de-watering and vapor flow that can be achieved with longer events.

Subsequent gauging and monitoring activities at sites where the extended duration AFVR events have been implemented reveal decreasing measurable LNAPL thicknesses and a significant increase in sites where measurable LNAPL is no longer found. Further, the extended-duration AFVR events have been successfully used to significantly decrease concentrations of petroleum.

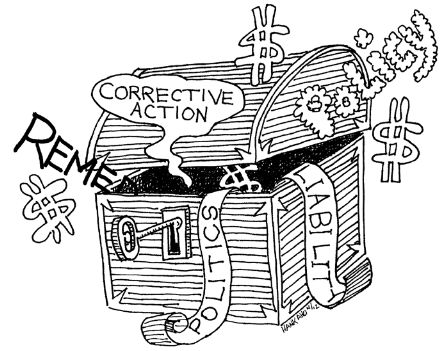
Extended duration AFVR events are not the most efficient solution for every site. Longer-chain (less volatile) fuels such as diesel do not respond very well. Further, sites that generate copious quantities of water, and can't be de-watered sufficiently to allow vapor flow, do not respond well. Effective LNAPL recovery also requires a recovery-well network with overlapping radii of influence. If the area with LNAPL is large enough to require a large recovery-well network, use of a mobile AFVR strategy may not be the most efficient cleanup mechanism.

The UST Division will continue to learn from and refine the long-term AFVR process to maximize the efficiency with the goal of decreasing risk and expediting site closures. ■

*Read Miner is a hydrologist with the South Carolina Underground Storage Tank Management Division. He can be reached at MINERRS@dhec.sc.gov.*

# Unlocking the Mystery of FR

*A straight-talking column by Jill Williams-Hall, a Sr. Planner with the Delaware DNREC, on assignment to USEPA's Office of Underground Storage Tanks, Washington, DC. Jill can currently be reached at: williams-hall.jill@epa.gov.*




## *Hmmm...*
## What Is This Self-Insured Retention on My Tank Insurance Policy?

Is a self-insured retention the same thing as a deductible on an insurance policy? Absolutely not! A self-insured retention and a deductible are both monetary amounts that the insured is responsible for paying. But that is where the similarities end.

### Some Definitions, Please

A *self-insured retention* is the dollar amount that must be paid by the insured before the insurance policy starts paying. Under a policy with a self-insured retention the insured would have to pay cleanup, third-party damage, and legal costs until the total amount of the self-insured retention limit was reached. Only after that point would the insurer start to make payments for costs covered by the policy.

For example, a $20 million policy issued on top of a $1 million self-insured retention effectively amounts to $21 million in loss coverage. The insured would pay the first $1 million (self-insured retention) and only after that full amount has been paid will the insurer then pay up to $20 million under the policy.

A *deductible* is the amount that an insured is responsible for paying, but it does not have to be paid by the insured before the insurance policy starts paying. A self-insured retention differs significantly from a deductible in a tank policy due to the requirement in 40 CFR 280 that a tank policy must provide 'first dollar coverage' for any deductible amount. This means that the insured does not have to expend the amount of the deductible before the insurer must make payments on a claim. The insurer must begin paying on the claim even if the insured has not paid the deductible. The insurer is entitled to pursue the insured and recoup the deductible amount, but the cleanup or third-party damage claim is not delayed while the insurer waits for payment of the deducible amount.

For example, a $20 million policy with a $1 million deductible effectively amounts to $20 million in loss coverage. The insurer starts paying from the first dollar in costs and would pay up to $20 million in claims. The insurance company can then recover the $1 million deductible, effectively costing the insurance company $19 million.

***An owner or operator would have to show proof of financial responsibility for the amount of the self-insured retention.***

### Why Would Someone Purchase a Policy with a Self-Insured Retention?

The insurer assumes a somewhat lesser risk when a self-insured retention is attached to a policy —the insured may be insolvent and unable to pay the self-insured retention, thus, the insurer would be relieved of any obligation to pay on the claim. The insurer may therefore charge a somewhat lesser premium for the policy.

Does a policy with a self-insured retention fulfill the regulatory FR requirements?

An insurance policy with a self-insured retention is only a partial financial responsibility mechanism. It does not fulfill the financial responsibility requirements of 40 CFR 280 on its own. A combination of mechanisms would have to be utilized to comply with financial responsibility requirements. *An owner or operator would have to show proof of financial responsibility for the amount of the self-insured retention.* It is unclear whether state UST regulators and tank owners and operators are fully aware of this.

Further, the certificate of insurance form in 40 CFR 280 does not show you whether the policy is subject to a self-insured retention. You must have the actual policy or possibly the declarations statement to determine if the policy is subject to payment of a self-insured retention.

State tank inspectors need to verify that any insurance policy used to comply with financial responsibility requirements does not have a self-insured-retention. This may mean that states must request copies of the insurance policy if one is not on-site at the time of inspection.

### Education is the Key

Once again, education is the key to success. Tank inspectors, owners and operators, and insurance providers need to be fully aware that an insurance policy, if it includes a self-insured retention, does not fulfill the financial responsibility requirements unless a second mechanism covering the self-insured retention is documented. ■

# It's Déjà vu All Over Again

# Retroactive Dates and Gaps in Coverage

*by Patrick Rounds*

The new round of federal UST regulations will result in a significant increase in reported releases—similar to the early 1990s. Releases will be discovered as tank systems are closed, components are removed/replaced, and soil and groundwater testing is conducted.

The original federal UST regulations published October 26, 1988, required owners and operators of UST systems to demonstrate financial responsibility (FR) to address corrective action and third-party liability if a release occurs. With the projected increase in reported releases, the success of the FR requirements is about to be tested.

In 1988, it was too late to purchase insurance as thousands of releases with billions in corrective action liability had already occurred and were about to be discovered due to mandates associated with the other provisions of the new regulations. Pre-existing conditions, inadequate technical standards for tanks, and inconsistent environmental corrective action standards were key issues limiting the availability of reasonably priced tank insurance.

In response to the upgrade deadline, approximately 400,000 releases were reported. To date, 47 state funds have addressed over $20 billion of corrective actions. Regulations to prevent, detect, and clean up releases were implemented. With thirty years of history, well-developed regulations, and billions spent, we are much better prepared and will never have to face unfunded releases again—right?

## Private Insurance Coverage

Once pre-upgrade releases were addressed, and the new upgrade requirements created an insurable tank population, insuring tanks for future releases became much easier. Pre-existing conditions were addressed and new tank standards created predictable risks. For future releases, the three primary FR mechanisms available to most owners were State Funds, self- insurance, and private insurance. In the 14 states without state funds, private insurance is the primary mechanism. Both state funds and private insurance, though, have limitations on eligibility for coverage. Thirty-two of thirty-six remaining state funds have "date of release" as an eligibility criterion. Private insurance also has coverage limitations based upon the date of release. This article addresses private insurance coverage.

Private insurance is a contract between two parties. Both parties have obligations that are defined in the insurance contract. Along with the contractual nature of insurance, there are a few key concepts that regulators and owners should understand:

> ***With a gap in coverage, the insured will now have to document that a release occurred on or after the retroactive date of the policy if a release is discovered.***

- **Claims-Made Policy:** Virtually all UST pollution insurance policies are "claims-made" policies. A claims-made policy only pays for claims reported during the period covered by the policy.
- **Retroactive Date:** Only covers releases that occur after the retroactive date in the insurance policy. If a release from an UST occurred prior to the retroactive date, this insurance policy will not cover it.
- **Gap in Coverage:** A period of operation for which there is no coverage. If a tank system was operational prior to the retroactive date of the current policy, there may be a gap in coverage. In this case, any release that occurred prior to the retroactive date will not be covered by the policy.

In general, UST insurance covers a release that occurs after the retroactive date and is reported during the policy period. Reporting necessarily requires discovery.

## What About That Gap?

Today, most UST releases are not catastrophic, are not discovered immediately, and may not be discovered for many years. Most releases occur from components, such as the dispenser, that are not monitored by existing leak detection systems and are generally not discovered until soil and groundwater tests identify contamination.

Unfortunately, many tank owners conduct business under the assumption that if a release has not been discovered, then it has not occurred. For these owners, tank insurance is just another expense to be managed and obtained for the best price. As rates increase for older tanks, owners often shop for less expensive coverage, and many times will purchase new coverage without requiring the new carrier to pick up the old policy retroactive date. To save on insurance premiums, a gap in coverage has been created.

Actions have consequences and you can't change yesterday. This is true whether we are referring to a decision to save money by not performing routine maintenance or by purchasing less expensive insurance without keeping the previous retroactive date. With a gap in coverage, the insured will now have to document that a release occurred on or after the retroactive date of the policy if a release is discovered.

If a tank owner replaces a piping run or a sump and discovers

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## ■ Retroactive Dates and Gaps in Coverage *from page 25*

contamination, then what? When the non-catastrophic release is discovered, how will the owner determine when it occurred? Leak detection records may not help because the release may not have been monitored by the leak detection system and was not detected when it occurred. Age-dating contaminants from soil and groundwater samples may not help because it is an inexact science that is subject to wide-ranging interpretation. For an insured with a gap in coverage, the proof of when the release occurred will be a challenge.

*Any time an owner is going to switch from one FR mechanism to another, either have the new FR provider pick up the old retroactive date (back to the install date or last baseline) or conduct a new baseline assessment before the expiration of the existing FR mechanism. Both options will cost money, but not nearly as much as the cost of corrective action if a release has occurred.*

### The Solution Is to Eliminate Gaps in Coverage.

The best method to identify when a non-catastrophic leak occurred may be to document the last known date when a release had not occurred. If an insured can document that there had NOT been a release as of the retroactive date, any release discovered thereafter can be presumed to have occurred after the retroactive date.

A comprehensive analysis establishing the existence or absence of petroleum contamination is known as a baseline assessment (baseline). Versions of baselines are conducted at system closure, during component replacement, prior to new installations, or as part of phase II assessments associated with sales transactions. Due diligence requires a phase II environmental assessment in any sales transaction involving a petroleum UST.

Baselines should also be conducted when establishing a new retroactive date for UST insurance. Unfortunately, baselines cost money and when shopping for insurance, most owners are not looking for ways to spend more money.

How can we eliminate gaps in coverage? Maintaining a retroactive date that coincides with the install date eliminates the chance of a gap. Establishing a new baseline prior to obtaining a new retroactive date greatly reduces the chance of a gap.

### It's Worth the Price

Insurance is a valuable FR mechanism for owners who understand the terms of the policy. To eliminate a gap in coverage, two steps should be taken:

- Make sure retroactive dates coincide with the install date or a baseline assessment.
- Make sure coverage is continuous until the next baseline assessment.

Any time an owner is going to switch from one FR mechanism to another, either have the new FR provider pick up the old retroactive date (back to the install date or last baseline) or conduct a new baseline assessment before the expiration of the existing FR mechanism. Both options will cost money, but not nearly as much as the cost of corrective action if a release has occurred. ■

*Patrick Rounds is President of PMMIC Insurance in Urbandale, IA. He can be reached at pjr@pmmic.com.*

## ■ Annual Containment-Sump Inspections *from page 10*

that has been passing triennial integrity testing utilizing low-level testing (see Moreau cover article)? How does one proceed? Obviously, if the torn boot is at a height that would include low-level testing, then the boot must be repaired.

However, what if the boot is above the test-fluid level, must this boot be repaired? An argument could be made that if the sump passes low-level testing and the pump shut-down is in place, there is no need to fix the higher torn boot. The logic would be that because the leak would never reach the height of the torn boot (assuming pump shut down occurs as intended) there would be no release to the environment. Does our history of detecting leaks before a release to the environment occurs support this logic? Does this give me a warm and fuzzy feeling about the concept of performing low-level integrity testing?

What if you interpret the rule to require that the torn boot is repaired regardless of the height above the bottom of the sump or if low-level integrity testing is done? Then we must consider what kind of sump-integrity test is acceptable to demonstrate that the sump has been properly repaired. Is it OK to perform a low-level test? Is it OK to test the sump at a fluid level four inches above the repaired boot? Must the entire sump be tested as is required by PEI RP1200 at a height of four inches above the highest penetration fitting or seam?

*It seems likely that all of this talk about low-level integrity testing is going to create a great deal of confusion.*

It seems likely that all of this talk about low-level integrity testing is going to create a great deal of confusion. I suspect many will think (or at least claim) that all you have to do is low-level testing regardless of the circumstances. This, however, could indeed be a very undesirable consequence of low-level testing. ■

*Kevin Henderson is a a petroleum storage tank consultant. He can be reached at kevin4824@comcast.net*

## FAQs from the NWGLDE

……continued from page 21

### In Summary

SIR must be a quantitative report with a calculated leak rate and a calculated leak threshold for the data set. The data and data collection should also meet all third-party-evaluated (NWGLDE-listed) criteria. For SIR to "pass," the following must be met:

- The data set calculated leak threshold and the minimum detectable leak rate need to be calculated from the set of data analyzed.
- The data set calculated leak threshold cannot exceed half the minimum detectable leak rate.
- The data set calculated leak threshold must be less than or equal to the third-party-evaluated (NWGLDE-listed) leak threshold.
- The data set calculated leak threshold must be less than or equal to half the minimum detectable leak rate.
- The calculated leak rate (for the system for that period) is less than the data set calculated leak threshold. ■

## Tank News From NEIWPCC.......

NEIWPCC has a new website! Since the last *LUSTLine* issue, we have worked hard to develop a user-friendly site that offers our same tank-related resources in a new and improved format. Log on today and read archived *LUSTLine* articles, view a training webinar, or learn more about the 26th National Tanks Conference & Exposition (NTC), scheduled for September 11–13, 2018, at the Galt House Hotel in Louisville, Kentucky. NEIWPCC's UST/LUST program homepage can be found here: http://neiwpcc.org/our-programs/underground-storage-tanks/.

Speaking of the NTC, the call for abstracts has been posted and will remain open through February 9th, 2018. We welcome all submissions—are you interested in developing a pre-conference workshop? a conference session? a poster? We are looking for presentations that focus on issues relevant to a wide audience of UST, LUST, and Financial Responsibility professionals. Please visit the conference website for more information: *http://www.neiwpcc.org/tanksconference/*.

Since the last *LUSTLine* issue, NEIWPCC has worked with our partners to provide a number of training opportunities for state, tribal, and territorial employees. We continue to offer online training through our UST Inspector Training Webinar Series, which is aimed mainly at UST inspectors and release prevention professionals. Our most recent training topic in the series was on UST System Repairs and UST System Manifolds. Archived inspector training webinars can be found here: *http://www.neiwpcc.org/inspectortrainingwebinararchive.asp*.

For those interested in LUST issues, we offer our LUST Corrective Action Webinar Series. Our latest training offering in this series focused on Risk-Based Corrective Action (RBCA). Please visit our archive to view the RBCA webinar and previous LUST training webinars: *http://www.neiwpcc.org/lust-cawebinararchive.asp*. NEIWPCC plans to offer more training webinars for each webinar series over the next year, and we will add these recordings to our archives.

If you have any questions about the NTC, training webinars, or other aspects of NEIWPCC's UST/LUST program, please contact Drew Youngs at dyoungs@neiwpcc.org. ■

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