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L.U.S.T.LINE

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

The GISST of GoNM

Prioritize Inspections, Target Remediation, Reduce Claims to the State Fund

by Jennifer Pruett and Suzan Arfman

New Mexico is developing an exciting new Geographic Information System (GIS) tool with applications to its inspection, remediation, and state fund programs. In the face of decreasing resources and increased demands, the state's Petroleum Storage Tank Bureau is hopeful that this new tool will allow it to better and more effectively carry out all aspects of its mission. It's called GoNM, which stands for GISST (Geographic Information System Screening Tool) of New Mexico, and this article explains how it is being developed and implemented, as well as the goals for using it in the future.

Big State, Big Challenges

As the nation's fifth-largest state, New Mexico has a substantial geographic area with UST facilities scattered over wide-ranging inspector territories. The Bureau's Prevention/Inspection Program currently has 10 inspectors, down from 13 several years ago, in eight field offices around the state. The program regulates approximately 4,800 tanks (3,500 USTs and 1,300 ASTs) at 1,830 facilities with 748 owners. Historically the program easily met the Energy Policy Act's three-year UST inspection cycle, inspecting each facility annually. In recent years, however, as staff has decreased and inspector responsibilities have increased, the program is now on an 18- to 30- month inspection schedule.-

The impact of the federal Energy Policy Act on New Mexico's program (and the programs of most states) cannot be underestimated. Our inspections must now be much

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Inside

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more detailed, requiring review of many additional requirements and features—more testing and maintenance reporting, follow-up, and paperwork. In addition, the Bureau has added inspection priorities, requiring that every active LUST site be inspected annually (to ensure the state Corrective Action Fund that it is not spending money on remediation at sites with significant compliance violations). As the Bureau has developed more aggressive delinquent fee and account-receivables programs, inspectors are asked to spot-check facilities for unreported transfers or other fee-related issues.

The Bureau has adopted several strategies for meeting the three-year inspection requirement, including using a "30-month" list, which is a monthly accounting of all facilities not inspected within the last 30 months. It is sent to all inspectors to ensure they inspect those facilities before the 36-month deadline. Inspectors are encouraged to visit problem facilities more often, to push for compliance, and to delay inspections of facilities that are usually in compliance with all Significant Operational Compliance (SOC) requirements. The problem facilities should be inspected each year, if possible, while the better facilities can wait for 30 months.

Then Came GoNM

Like many states, New Mexico has been under a hiring freeze for nearly two years—and we do not anticipate being able to hire additional inspectors for the foreseeable future. So it is critical that the Bureau maintain USEPA grants and federal funding by maintaining our required inspection frequency. With the state's delivery prohibition rules soon to be adopted and implemented, inspectors will face additional enforcement responsibilities. All of these factors require the Bureau to do more with less.

The GoNM project is a key strategy for maximizing available resources. It is GIS-based, and rates UST facilities on their potential to leak. The tool can also be used to facilitate remediation by providing both location-specific data and a reference for determining which remediation technologies have worked at similar locations. The Bureau may also use the tool to prioritize inspections, ensuring that facilities with the highest risk of release are inspected more often.

Developed with a grant from USEPA Region 6, the project is based on CRUST (Cumulative Risk for Underground Storage Tanks) developed by Frank Harjo, Cherokee Nation; the Inter-Tribal Environmental Council UST Program; and GISST developed by EPA Region 6 (Dr. Gerald Carney and Jeff Danielson).

GoNM Information Layers

The GoNM project includes GPS coordinates for all tank-system features. A first step in accomplishing this is collecting GPS coordinates for all aspects and equipment of our operating gas stations—fill ports, monitoring wells, vapor-recovery locations, submerged turbine pumps, automatic tank gauges, vent lines, and other equipment particular to a facility. While some GPS coordinates are already in the New Mexico database, most must be collected by local inspectors or the project leader.

The Area of Analysis for each facility is a quarter-mile buffer around the facility. Within this area, the program reviews physical, environmental, and demographic data and scores each factor based on the risk of environmental damage from a release. Each facility is scored on approximately 70 criteria compiled from the following three dataset layers:

- **LUST Ranking Layer** — addresses the physical surroundings of the facility, including factors such as aquifer geology, road density, stream density, floodplain proximity, rainfall, distance and depth to water, air features, and soil permeability. The data are based on a USEPA dataset originally called Landscape, which was modified for New Mexico by adding layers with data for remediation and cost prediction.
- **Socioeconomic Layer** — based on United States Census data. Criteria examined in this layer include population density, percentage of economically stressed households, percentage of children, percentages of people over 55, age of housing, percentage of residents without high school degrees. These socioeconomic and demographic data are very important for addressing environmental justice issues.
- **Facility Criteria Layer** — based on the Bureau's OneStop tanks database, includes all equipment and technical features of each UST facility, including number of dispensers, tank composition, piping construction, secondary containment, overfill protection, leak detection method, records for both tanks and piping, tank(s) age and capacity, type of cathodic protection (if steel tanks or piping), and history of Notices of Violations.

Risk Scoring

The Bureau was able to merge data for parameters already in its database and incorporate it into the GoNM project. A team of inspectors then gave each of 35 to 40 parameters a risk score of 1 to 5 (5 = highest risk, or "worst" score; 1 = lowest risk of release, or "best" score). Table 1 is an example of scor-

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Variable	Overfill Protection	Score
I-01	Product Level Sensor/Alarm	2
I-02	Automatic Tank Fill Shut-Off	2
I-04	<25 Gal at a time Trans Tank	5
I-05	None	5
I-10	Ball Float Valve	2
I-11	Flapper Valve	2
	Product Level Sensor/Alarm, Automatic Tank Fill Shut-Off	1
	Product Level Sensor/Alarm, Ball Float/Flapper Valve	1
	Automatic Tank Fill Shut-Off, Ball Float Valve	1
	Product Level Sensor/Alarm, Flapper Valve	1

TABLE 1. *Overfill-prevention equipment and scores*

ing for overfill-prevention equipment that can be found at a given facility.

Each parameter within each layer is assigned automatically a 1 to 5 score. Each layer also receives a score. Then the scores for each of the three layers are averaged to produce the cumulative-risk score for each facility. The lower the score, the less likely a facility is to have a release and thus fewer inspections are needed; these facilities could perhaps slip to being inspected every 24–30 months, rather than annually. Conversely, facilities with higher scores and potential risk can be inspected on a more frequent schedule (such as annually) to perhaps prevent a release and risk to human health and the environment.

In the future, the Bureau may weigh particular criteria or layer scores as higher risks than others. For example, the Bureau could assign higher risk scores to facilities where the depth to water is quite shallow or located in close proximity to drinking water wells, whereas facilities in very rural areas with great depth to water and few human receptors would be assigned lower risk scores. The Bureau could also manipulate the scores to increase weight on the Socioeconomic Layer to emphasize environmental justice concerns.

Close-up of a Facility Score

Figure 1 shows how an individual facility is approached in the GoNM project. On the bottom right, a state map shows the location of the facility. Next to that is a smaller-scale map indicating where the facility is in the county and identifying major roads. The aerial view of the facility indicates the major pieces of UST equipment and provides scores for the three layers and the averaged site score.

Both inspectors and remediation project managers use these maps and data in site analyses, working with contractors and facility operators, and in public meetings. The GoNM maps can be prepared to show all the facilities in a particular community, which is particularly useful for city council or neighborhood meetings. Similarly, maps can easily be made so that state legislators can see all current remediation sites in their district.

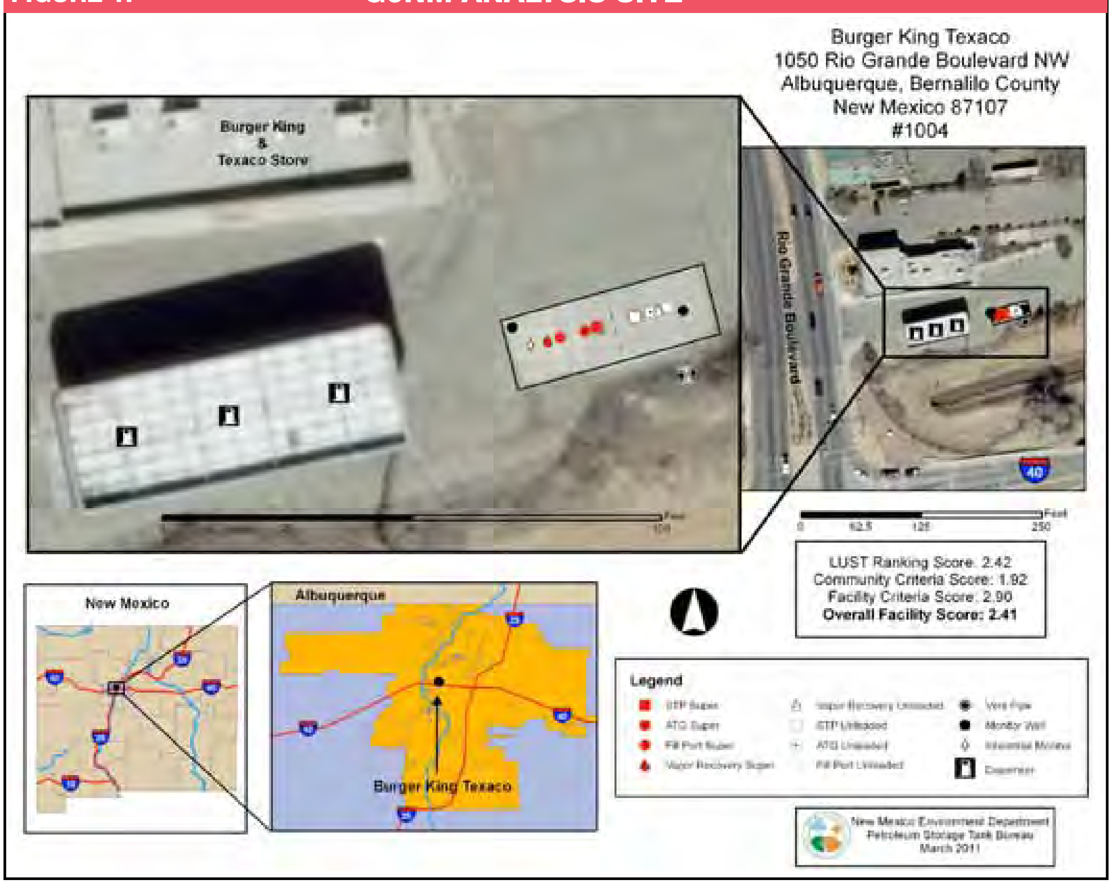
Placing detailed information and documentation of the equipment and surrounding factors for each facility in a database provides very helpful information for inspectors in case of staff turnover or re-assignment of facilities. These peripheral benefits of the project have been very helpful to the Bureau.

Looking to the Future

The Bureau is in the process of integrating all facilities in its database into the GoNM project. Recently, we expanded the criteria evaluated. We must still verify or add data for some of the parameters; not all facilities have accurate data for all parameters. Quality control remains a

■ continued on page 4

FIGURE 1. **GoNM ANALYSIS SITE**



■ The GISST of GoNM *from page 3*

challenge when dealing with data for approximately 1,511 UST facilities.

As more and more facilities are accurately scored, the use of the GoNM program increases. We can look for trends. Which owners have the most leaks? Does one piece of equipment leak more than others? Are some release-detection methods more accurate than others? Similarly, the program can be used to minimize releases and allow the Bureau to be proactive in preventing releases at high-risk sites, rather than reactive once a release occurs. The facility scoring can provide a more rigorous inspection schedule that targets high-risk facilities in an objective manner.

In times of shrinking budgets and staff, the GoNM program can also allow the Bureau to efficiently utilize its resources, providing a basis for more effective inspection scheduling and identifying remediation technologies that are most effective at particular facilities or certain physical surroundings.

As pressure mounts to examine and address environmental justice concerns, the GoNM program will allow us to determine if fuel releases and high-risk facilities prevail more frequently in lower income communities or communities dealing with environmental justice issues. GoNM provides a good tool to document compliance with environmental justice principles to ensure that all areas and populations are treated equally based on a risk calculation.

The possibilities for the GoNM program are enormous, and we look forward to continuing its development. The Bureau thanks USEPA Region 6 for its support and funding for this program, and looks forward to sharing our experiences with the GoNM program with other federal and state programs. ■

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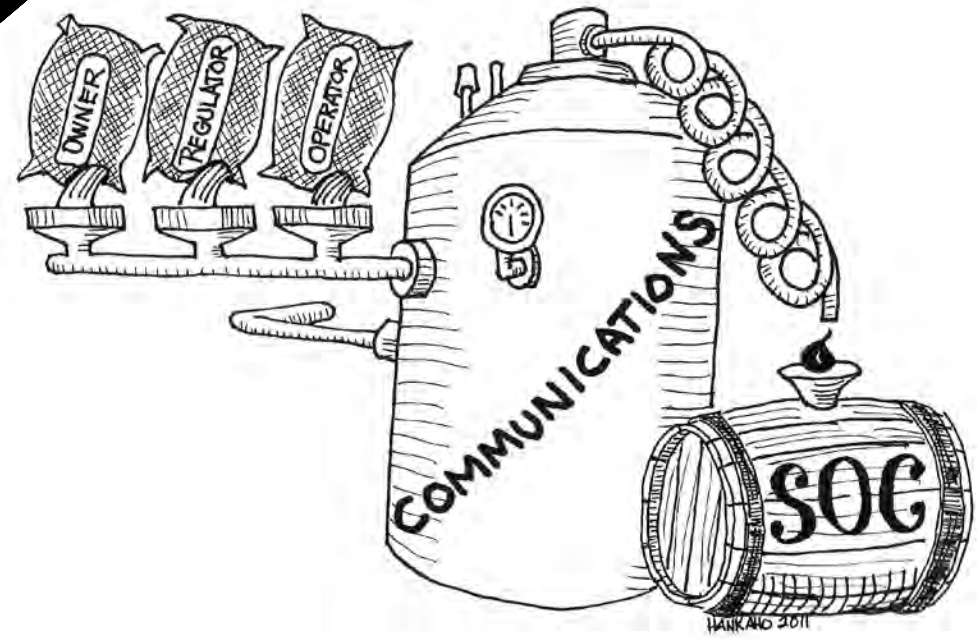
KENTUCKY

Distilling the Essence of SOC

by Leslie Harp



Kentucky is known for a lot of things—fast horses, cool Corvettes, smooth bourbon, Southern hospitality—but significant operational compliance (SOC) at UST facilities is not listed among them. The good news is that after streamlining internal processes and implementing new strategies for compliance assistance, Kentucky's SOC rates have increased, in some cases as much as 20 percent in a single year.

SOC is essentially a snapshot in time to help determine whether an UST facility is in compliance at the time of inspection. In 2003, SOC became the measure employed by USEPA as a general assessment of UST facility significant operational compliance. At that time Kentucky's SOC rates hovered around the 40 percent mark. The Compliance Section of Kentucky's Underground Storage Tank Branch was tasked with finding ways to effectively improve SOC rates. Three key factors were identified for improvement: data integrity, consistency of inspections, and compliance assistance.

Data Integrity

In 2005, Kentucky implemented a department-wide database called Tools for Environmental Management and Protection Organizations (TEMPO). After implementing the database, inspectors and compliance reviewers noticed that it had incorrect information regarding UST-facility equipment. In order to begin any sort of compliance-assistance process, we had to resolve these data integrity issues.

We started by taking the inspectors out of the field for approximately three months to assist with database "cleanup." Although we knew this move could delay our UST inspection cycle, it was decided that the benefits would outweigh this setback.

At the end of the data review, the inspectors learned a great deal about data integrity and why that level of integrity was difficult to maintain without the active participation of field inspectors. As an added benefit, inspectors found a new appreciation for the work of the technical compliance staff that input and maintain the data. After all was said and done, Kentucky still met its statewide three-year UST inspection deadline through the cooperative efforts of the regional offices.

Consistency of Inspections

In order to improve the consistency of facility inspections, we ramped up our inspector training. Thorough training in inspection methods ensured that field inspectors were equipped to evaluate system components. By updating our standard operating procedures, we offer new inspectors the ability to perform inspections with the same consistency as veteran inspectors, all the while ensuring that our violations are being issued using consistent criteria across the state. Consistent inspections and data entry have allowed for effective reporting to better identify problem areas within the SOC criteria.

Compliance Assistance

After addressing the first two areas for improvement, it was time to implement the third and most complex part of our plan: compliance assistance. In Kentucky, three groups are involved in achieving and recording compliance: the owner/operator, the inspector, and the technical compliance reviewer. Each group had a unique set of issues that needed to be addressed under the plan.

- **Owner/operator**

  One of the issues we faced was the fact that a significant number of UST owners and operators were overwhelmed by the array of technical compliance requirements and often lost track of what was required. The key to improving compliance centered on the education of owners and operators as to the site-specific requirements they must meet. Rather than present them with broad information on all of the various types of UST systems, we wanted to focus our efforts on the site-specific UST system requirements for their UST facility. This effort was designed as a precursor to the technical-compliance inspection, so the owner and operator would know what was expected and be prepared when the inspector showed up.

- **Inspector**

  During inspector training, we noted that inspectors spent a large amount of time chasing down paper violations rather than finding and stopping leaks. New standards of practice were developed that placed an emphasis on the technical inspection aspects of their role.

- **Technical compliance reviewer**

  Back in the office, our technical reviewers were not only going over paperwork associated with the initial field inspection, making corrections to the database, and making an SOC determination, they were also fielding phone calls from owners/operators and contractors with questions regarding site-specific testing dates and requirements.

It Comes Down to Communication

After analyzing these three factors, we realized that we needed to establish a clear, focused, and efficient communication process. So we dramatically streamlined that process for all three groups of people by providing owners/operators with notifications regarding when testing is due. These programmatic changes required restructuring our review process to include an outreach component that would not only help owners remain in compliance, but also decrease the amount of time inspectors were required to spend on each site.

We now provide owners/operators with an annual reminder letter that lists which tests are required and the dates those tests are (or were) due. We also take this opportunity to request information for any data gaps in our files (e.g., tank and piping materials, types of leak detection used). This, in turn, has increased the number of calls from owners/operators and opened the door to increased communication between the regulators and the regulated community.

By sending out the reminder letters, our inspectors often already have their paperwork without having to request it, thus reducing the amount of time they spend chasing down various items. The reminder letters go out. The owners/operators have any tests done that are due for their system and submit them to us via mail, fax, or email. The compliance reviewers receive the test information and put the dates the tests were performed and the results into TEMPO. When the UST Inspectors go into the database to prepare for an inspection, they can easily determine whether the testing is current or whether they need to request that information.

To ease the burden of reporting, we designated a new email address that is specifically used for receiving the electronic submission of testing results. Electronic submittal has proven to increase the ease of submittal as well as provide a timely response to deficiencies noted within the reports. This simple step has also significantly increased communication among staff, contractors, and owners/operators.

The Kentucky UST Branch is also beginning its third year of publishing the *UST Quarterly*, a newsletter that offers timely information to the regulated community on a wide array of information, including technical compliance. This, in conjunction with enhanced information on the branch webpage, offers owners and operators additional assistance in maintaining compliance.

Hey, Not Bad!

The results of implementing all three components of our plan to increase SOC have been very positive! In only one year, SOC rates have increased by nearly 20 percent in some areas; Kentucky's overall SOC rate has increased by 13 percent. Several owners and operators have called to compliment the new process and say how helpful the changes have been.

By demonstrating to the regulated community that we are trying to be more a helping hand than a hammer, we hope to see improved two-way communication and a decrease in violations. While we are busy implementing many more requirements in accordance with the Energy Policy Act of 2005, our regulated community seems to see that our helping hand has arrived at a perfect time. In turn, these changes are making our new inspection requirements easier to achieve. ■

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Compliance Assistance Is a Big Priority in Oneida Country

by Victoria Flowers

The Oneida Tribe of Indians of Wisconsin Compliance Assistance Program continues to contribute to the development of tribal capacity to track, record, and report on federally regulated underground storage tanks (USTs) within the Oneida Reservation. As a result, 100 percent of facilities on the Oneida Reservation have been inspected by Region 5 USEPA and are in significant operational compliance (SOC). The Tribe's Compliance Assistance Inspector, Shawn Suri has received federal UST inspector credentials, as well as State of Wisconsin credentials as an installation inspector and UST inspector.

The Oneida Tribe of Indians of Wisconsin is a member of the Six Nations or Haudenosaunee (People of the Longhouse), indigenous to New York State, who started to come to Wisconsin in 1822. On February 3, 1838, the 65,400-acre Oneida Indian Reservation (the Reservation) was established pursuant to the Oneida Treaty of 1838 and is located in northeastern Wisconsin. The primary land use is agriculture, followed by residential and forest. There are 233 miles of rivers, creeks, and streams, 78 lakes and ponds covering approximately 112 acres, and about 1,450 acres of wetlands. The land is "home" to 16,622 enrolled Tribal members; 4,225 of those members live on the Oneida Reservation; 2,854 members live in adjacent Brown and Outagamie Counties and have access to Tribal services and amenities of the Reservation. The remaining members live outside the northeastern Wisconsin area.

Five municipalities and two counties are present within the Reservation boundaries. The federal government retains primacy for environmental regulation within the Reservation. However, federally delegated programs (to the state), nontribal ownership of land, and local zoning authorities create a complex mix of tribal, local, state, and federal authorities. In response to this challenge, Oneida's Compliance Assistance Program (OCAP) has developed working relationships with nontribal business partners and the State of Wisconsin's Underground Storage Tank Inspectors that establish the OCAP as a resource for ensuring compliance with 40CFR280.

OCAP has provided resources to stations and other federally regulated facilities to assist them in achieving SOC at their facilities. The resources include a *Compliance Assistance Handbook* (see page 24), bimonthly newsletters to federally regulated facilities, and petroleum spill kits. The materials and the capacity developed under this program are available to other Wisconsin tribes if requested. So far, one Wisconsin tribe has requested assistance for a tank system installation. Additionally, Shawn Suri has been asked by the states of Wisconsin and Maine and off-reservation nontribal facilities to use the OCAP materials for their programs and/or stations.

Annual Tribal Meeting attendees at compliance assistance field trip.

On May 3–5, 2011 the Annual Tribal/USEPA National UST meeting was hosted by Oneida and attended by representatives from 32 tribal nations, USEPA regional and headquarters staff, NEIWPCC, and the State of Wisconsin. The meeting featured an opening thanksgiving prayer and welcome address by Oneida Councilman Tehassi Hill, presenting of colors by the Oneida Veterans group, and a welcome by the Oneida Nation Dancers. During the meeting, OCAP and State of Wisconsin representatives gave a presentation on how the OCAP and state UST programs have identified common goals for ensuring improvement of SOC rates. They also discussed how the OCAP has increased its capacity by taking advantage of state training and receiving state credentials that demonstrate the proficiency of the tribal compliance inspector.

The capstone of the meeting was the field visit to a tribal retail facility to conduct a practice compliance assistance visit. During this visit the group heard from Oneida Retail about the proactive measures they institute as a part of good business practices to improve the bottom line. Practices they highlighted included making sure location managers (Class B operators) had a good understanding of their tank systems and that Oneida Retail management (Class A operators) communicated best practices and the effect on the "bottom line" to Class B operators. ■

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The Frontline in the Leak Detection Battle

Testing Automatic Line-Leak Detectors

by Kevin Henderson

After more than 20 years of battling leaks from underground storage tank (UST) systems, it is apparent that, with some notable victories here and there, the battle lingers on. Despite the myriad regulations that require all kinds of monitoring, maintenance, and testing, leaks continue to vex our efforts. Therefore, our ability to quickly and effectively detect leaks is of mission-critical importance. The frontline of defense and probably the most important weapon we have in our struggle to quickly detect leaks in pressurized piping systems is the automatic line-leak detector (ALLD). Therefore, it is manifest that our attention be directed at ensuring that these soldiers serve as an effective fighting force. How do we accomplish this? 1) Ensure that these devices are tested so that they perform as intended and 2) train personnel to evaluate whether or not the testing has been conducted properly. This attentiveness is fundamental to our battle plan. Even though line-leak detectors have been around for more than 50 years, the operation, maintenance, and testing of these devices is still poorly understood.

Mission Briefing — The Need to Answer the Eternal Questions

ALLDs are relatively simple mechanical (and in more recent years electronic) pressure-sensing devices that test piping systems for relatively large ("catastrophic") leaks. When functioning correctly, leak detectors are capable of detecting catastrophic leaks equal to or greater than 3 gallons per hour (gph) at a line pressure of 10 pounds per square inch (psi). As this article will focus on the testing of mechanical ALLDs, a brief summary of how they work is needed, as well as an articulation of the ALLD eternal questions. (For a more detailed discussion see "Of Blabbermouths and Tattletales – The Life and Times of Automatic Line Leak Detectors" in *LUSTLine* #29.)

In normal operation, if the line pressure falls to near zero the mechanical leak detector will "trip" or close, enabling a test of the piping to be conducted the next time the pump is activated. When the pump is turned on, the leak detector moves into the leak-sensing position, and a metered volume of product is allowed to enter the line at a certain pressure. If the leak detector is not able to pressurize the line above the metering pressure, it will remain in the leak search position.

If the leak detector remains in this search position and is unable to fully open, this is an indication that a leak equal to or greater than 3 gph at 10 psi may exist. Under this condition, someone attempting to dispense product will face the familiar "slow flow" that we have all experienced at the corner gas station. The annual "functionality" test of a leak detector is simply confirming that the device stays in the leak search position while a simulated leak equivalent to 3 gph at 10 psi is intentionally introduced in the piping system.

So I ask: With our extensive training requirements, why is it that most people still do not really understand how leak detectors work? Why, with all our certification requirements, do we still have many people testing these devices in a manner that is simply wrong? In some cases, this "testing" is so grossly wrong that it possibly does more harm than good. Why is the correct procedure for testing leak detectors so poorly understood? Why does the test procedure vary so much, depending on who is conducting the test? Why do we allow testing practices of dubious validity to go virtually unchallenged? Why don't we do something about it? Why? Why? Why? How about some answers?

Basic Training — The UST Rules and Regulations

According to the federal rule (40 CFR 280.44(a)) ALLDs must be able to detect leaks of 3 gph at 10 psi line pressure within one hour with at least a 95 percent probability of detection and no more than 5 percent probability of false alarm. The rule also requires that leak detectors be tested annually in accordance with the manufacturer's requirements.

Since it is left up to the manufacturer, there is no consistency in determining how the testing must be conducted. Somehow, we have even wound up with third-party manufacturers of testing equipment, who have their own protocols for how the testing is done. This has led to a mishmash of convoluted test procedures from various manufacturers and third parties.

To further obfuscate things, although the rule dictates that the leak detector must be capable of detecting a 3-gph leak at a line pressure of 10 psi, many years ago USEPA issued an interpretation that the annual test does not have to actually determine whether or not the leak detector is capable of seeing such a leak. The test that is required is referred to as a "functionality" check. The size of the leak that must be simulated during the test is not specified. As long as the leak detector "sees" the leak (irrespective of how large that leak may be) it is declared to be functioning.

This is akin to having a military specification for an automatic rifle that says it must have an accuracy of plus or minus one inch at 100 yards when new, but once the gun has been taken out of the box, it doesn't matter whether you can hit the broad side of a barn. As long as it still shoots, it is considered to be "functioning" properly. Is this a good idea? Would you consider the analogous scenario we have with ALLDs to be a good idea? While some manufacturers have rejected this and require that the leak detector be able to see a leak equivalent to 3 gph at 10 psi, there are others that are still fine with hitting the broad side of a barn.

Theatre of War — Historical Background

Where did the regulatory standard of 3 gph at 10 psi come from? In the

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■ **Testing ALLDs** *from page 7*

mid-1980s, when the federal rules were being developed, the industry standard mechanical line-leak detector operated (looked for a leak) at a metering pressure of 10 psi. After some debate, it was decided that the devices available at the time were capable of detecting leaks of 3 gph. Since the devices of the day metered at a pressure of 10 psi, the leak detection threshold of 3 gph was related to 10 psi. Today, it is not uncommon for leak detectors to operate at metering pressures other than 10 psi.

Logic would seem to dictate that all leak detectors should be able to detect leaks of 3 gph regardless of the pressure at which they operate. However, this is not the case. The actual leak rate is allowed to vary with the metering pressure. As illustrated in Table 1, if a leak detector meters at greater than 10 psi, the leak rate that occurs is correspondingly higher. Out of this confusion, the leak detector is said to be able to detect a leak that is equivalent to 3 gph at 10 psi.

Surely it is time we demanded more of our ALLDs. Surely after all these years, we should be able to agree that a leak detector must be able to detect a leak that is equivalent to 3 gph at 10 psi, no matter how long it has been in service. Surely we should be able to agree on how the testing of these devices is to be conducted. Surely we should expect that the people conducting these tests know what they are doing. Surely we should expect the people that review these test records (i.e., regulators) are scrutinizing them to ensure the test has been done properly. Perhaps a formal battle plan would be more emphatic.

Pressure (pounds/ inch^2)	Leak Rate (milliliters/ minute)	Leak Rate (gallons/ hour)
10	189	3.0
11	198	3.1
12	207	3.3
13	216	3.4
14	224	3.5
15	232	3.7
16	239	3.8
17	247	3.9
18	254	4.0
19	261	4.1
20	268	4.2
21	274	4.3
22	281	4.5
23	287	4.6
24	293	4.7
25	299	4.7
26	305	4.8
27	311	4.9
28	317	5.0

TABLE 1. *Variation of leak rate with pressure change through an orifice calibrated to allow 3 gph @ 10 psi.*

■ ALLD BATTLE PLAN ■

1. **Develop standardized test procedure.**
2. **Develop standardized test form.**
3. **Educate regulators and contractors.**
4. **Critically evaluate test results.**
5. **Demand testing be done correctly.**
6. **Deploy ALLDs that can quickly find leaks as they are intended.**

Tour of Duty — Leak Speak

Just like everything else, there is specialized jargon associated with leak detector testing. In order for us to begin to understand the issues and strategize an effective battle plan for standardizing a test protocol and documenting the test data, we must first have a firm comprehension of leak speak:

- **Full pump pressure (a.k.a. operating pressure or pump pressure).** The maximum line pressure that the submersible pump is capable of producing, measured while the pump is operating but not dispensing. Typically, the pump pressure is between 22 and 40 psi, although this can vary depending on the type of pump and the operational conditions. We need to know what the pump pressure is so that when the test is conducted, we are able to recognize whether or not the leak detector has fully opened.
- **Holding pressure (a.k.a. check-valve seating pressure, seating pressure, functional-element seating pressure, or static line pressure).** The pressure at which the line will decay immediately after the pump motor is turned off. The holding pressure is determined by the type of check valve and/or functional element (a check valve that incorporates a pressure-relief mechanism) that is installed in the submersible pump. The holding pressure must be determined in order to confirm that the check valve and/or functional element are working correctly. In addition, in systems that are designed to allow the line pressure to decay to some predetermined pressure (i.e., the holding pressure is less than the full pump pressure), this data can be used to confirm that the pump motor is properly cycling on/off during normal conditions. Note that if the holding pressure is the same as the full pump pressure, the person conducting the leak detector test must manually confirm that the pump motor properly cycles on/off.
- **Resiliency (a.k.a. bleedback).** A measure of the elasticity of the pipe determined by measuring the volume of fluid that returns when the line pressure is allowed to decay from the holding pressure to zero. If it is a very rigid pipe, the bleedback will be low (on the order to 50–100 mL). If the piping is flexible and relatively long, the bleedback will be much greater (on the order of 300–500 mL). If the amount of bleedback is greater than what would be expected given the length and material of construction of the piping, this generally means that there is an air pocket trapped in the line.
- **Metering Pressure (a.k.a. leak-sensing pressure).** The pressure at which the leak detector operates while searching for a leak. The metering pressure is typically 10–15 psi, although it can vary considerably depending on the model of leak detector. We need to determine what the metering pressure is in order to know that the leak detector is in the leak-sensing position. In addition, it is important to understand that the metering pressure determines what the actual leak rate is when the

leak detector test is conducted. This is because the leak orifice is calibrated to allow a flow rate of 3 gph at 10 psi. If the metering pressure is greater than 10 psi, the actual flow rate (leak rate) that is allowed during the test will be greater than 3 gph. Conversely, if the metering pressure happens to be less than 10 psi, the actual leak rate will be less than 3 gph. To determine the leak rate that corresponds to a given pressure, refer to Table 1.

- **Opening time (a.k.a. step-through time).** The length of time it takes for the leak detector to conduct a test of the piping if there is no leak under normal operating conditions. Generally, it is considered to be the length of time it takes once metering pressure is achieved until full pump pressure is obtained. It is sometimes described as the length of time it takes from initially turning the pump on until full pressure is achieved. Typically, the opening time is 2–4 seconds, but can be substantially longer if the piping has high elasticity or trapped air pockets. Of special significance is the possibility that a long opening time may be an indication that a small leak (one less than 3 gph at 10 psi) is present in the line.
- **Leak-test pressure.** The actual line pressure observed when the leak detector test is being conducted with the leak detector in the leak-search position. The leak-test pressure should be approximately the same as the metering pressure. It is important to document the pressure observed while the leak detector test is being conducted as confirmation that the leak detector is in the leak-search position. If it is significantly different, it normally means the leak detector is not in the proper leak-search position and the test is invalid.
- **Leak-test volume.** The actual volume of product that passes through the simulated leak orifice during the timed interval of the test and normally measured in milliliters. The leak-test volume should be equal to the leak rate expressed in milliliters per minute, indicated for the corresponding leak-test pressure in Table 1. If the volume is significantly different, this indicates that the leak-test-apparatus orifice is not properly calibrated.
- **Test leak rate.** The actual leak rate that occurs during the leak detector test. It is important to note that this will vary, depending on the metering pressure of the leak detector. For example, if a leak detector meters at exactly 10 psi, the leak rate that will occur with a properly calibrated orifice would be exactly 3 gph. If the metering pressure is 15 psi, the leak rate through this same calibrated orifice would be 3.7 gph. The metering pressure determines the leak rate that the leak detector "looks at" when the test is conducted.

If the testing and/or documentation are sloppy, then it is usually because the regulator accepts this as adequate. As regulators, we must scrutinize these testing records to ensure the test was done properly.

- **Leak-search position (a.k.a. tripped, closed position, or relaxed position).** When the line pressure drops to some predetermined pressure (generally 1–5 psi, depending on the model of mechanical leak detector), the leak detector closes (or trips) and moves into a position that enables the device to conduct a test of the piping when the pump is activated and the line is repressurized. It is important that the test be conducted with the leak detector installed in the pumping system and under normal operating conditions. This is because we must ensure that there is not excessive static head pressure in the piping system. If there is too much static head pressure, the leak detector will not trip and will never conduct a test. The commonly accepted rule of thumb is that in a gasoline system, an elevation change of 38 inches between the height of the leak detector and the highest dispenser will produce a static head pressure of one psi. Since we know that some leak detectors will not trip unless the line pressure decays to a certain pressure, the test must confirm that the leak detector will trip under normal static operating conditions.

The Salient Front — Adjusting the Orifice

When a leak detector is tested, a leak is created in the piping system through an orifice. The orifice is sized to allow a leak of 3 gph at a line pressure of 10 psi. Proper sizing of the leak orifice is of paramount importance when testing leak detectors. The leak orifice must be adjusted or calibrated each time the test is conducted. The most common method is to adjust the line pressure to be equal to 10 psi and then adjust the size of the orifice until the desired leak rate of 3 gph (189 milliliters per minute) is achieved.

Why must the orifice that is used to simulate the leak be adjusted each time the test is conducted? This is not any more complicated than the basic principle that, since different fluids have different viscosities, they will have different flow (leak) rates through a given size orifice at a given pressure. Viscosity is a measure of the thickness of a fluid or its resistance to flow.

To put it in an everyday example, think about the flow rate of honey versus water. It is not hard to see that the flow rate of honey through a small opening (orifice) will be very different than the flow rate of water through this same opening. Although not nearly as pronounced, the same principle applies to product flow rates in a typical UST piping system. The flow rate of diesel fuel, for example, will be different than the flow rate of gasoline if they are pumped through the same orifice at the same pressure.

Differing fuel viscosities is the reason there are different leak detectors for gasoline and diesel fuel. Have you ever wondered why it is said to be acceptable (from an operational perspective) to install

■ continued on page 10

■ **Testing ALLDs** *from page 9*

a gasoline leak detector in a diesel system, but not vice versa? Since the viscosity of diesel fuel is greater than the viscosity of gasoline, the size of the metering orifice in a diesel leak detector must be larger than the metering orifice in a gasoline leak detector in order to achieve the same flow at the same pressure.

Thus, if you install a diesel leak detector in a gasoline system, you are actually allowing more than 3 gph to be metered into the piping when the leak detector is conducting a test. If you are allowing more than 3 gph to be metered into the piping, the leak you are able to see is correspondingly greater than 3 gph. It is okay to install a gasoline leak detector in a diesel system since the smaller metering orifice of the gasoline leak detector actually allows less than 3gph to be metered into the piping, and the leak that can be seen by the leak detector is less than the required 3 gph.

Temperature also affects viscosity and is another reason why the leak orifice must be adjusted in order to conduct an accurate test. Diesel fuel that is at 50 degrees will have a substantially different flow rate from that same diesel fuel at 90 degrees.

Biofuels complicate things even further. Ethanol-blended fuels have a lower viscosity than 100 percent gasoline. Biodiesel has a considerably higher viscosity than 100 percent diesel. Finally, since all fuels in the market are fungible, even if you are testing the same grade of product (e.g., E10 gasoline) at the same temperature but at two different facilities, it is entirely possible that the fuel viscosity will vary enough between the two facilities to cause a measurable difference in the flow rate through an identically sized orifice.

Night Vision Goggles — Types of Testing Equipment

Because different fuels under different conditions have different flow characteristics, testing equipment using fixed orifices that cannot be adjusted to compensate for these different flow characteristics, in my opinion, should not be allowed. In addition to fixed-orifice testing devices, some kinds of testing equipment make use of flow meters. Flow meters allow the operator to determine the flow rate through the leak orifice without having to measure the volume of fluid over a time interval. This makes the process of calibrating the leak orifice much easier and quicker. However, because flow meters are calibrated with a specific product that has specific flow characteristics, if you change the fuel, you are potentially changing the flow.

If, for example, you attempt to measure the flow of E85 gasoline with a flow meter that was calibrated utilizing standardized diesel fuel, that flow meter will likely not accurately measure the flow rate because the flow characteristics are markedly different between these two fuels. Thus, devices with flow meters have limitations similar to those of fixed orifice devices—the inability to compensate for the differing flow characteristics of differing fuels.

From this discussion, it should be apparent that the leak orifice must be adjusted and the flow rate measured manually (volume measured over a timed interval) each time a test is conducted. If this is not done, it is not possible to say with certainty that the leak orifice has been properly calibrated to the regulatory standard of 3 gph at 10 psi.

Final Assault — Conducting the Test

Once the size of the leak orifice is determined, the test is conducted without any regulation of line pressure by the test apparatus. The actual pressure that is applied to the orifice during the test is dependent upon the metering pressure of the leak detector. Thus, if a leak detector meters at exactly 10 psi, the resultant leak rate will be exactly 3 gph. However, if for example, the leak detector operates at 15 psi, the resultant leak rate will be 3.7 gph. Thus, the leak detector test does not necessarily confirm that the leak detector is capable of seeing a 3-gph leak. Instead, we say that the leak detector is capable of seeing a leak that is equivalent to 3 gph at 10 psi. What we are really saying is that the leak detector is capable of seeing a hole (breech of integrity) in the piping that would allow a leak of 3 gph to occur if the line pressure was 10 psi.

A detailed, step-by-step procedure for testing leak detectors is beyond the scope of this discussion; however, Table 2 provides a simplified version. A detailed testing procedure for both mechanical and electronic leak detectors and a comprehensive form may be accessed at the Mississippi Department of Environmental Quality website (*www.deq.state.ms.us/MDEQ.nsf/page/UST_Publications?OpenDocument*).

1	**Determine operating parameters**	
	a	Confirm pump cycles on/off
	b	Determine full pump pressure
	c	Determine holding pressure
	d	Confirm leak detector trips
	e	Determine metering pressure
	f	Determine opening time
	g	Determine resiliency
2	**Calibrate orifice to simulate a leak equivalent to 3 gph @ 10 psi**	
3	**Conduct test**	
	a	Cause leak detector to trip by bleeding line pressure to zero
	b	Turn pump on allowing simulated leak of 3 gph @ 10 psi to occur
	c	Monitor line pressure with pump running and simulated leak occurring
4	**Determine test result**	
	a	Pass – Line pressure does not rise above metering pressure during the test
	b	Fail – Line pressure increases to full pump pressure during the test

TABLE 2. *Simplified mechanical line-leak-detector test.*

In addition, the Petroleum Equipment Institute (PEI) is developing a recommended practice that should, among other things, provide a comprehensive line-leak-detector test procedure and standardized forms for recording test data. The PEI recommended practice will finally provide an industry standard by which leak detector testing should be conducted. It is expected to be published in early 2012.

Debriefing — New Marching Orders

In today's economic climate, we must get the biggest bang for our testing dollars. Even after more than 20 years of regulating UST systems, it is still painfully obvious that much of the leak detector testing that we spend good money on is not accomplishing what it could. Another crucial component of the equation is that regulators are accustomed to simply looking at someone's testing records, checking the date, and ensuring the test result was "pass." But if we are to move forward, we must get past this frame of mind.

In my experience, the quality of UST system testing and the documentation of such testing are directly related to what the authority having jurisdiction (i.e., the regulator) accepts. If the testing and/or documentation are sloppy, then it is usually because the regulator accepts this as adequate. As regulators, we must scrutinize these testing records to ensure the test was done properly.

If you don't think it's your job as a regulator to make sure leak detectors are tested properly, consider the recent Deepwater Horizon oil spill in the Gulf of Mexico. Okay, that event was certainly not comparable in scope or size to our leak scenarios, but look at what happened in the wake of that disaster. While many fingers were pointed, laying potential blame at many different parties, one of those fingers was pointed directly at the federal Minerals Management Service (MMS) charged with regulating offshore drilling operations.

Much of the post-blowout investigation centered on the possibility that certain "functionality" testing of various pieces of equipment on the rig (notably the blowout preventer) was not conducted properly. In the investigation that followed, the regulators at MMS were faulted for possibly not providing adequate government oversight relative to, among other things, the required "functionality" testing of the blowout preventer.

Going back to UST systems, as we know all too well from experience, leaks from pressurized piping systems that go undetected for extended periods can have serious consequences. In the struggle to quickly detect leaks from UST systems, we have our own mini version of blowout preventers—automatic line leak detectors. Still don't think it's your job? Think again. ■

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Observations on Annual Maintenance of ATG Systems

by Chris Prokop

The Code of Federal Regulations (CFR) provides the governing statement regarding the maintenance of release detection equipment for UST systems at 40 CFR § 280.40(a)(2). This section states that release detection equipment must be "installed, calibrated, operated and maintained in accordance with the manufacturer's instructions." Over the years, this statement has led to some ambiguity for federal, state, and local regulatory entities regarding what constitutes proper maintenance of release detection equipment. For example, some state and local regulatory entities require annual maintenance of automatic tank gauge (ATG) systems, whereas other regulatory entities do not require this maintenance. This article focuses on the maintenance of ATG systems.

Industry Standards for Maintaining ATG Systems

During my eight years of conducting UST inspections, the majority of the ATG systems that I have observed were manufactured by Veeder-Root, or an affiliated company (e.g., Gilbarco). While many other ATG brands are in use nationally (e.g., Incon, OPW, EBW, Petro Vend, Ronan), I will focus my discussion on Veeder-Root due to their market share and good maintenance documentation.

Section 31 of Veeder-Root's *Operator's Manual* (Manual No. 576013-610, Revision Y) contains a Periodic Maintenance Checklist, which addresses recommended frequencies of maintenance, as well as the maintenance procedures, for the ATG console, magnetostrictive probes, line-leak detectors, magnetostrictive sump sensors, and other sensors.

Page 9 of Veeder-Root's *Operability Testing Guide* (Manual No. 577013-814, Revision E) discusses Veeder-Root's recommended procedures for "Verifying Operability of UST Leak Detection Equipment." Both the *Operator's Manual* and the *Operability Testing Guide* state that conducting regular maintenance of Veeder-Root's leak detection equipment associated with ATGs may extend the life of that equipment but is not required for proper operation (see *www.veeder.com/page/Monitoring-Consoles*).

Veeder-Root's rationale for this statement is that the components of the leak detection equipment connected to ATGs are self-diagnosing (i.e., alarms will be indicated on the ATG console if malfunctions occur). The takeaway message is that Veeder-Root (and probably most other ATG manufacturers) recommends annual maintenance of their ATG systems, but they do not require it. However, most states and local regulatory entities within Region 9 require some form of annual ATG maintenance, as well as some type of standard maintenance checklist.

However...

When I first began conducting UST inspections several years ago, I rarely saw documentation demonstrating maintenance of ATG systems. When I did see such documentation, it was often presented in an irregular format, or it only addressed very basic operations of the ATG systems (e.g., ATG power on, audible alarm operational). As I learned more through experience and training, I began requesting that proper annual maintenance of ATG systems be conducted and documented. As a consequence, I began to see better written examples of annual ATG maintenance that included detailed checklists, supported by some or all of the following ATG printouts documenting:

- Fuel/water alarms simulated by manipulating containment sump sensors (e.g., turning the sensors upside down or placing them in water)
- Alarms for probe out, high water, low product, and overfill simulated by removing the in-tank probes and manipulating the floats,

■ *continued on page 12*

■ Annual Maintenance of ATGs

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- UST annular space alarms simulated by removing the sensors from annular spaces (where possible) and immersing the sensors in fuel/water.

During my UST inspections, I also review and print the alarm histories for all sensors in order to independently verify that the ATG was "calibrated" on the date shown on the ATG system checklist. The manner in which annual maintenance of ATG systems is conducted depends on the role the ATG plays in leak detection. By this I mean that different components of the ATG system need to be evaluated depending on whether:

- UST leak detection is conducted by volumetric leak testing or annular space monitoring
- Piping leak detection is conducted by containment sump sensors (for double-walled piping) or annual tightness tests
- Another leak detection method is being used, such as Statistical Inventory Reconciliation (SIR) using inventory data from the ATG.

In addition to printing leak-test and sensor-alarm histories from ATGs, I request that maintenance technicians evaluate the appropriateness of the "setup" parameters for the ATG. At one site, the maintenance technician indicated to me that the overfill alarm on the ATG had been set too low, and he adjusted it.

I also request that maintenance technicians compare the fuel volumes from the in-tank probes to the fuel volumes from stick readings. Visual inspections of all containment sumps are another important component of the annual maintenance of ATG systems because they allow electrical wiring to be checked for any evidence of deterioration.

California's Form for Documenting UST/ATG System Annual Maintenance

The State of California requires that owners and operators of UST systems conduct annual maintenance of those systems, and that this maintenance be documented on its "Monitoring System Certification" form (see *www.waterboards.ca.gov/water_issues/programs/ust/forms/index.shtml*). This form contains a thorough UST facility equipment section, good checklists for "Testing/Servicing," "In-Tank Gauging/SIR Equipment," and "Line-Leak Detectors." It also includes a page for diagramming the UST facility and an UST technician "Certification" section for attesting that all work was conducted in accordance with the manufacturers' specifications. Although under the jurisdiction of USEPA, many tribal UST facilities in the state are requiring that their service technicians conduct California-equivalent annual UST system maintenance, which is documented by this Monitoring System Certification form and supporting records.

And So...

Although ATG manufacturers recommend but do not require annual maintenance of their ATGs, I strongly believe that annual maintenance is an important means for ensuring the integrity of these systems. In addition, owners and operators of UST facilities should document this annual maintenance with detailed checklists supported by printouts from the ATG and related records. ■

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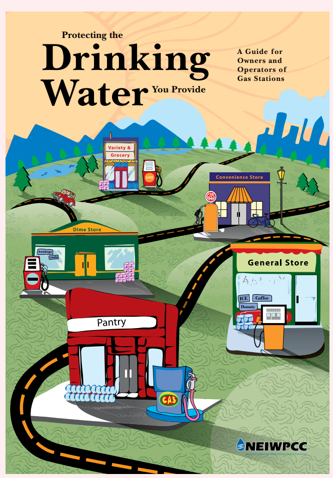
Help UST Owners and Operators Protect Their Drinking Water



Drinking water and gasoline should never mix. That's why it is especially important that gasoline facility owners and operators make sure that any onsite well is protected. The New England Interstate Water Pollution Control Commission's (NEIWPCC) publication, *Protecting the Drinking Water You Provide: A Guide for Owners and Operators of Gas Stations*, is a great resource to help tank owners and operators with onsite wells understand their responsibilities in meeting drinking water regulations and protecting the health of those who drink the water or otherwise come into contact with it.

This colorful booklet can be distributed electronically or as printed copies (instructions for printing are located on the NEIWPCC website). Also, for those who want to train others through a presentation, NEIWPCC provides PowerPoint slides that highlight the major themes of the guide. The guide and PowerPoint presentation can be found at *www.neiwpcc.org/tncguide.asp.*

USEPA Seeks $233,000 in Penalties for UST Violations in New York

USEPA has issued a complaint to the owners and operators of several upstate New York gasoline stations for violating federal regulations governing 17 USTs. The complaint, which seeks $233,000 in penalties, was issued to one individual and three companies that owned or operated gasoline stations in four towns. The complaint alleged that the various owners and/or operators failed to:

- Test cathodic protection systems in three USTs
- Perform automatic line-leak detector tests in 16 USTs
- Provide adequate overfill-prevention equipment in three USTs
- Conduct annual leak tests—or monthly monitoring—for five pressurized underground lines
- Properly cap off and permanently close one UST
- Report, investigate, and confirm a suspected release at one facility
- Keep adequate records of release detection monitoring.

MINNESOTA

Where's the LNAPL?
How about Using LIF to Find It?

by Paul Stock

The Minnesota Pollution Control Agency (MPCA) Petroleum Remediation Program (PRP) routinely uses data from laser-induced fluorescence (LIF) probes to target petroleum light non-aqueous phase liquids (LNAPLs) when remediation is necessary. Given our experience in using LIF, PRP staff had gained a great deal of insight on LNAPL behavior and found themselves nodding their heads in agreement during the Interstate Technology Regulatory Council's (ITRC) internet-based training on LNAPL behavior when it first became available in March 2009.

A couple of months ago, several PRP technical staff were invited to attend a dry run of the ITRC's LNAPL Classroom Training in order to provide the ITRC's LNAPL Team with feedback. The LNAPL Team has developed a set of excellent classroom training modules that lay out the latest understanding of LNAPL behavior using a multiple lines of evidence approach—LNAPL science. if you will. This science is consistent with and provides a much deeper understanding of what PRP staff have observed about LNAPL behavior using LIF. The LNAPL Classroom Training also includes a process for selecting the appropriate remedial technology to address specific LNAPL concerns using an LNAPL science-based site conceptual model (SCM). You may have guessed by now that one of the first things one needs know is: where's the LNAPL?

The PRP has found that LIF data can reliably answer the question: where's the LNAPL? Moreover, LIF data can also help lead to answers for many other important questions about site-specific LNAPL behavior and its remediation. After more than a decade using LIF, we have concluded that its strategic application results in cost-effective use of limited resources. The word must be getting out. More frequently over the past couple of years, we have been contacted by regulators, consultants, contractors, and even some responsible parties from other states inquiring about the PRP's use of LIF. Recently, a regulator from another state invited PRP staff to train their staff on how to interpret LIF data. The following discussion has been designed to address some of these questions.

NOTE: I should explain that, as we became more aware of what LIF was telling us about the behavior of petroleum products released in the subsurface, we began to abandon the term "free product" in favor of LNAPL. We believe that LNAPL is more scientifically accurate and descriptive, and less prone to past and existing misconceptions about free product. However, I will occasionally use the term "free product" in the following discussion when historically appropriate.

What Is LIF?

Folks working the oil patch have long used ultraviolet light to induce fluorescence when examining drill cuttings for the presence of petroleum hydrocarbons. That basic principle can be applied to the down-hole environment. As a probing tool is advanced to depth, ultraviolet light is directed through a transparent window on to the immediately adjacent soil and whatever fluid occupies the soil pores. A sensor detects and records any florescent light returning through the window.

Essentially, the more petroleum present in the pores adjacent to the window, the stronger the recorded fluorescent response. Because different chemical compounds predictably fluoresce at varying wavelengths and decay times, even more information can be gleaned from further analyses of the light returning to the sensor. In addition, filters can be used to eliminate or reduce unwanted responses.

I am aware of two companies that design and produce commercially available field sensors using ultraviolet light to induce fluorescence of aromatic hydrocarbons for detecting petroleum LNAPLs in the subsurface: Vertek, a division of Applied Research Associates, Inc., out of Randolph, Vermont; and Dakota Technologies, Inc. (DTI), out of Fargo, North Dakota. Information on Vertek's and DTI's respective sensors can be found at *www.vertekcpt.com* and *www.dakotatechnologies.com.*

These sensors are designed to detect lighter and heavier petroleum-based fuels, oils (including crude and lubricants), and/or creosote and tar. The main output is in the form of a graph, typically called a log, of fluorescent response versus depth for each probing location. When a laser is used to generate the ultraviolet light, the technology is generically referred to as laser-induced fluorescence, or LIF for short. Figure 1 shows a sample LIF log.

The Ins and Outs of LIF

It is important to note that induced fluorescence data must be integrated with all available standard site data, including site history, present land use, geology, and soil and groundwater contamination, to develop an SCM using multiple lines of evidence. Moreover, considering typical geological heterogeneity and consequential LNAPL behavior, the benefits of viewing side-by-side LIF and geology data can hardly be overstated.

The induced fluorescent tools are typically deployed with Cone Penetrometer Testing (CPT) or Electrical Conductivity (EC) sensors. These sensors allow collection of side-by-side, high resolution, geologic data. CPT and EC often provide a more objective and complete data set than obtained from typically limited geologic descriptions of physical soil samples collected during routine site investigations.

LIF detects polycyclic aromatic hydrocarbon (PAH) molecules (e.g., naphthalene, perylene, anthracene) that fluoresce efficiently when present in an aliphatic solution like typical petroleum LNAPLs composed of gasoline, diesel, heating oil, kerosene, jet fuel, and so on. We have also used LIF to delineate heavier

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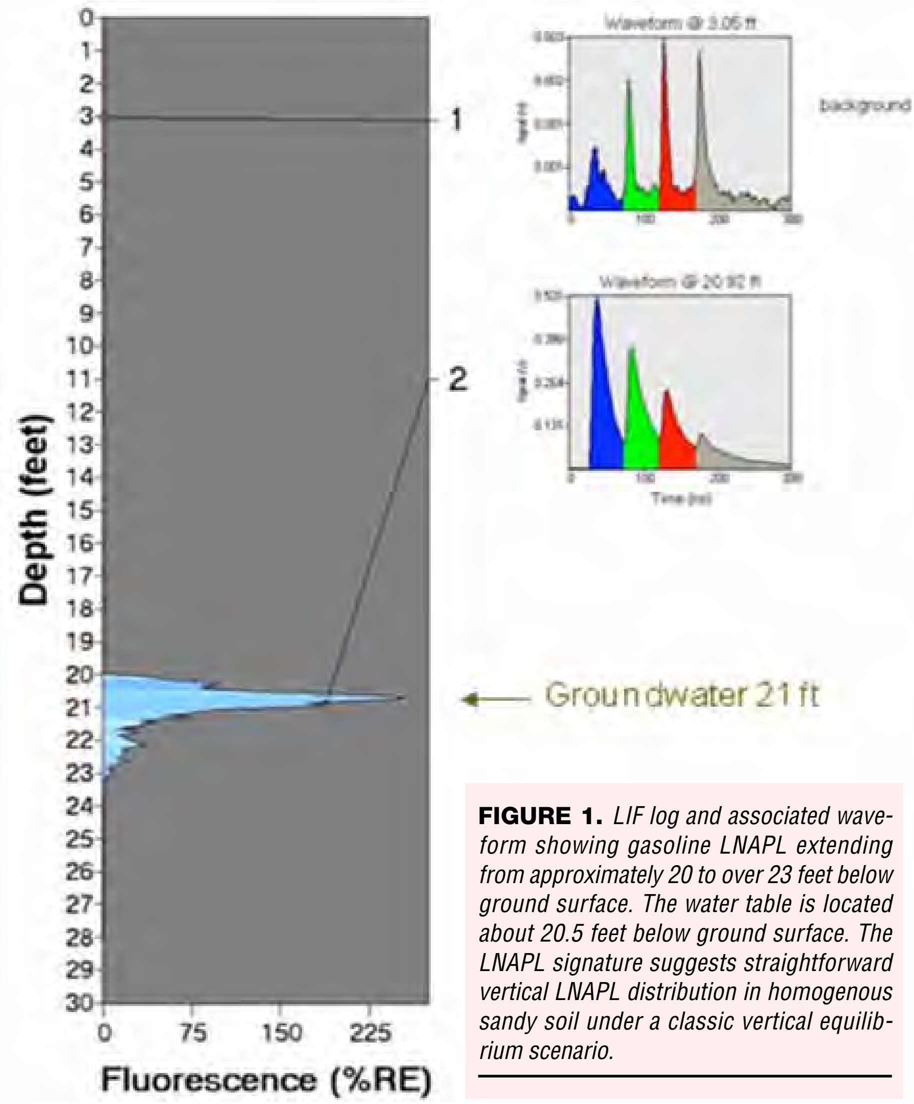

FIGURE 1. *LIF log and associated waveform showing gasoline LNAPL extending from approximately 20 to over 23 feet below ground surface. The water table is located about 20.5 feet below ground surface. The LNAPL signature suggests straightforward vertical LNAPL distribution in homogenous sandy soil under a classic vertical equilibrium scenario.*

■ **Using LIF** *from page 13*

petroleum products such as no. 6 fuel oil, motor oil, and hydraulic oil.

Monoaromatic compounds do not fluoresce efficiently, so LIF will not reliably detect LNAPLs composed of, for example, pure benzene or xylene. In addition, LIF does not detect individual contaminant molecules occurring in the other three physical phases of subsurface petroleum contamination commonly associated with an LNAPL—the aqueous, vapor, and adsorbed phases. In other words, LIF does not detect PAHs, BTEX, or other petroleum-related molecules dissolved in water, dissolved in soil gas, or adsorbed to soil solids because they do not fluoresce efficiently.

Although not responding to PAHs, we have also used LIF to successfully investigate a release of 100 percent soy biodiesel—that's when we found out that even banana skins will fluoresce. There are some other nonpetroleum compounds that fluoresce when stimulated by ultraviolet light (e.g., mineral calcite and many natural organic molecules, such as those found in peat and other carbonaceous sediments).

To discriminate between interfering fluorescence and fluorescence caused by LNAPL, LIF can display waveforms (Figure 1) from selected depths (e.g., call-outs) which, along with a multiple lines of evidence approach, are useful for eliminating these false positives. Moreover, the waveforms vary systematically among different petroleum products; thus they can be used forensically to differentiate situations such as side-by-side or overlapping gasoline and diesel LNAPL bodies. However, differential weathering and other phenomena can also result in differing waveforms from borings completed across a single LNAPL body. For this reason, forensic use of LIF should be done very cautiously with corroboration by multiple lines of evidence and logical consistency.

LIF has given us pause when considering a definition for the sometimes-confounding term "soil contamination." Conceptually, we have found it more straightforward and useful to determine in which of the four physical phases a detected organic contaminant molecule exists in the subsurface, rather than classifying it generically as soil contamination.

Because many organic contamination detection methods, such as headspace screening and laboratory analysis, are nonspecific with regard to contaminant phase, we have found that misconceptions about soil contamination can lead to confusion when developing an SCM and designing corrective action. LIF's ability to detect only the LNAPL is perhaps the single most important concept to understand when using LIF data.

A Real Free-Product Eye-Opener!

Although some fundamental principles of LNAPL science, such as vertical equilibration and multiphase flow, were already understood, it is fair to say that, back in the 1980s and 1990s, free product behavior was somewhat of a mystery to many regulators, including the PRP. It is also fair to say that some misconceptions persist to this day. The PRP began experimenting with LIF in 1998 and, by 2000, began to recognize its usefulness for understanding LNAPL behavior and mapping its actual distribution in the subsurface. This simple mapping approach caused us to abandon long-held preconceptions about free product that were simply not supported by an objective evaluation of the new evidence supplied by LIF.

With tongue in cheek, a colleague from a southern clime once asked me if we have ever found any frozen LNAPL in Minnesota using LIF. No we have not, but one of the first things we learned from LIF is that LNAPL is ubiquitous. Its presence should be suspected at all petroleum release sites, even if direct evidence of LNAPL, such as measurable thicknesses in monitoring wells, is not present.

Perhaps the most profound misconception held by many of us was that petroleum releases organized themselves into a layer of free product floating on top of the water table in the formation. Admittedly, this concept seemed self-evident in light of how free-product floats on top of the water in monitoring wells. Indeed, monitoring wells were designed to straddle the water table with this misconception in mind.

LIF evidence made it immediately obvious that LNAPL does not float on the top of the water table. In fact, it was clear that the majority mass of LNAPL was almost always situated in the pores below the water table. We realized this had profound implications for development of successful remediation strategies. By 2003, the PRP started requiring LIF data at many high-risk leak sites where aggressive remediation was necessary.

LIF data allowed us to confidently target remediation efforts on the LNAPL with almost surgical precision. At the same time, we groaned upon realizing that earlier soil excavations had often stopped at the water table while soil-vapor extraction would not have significantly affected submerged LNAPL. On the other hand, we realized why air sparging had, perhaps inadvertently to a degree, resulted in some notable successes.

Until we learned that LNAPL does not float on the water table, we assumed that free product would simply follow the water table gradient as it migrated away from the release point. LIF data showed us that this is rarely the case; rather, migrating LNAPL follows the path of least resistance above and below the water table. Upon encountering the water table, the LNAPL continues to penetrate downward some distance and then spreads laterally in all directions within the saturated zone, including opposite the hydraulic gradient. That is not to say that the LNAPL continues to expand forever.

Strategic Regrouping

Under the misconception that free product was floating on the water table and migrating down gradient, almost like water flowing down a hill, we had conceptualized that there was nothing much stopping it from continuing to migrate, albeit slowly in most cases. There was no way we wanted to close sites if there was any chance of free product migration, while the risks posed by free-product migration seemed ever present.

However, after mapping LNAPL bodies with LIF data, and integrating standard investigation and long-term monitoring data, the LNAPL bodies from legacy releases appeared remarkably stable under prevailing, natural, hydraulic conditions. Obviously, there were, albeit poorly understood by us at the time, natural forces counteracting the forces behind LNAPL migration.

LIF allowed us to strategically locate monitoring and remedial wells inside and outside an LNAPL body. At first we were surprised when no LNAPL showed up in some wells purposefully screened across the LNAPL body. We also noticed how rarely actively migrating LNAPL was observed in the sentinel wells purposefully located just outside an LNAPL body from a legacy release. It became apparent that, after a relatively short-duration, active-migration period immediately following a release, an LNAPL body becomes stable. However, the LNAPL within the stable LNAPL body manifested itself in one of two basic fractions within the subsurface: mobile and immobile.

Clearly, the mobile fraction was locally mobile but, more importantly, not necessarily migrating en mass from the locales where it was found. We also noticed that mapping an LNAPL body often provided clues as to where the mobile fraction could be found within the LNAPL body footprint. On the other hand, we realized that both mobile and immobile LNAPL act collectively as a source of the chemicals of concern (COC) for the more extensive aqueous and vapor phases.

LIF quickly taught us that the migration and, ultimately, the distribution of LNAPL in the subsurface is often complex, with abrupt changes occurring over short lateral (and vertical) distances, due in large part to geologic heterogeneity. Infrequently, heterogeneity manifested itself with LNAPL-less borings inside the footprint of an LNAPL body.

We have found that geologic heterogeneity must be accounted for not only when completing a LIF investigation and corrective action design, but also when evaluating standard site investigation data, such as laboratory analysis of discrete soil samples. In other words, samples collected using standard methods may not be as representative as often assumed, especially if not evaluating the standard data with an SCM accounting for the four phases of subsurface petroleum contamination.

LNAPL Loves Sand and Hates Clay

A somewhat crude rule of thumb developed from our LIF experience is that LNAPL loves sand and hates clay. However, that's only part of the story, especially when it comes to clay. Pore size, structure, and geometry, rather than grain size per se, seemed to control LNAPL migration and distribution. LIF showed us that LNAPL readily occupies a clay's secondary porosity features, such as cracks and fractures (i.e., relatively large pores), while not being present within the primary porosity (i.e., very small pores).

I personally confirmed what the LIF data was telling us when I observed this behavior in fractured clay till while attending an excavation of an LNAPL body. Moreover, the LNAPL can penetrate far into the saturated zone along these fractures. A better description of LNAPL's seemingly curious behavior in fine-grained soil is presented in a paper by Mark Adamski and others in the Winter 2005 edition of the National Ground Water Association's publication *Ground Water Monitoring and Remediation*. This subject is also covered in the ITRC LNAPL Classroom Training, including a couple of very clever but straightforward demonstrations that you can even try at home.

Keeping in mind that LNAPL does not like clay, LIF data showed us that LNAPL can be found under several general geologic scenarios when coarser-grained lithologies are present. When homogenous, sandy geologic conditions are present, the

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LNAPL will usually be found floating *in* the water like an ice cube in a glass of water (not *on* the water like a solid sheet of ice on a Minnesota lake in the depth of winter; see Figure 1). Unfortunately, this ideal, simple scenario appears to be rare in Minnesota.

Things get much more complicated when both finer- and coarser-grained soils are present in discrete layers. In the unsaturated zone, LNAPL can be found perched on top of a clay layer, and the attitude of the clay's upper surface can control LNAPL accumulation and migration direction. Within the saturated zone, LNAPL can be found in discrete layers reflective of inter-layered finer- and coarser-grained soils, including finer- versus coarser-grained sand layers.

Most surprisingly, under appropriate geologic conditions, an LNAPL layer can be found along the top of a hydraulically confined sand unit (an aquifer!), several to a dozen or so feet *below* the water table present in the overlying, confining clay unit. It shouldn't be a surprise that LIF data has shown that more than one of the above-described LNAPL distribution scenarios are present at a single geologically complex site.

Watch Out for Those LNAPL Arms

Now I don't mean to say that hydraulic gradients have nothing to do with LNAPL migration. Mapping of LNAPL bodies with LIF data has shown us that even apparently minor, induced (i.e., not natural) hydraulic gradients can have a significant effect on LNAPL migration, even when the induced gradients are applied some time after the initial migration period when an LNAPL body has stabilized under prevailing natural conditions.

Most LNAPL bodies will be more or less circular, or roughly oblong, and centered under the release source in map view. However, some will have lobes and some of these lobes may take the form of relatively narrow and sometimes surprisingly long arms. Only because of a dense LIF grid pattern (discussed below), and probably some luck, have we been able to identify some of these LNAPL arms.

If there is an LNAPL arm, I know where I am going to go looking for actively migrating LNAPL. But, my main point is that we have observed LNAPL arms that apparently developed due to human-induced hydraulic gradients caused by pumping water wells screened within the hydro-stratigraphic unit where the LNAPL occurs. LIF data have shown us LNAPL arms reaching out from an LNAPL body toward: a) a relatively deep, high production municipal well located several hundred feet away; b) a relatively shallow, low-production domestic well located less than 200 feet away, or c) a perennially pumping but low-volume basement sump less than 100 feet away. (The sump pump example was a big surprise, especially since it was located up gradient.) Moreover, when very strong induced vertical gradients are present, the LNAPL arms have been observed "diving" deeper as they migrate laterally.

Added Value of LIF Logs

LIF data led us to another unanticipated but very important benefit. We found the LIF logs to be very useful when negotiating cleanup plans with responsible parties. It must be the visual thing. The LIF logs allowed the responsible parties to "see" the LNAPL at their sites and better understand the nature of the problem. This clearer understanding often led these important stakeholders to take more ownership of the problem and its resolution. Moreover, it often elicited additional important site history information that, in turn, yielded a more informed SCM. Indeed, some parties wanted to use LIF on their other problem sites as quickly as possible due to LIF's problem resolution capabilities.

LIF Investigation Strategy

It should be understood that the PRP's requirements for LIF investigation and data analysis are typically designed to yield a well-defined remediation target while also developing an updated, evidence-based SCM including the role of LNAPL. Thus, a LIF investigation is typically completed after a standard site investigation; so there is often standard data to guide LIF planning. Nonetheless, we require prior submission of a site-specific LIF investigation work plan for our review before approving LIF investigations.

If available, we often recommend that LNAPL samples be collected from monitoring wells before conducting a LIF investigation. This can be done well before mobilizing the LIF equipment to the site. The samples can be held to the probe window to see how the LNAPL responds to LIF. One can also obtain LNAPL waveforms from the samples to confirm how well the LNAPL from the wells matches the LNAPL in the formation.

For targeting purposes, and subsurface heterogeneity being the rule rather than the exception when faced with Minnesota's complex glacial terrane, the PRP generally requires that borings be completed across a grid with 25 to 35 feet node spacing. However, it is important to slightly adjust, or add, some nodes within the grid so as to be directly adjacent to known or suspected LNAPL occurrences such as at standard borings or monitoring wells with evidence of LNAPL, as well as potential or known release locations (e.g., tanks, dispensers, product lines, spills).

LNAPL is laterally delineated by LIF borings completed at grid nodes in all directions around a confirmed detection until the LNAPL body is completely circumscribed by LIF pushes with no evidence of LNAPL. To be sure, some delineation node locations may need to be adjusted slightly to accommodate small footprint obstructions.

Large footprint obstructions such as buildings or other major infrastructure should be accommodated with delineation probes completed on all sides. This is due to the often unexpected, complex nature of LNAPL migration in the subsurface that could render convenient assumptions about limited LNAPL distribution unwise. The requirement for complete lateral delineation during a single LIF equipment mobilization event belies our advice to obtain site access permission beforehand for all properties where LIF data may be needed.

Vertically, we generally require that all LIF probes be advanced to depths at least 10 feet below the deepest detectable LNAPL at a given site (one of the reasons to start probing in the source area) or below the water table. But it is often wise to go deeper, depending on site geology or other evidence suggesting that deeper LNAPL may be present. Regardless, we generally require at least one boring to 20 feet below a site's deepest detectable LNAPL or the water table to confirm that there is no deep LNAPL. We have sometimes been surprised. The surface elevation of all LIF borings must be surveyed relative to the same on-site datum used for groundwater elevations and other site features.

It is important to note that LIF data is displayed in real time as the probes are advanced, and entire logs can be generated on-site immediately after completing a boring. With an ever-evolving SCM in mind, this capability allows a seasoned investigator to rapidly adapt and make informed decisions in the field as to how deep to advance the probe or where to go to conduct the next boring.

LIF Data Analysis Strategy

The evaluation of any LNAPL body via LIF log interpretation usually begins with the logs from the release location, if known; otherwise, from where the obvious shallowest and/or thickest LNAPL is observed, as these often provide clues about the release location. After the release area logs are interpreted, we move on to interpret the logs in order of distance from and in all directions around the release point. In other words, we follow LNAPL migration pathways away from the release point. This will usually result in immediate insights as to LNAPL migration behavior over time, including why the LNAPL is distributed as it is now and where it may migrate in the future.

If side-by-side geology data from CPT or EC are available, those are also interpreted when evaluating respective LIF data; otherwise, geology from nearby standard borings is used cautiously. In addition, LNAPL thicknesses and corrected water level elevations—including fluctuation history—from nearby monitoring wells are noted. "Snapshot" boring water levels are considered less useful than long-term monitoring well data but can be useful for identifying perched conditions in the unsaturated zone.

Each LIF log is first evaluated for the presence of LNAPL using a "machine-language" approach—is LNAPL present or not? False positives, if any, are also identified and discounted. If LNAPL is present, the top and bottom depths of the LNAPL interval are noted, as well as the maximum fluorescence response and its depth within the LNAPL interval.

With hydrogeology of the LNAPL interval in mind, we also note the shape, or signature, of the fluorescent response as it varies vertically across the LNAPL interval. We have found that this signature is evidence of varying pore structure and geometry (i.e., geology) and/or relative LNAPL pore saturations within a homogeneous geologic unit.

Under homogenous hydrogeologic conditions, the LIF signature can reflect a pore saturation profile reflective of the vertical equilibrium model for LNAPL behavior under multiphase flow conditions in porous media (Figure 1). More often than not, complex geology results in complex LNAPL distribution, and the LNAPL may be present in relatively thick and/or thin, discrete sand layers.

When clay geology is predominant, keep in mind that intermittent, very thin, solitary LNAPL signatures may indicate the LNAPL is in secondary porosity features, especially if they don't correlate between adjacent borings. As one interprets each LIF log, adjacent LIF logs are kept in view and progressively correlated with each other, often illuminating an overall pattern of LNAPL body geometry and behavior across the site as it relates to release and migration history, and geology and hydrogeology.

LNAPL Structural Mapping

Once the LIF logs are systematically interpreted, LNAPL elevations are calculated and all the LIF data interpretations and calculations are tabulated. The data are then used to map the structure of the LNAPL body from two perspectives: map (plan) view and cross section. Usually, at least four types of LNAPL body structure maps are constructed by contouring four LIF data sets: 1) maximum fluorescence response; 2) elevation of the top of the LNAPL body; 3) elevation of the bottom of the LNAPL body; and 4) LNAPL body thickness (i.e., isopach).

Sometimes a depth, rather than elevation, datum is used to map the structure of the LNAPL body when more appropriate for the proposed remediation strategy (e.g., an LNAPL body excavation). At this point, I should admit to being a former coal geologist; thus I like to treat the LNAPL body as a coal seam or an ore body, if you will. I also happen to be partial to LNAPL body excavations since I can be confident in the quick risk reduction that occurs when one removes nearly 100 percent of the LNAPL mass.

The maximum fluorescence response map is completed first. Preparation of the maximum fluorescence-response map is initiated by first mapping the horizontal extent of LNAPL. This is easy to do if the LNAPL has been delineated using the grid approach; simply draw a line weaving along halfway between LNAPL-present and LNAPL–not present data points. All of the LNAPL structure maps are then constructed by contouring the data inside this common LNAPL body footprint.

Cross-sections are constructed showing the LNAPL body as it relates to site geology, hydrogeology (e.g., fluctuating water levels), and the other dependent contamination phases. The cross sections should also show other relevant site features such as buildings, basements, buried utility lines, water wells, and other preferential migration pathways, barriers, obstructions, and receptors. The vertical and horizontal variation of fluorescence response within the LNAPL body can be contoured on cross sectional views to illuminate patterns of internal LNAPL body structure, providing additional insights about LNAPL migration and behavior.

The various LNAPL structure maps and cross-sections are used to accurately target the LNAPL body with the remediation strategy in mind. For example, the LNAPL structure maps can be used to strategically plan an LNAPL body excavation so as to remove only LNAPL-impacted soil for expensive treatment while using the segregated overburden as backfill (remember, I am a formal coal miner).

The LNAPL body isopach map allows for accurate estimation of

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■ **Using LIF** *from page 17*

the in-place volume of the LNAPL-impacted soil to be selectively removed. Alternatively, if a multiphase extraction system will be used under a dewater and aerate remediation strategy, the elevation of the bottom of the LNAPL body map can be superimposed with flow maps constructed with pilot-test or full-scale system hydraulic data for evaluating the degree and extent of LNAPL body dewatering around and between extraction wells. The structure maps and cross sections can also be used to explain the remediation strategy (e.g., by superimposing various proposed remedial structures, such as extraction or injection wells, on them).

If geology is a key factor in controlling LNAPL behavior and employment of a given remediation strategy, structural geology elements, such as the elevation of a clay/sand contact are also contoured. Facies changes, as well as sand bodies or buried sand channels embedded within finer-grained soil, should also be mapped, if relevant.

As an example of geologic mapping's usefulness when combined with LIF data, we have seen evidence of perched LNAPL stranded in syncline- or basin-like geologic structures. We have also seen evidence of perched LNAPL migrating "down dip" and cascading off the edge of the confining unit like a slow motion subsurface waterfall. We have observed the migration of submerged LNAPL, apparently controlled by anticline- or dome-like geologic structures at the top of a hydraulically confined sand unit.

From a remediation strategy perspective, geologic mapping allows one to be aware of the limitations imposed, but also the opportunities presented, by site-specific geologic structures. Of considerable importance, we have found that integrating LNAPL distribution with geology results in the need to consider more than one remediation strategy to address different areas of a complexly distributed LNAPL body.

We also like to point out that one can sometimes take advantage of LNAPL's propensity to distribute the bulk of its mass in more highly permeable layers. Understanding the location of the LNAPL relative to geologic structure is particularly useful for designing remediation wells to precisely focus remediation efforts and/or avoid short-circuiting.

Proximal, standard soil, groundwater, and soil-gas analytical data are also reviewed and evaluated to see what they are telling us about LNAPL chemistry, the COCs in particular, and the evolution and behavior of the aqueous and soil-gas plumes originating from the LNAPL. For example, soil-gas data can sometimes appear confounding, with the need to sort out false positives.

Soil and groundwater samples collected from within the LNAPL body often contain entrained LNAPL. Even if they don't, the samples are likely representative of the COCs present in the LNAPL. So, if no benzene is detected (and the benzene detection limit is not elevated) in soil and groundwater samples directly associated with a given LNAPL body, it would be logically consistent to use that line of evidence for questioning any positive detection of benzene in a soil-gas sample when evaluating the vapor-intrusion pathway.

Moving Forward

In August 2010 we implemented a new policy for managing LNAPL risks, including a risk-based definition of free-product recovery to the maximum extent practicable when only LNAPL migration risks are present. The development of this new policy is the direct result of integrating what we learned from LIF and the ITRC.

The PRP is in the business of reducing risks posed by LNAPL in the formation pores, not cleaning up individual wells, so we no longer use an in-well minimum free-product thickness criterion for determining the need for and completion of LNAPL recovery efforts. We believe our approach is consistent with the requirements listed in 40 CFR 280.64, including to "use abatement of free-product migration as a minimum objective." The policy is outlined in MPCA Guidance Document 2-02 "LNAPL Management Strategy" which can be downloaded from *www.pca.state.mn.us/bkzq810.*

More recently, we implemented new policies for oversight of corrective action, in particular, the design and implementation of aggressive remediation systems targeting LNAPL. The development of new corrective action policies was substantially informed by what we learned about remediation using LIF to target LNAPL bodies. In most cases, the entire LNAPL body must be targeted when risks are posed by COCs that originate from the LNAPL. This includes the immobile, sometimes called residual, fraction of the LNAPL that cannot migrate but is still a potent, long-term, source of COCs. These new policies are outlined in MPCA Guidance Document 7-01, *Corrective Action Design and Implementation*, which also contains LIF guidance in Appendix B. That document can also be downloaded from *www.pca.state.mn.us/bkzq810.*

I am very excited about ITRC's plan to take their LNAPL Classroom Training on the road. The training is designed for regulators, consultants, and others LNAPL remediation stakeholders.

Although a finalized schedule has not been publicized, I have been told the first two-day course will be offered during fall 2011. A total of up to twelve training events across the country are envisioned, so most everyone should have an opportunity to attend a relatively nearby offering. In the meantime, the ITRC's internet-based training is still being conducted and past sessions can be downloaded for review at your convenience. For more information on the internet-based training schedule or downloads, check the ITRC's website, *www.itrcweb.org.* The classroom training schedule will be posted there when it becomes available. Two ITRC LNAPL-related publications can also be downloaded, as well as other useful documents and links to other relevant websites.

In conclusion, I hope Minnesota's story will give you some reasons to consider induced fluorescence methods the next time you find yourself trying to answer the question: where's the LNAPL? ■

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USEPA's Plan for Petroleum Vapor-Intrusion Guidance

The USEPA has prepared the following petroleum vapor-intrusion (PVI) communications paper, which briefly articulates differences in vapor intrusion potential between petroleum and chlorinated hydrocarbons and discusses USEPA's plans to develop communications and technical products to support the guidance now scheduled for completion by the end of 2012. As part of this effort, the USEPA Office of Underground Storage Tanks (OUST) has also prepared a draft paper entitled "How does the vapor-intrusion pathway differ for petroleum and chlorinated hydrocarbons?," which describes in detail how petroleum and chlorinated hydrocarbons behave differently in the subsurface and how these differences can influence whether there is a potential for vapor intrusion to occur. OUST is inviting comments on this paper, which can be found at www.epa.gov/oust. OUST is currently developing a dedicated Petroleum Vapor-Intrusion Compendium website, which will be online this summer. For more information, contact Hal White (white.hal@epa.gov).

COMMUNICATIONS PAPER

Why is USEPA developing petroleum vapor intrusion guidance?

Petroleum hydrocarbon vapors from leaking underground storage tanks can migrate into inhabited buildings and threaten public health and safety. To address this threat, OUST is developing petroleum PVI guidance to assist regulators, consultants, and other practitioners in their investigation and assessment of petroleum-contaminated sites where PVI may occur. The guidance applies to and will focus on the most common federally regulated (RCRA Subtitle I) UST sites, which are typically gas stations. The guidance will contain information and practices that will also be useful at other sites (for example, fuel terminals and airport hydrant systems) where petroleum contamination and PVI are potential concerns. USEPA's Office of Solid Waste and Emergency Response (OSWER) is developing vapor intrusion guidance that applies to hazardous substances other than petroleum (e.g., chlorinated hydrocarbons) that have been released into the environment from any source, including USTs.

What is vapor intrusion?

Vapor intrusion occurs when toxic chemicals volatilize from source materials, contaminated soils, or groundwater plumes, and migrate into inhabited buildings. Vapor intrusion is a potential concern because of both immediate threats to safety (e.g., explosive concentrations of petroleum vapors or methane) and possible adverse health effects from inhalation exposure to toxic chemicals. The toxic impacts of VI are usually associated with two classes of chemicals that cause soil and groundwater contamination across the country: petroleum hydrocarbons (PHCs), such as gasoline, diesel, and jet fuel; and chlorinated hydrocarbons (CHCs), such as dry cleaning and degreasing solvents. Vapor intrusion associated with PHCs is referred to as PVI, and vapor intrusion associated with CHCs is referred to as chlorinated vapor intrusion (CVI).

How do petroleum hydrocarbons and chlorinated hydrocarbons differ with respect to the vapor intrusion pathway?

The most significant difference between these two potential sources of contamination is that petroleum hydrocarbons are typically consumed by microorganisms (biodegraded) in groundwater as well as in unsaturated soil zones. When sufficient oxygen is present, this biodegradation can limit the potential for PVI. In contrast, chlorinated solvent compounds, if they biodegrade, tend to degrade more slowly and in anaerobic environments. As a result, there are generally more sites in which CVI has been an issue relative to sites with PVI. OUST is developing an information paper to more expansively describe how petroleum and chlorinated hydrocarbons behave differently in the subsurface and how these differences can influence whether there is a potential for vapor intrusion to occur.

How does this guidance relate to USEPA's existing draft vapor intrusion guidance?

In November 2002, OSWER issued *Draft Guidance for Evaluating the Vapor Intrusion to Indoor Air Pathway from Groundwater and Soils* (Draft VI Guidance). This guidance was developed primarily to address vapor intrusion from solvents and other CHCs, and it specifically states that the Draft VI Guidance is "not recommended for use at Subtitle I Underground Storage Tank (UST) sites at this time." OSWER is currently revising the Draft VI Guidance and plans to have it completed by the end of 2012.

Concurrently, OUST is developing additional guidance specifically to address PVI at Subtitle I UST sites. The PVI guidance will discuss important differences between petroleum and chlorinated hydrocarbon contaminants that require a different approach to investigating and assessing sites where PVI may occur. The PVI guidance will complement the overall OSWER vapor intrusion guidance and will not replace or duplicate that guidance effort. Mitigation approaches, where needed, will be addressed in the overall OSWER vapor intrusion guidance.

What does the USEPA PVI guidance aim to provide?

The PVI guidance will provide a framework for investigating Subtitle I UST sites to determine whether PVI is not a concern, is a potential concern, or is an actual concern where the exposure pathway is complete. The PVI guidance will address the following issues and also provide links to additional sources of information:

- **What PVI is and how it is different from CVI**
- **What criteria are used to assess the potential for PVI**

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■ **PVI Guidance** *from page 19*

- How to develop a conceptual site model (CSM) that includes the potential for PVI
- How to conduct a field investigation to assess the potential for PVI
- How to appropriately use a model to support a data-based PVI assessment
- How and when to engage the potentially impacted community.

What additional components and products is USEPA developing as part of the PVI guidance?

USEPA is developing an information paper that more expansively describes how PHCs and CHCs behave differently in the subsurface and how these differences can influence whether and how vapor intrusion occurs.

USEPA is also in the process of assembling a database of petroleum release sites where the PVI pathway has been evaluated. USEPA plans to use the dataset to provide evidence for biodegradation and for model testing.

Additionally, USEPA's modeling studies are assessing the uncertainty associated with PVI model usage to demonstrate the capabilities and limitations of currently available models. The results of these studies will form the basis for appropriate incorporation of model usage within a PVI assessment.

How is USEPA engagi ng stakeholders, communities, and the public throughout the PVI guidance development process?

OUST has engaged a work group of stakeholders from states and tribes, industry, and USEPA Regional offices to obtain their individual technical and practical input on PVI. OUST has presented its proposed plans for PVI guidance at several conferences, workshops, and meetings over the past year and will continue to involve the workgroup and other stakeholders during the guidance development process. One of the major thrusts of these activities will be to gather public perspectives on appropriate and effective community outreach for PVI investigations. ■

High-Tech Water Treatment Plant Restoring Santa Monica's Drinking Water Supply

On February 24, folks in Santa Monica, California, celebrated the dedication of the city's Charnock water wells and the state-of-the-art renovation of the Santa Monica Water Treatment Plant. This important milestone marks the full restoration of the city's local groundwater and the reduction of the use of expensive imported water from northern California and the Colorado River. It secures a sustainable supply of locally produced water for future generations. Santa Monica, which was one of the first victims of methyl-tertiary butyl ether (MtBE) pollution, is now setting the standard for MtBE cleanup.

The Charnock Well Field has been used as a drinking-water source since 1924. That supply was threatened in 1996 when MtBE was discovered in the city's groundwater. The gasoline additive had leaked into the well field from gas stations in the area. (MtBE is no longer used in gasoline in the United States, primarily because of liability concerns.) The well fields, which in 1996 supplied 50 percent of Santa Monica's drinking water, had been shut down for the last 15 years due to MtBE contamination.

With its wells back online, Santa Monica can now produce about 70 percent of the water it needs on a typical day. The rest is purchased from the Metropolitan Water District, which gets its supplies from Northern California and the Colorado River. The city hopes to be 100 percent self-sufficient in supplying its own water by 2020.

The Treatment System

The cleanup and filtration system includes a granulated activated carbon system and then a three-stage Reverse Osmosis (RO) membrane system, which softens the water by removing minerals (calcium and magnesium). RO uses pressure to force water through membranes with pores so small the minerals can't pass through. The final step, aeration and storage, uses the existing air-stripping technology in the five million gallon reservoir to remove any remaining volatile groundwater contaminants.

Pretreatment > Reverse Osmosis Filtrations > Water Quality Adjustments > Aeration and Storage > Final Delivery

In 2006, Santa Monica reached an agreement with all major oil companies responsible for the MtBE contamination, allowing the city to restore the Charnock Well Field so that it could once again be a viable drinking water source.

The Santa Monica Water Treatment Plant treats water from three city groundwater well fields—Charnock, Olympic and Arcadia—providing eight and a half million gallons of drinking water each day to its 89,000 residents. With the plant upgrade to state-of-the-art technology the city is ensured of additional water quality benefits and added protection against potential pollution in the future. ■

E15? The Sky Need Not Fall

by Robert Renkes

USEPA is moving full steam ahead with plans to allow the use of ethanol blends up to E15 in model year 2001 and newer light-duty motor vehicles, which includes passenger cars, light-duty trucks, and medium-duty passenger vehicles, provided conditions for mitigating misfueling and ensuring fuel quality are met. When petroleum marketers will actually start selling the new fuel is anyone's guess, since various state and local laws—plus supplier contracts, insurance agreements, liability issues, bank covenants, equipment costs, local retailer competition, and decisions at the terminal level—will have to be considered before a drop of E15 is dispensed. But eventually it will be sold in almost every state of the nation, and before it is, we have to ask ourselves if it can be done safely from a fire safety standpoint and without damage to the environment.

What Do We Know?

We already know something about the effect mid-level ethanol blends have on dispensing equipment (see *LUSTLine* #66, December 2010), and have learned that things are not so cut-and-dried on that front. The National Renewable Energy Laboratory's (NREL) study—carried out by Underwriters Laboratories Inc. (UL)—provides data on the impact of introducing gasoline with an additional amount of ethanol, such as E15 and E20, into legacy (existing) dispensing equipment that was not listed by UL for ethanol blends greater than E10. (See report at: *www.nrel.gov/docs/fy11osti/49187.pdf*.)

Although the UL report concluded that there were "no noted effects on metallic parts of equipment," some other equipment demonstrated "a reduced level of safety or performance, or both, during either long-term exposure or performance tests." According to UL, "leakages are largely attributed to effects of exposure on the gasket, seal, and hose material."

Influenced by its findings, UL retracted its earlier (February 2009) position on E15 dispensers which stated that it supports authorities having jurisdiction who decide to permit legacy system dispensers, listed to UL87, to be used with fuel blends containing a maximum ethanol content of 15 percent. Now—since December 2010—UL has maintained that the use of greater than E10 ethanol blends in these dispensers certified under UL Standard 87 is "contra-indicated."

Dispenser manufacturers, however, don't see E15 as a problem for their standard dispensers. Last year, DresserWayne and Gilbarco announced that warranties for their standard fuel dispensers would apply for ethanol blends up to E15. Both manufacturers confirmed and reiterated that their standard dispensers can dispense E15 safely for the life of the dispenser in the second quarter 2011 issue of the *PEI Journal* (see *www.peijournal.org*). Generally speaking, fire marshals have allowed nonlisted dispensers for E85 in the past as long as the owner is willing to commit to an enhanced equipment inspection program. Since the equipment is aboveground and accessible, this seems to be a satisfactory compromise between the dispenser owner and the local authority having jurisdiction.

How Do We Deal with What We Don't Know?

However muddled it is, that's what the industry knows about dispensers and hanging hardware in mid-ethanol blend service. But what about the underground equipment? What is the likely impact of using E15 in legacy UST systems?

Although UL does not provide a specific E15 rating for USTs, piping, and associated equipment, certification ratings that include E15 are made public by UL and by the manufacturer of the product. Provided the tank owner and regulator know the date of manufacture and who made the tank, piping, and associated underground equipment, they can determine if the equipment is certified or listed by an independent testing laboratory for use with ethanol blends.

It is widely recognized, however, that many components of the UST system may never have been tested for compatibility with ethanol in the first place and therefore are not listed by UL for compatibility with any ethanol blend. Other UST system components that today are listed as ethanol-compatible were not listed as such at the time they were first manufactured and installed. In other words, identical equipment may be deemed compatible in some contexts and not listed as compatible in other cases. In those cases, a statement of compatibility from the manufacturer—much like that provided by dispenser manufacturers—should also suffice to demonstrate compatibility.

From my perspective, if a manufacturer is willing to stick its neck out and go on record to approve equipment for use with E15, that manufacturer must have done the requisite testing to be confident about its compatibility with E15.

What Do UST Regulators Do?

No tank owner in his or her right mind is going to put E15 in a noncompatible system. Today's tank owners are too sophisticated and environmentally savvy to do otherwise. They know that if they store E15 in systems that are not certified either by UL or the manufacturer as compatible with that fuel, they could expose themselves to myriad legal difficulties, any of which could threaten the future of their businesses. Absent certification, tanks owners—particularly retail station owners—could be held in violation of:

- OSHA regulations
- State UST insurance policies
- Local fire codes
- The terms of their mortgage and other loan agreements, which routinely include compliance-with-law provisions
- State-based common law tort liabilities.

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■ **E15** *from page 21*

And what if some "bad actor" tank owners pop up and try to store E15 in systems not listed, certified, or approved for E15? That is where the state comes in. In my opinion, the UST regulator—provided he or she has the power—simply doesn't allow it. If the serial numbers and model numbers for the UST system components don't match up to serial and model numbers provided by UL and/or the manufacturers, tank owners can't use E15 until the owners replace the components with E15-compatible equipment.

Congress passed the UST law back in 1984 because tank systems were failing and leaking product into the ground. To a great extent, we fixed that mess. Then we learned from our experience with MtBE that when the fuel composition changes our storage and fueling equipment infrastructure must be reevaluated to make certain it is compatible. There is no reason why systems should be allowed to fail again, but that's a risk regulators will be taking if they do not establish adequate safeguards to protect the environment against a few tank owners who may try to market E15 stored, monitored, and dispensed in noncompliant equipment.

Bottom line, I don't think E15 will impact the environment surrounding UST systems any more than E10 has. Like E10, E15 must be stored in compatible equipment. We know what is compatible and what isn't. UST owners and regulators—together with UST providers and installers—have every reason to do it right. And I have confidence they will. ■

Robert Renkes is Executive Vice President of the Petroleum Equipment Institute (PEI) and is author of the LUSTLine column "Field Notes." He can be reached at: rrenkes@pei.org.

BIOFUELS HAPPENINGS

Iowa Establishes Nation's First E15 Incentive for Fuel Retailers

Iowa recently enacted comprehensive renewable fuels legislation that establishes the nation's first specific E15 incentive for the state's petroleum retailers to offer the mid-level blend to motorists in the state. Among other things, the new law:

- Provides retailers with a 3-cents-per gallon retailer income tax credit for sales of E15.
- Extends a 16-cents-per-gallon E85 Promotion Credit until December 31, 2017.
- Provides $3 million per year for biofuels infrastructure (e.g., blender, E85 and biodiesel dispensers).
- Provides retail stations with liability protection from consumer lawsuits for misfueling, as long as the retail station has provided the proper and legal labeling.
- Encourages petroleum marketers to blend biodiesel into on- and off-road diesel in a multiyear incentive program. In 2012, retailers will earn 2 cents per gallon for B2 blends and 4.5 cents per gallon for B5. Retailers will earn 4.5 cents per gallon for selling B5 from 2013 through 2017, but the B2 blend credit will disappear after 2012.

Fuel retailers in Iowa will be eligible to receive the 3-cents tax credit beginning July 1, or as soon as USEPA clears the fuel for legal sale. USEPA is expected to give final approval for E15 this summer for use in all 2001 and newer cars and light-duty trucks. ■

USDA Announces Blender Pump Program

In April, United States Department of Agriculture (USDA) Secretary Tom Vilsack announced a program to increase production and use of higher ethanol blends by adding 10,000 flex-fuel pumps across the country over the next five years. Vilsack acknowledged that the cost of a new flexible-fuel system (tank and dispenser system) would run somewhere around $120,000, leaving the impression that the USDA's grant and loan guarantee program would go beyond the cost of the dispenser itself. The funding would come through the USDA's Rural Energy for America Program. According to USDA, there are 8.5 million flexible-fuel vehicles in the U.S., which make up 3.5 percent of the approximately 250 million vehicles on the road. The agency estimates that 2,350 retail outlets are currently offering E85. ■

E15 Still Only Legal for Flex-Fuel Vehicles

E15 blends cannot be sold for use in 2001 and newer conventional-fueled vehicles until the conditions of the E15 partial waivers granted for using E15 are fulfilled. The fuel and fuel additive manufacturers must detail how they will address misfueling of vehicles, engines, and equipment not covered by the E15 partial waivers and certain fuel quality requirements. Additionally, E15 must also be registered, which includes completion of emissions speciation and health effects testing. USEPA is also in the process of finishing a rulemaking that will help facilitate compliance with the waiver conditions, which include labeling requirements for pumps dispensing E15. There may also be state and local government requirements that must be addressed before E15 can be sold in some areas. Until all federal, state, and local statutory and regulatory requirements are satisfied, E15 may be sold only for use in flexible-fueled vehicles or engines.

To avoid significant civil penalties for improper fuel blending, USEPA suggests that retail gasoline stations currently selling gasoline blended with more than 10 percent ethanol for use in flex-fueled vehicles take appropriate steps to prevent misfueling. The agency says the likelihood of violations can be reduced if the retailer selling more than 10 percent ethanol affixes warning labels to all pumps dispensing this product, informing the public that the product may only be used in flexible-fueled vehicles or engines. USEPA also encourages fuel providers to "employ other strategies at their facilities that are cost-efficient and effective in further reducing the risk of misfueling." ■

FAQs from the NWGLDE

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

Getting the Most Out of the NWGLDE Website

In this LUSTLine FAQs from the National Work Group on Leak Detection Evaluations (NWGLDE), we look at the information that is accessible from the NWGLDE website at www.nwglde.org. *Note: The views expressed in this column represent those of the work group and not necessarily those of any implementing agency.*

Q. ***Other than a list of accepted leak detection equipment, what other information is available from the NWGLDE website?***

A. A variety of leak detection information is available on the NWGLDE website, covering a wide range of topics.

Besides the listings of types of leak detection equipment currently evaluated by the work group under "Test Methods" on the left side of all the NWGLDE web pages (the most used tab on the website), the website includes an alphabetic listing, by vendor, of leak detection equipment (e.g., Vendors: A-F). These pages also include a helpful alphabetic "Outdated Vendor" cross-reference, tracking outdated names to current names.

The "Downloads" tab, also located in the left margin of every NWGLDE web page, provides links to downloadable information, such as annual additions of the NWGLDE list, minutes from all NWGLDE meetings, and NWGLDE policy memos, and links to utilities used on the NWGLDE website. Past meeting minutes provide a good history of discussions and decisions made by the work group.

The next tab on the left side of the page, "Links," provides links to websites with leak detection information such as evaluator, states and USEPA, vendors, and other miscellaneous sites. Also included is reference information that can be valuable for use by UST inspectors.

The "Disclaimer" tab on the left side of the website is frequently overlooked, but very important. All the NWGLDE list disclaimers are included here. A good discussion of the NWGLDE disclaimers can be found in *LUSTLine* Bulletin #55 (June 2007), which can be found on our website under the "Library" tab with all the other *LUSTLine* articles written by the work group.

The next tab on the left side of the page, "News and Events," lists changes and/or additions to listings since the last annual NWGLDE hard-copy list was added under "Downloads." On the right margin of this page there are also links to information regarding future NWGLDE meetings and other events relevant to the subject of UST leak detection.

On the bottom of the website pages, several other pages can be accessed. Clicking on "Email" will allow you to email questions to the work group regarding the website, listings, or other pertinent subject matter. Clicking on "Protocols" brings up a list of all leak detection equipment evaluation protocols currently available. "Checklists" contains ATG and line-leak detector maintenance checklists. The "Glossary" contains important definitions that help clarify information on the NWGLDE list.

Very important information for leak detection equipment manufacturers can be found under "Listing Procedures and Requirements" on the home page just above the NWGLDE Chairperson's name. This provides a list of information that must be provided to the work group when submitting a protocol for review.

If you are looking for a specific item and are not sure where to find it on the website, you can perform a search from the link in the top right margin of all website pages.

If you have not visited the NWGLDE website, check us out at *www.nwglde.org.* ■

■ About the NWGLDE

The NWGLDE is an independent work group comprising ten members, including nine state and one USEPA member. This column provides answers to frequently asked questions (FAQs) the NWGLDE receives from regulators and people in the industry on leak detection. If you have questions for the group, contact them at questions@nwglde.org.

L.U.S.T.LINE
New England Interstate Water
Pollution Control Commission
116 John Street
Lowell, MA 01852-1124

Non-Profit Org.
U.S. Postage
PAID
Wilmington, MA
Permit No.
200

NEW L.U.S.T.LINE INDEX
August 1985/Bulletin #1 – June 2011/Bulletin #68

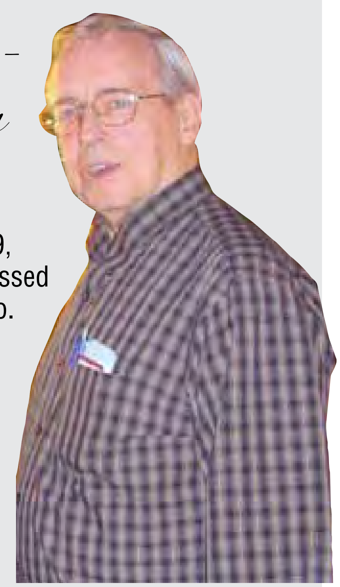
The *LUSTLine* Index is ONLY available online. To download the *LUSTLine* Index, go to *www.neiwpcc.org/lustline/* and then click on *LUSTLine*.

Oneida Tribe's New Compliance Assistance Flip Book Has Great Recipes for UST Operators

The Oneida Tribe of Indians of Wisconsin has published a well-received UST Compliance Assistance Handbook that provides information for all levels of UST operators (A, B & C). It offers textual and visual information for operators to ensure their facility is in compliance. Its spiral-bound "recipe" booklet format, with water-resistant front and back covers, and the presentation of information in color-coded sections, makes it easy to use, and convenient to store and carry. It is intended for distribution to employees of facility and allows for operators to fill in information specific to their facility. It can be used as an instructional aid.

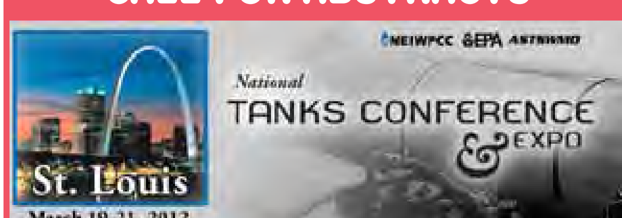
For more information about the handbook, contact Victoria Flowers at vflowers@oneidanation.org. The entire handbook is posted on NEIWPCC's website at *www.neiwpcc.org/lustline/supplements.asp*.

Remembrance – Richard Ostrom



Our tank community has lost a valued member. On June 9, 2011, Richard Ostrom passed away in his home in Idaho. Before his retirement, Dick was the state fund manager for the Idaho Petroleum Storage Tank Fund. Dick was also a valued member of the ASTSWMO State Fund Task since its inception in 1993. Dick hosted a fantastic state fund administrators meeting in Boise, Idaho in 2002.

CALL FOR ABSTRACTS



Abstracts are currently being accepted for the 23rd National Tanks Conference & Expo (NTC), which will be held March 19–21, 2012 at the St. Louis Union Marriott Hotel. We are inviting anyone interested in giving an oral presentation, poster, or workshop to visit the NTC website at *www.neiwpcc.org/tanksconference/* and submit an abstract or idea! The Call for Abstracts will be open until August 26, 2011. The conference planning team is particularly interested in presentations, posters, and workshops that focus on cross-programmatic issues addressing UST, LUST, and State Funds.