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L.U.S.T.LINE

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

It's Always Something!

That Element of Surprise in Analyzing for Gasoline Compounds

Petroleum products—gasoline, diesel fuel, heating oil—are composed of hundreds of chemicals, some of which are present in crude oil and some not. Fuels contain various classes of compounds. The bulk of the fuel is composed of petroleum hydrocarbon constituents that are either present in crude oil or in very similar compounds produced by refining (e.g., iso-octanes). The refineries blend these compounds into a finished product according to complex requirements derived from regulation, crude-oil type, component abundance, and operating characteristics. Additives are used for a wide variety of purposes. Some, for example, are detergents required by the Clean Air Act Amendments (CAAA) of 1990. Because fuel additives are proprietary, we know little about their properties and environmental behavior.

At the beginning of the underground storage tank program our approach to site assessment at a fuel-release site was to look for benzene, toluene, ethylbenzene, and xylenes (BTEX). This was a logical approach for three key reasons: benzene is a carcinogen; many gasoline compounds have a very low effective water solubility; and highly volatile compounds are quickly lost to the atmosphere. However, this approach began to change when methyl *tert*-butyl ether (MtBE) usage and releases became common in reformulated gasoline after the passage of the CAAA.

Most of us now know that MtBE was used earlier as an octane booster to replace leaded additives. Although some warnings about MtBE were raised, most people in the LUST program were unaware of the impending problems this chemical would cause. And MtBE isn't the only fuel additive whose use has resulted in unpleasant surprises: ethers such as *tert*-amyl methyl ether (TAME), di-isopropyl ether (DIPE), and to a lesser degree ethyl *tert*-butyl ether (ETBE), and alcohols such as *tertiary*-butyl alcohol (TBA),

What is in these gasoline free-product samples—BTEX? MtBE? TBA? 1,2 DCA? TAME? DIPE? EDB? ETBE?...

ethanol, and methanol can also be found in various petroleum products.

As we've learned from New England Interstate Water Pollution Control Commission surveys of state LUST program experiences, many states don't analyze for these compounds. (See *LUSTLine* #56, "The Results of NEIWPCC's 2006 Survey of Tank Programs…") Because the ethers are used to boost octane, they have been used in conventional gasoline. Some states that may have thought they didn't have these chemicals because they were not required have been surprised.

And we're on the verge of another surprise—the lead scavengers. These compounds, which were used until the

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late 1970s to prevent lead precipitation on engine components, have persisted in groundwater to this day.

So, it has become apparent that our traditional approach to site characterization does not serve us well for anticipating problems and preventing exposure to chemicals in gasoline, including BTEX. (See articles on monitoring wells, *LUSTLine* #42, and diving plumes, *LUSTLine* #36.)

Just as we've taken some strides to improve our site-characterization approach by embracing new technologies (e.g., direct push sampling) and employing "unconventional" techniques (e.g., installing nested monitoring wells to look for diving plumes), we can also improve our ability to prevent pollution from LUST sites by evaluating product composition in more detail than we have previously. This suggestion can take many forms. Some state programs, such as in Maine, are actively monitoring the composition of petroleum product that comes into their states. This provides a statewide perspective on fuel composition.

Nationally, research into fuel composition, as being undertaken by USEPA ORD, is revealing previously unknown aspects of fuel composition, even for conventional gasoline and traditional chemicals such as BTEX. At the site level, judgment is needed for the use of all advanced technologies, including product characterization. A few judiciously chosen product analyses may provide us with the information we need to better protect public or private drinking water sources.

The following two articles, from Minnesota and Delaware, provide good examples of the kinds of surprises that can pop up when a state LUST program ventures beyond the comfort of conventional thinking and heads out on the road to enlightenment.

L.U.S.T.Line

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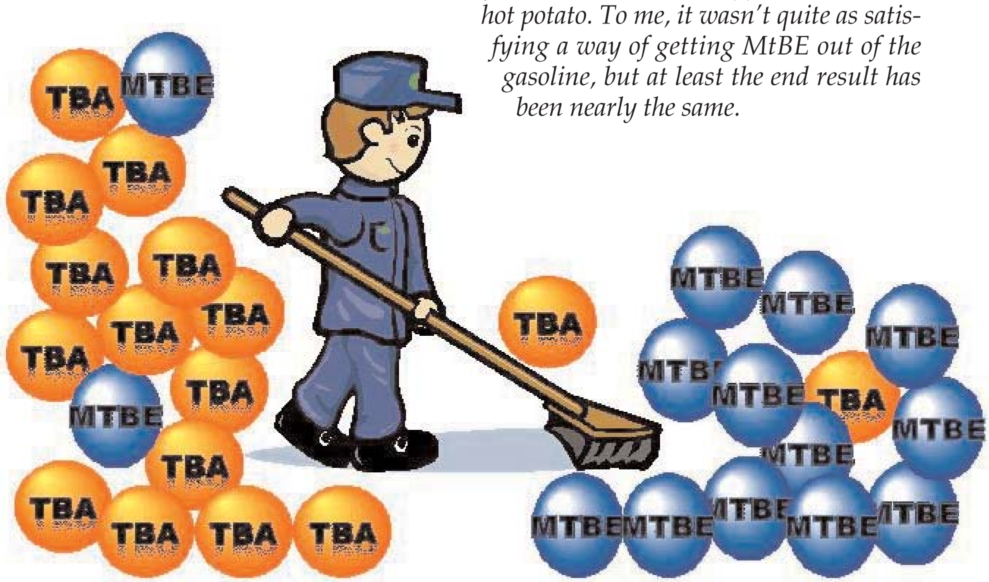
TBA, Go Away!

by Patricia Ellis

Most LUSTLine *readers probably know that I've been crusading against MtBE (or rooting for an MtBE ban) for more than ten years. USEPA's Blue Ribbon Panel on MtBE recommended that MtBE in gasoline be phased out or its use substantially curtailed. Though it didn't happen, through the years more and more states climbed on the "Ban MtBE" bandwagon, either because they saw impacts to the groundwaters of their states, or because it was a way to increase ethanol usage. Delaware proposed banning MtBE during several legislative sessions, but to my disappointment, each time they failed to bring the issue up for vote. The Energy Policy Act of 2005, while not banning MtBE, accomplished much the same result by not granting protection from lawsuits claiming that MtBE was a defective product. Between not being protected from lawsuits and the requirement for increased use of renewable fuels, refiners and blenders dropped MtBE like a hot potato. To me, it wasn't quite as satisfying a way of getting MtBE out of the gasoline, but at least the end result has been nearly the same.*



MtBE—Leaving a Legacy?

It's been a little over a year since MtBE disappeared from Delaware's gasoline (April-May 2006). Many of my newer LUST sites started showing significant decreases in MtBE concentrations fairly quickly after its disappearance, and some are just now starting to show declining trends in MtBE in the groundwater. We'll get rid of it eventually. But I'm still faced with another problem—high levels of recalcitrant *tert*-butyl alcohol (TBA). As a matter of fact, some sites have shown massive increases in TBA concentrations in groundwater samples as the MtBE has declined.

Some of the sites show the classic high levels of MtBE followed by a decrease in MtBE concentrations and a corresponding increase in TBA concentrations, indicating biodegradation of the MtBE to TBA. But what I don't often see is a subsequent drop in TBA levels as the MtBE supply is exhausted and TBA-degrading bacteria have kicked into high gear. TBA seems to increase and stay high, or increase and continue increasing. Come on bugs, you can do it. It's alcohol and doesn't smell or taste nearly as bad as MtBE!

A few years ago, John Wilson, from USEPA's Ada, Oklahoma lab, performed some isotope analyses of groundwater samples from one of my sites. The results showed that approximately 95 percent of the MtBE had degraded under anaerobic, methanogenic conditions. Unfortunately, I now have a site with TBA levels as high as 1,650,000 ppb TBA. We've blasted the site on several occasions with massive amounts of an oxygen-releasing compound, and managed to get respectable levels of oxygen dissolved in the groundwater. The MtBE continues to decline, but the TBA is definitely not showing signs of going away.

I've got a number of other sites where all other chemicals of concern are below our cleanup levels, but hundreds of thousands of parts per billion TBA remain in the groundwater. Delaware's Risk-Based Corrective Action (RBCA) program sets its cleanup goals based on distances to a point of compliance, rather than just whether there are any specific receptors within reach. One point of compliance is the property boundary. This was done specifically to minimize impacts to other properties.

We can also justify closing a site if a stable or shrinking plume can be demonstrated, but on many of these sites, the TBA really isn't showing signs of decreasing. Our TBA standard is an action level, not a cleanup number, but I really want to have some sort of a warm fuzzy feeling before I'll close a site, and a million parts per billion doesn't make me feel warm or fuzzy.

We're now armed with a new guidance document from the American Petroleum Institute (API) for evaluating the natural attenuation of MtBE (*Technical Protocol for Evaluating the Natural Attenuation of MtBE*, API Publication 4761, May 2007, *http://www.api.org/ehs/groundwater/oxygenates/upload/4761new.pdf*). However, when I apply these protocols to TBA, the data indicate that the TBA is not naturally attenuating to any significant extent.

[See also *LUSTLine* #34, February 2000, "Tertiary Butyl Alcohol (TBA): MtBE May Not Be the Only Gasoline Oxygenate You Should be Worrying About" by Steve Linder.]

Developing Action Levels/Cleanup Standards

Which brings us to the question—How do we come up with action levels/cleanup levels for a chemical if these levels are normally generated by starting with some sort of health-based information? The 2006 *NEIWPCC Survey of State Experiences with Petroleum and Hazardous Substance Releases at LUST Sites, Heating Oil Sites, and Out of Service Tanks* had

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TABLE 1

A summary of the result of state responses to a question on state standards for TBA in the 2006 NEIWPCC *Survey of State Experiences with Petroleum and Hazardous Substance Releases at LUST Sites, Heating Oil Sites, and Out of Service Tanks*

State	GW Action Level	GW Cleanup Level	Soil Action Level	Soil Cleanup Level	Primary Drinking Water Std.	Secondary Drinking Water Std.	State (or other) Advisory
CA					12 ppb		
CT					100 ppb		
DE	140 ppb		0.05 ppm				
FL		1400 ppb		5.7 ppm			
KS	43 ppb	43 ppb					
MA	1000 ppb		100 ppm				
MI	3900 ppb		78 ppm		3900 ppb		
MO	286 ppb		0.563 ppm				
NC	Detection limit for all categories – Violation if exceeded						
NH		40 ppb					
NJ		100 ppb		4.10 ppm			
NY					50 ppb		
SC	1400 ppb						1400 ppb
VT	1 ppb						
WY	2200 ppb	2200 ppb					

■ Analyzing for Gasoline Compounds – TBA *from page 3*

a question dealing with TBA soil and groundwater action levels, cleanup levels, and drinking water standards. A number of states said that their TBA numbers were site specific, while many more states evidently are not yet dealing with TBA. Judging from the range of values in Table 1, which summarizes the numbers from the states that provided them, we've all chosen different methods to come up with our numbers. (See *LUSTLine* #56 for more information about the survey.)

I developed the Delaware numbers a few years ago (which are still in draft form), using the only health-based information that I could find at the time, which happened to be the California number. California had a drinking water advisory level of 12 ppb, considering TBA as a probable carcinogen. According to the 2005 survey that Mike Martinson of Delta Environmental has on USEPA's website, the California number is now an enforceable Provisional Action Goal *http://www.epa.gov/swerust1/mtbe/oxytable.pdf.*

I used that value to back-calculate a reference dose, and then ran that number through our RBCA software to arrive at soil and groundwater action levels. More recent evaluations of the health risks associated with TBA say that the mechanisms on which the California number is based are specific to rats and that the same mechanism doesn't operate in humans. Other studies find that the kidney tumors induced in rats in that study could be used for human risk assessment. The study in question (Cirvello et al, 1995) included such phrases as "some evidence of carcinogenicity" in male rats based on…, but "no evidence of carcinogenicity" in female rats; and "equivocal evidence of carcinogenicity" based on…; and "some evidence of carcinogenicity" in female rats based on…" So who's to say that I'll behave as a rat when exposed to TBA?

There are two major recent compilations of TBA health studies of which I am aware. The first is a compilation prepared by ENVIRON and published by the American Petroleum Institute *(Hazard Narrative for Tertiary-Butyl Alcohol (TBA).* API Publication Number 4743, October 2005, *http://www.api.org/ehs/ groundwater/upload/4743final.pdf)*. In that study, analysis of various studies resulted in a reference dose (RfD) of 220 micrograms/kg/day. Assuming an average body weight of 70 kg and an average daily water consumption of 2 liters, the average drinking water concentration for TBA associated with the RfD would be approximately 8 mg/L. From Table 1, you can see that no state has action levels, cleanup levels, or drinking water numbers as high as those that would be generated from the Reference Dose in the API report. I have not tried to contact any of these states to see how their numbers were derived—I tried that once with MtBE and it was a futile effort.

Five years from now we don't want to be kicking ourselves because we closed a few hundred (or thousand) sites with significant TBA impacts that we didn't think could cause a problem.

The second compilation, prepared by the Production High Volume Chemicals Branch of EPA's Office of Pollution Prevention and Toxics *(Screening-Level Hazard Characterization of High Production Volume Chemicals - t-Butyl Alcohol)*, was released in August 2007 and can be accessed at *http://iaspub.epa.gov/oppthpv/hpv_hc_characterization.get_report* (TBA is listed as 2-Propanol,2-methyl-).

Among the conclusions of the study are the following statements: (1)TBA is not readily biodegradable in the environment; (2) two carcinogenicity studies provide some evidence for carcinogenicity of t-butyl alcohol, and (3) the potential health hazard of t-butyl alcohol is moderate based on the results of the repeated-dose and reproductive / developmental toxicology. I don't want it in my drinking water. Do you want it in yours?

We're still waiting for a more definitive health number from USEPA for MtBE. According to the USEPA document *Regulatory Determinations Support Document for Selected Contaminants from the Second Drinking Water Candidate List* (EPA Report 815-D-06-007, Chapter 14: MtBE, *http://www.epa.gov/safewater/ccl/pdfs/reg_determine2/report_ccl2-reg2_supportdocument_ch14_mtbe.pdf)*, the health-risk assessment for MtBE was scheduled for completion in April 2007. The IRIS-tracking report states that the MtBE assessment was started in 1998, and the final edited version is now scheduled for completion in 2009. I guess I shouldn't hold my breath until it's done.

USEPA is doing a literature review on the health effects of TBA. But in the meantime, I believe that we need to err on the conservative side to be protective of human health. TBA doesn't have that early warning stink that MtBE has, so we can't expect people to stop drinking it because they taste or smell it in their water. Five years from now we don't want to be kicking ourselves because we closed a few hundred (or thousand) sites with significant TBA impacts that we didn't think could cause a problem.

Oh, Did I Say MtBE Is Gone?

I am a member of Jim Weaver's (USEPA ORD, Northeast Regional Lab, Athens, Georgia) gasoline sampling crew. He is studying the regional and seasonal differences in gasoline composition, RFG and non-RFG areas, and which oxygenates are being used in what areas. I recently received the results of the February 2007 sampling and was amazed to still see MtBE in several of the Delaware gasoline samples eight or nine months after we thought it would be gone.

Both of the samples where MtBE was detected were of 93 octane gasoline, and MtBE was detected at 0.21 and 0.44 percent, by volume. Neither of the stations are very high-volume, and I suspect that the operators of both of these stations did not follow our recommendations about having their tanks cleaned prior to the switch to ethanol, but I was still surprised that after all these months, the MtBE was still present. According to Jim, some of the samples collected in other areas also showed low levels of MtBE, but it wasn't common. I've just completed the August 2007 gasoline sampling. I'll be curious to see if we've managed to dilute it out of those tanks by now.

For now, I'll just sit back and see if any of my new groundwater analyses for ethanol will manage to exceed the TBA numbers I've seen. Ah….almost! I've got 1,300,000 ppb ethanol in MW-2! At least I think that the ethanol will disappear soon, but it may have managed to remobilize free product that we hadn't seen in the last few years, because the free product in some of the wells seems to have a weathered look about it. ■

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Never Mind EDB, What About 1,2-DCA?

Minnesota's Curious Little Piece of the Puzzle

by Mark Toso

As state regulators, working the day-to-day grind of site remediation, we often only see what's happening in our own little worlds. Because of this, we sometimes have information we've picked up along the way that could be beneficial to others but that gets lost in the shuffle or filed away when the next big project comes along. This occurred to me one day while reading through some past issues of LUSTLine. *While a few articles made it pretty obvious that there was a heightened national concern over the leaded gasoline additive ethylene dibromide (EDB), my first reaction was: "Never mind EDB, what about 1,2-DCA?" (See* LUSTLine *issues #47, "Lead Scavengers: A Leaded Gasoline Legacy?," #50, "What South Carolina Is Learning about Ethylene Dibromide at LUST Sites," and #51, "Leaded Gasoline? Hmm, What's in Those USTs?")*

Our Long-Term Scavenger Hunt

Recent articles and presentations at the National Tanks Conference by other states (particularly South Carolina) have emphasized the need to expand groundwater analysis to include the leaded-gasoline additives EDB and 1,2-dichloroethane (1,2-DCA). In Minnesota we've been fortunate to have some very forward-thinking people in our environmental programs. Since the creation of our LUST program in 1987, volatile organic compound (VOC) analysis using USEPA method 8260 has been required for all first-round groundwater sampling. Our VOC-parameter list was designated by our Health Department lab and included the leaded-gasoline additives EDB and 1,2-DCA (and with even more impressive foresight, MtBE in 1989). Although it's likely our VOC sampling requirement was implemented to screen for nonpetroleum contaminants (more than one chlorinated plume was discovered this way), we've been keeping track of EDB and 1,2-DCA for a long stretch.

As reported previously in *LUSTLine*, both EDB and 1,2-DCA were part of the tetraethyl lead (TEL) additive package designed to remove excess lead from gasoline-engine combustion chambers. Since 1942, these two compounds were added in molar ratios with lead that resulted in almost equal quantities, ranging from 0.27 – 0.34 g/L, (Falta, June 2004). An interesting side note is that EDB is added to aviation gasoline because chlorine from 1,2-DCA in the exhaust would be corrosive to aluminum airframe parts. And since TEL was only added to increase the octane rating for gasoline engines, it would never have been used in any turbine engine (jet) fuels, which comprise the vast majority of aviation fuels used today.

Minnesota's experience with these two additives is that EDB is not a significant problem. An informal survey of Minnesota Pollution Control Agency (MPCA) petroleum-remediation program staff found that while we have numerous examples of drinking water wells that are contaminated with 1,2-DCA, only two are known to contain EDB (up to 1.4 µg/L). In both cases, the 1,2-DCA concentrations were much higher than the EDB and also exceeded the state drinking water standard of 4 µg/L (the federal MCL is 5 µg/L). In addition, routine analysis of public water supply wells by the Minnesota Department of Health, using method 8260B, has never detected EDB; however, 1,2-DCA has been detected in 26 wells.

Looking Harder and Meaner for EDB

Because of the extremely low drinking water standards for EDB (0.004 µg/L state HRL and 0.05 µg/L federal MCL), the elevated detection limits with method 8260B were a concern. We began to think that perhaps EDB was persistent below detection levels, which typically are in the 0.4-1.0 µg/L range. So when the USEPA Office of Underground Storage Tanks (OUST) in collaboration with the USEPA Office of Research and Development (ORD) got word out that it was looking for leaded-gasoline release sites to sample for low-level EDB using EPA method 8011 through the Kerr Environmental Research Lab, we were more than happy to participate.

One site we submitted represented a typical scenario seen in Minnesota. In the beautiful north central city of Alexandria, a large petroleum-distribution terminal is situated above an aquifer consisting of predominantly sand, occurring from 80-120 feet below grade. Separating this deep aquifer from a shallow surficial aquifer is a confining unit consisting of clay-rich till that is 30-40 feet thick. The deep aquifer is considered the sole source for the city and surround-

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ing area, and downgradient from the terminal it is contaminated with 1,2-DCA, but not EDB.

Since the terminal is located just inside the city limits, approximately 300 deep-aquifer wells were impacted in new residential developments outside the city. We have been tracking 1,2-DCA concentrations of up to 8.0 µg/L in select offsite wells in this area; several have exceeded the state standard of 4 µg/L (MCL is 5 µg/L). These levels have remained relatively consistent over the last 12 years. The front edge of the plume has been migrating slowly to the current maximum extent of 3,200 feet downgradient (ironically, the few residences that have shallow sand-point wells have no contamination). With the exception of the rare, extremely low-level detection of a BTEX compound, 1,2-DCA was the only compound detected.

The highest 1,2-DCA concentration seen in any onsite deep well was 20 µg/L, again without any detectable EDB. The last EDB detection at the site was in a shallow aquifer well in June 1994 at 1.2 µg/L. There have been no detections of 1,2-DCA in a shallow-aquifer well since April 1999. This could be the result of various remediation systems that have operated entirely in the shallow aquifer since the early 1990s.

A total of eight well samples were submitted to the Kerr Environmental Research Lab for low-level method 8011 EDB analyses. Of these, two were onsite-monitoring wells, and the remaining six were offsite private wells. These wells were all selected based on historical detection of 1,2-DCA. All samples were also analyzed for VOCs using EPA method 8260B. As shown in Table 1, all but one well had a detection of 1,2-DCA. However, the 8011 analysis did not detect EDB in any of the wells at a level of 0.010 µg/L.

And the Winner Is...1,2-DCA

As is typical of what we experience in Minnesota, the 1,2-DCA outlived all the other VOCs at this site. While the degradation of these two additives in leaded-gasoline releases is not well understood, it's clear that at least in Minnesota, EDB is attenuating at a rapid rate and 1,2-DCA is not. In fact our experience has been that of all the VOCs we analyze for at petroleum-release sites, 1,2-DCA is the longest-lived, most traveled compound we've seen. It may even rival MtBE for risk to drinking water supplies (incidentally, MtBE was found in the onsite deep wells beginning in 2003).

Why Minnesota's data seem to contradict those of states such as South Carolina, where EDB is more prevalent, is a puzzle. This is especially interesting when you consider that we see the same results across a wide variety of geologic settings (i.e., glacial, carbonate, and igneous bedrock formations). Perhaps there are some significant differences in geochemistry (there is the obvious difference in temperature) or some other factor. It's known that EDB had been used as an agricultural pesticide more widely in South Carolina and that there might even be more recent leaded-racing-gasoline releases than Minnesota.

So far, there is nothing to suggest that we need to make a change in our investigation and cleanup policy. However, if you are concerned about EDB and not currently sampling for 1,2-DCA, you might want to think about reevaluating your strategy. And stay tuned for additional information as we plan to develop this and several other case studies as part of the national evaluation of leaded-gasoline scavengers.

But That's Not Quite the End of Our Story

It's always something! We have also been seeing occasional detections of 1,2-dichloropropane (1,2-DCP), which is usually found associated with 1,2-DCA. Often the levels are right at the detection limits of method 8260B, but some have been as high as 46.5 µg/L (MCL is 5 µg/L). While one of the listed uses of 1,2-DCP is as a lead scavenger, a major manufacturer of TEL additives claims its use was extremely limited. There is the possibility that 1,2-DCP is produced as a byproduct during the manufacture of 1,2-DCA. However, there was apparently an acute shortage of 1,2-DCA between 1957 and 1960, and 1,2-DCP was used as a replacement. This may hold promise for dating some old releases. We plan to investigate this further as well. ■

TABLE 1 Benzene, 1,2-DCA, MtBE, and EDB in the Deep Aquifer Alexandria Terminal, April 24, 2007

Well ID	Distance of well from site (ft)	Benzene	1,2-DCA	MtBE	EDB
HRL/HBV		5	4	70	0.004
Cemetery Shop	1215	ND	2.4	ND	ND
313 Agnes	1125	ND	ND	ND	ND
Jerry's Bar	900	ND	3.6	ND	ND
708 Kinkead	1665	ND	2.5	ND	ND
903 Van Dyke	2475	ND	2.1	ND	ND
1007 Van Dyke	2790	ND	1.8	ND	ND
MW-57D	–	ND	8.2	68	ND
MW-58D	–	ND	6.0	11	ND

All results in µg/l = micrograms per liter
Analysis by Method 8260B except EDB by method 8011
ND = Not detected
HRL = Minnesota Department of Health, Health-Risk Limit
HBV = Minnesota Department of Health, Health-Based Value

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Tanks Down East

by W. David McCaskill

David McCaskill is an Environmental Engineer with the Maine Department of Environmental Protection. "Tanks Down East" is a regular feature of LUSTLine. *David can be reached at* David.Mccaskill@maine.gov. *As always, we welcome your comments.*

Musings on the UST Challenges of the Future

While hypnotized by the gentle wash of waves on a pocket beach, numbed by the cold Labrador Current as it swept across the Gulf of Maine, I got to thinking (heaven help me!) about tanks...about where the whole business of tanks and groundwater salvation and regulations was heading. And maybe with the various UST provisions of the Energy Act of 2005 the future may be smoother than the past 20 years, once we get that initial beach sand out of our shoes. When I finally snapped to, I decided it was time to start writing and throw out some questions that we might want to ponder concerning the possible and probable future challenges that we face in our little esoteric world of USTs and LUSTs. After all, if we don't ask the questions, we won't be able to answer them. If we don't answer them, we might find some of those waves washing right over us.

Will Secondary Containment Ever Contain?

As many avid *LUSTline* readers know, there have been various studies in California and New Hampshire concerning vapor leaks and the extreme measures needed to reduce them. Will we need vapor-tight secondary containment for everyone? Years ago we were asking the same question about run-of-the-mill, liquid-tight secondary containment. "Vapor-tight" secondary wasn't even in our lexicon back then! Here in Maine, we moved to secondary containment in 1991, and now the Energy Act will practically require it nationwide. A good thing, but will we now need a new generation of secondary containment? One with more expensive vapor-tight tanks, piping, containment sumps, and double-walled spill buckets to ensure that our ever-vulnerable drinking water supplies are protected?

Oh well, we are only in the 21st century, a place that was always in the future and where all problems were supposed to be solved. And we are only talking about storage of the most dangerous and toxic and flammable liquid that we routinely come in contact with throughout our daily lives. Why worry?

Who Owns These Tanks?

In the old days—and for all practical purposes, we are talking about some 30 years ago in Maine—the "seven sisters" major oil companies owned most of the service-station tanks. Now the majors have moved on to tend their crops out in the Gulf, North Sea, and North Slope, leaving the feeding stations to the large oil jobbers and mom 'n pops. In Maine, it was basic market share, or lack of it, that seemed to move the majors out of our territory.

Also in Maine, as I would expect elsewhere in the country, we've got the very capable oil jobbers and mom 'n pops and then we've got those that the Operator Training requirements of the Energy Act will hopefully help to become capable. With this change of tank ownership we are also challenged with communicating with some folks who are not fluent in the language of the rules with which they must comply. Being a nation of immigrants, this is not a new challenge. But, considering the technical nature of these rules, all training and information will need to be clear and intuitive.

Will We Recognize the Right Problem and Have the Right Solution?

Are we going to be smart enough to recognize the next MtBE or the next flex-pipe fuel-compatibility issues and head them off before they become problems? Many of us are already thinking about ethanol, especially E85, and its fate and transport and equipment-compatibility issues. Good training for the folks in charge of forecasting the future! Maybe, as was pointed out at the last "states only" session during the 2007 Tanks Conference, USEPA should sponsor some/more up-front research on these issues. We did get the message that EPA will come up with some UST component/ethanol compatibility guidance.

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How Many Times Do We Clean Up a Site?

First it was BTEX, then MtBE, and now it's TBA and EDB and 1, 2-DCA. What's next? Back to the future with ethanol-mobilized BTEX plumes? Know thy contaminant and thy risk!

What Happens When the Rug Is Pulled Out from Under Us?

It has happened in the past. So it will be true in the future. Some tank and pipe companies will go out of business, leaving the owners with little or no technical support. And what about the miles of first-generation, recalled, flex pipe left in the ground long after the manufacturer has gone out of business?

And what about warranties? In Maine, we require tanks to be removed at the end of their warranty. This is usually 20 years for cathodically protected (CP) steel tanks installed before October 1985 and 30 years for most other tanks—be they CP steel, fiberglass-reinforced plastic (FRP), or jacketed steel. Now the Steel Tank Institute has limited its warranties to 10 years. Now what? Who's next? What's next?

In Maine, we have documented about a dozen (and more on the horizon) cases where a double-walled CP or jacketed-steel tank's primary shell has been breached due to internal corrosion. The good news is that the secondary containment worked and nothing got into the environment. But the bad news is that the owner only got 15 years of life out of the tank, rather than the warranted 30 years.

I recall the sagely prognostication of one of my colleagues 20 years ago when he said, "Now that we are protected against external corrosion we'll start seeing internal corrosion." If double-walled tanks are leaking from internal corrosion at 15 years, might not the single-walled tanks be leaking as well? We have now instituted a policy to take water samples at the tap of convenience stores with single-walled CP tanks located within 300 feet of a private well. Maybe we'll catch some horse-out-of-the-barn leaks before they run too far.

What about Those Errant Delivery Drivers?

Many states have trained UST tank installers and inspectors and, thanks to the Energy Act requirements, will hopefully be training operators, but what about delivery drivers? These are the folks who are responsible for safely filling tanks and preventing spills and overfills. To my knowledge, there are currently neither requirements for that sort of training nor any regulatory hook to hold them accountable.

Talk about being out of the loop! Who's going to train these folks? Our spill-response records rank overfills as the leading source of releases from all tanks—above or below ground. We recently sponsored an overfill module as part of a half-day industry hazmat training session for heating oil and transport truck drivers, which was organized by the Maine Oil Dealers Association. This federally required hazmat training deals with placarding and emergency response and is also a good way to get much-needed UST and AST overfill training to the drivers, since they are gathered together and in training mode already. The feedback on the training was positive, and we plan to continue this collaboration with the Maine Oil Dealers Association.

As part of the Energy Act delivery-prohibition requirements there is a regulatory hook that makes delivery drivers liable for filling out-of-compliance ("red tag") tanks. This seems to be a good start toward getting them involved in the UST regulatory chain, but in order to actually prevent overfills in the future they need to be trained, as well.

Will We Ever Get Spill Buckets Right?

Spill buckets—they are not just future problems; they are ongoing problems in the here and now! Florida's Leak Autopsy Study shows that spill buckets in that state have a relatively short working lifespan. I shudder to think what the lifespan of the spill bucket is here in Maine, with sand and salt continuously washing into them during the winter months, not to mention snow plows playing hockey with their puck-shaped lids.

Coupled with malfunctioning and misused overfill devices, releases at this human/UST system interface will no doubt persist. Will double-walled 15 gallon spill buckets solve the problem? In Maine, we have a requirement that all new and replacement spill buckets have a capacity of 15 gallons to hopefully capture the contents of the delivery hose when delivery "mistakes" are made. (See "Small Spills Count ….The Spill Drill," *LUSTline* #49). I guess now we need to contemplate the prospect of double-walled spill buckets. We persevere……

Out Over the Horizon

Woven throughout the future of the UST program are the provisions of the Energy Act—and any subsequent provisions. We will likely see both positive and perhaps not so positive effects. I believe that since many of the provisions in the Act were already on our wish list, the future problems may be more predictable in our regulatory minds. As far as the unforeseen problems are concerned, maybe we, as states, territories, and tribes, should come together with our brain trust of knowledge and peer out to the horizon with an eye to preparing for any gathering storms, rather than blithely wait for future problems to wash up and over us. ■

••Snapshots from•• ••••• the Field ••••••

Photo: Courtesy of Ben Thomas

Midwest "Biowillie" Dispenser

Tank-nically Speaking

by Marcel Moreau

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

The Gospel According to Phil:

"Be Sure You Know What You Are Talking About!"

One of my best and most respected mentors during the mid 1980s, when I was a regulator at the Maine Department of Environmental Protection, was a service station owner named Phil. This was back in the days when a gas station was a place you went to get your car fixed and to buy gasoline, but not to buy beer and groceries. Phil was active in his industry and was a frequent spokesperson for the state's gasoline retailers, so we often found ourselves on opposite sides of tank regulatory issues. But because of a deep respect for one another, these differences often led to great debates and discussions rather than great animosity.

As I began to investigate the more or less newly recognized tank problem in the state, Phil was one of the first people I visited to learn more about the tank owner's perspective on tank issues. I remember he took me into a cramped office that was just barely big enough for a desk and talked to me about the challenges of running a service station. He told me about some of the tricks attendants used to steal money from him or his customers, how to keep customers coming back ("Always tell them the truth"), and, very importantly for me, how to keep fuel-inventory records. Phil had a shelf full of binders with many years worth of carefully detailed fuel-inventory records. He kept inventory not because anybody said he had to but because he thought anybody who didn't was foolish. And Phil was definitely no fool.

I recall one day, over a drink, he leaned across the table, and I saw from the look in his eye that he had something important to say. "Do you know who you are when you walk into a gas station?," he asked. I was a bit stumped; I wasn't sure what he was driving at. "Well," I began slowly, "I guess I am a representative of the state."

"No," he said. "That may be the way you see yourself, but to the person on the other side of the counter or desk, you are GOD." I must have looked somewhat puzzled, because Phil went on to explain. "When you walk in to a gas station, the owner or attendant believes that you have the power to do anything you want to his

■ continued on page 10

■ **Tank-nically Speaking**
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business, and that whatever you say is the law. So you'd better know what you're talking about."

There have always been, and there always will be, business owners who have little respect for regulators or regulations. But there is also a significant percentage of tank owners who generally strive to do the right thing. It is this latter group that tends to hear the regulator's word as gospel. These are also the people who complain to me about situations where regulators have given them various erroneous or illogical interpretations of regulatory requirements. When I ask them why they don't point these things out to the regulators, there is typically a shrug of the shoulders, a look of resignation, and silence. In the silence I hear Phil's answer: "What can we do …?"

Consider some of the complaints concerning regulators I have heard of late.

The Mistaken Swing Joint

A regulator inspected a new tank installation and refused to approve it because of a couple of elbows connected by a short length of pipe. Traditionally, this combination of fittings was known as a swing joint, and it was used to provide flexibility for galvanized steel piping. Swing joints are generally not acceptable as a means of providing flexibility, but in this particular case, the fittings were installed not to provide flexibility (the piping was flex pipe) but to facilitate the alignment of the pump outlet with the flexible piping. Thus while the fittings used were those of a traditional swing joint, the function of the fittings was completely different—and completely acceptable.

In this case, the inability of the regulator to differentiate between the two uses of the fittings (providing flexibility versus aligning the piping) caused much gnashing of teeth on the part of the installer.

The Redundant Ball Float

There are a number of tank installations where both ball-float valves and drop-tube shutoff overfill devices are installed. To be clear, this is a practice I would discourage, but that is a topic for a different article. Because they treat both of these devices as overfill-prevention devices, there are regulators who require that the ball float be set at 90 percent of tank capacity and the shutoff device at 95 percent. When only one of these devices is installed in a tank this is reasonable, because this is one version of what the tank rules require when these devices are installed for overfill prevention.

When both devices are installed, however, locating the ball float at 90 percent and the shutoff device at 95 percent is a problem, because the ball-float valve will operate first, since it is set at a lower level in the tank. Once the ball float closes and reduces the fuel flow into the tank, the shutoff device is essentially disabled. This is because the flow rate of the fuel down the drop tube is reduced to less than what is required to close the shutoff valve.

Not only is the shutoff valve rendered useless, the hapless delivery driver who fills the tank past the point where the ball float closes will be in for a rude surprise. Because the driver likely observed that a shutoff valve was installed, he would reasonably assume that the shutoff device was the overfill device on the tank. While a shutoff device allows a driver to drain the delivery hose very soon after the shutoff device operates, a ball float requires a substantial delay to relieve the pressure in the tank. If the driver mistakenly assumes that he is dealing with a shutoff valve rather than a ball float, and does not wait before he disconnects the hose, he will likely get a bath in fuel as the backpressure in the tank forces product out of the hose. (For more information on the operation of ball floats, see *LUSTline* #21, December 1994, "What Every Tank Owner Should Know About Overfill Prevention.")

It is for these reasons that PEI RP100-05, *Recommended Practices for Installation of Underground Liquid Storage Systems* warns against the installation of ball-float valves lower than the activation point of a drop-tube shutoff valve (Section 7.3.3). An incomplete understanding of the operation and function of equipment by regulators can create hazardous situations. While the tank manager who told me this story opted not to install the ball float at all as a result of this requirement, other, less informed owners may have to pay the price of a delivery spill because of misguided regulatory policy or interpretation. Needless to say, the regulator's credibility with the regulated community also suffers.

To Lift a 42-Inch Manhole Cover

There is at least one state that wants to include as part of its operator training information the recommendation that operators visually inspect submersible pumps on a weekly basis. There are many hazards associated with inspecting submersible pumps. For starters, there is a substantial traffic hazard because the tank pad is frequently located in a traffic area, the lids are often difficult to remove and heavier than many store personnel can safely handle—and there could be flammable vapors present. Frequent removal of the lids will also encourage the omission of seals and gaskets that help to keep precipitation out of secondary-containment sumps. Is inspection of submersible pumps an appropriate task for store clerks and facility managers?

The PEI UST Inspection and Maintenance Committee discussed the issue of submersible pump inspection in producing PEI RP900, *Recommended Practices for the Inspection and Maintenance of UST Systems.* (See "Field Notes" on page 13.) The Committee decided that large manway inspection was too hazardous to be conducted by store personnel. The document recommends that such below-grade components be inspected annually by qualified personnel (e.g., service technicians), not store personnel.

I agree with the RP900 Committee that routine visual inspection of submersible pumps by store personnel is a practice to be avoided rather than encouraged. Regulators who promote such a practice ignore basic safety and common-sense considerations. From its inception, the goal of the tank program has been to protect human health and the environment. Let us not forget that human health comes first. The "safe" way to keep an eye on submersible pumps is to install them in liquid-tight sumps with continuously monitored sensors.

Electronic versus Mechanical LLD

Another state is proposing that all line-leak detectors (LLDs) shut down the submersible pump when a 3 gallon per hour leak is detected. This change would essentially force a switch from mechanical to electronic line-leak detectors. Now generally speaking, I think this is probably a good way to go. Electronic line-leak detectors offer the ability to periodically test for smaller leaks as well as 3 gallon per hour leaks, and have diagnostic features that can facilitate troubleshooting. There are some situations, however, where mechanical LLDs may have an edge over electronic ones. This is because electronic LLDs generally take a longer time to detect 3 gallon per hour leaks than mechanical ones.

Many electronic LLDs incorporate a multiple-test feature to help reduce false alarms due to temperature effects in the piping. Remember that volume changes due to temperature are a significant cause of false alarms in mechanical LLDs. (See "Of Blabbermouths & Tattletales, The Life and Times of Line Leak Detectors," *LUSTline* #29, June 1998).

Because volume changes due to temperature diminish over time, repeating a test cycle is a good way to distinguish temperature effects from real leaks. If the measured volume or pressure loss diminishes over time, it is likely due to temperature. If the measured volume or pressure loss is consistent over time, it is likely due to a leak. So, although not declaring a leak until several tests have been run is a good way to evaluate whether temperature effects are influencing the results of a test, it takes time to run these multiple tests.

The test cycle of electronic LLDs is generally interrupted if a customer activates the pump to dispense fuel. This means that a period of several minutes of uninterrupted quiet time sufficient for several tests to be run is generally required for a leak to be declared. One brand of electronic LLD requires upwards of 10 minutes of uninterrupted quiet time to declare a leak. At very high-volume facilities, this amount of quiet time is going to be infrequent at best, if it is present at all.

While very active facilities pose problems for both mechanical and electronic LLDs because the pumps are "on" most of the time, there is no question that most electronic LLDs require a longer time to find 3 gallon per hour leaks (minutes) than mechanical LLDs do (seconds). (See "The Trouble with Truck Stops," *LUSTline* #56.) Thus for very active facilities, mechanical LLDs may be a better choice in terms of timely detection of large leaks than electronic LLDs. While this seems counterintuitive at first, I believe that this is a factor that should be considered before deciding whether electronic or mechanical LLDs are a better bet for leak detection.

There is a solution here in the form of hybrid LLDs that essentially use a mechanical LLD to activate a switch that will cut off power to the pump, but these types of LLDs are not as widely known as the standard electronic LLDs. The point is that today's leak-detection technologies and gas station operating characteristics must be carefully evaluated to determine the "best" method of leak detection for a particular facility.

"Be Sure You Know What You're Talking About."

For better or for worse, a regulator's words may be taken as gospel by tank owners who are doing their best to obey the rules and are unwilling to gainsay a voice endowed with regulatory authority. Whether or not their proclamations are regarded as providential, in my view, regulators have an obligation to be sure that the positions they take with regard to regulatory requirements are sound.

I expect there are many more examples of regulatory misinformation and shortsightedness that could be cited. These are just examples that I have recently come across. There is much attention being focused these days on the proper training of UST operators. Let us not presume that UST operators are the only ones in need of training. To be credible and effective, regulators must be knowledgeable and exercise a reasonable degree of common sense.

As the Energy Act's three-year inspection requirements are implemented and regulator/tank operator encounters become more frequent, keep in mind the simple but pithy gospel according to Phil. ■

Snapshots from the Field

Florida "Sinkhole" Dispenser

Photo: Courtesy of Ben Thomas

Arizona "Old Timey" Dispensers

Photo: Steve Purpora

SPEAKING OF TRUCK STOPS...

*Marcel Moreau's cover article, "The Trouble with Truck Stops…," in our last issue (*LUSTLine *#56) was followed up with news of a recent release at a truck stop in Missouri and a note from Kevin Henderson (Mississippi Department of Environmental Quality UST program) with examples of truck-stop releases in that state.*

Missouri

The appearance of fuel in a stormwater retention pond in June 2007 was the first indication of a release at this high-volume truck stop, located on an interstate highway. Investigation into the cause of the leak and why the leak-detection equipment failed to detect it, is still underway. Cleanup costs will be significant; more than $300,000 was spent for the initial response, which included excavation of impacted soil and installation of a recovery trench.

Mississippi

"Having read 'The Trouble with Truck Stops' in the last issue of *LUSTLine*, I was reminded of some incidents we have experienced with truck stops. The photo in Figure 1 depicts what happened when a customer drove off with the nozzle still in the fuel tank. As a result of the drive-off, the dispenser cabinet was pulled from the mounting frame and the shear valve did not properly function. The system continued pumping until it was manually shut down by a store clerk—but not before some 1,300 gallons of fuel were released. Obviously, the fact that the leak-detection system was unable to recognize that this sudden and catastrophic release was occurring at this high-capacity pumping system leaves us with a lot to be desired.

FIGURE 1

FIGURE 2

Figure 2 depicts an incident that occurred in 2003 that also resulted in a catastrophic release, although this one occurred over a relatively long period of time. In this case, a relatively small leak in the underground piping system went undetected until it was eventually visually detected. Fuel came up through the expansion joints in the truck-stop parking lot and then made its way to the drainage ditch shown in Figure 3. Upon subsequent testing and excavation, it was revealed that the piping had failed near one of the dispenser-containment sumps.

Although the pipe failure shown in Figure 3 appears to be catastrophic, it was actually not as bad as it looks. Further investigation revealed that the path the leak was taking through this multi-layered pipe was such that the pipe would only leak if the line pressure was above 7 psi. Because this was a very high-volume truck stop, the mechanical automatic line-leak detector that was installed in the system had virtually no chance of detecting the leak. The fact that the leak would stop at 7 psi and that the facility was high volume meant that the line pressure would probably never decay to the 1 psi or less needed for the mechanical leak detector to go into the leak-detection mode. Clearly, we deserve better than this."

FIGURE 3

If you have any UST/LUST-related snapshots from the field that you would like to share with our readers, please send them to Ellen Frye at lustline@neiwpcc.org

Field Notes ✍

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

Egads, Not a Test!

The Petroleum Equipment Institute (PEI) has published seven recommended practices to date, with two more slated to be completed within the next year. The documents have been widely accepted by the contractors for which they were written. Because the subject matter of most of the documents involves either aboveground or underground storage tanks, *LUSTLine* readers and tank regulators also seem to find the documents useful.

If there is one knock on the recommended practices, it is that there is no means to gauge how well the users of the document understand what they read until they are out in the field—which for some contractors is too late. PEI is attempting to fill that void by preparing tests for each of the recommended practices it publishes. We began work on the project this summer and hope to have tests for all recommended practices completed by March 2008.

The tests are being written and proofed by the technical committees responsible for each document. The questions are in a multiple-choice format. Delivery and scoring will be available through the Internet. PEI will have a bank of questions available, so no two tests will be the same. We estimate that most tests will include around 70 questions and take 30 to 45 minutes to complete.

The contractors that we talk to about the tests are delighted with the prospect of giving the test to job applicants who claim to have experience in tank installation and/or inspection. Contractors also tell us that they would use the tests for refresher training and before they promote people from within their construction department.

We are not sure if tank regulators have a use for these tests. We think that they might be used for licensing and certification purposes. On the other hand, they have probably developed their own tests by now. Training and continuing education of inspectors is another possible use for the tests.

Pricing of the tests has not been determined. We want to keep them affordable to our contractor members and any regulatory agency that wants to use them. If you have a use in mind and want to discuss how you and PEI might work together in product delivery and pricing schemes, please let me hear from you. As the saying goes, I'm from private industry and I'm here to help. Email: *rrenkes@pei.org*. Phone: 918-494-9696 ■

Veeder-Root Issues Alert About Red Jacket FX Leak Detector

On August 1, 2007, the Veeder-Root Company notified its customers that a small percentage of Red Jacket Leak Detectors manufactured from December 2006 through May 2007 might not seal when installed into a submersible turbine pump packer-manifold. The company notes that this condition, if present, will not compromise the leak-detection function of the units. To detect this condition, the pump must be running with the line pressurized. If an improper seal is present, it can be found by making a visual inspection to see if seepage is occurring at the joint between the leak detector and the packer-manifold.

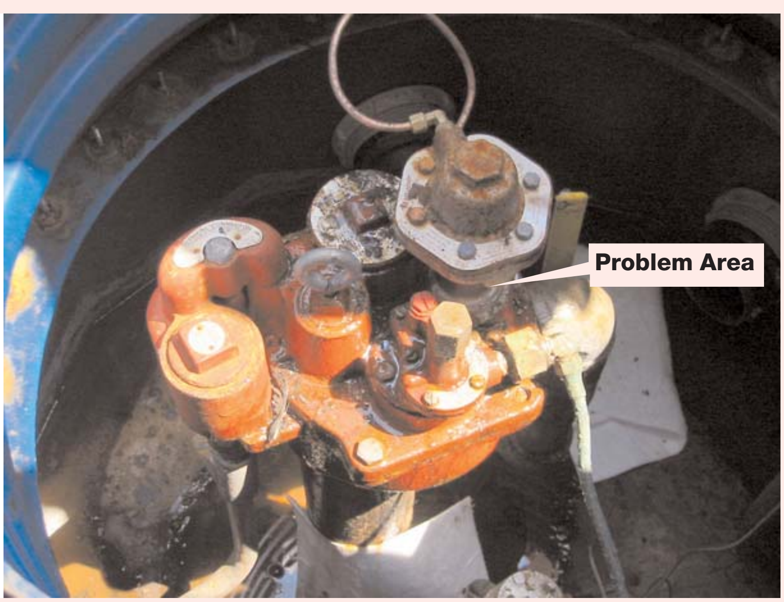

Photo: Courtesy of Marcel Moreau

The equipment affected is unit FX1V Part numbers 116-056-5 and 116-058-5, and unit FX2V Part numbers 116-057-5 and 116-059-5. The date code, printed on the name tag of the leak detector, indicates the manufacture date of the unit. Units manufactured during the affected time period will have a date code of X1206, 0107, X0207, X0307, X0407, or X0507.

For more information, contact the Veeder-Root customer service department at (800) 873-3313. ■

California Publishes a Field Study of ATG and LLD Systems

The California State Water Resources Control Board (SWRCB) recently published a project report entitled *Field Evaluation of Automatic Tank Gauging Systems, Electronic Line Leak Detection Systems, and Mechanical Line Leak Detectors.* As the title suggests, this project involved testing the effectiveness of ATG and LLD systems in the field. Using funding from the USEPA Office of Underground Storage Tanks, the SWRCB contracted with Ken Wilcox Associates to simulate leaks of 0.1 gph, 0.2 gph, and 3 gph at 106 UST facilities throughout California and assess how effective the ATG and LLD systems were at detecting the simulated leaks. As many individuals experienced with UST leak detection might expect, the results were encouraging in some cases and somewhat of a concern in others.

Summary of Findings for ATGs

The overall probability of detection of a leak of 0.20-gal/hr was estimated as 86%, somewhat less than the 95% prescribed by the USEPA performance standards. The probability of detection was significantly associated with the product in the tank, the material or type of construction of the tank, and the size of the tank. The probability of detection was 95% for tanks of 8,000 gallons and less; 84% for tanks from 8,000 gallons to 25,000 gallons; and only 63% for tanks of 26,000 gallons up to 50,000 gallons.

Summary of Findings for MLLDs

The overall probability of detection of a 3-gal/hr leak rate was estimated as 63%, but 76% of the MLLDs detected a leak rate of 5-gal/hr, and 88% detected leak rates up to 10-gal/hr.

Summary of Findings for ELLDs

The estimated probability of detection for ELLDs was 71% at the 3-gal/hr level and 76% at the 5-gal/hr level. A specific problem was identified when a Veeder-Root ELLD was used with an F.E.Petro turbine, leading to a failure of the ELLD to detect the 3-gal/hr leak rate. A maintenance bulletin had been issued earlier pertaining to this issue, but evidently it had not been implemented fully. With this corrected, the probability of detection of 3-gal/hr should increase substantially.

The overall probability of detection was estimated to be 80% for the 0.1-gal/hr leak rate. The overall probability of detection at the 0.2-gal/hr leak rate was estimated to be 70%. Nearly all of the missed detections were traced to an improper installation. Among the ELLDs that were correctly installed, the probability of detection was 96%.

If you are interested in knowing more about how ATG and LLD systems perform in the field, a complete project report for this field study is available at *http://www.waterboards.ca.gov/ust/leak_prevention/lld_atg_study/index.html*

Update on the Bad Gas in West Virginia Story

by Ellen Frye

Back in March 2003 (*LUSTLine* #43), I wrote a story called "Tanks Systems in a Jam—Contaminated Gasoline from a Kentucky Refinery Spurs a Flurry of Tank Cleanups and Lingering Concern." Since you may have forgotten some of the details of this case in the intervening years since that article, I will give you a short synopsis. From 2000 to 2002, Marathon Ashland Petroleum's Catlettsburg, Kentucky, refinery produced gasoline that contained rust, spent caustic, and mercaptan scavenger. This contaminated gasoline was then distributed to wholesalers and jobbers, who transported and sold it to gasoline stations throughout the State of West Virginia under various brand names. The Catlettsburg refinery supplies about 85 percent of the gasoline sold in West Virginia. In September 2002, Marathon undertook remedial efforts to remove the contaminants from the affected USTs.

However, many tank owners believed that Marathon's UST-system cleanup project (Project Mountaineer) was not effective and that their tanks are now damaged. In September 2004, four gasoline retailers from West Virginia filed suit in the United States District Court for the Southern District of West Virginia, Huntington Division (civil action number 3:04-0966, Loudermilk Services, Inc., et al. v. Marathon Petroleum Company LLC). The suit was filed on behalf of the four retailers and as representatives of all companies and persons in West Virginia that received the contaminated gasoline from the defendants. The suit requested the creation of a fund to monitor, test, repair, and potentially replace any USTs affected by the contaminated gasoline.

The first step of the legal process has now been accomplished—the court has certified a "class" for all owners and operators of underground storage tanks in West Virginia who received contaminated gasoline from Marathon Petroleum Company from February 1, 2000 through June 30, 2004. The trial date has been set for September 23, 2008. The court appointed as class counsel Richard Rowe of Goodwin & Goodwin, LLP, *rer@goodwingoodwin.com*; Robert T. Cunningham, Jr., Gregory B. Breedlove, Richard T. Dorman, and Bryan Comer of Cunningham, Bounds, Crowder, Brown and Breedlove, LLC; and James M. Cawley, Jr. of James M. Cawley, Jr., PLLC, *Jay@jaycawley.net*. You can contact the attorneys listed above for details of the case and a copy of the court order. ■

From MN to MA–
Jim Pearson Joins NEIWPCC

After serving for many years as Executive Director of Minnesota's Petroleum Tank Release Cleanup Fund, Jim Pearson is familiar to many in the tanks community. Now, he's taking on a new challenge: Pearson has been named the Director of Drinking Water and Underground Storage Tanks Programs at the New England Interstate Water Pollution Control Commission. NEIWPCC, which publishes *LUSTLine*, is based in Lowell, Massachusetts.

The job is new for Pearson and for NEIWPCC, which for the first time is placing its drinking water and underground storage tanks programs under the authority of one person. It's not a light load. Pearson will plan and facilitate meetings of NEIWPCC's various workgroups in these arenas, manage multiple projects including the creation of guidance documents, and support state and federal staff on the development and implementation of programs and regulations. He'll do everything from coordinating regional comments on federal policy initiatives to overseeing preparations for such events as the National Tanks Conference.

Pearson should be served well by his vast experience in state government in Minnesota, where he established a reputation for successfully building consensus around tough policy issues. His achievements included designing and implementing a statewide abandoned UST removal program that led to the removal of over 100 tanks. Despite his success in Minnesota, Pearson was ready for something new.

"This is a tremendous opportunity," Pearson said. "I'm keeping one foot in the tanks world, where I've enjoyed working for years, and I'll have the other in the drinking water realm, which is exciting on so many levels. It's also a great honor to be at NEIWPCC, which works to solve problems collaboratively, the same as I always have."

Pearson, who started work at NEIWPCC on Sept. 10, can be reached at 978-323-7929 ext. 233 or via email at *jpearson@neiwpcc.org*. ■

UL Not Quite Ready to List E85 Dispensers

Underwriters Laboratories (UL), Northbrook, Illinois, has determined that certain commercially available gasket and seal materials perform acceptably when exposed to concentrated ethanol blends such as E85, while other materials experience significant deterioration. In October, UL announced that it has established certification requirements for E85 fuel-dispensing equipment and is now accepting submittals for certification investigations.

In October 2006 UL suspended authorization for manufacturers to use UL listing or recognition on components for fuel-dispensing devices that specifically reference compatibility with alcohol-blended fuels containing greater than 15 percent alcohol (i.e., ethanol, methanol, other alcohols). The suspension was issued because studies on ethanol indicated that ethanol in high concentrations may significantly degrade equipment.

Some states have gone ahead and certified. According to the U.S. Department of Energy's Alternative Fuels Data Center (*http://www.eere.energy.gov/afdc/resources/technology_bulletin_0307.html*), several states (i.e., CO, IL, IA, MI, MN, NY, OH, OR) and organizations have chosen to grant variances/waivers or have produced a written stance on the E85 Underwriter Laboratories Certification requirements. The website provides letters from these state officials. ■

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STI/SPFA Offers Online Recertification for STI Cathodic-Protection Testers

The Steel Tank Institute/Steel Plate Fabricators Association (STI/SPFA) has announced that cathodic-protection testers for USTs can gain recertification through a new, online examination offered through STI. According to STI, the easy-to-follow, interactive exam is available to cathodic-protection testers currently certified by STI or NACE International. The exam is structured so that answers must reflect the body of knowledge in STI's recommended practice for cathodic-protection testing. All who wish to take the test must provide proof of active engagement in the field of cathodic-protection monitoring. In addition, cathodic-protection testers whose STI certifications have expired will be permitted to recertify under this program until February 29, 2008.

Lorri Grainawi, director of technical services for STI/SPFA, says that for several years STI has offered certification programs that require cathodic-protection testers to travel to various locations to obtain and maintain certification. "The online exam decreases time and cost commitments substantially," says Grainawi. "Testers can take the recertification exam from their offices or homes—even on a weekend, if they don't want to disrupt their work schedules."

To register for the exam, which costs $395, visit *www.steeltank.com*, where a library of downloadable review materials is available. After obtaining the materials, the registrant has 59 days to take the recertification exam. After starting the actual exam, the registrant will have 24 hours in which to complete the effort. To date, most testers have finished the exam within two to four hours.

Although the STI certification is generally accepted throughout the United States, some regulatory agencies may have additional requirements. STI recommends that those who wish to take the test check with regulators to ensure that they are aware of all cathodic-protection monitoring mandates in their service areas. ■

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