TANK BOTTOM LIFE, RISK-BASED INSPECTION AND CORROSION

What it takes to implement corrosion prediction of tank bottoms

INDUSTRY tank standards set limits on how long flat bottom tanks may be operated before being internally inspected [sidebar 1] based on tank bottom corrosion rates. But many companies are not collecting sufficient data or even the right kinds of data that would actually save them significant costs or even provide them with good optimal operating intervals. Moreover, without appropriate data collection, tank bottom life estimating methods such as 'similar service', 'risk-based inspection', and statistical methods cannot be properly used. The purpose of this paper is to deliver the following key points:

1. It is critical to collect the right kinds of corrosion data according to a formal protocol.
2. While linear corrosion rate theory may be used for tank bottoms, the corrosion rates are actually non-linear with time. This provides an opportunity for longer tank inspection intervals while decreasing risk.
3. Standards development organisations and corporate joint industry projects should sponsor data collection and assessment programmes that would allow for more accurately applying corrosion rates to increase the overall average inspection interval while at the same time reducing the prevalence of tank bottom leaks resulting from the current inadequate data collection methods and faulty methods being used.

While one might think that inspecting more frequently than necessary is a good thing; it is not. [Sidebar 2].

An important constraint on the scope of this white paper is that it applies only

SIDEBAR 1: Tanks typically have at least two kinds of important documented inspections. The simplest and easiest is the external inspection. This inspection assesses the condition of the tank without taking it out of service. Qualified, experienced, and certified inspectors use standard equipment examination methods such as visual inspection, ultrasonic testing, and other techniques to check the exterior and exposed components of the tank such as shell and roof, but they cannot inspect the tank bottom because of the liquid in the tank. The other kind of inspection is the internal inspection which requires that the tank be removed from service by draining the tank of liquid, cleaning and gas freeing the tank so that it is safe for personnel entry, and sufficiently clean to do a good job on inspection. Cleaning the tank and the internal inspection is the only way that a thorough and definitive inspection of the tank bottom can be made.

SIDEBAR 2: If costs and business interruption were no concern, would it be appropriate to do internal inspections on tanks very frequently such as once per year? The answer is no! Like many decisions in life there are tradeoffs. Taking petroleum tanks out of service generates large amounts of both liquid, solid and gas emissions. Taking them out too often means that the population of tanks must also be larger and the costs passed on to consumers increased. If a tank is taken out of service too infrequently, bottom leaks can develop and enter the ground and pollute ground water resources. If it is taken out too soon, then excessive air pollution results. Increased incidents due to damage mechanisms acting on the tank are also part of the costs of taking them out too frequently. The bottom line is that the best practice is to optimize the tank internal inspection interval and take them out only as often as absolutely necessary by balancing the chance of a corrosion hole and being too conservative on the inspection interval.

SIDEBAR 3: Stress corrosion cracking (SCC), also called environmental assisted cracking, is a common phenomenon for metals and alloys in contact with specific chemical solutions and temperature ranges. One of the most recent serious explosions involving SCC was the manufacture of NDK crystals used for electronic devices. Large pressure vessels containing silica and sodium hydroxide to grow crystals of quartz at high temperatures and pressures exploded on 12/7/09 and involved a fatality. Another common problem with SCC involves the storage of anhydrous ammonia in steel pressure vessels. The amount of water in the solution is critical to the ability of the steel to crack. Another common SCC incident involves austenitic stainless steel tanks, piping, and pressure vessels exposed to chloride containing solutions. When the temperature is somewhat above ambient temperature cracking though the wall thickness can occur in a matter of hours to days. The whole subject of SCC is highly technical and complex and surely in the domain of corrosion scientists and engineers who specialize in this topic. Fortunately, for flat bottom ambient temperature petroleum and petrochemical storage tanks, the problems with SCC have been minimal. However, there are some cases with storage tanks involving SCC. The most notable is fuel ethanol SCC. This corrosion mechanism has caused numerous tank bottoms and floating roofs to fail. The details are covered by API 939. There have also been rare instances of methanol SCC reported in refineries. But fortunately, today, the prevalence of ethanol SCC has been reduced by the action of corrosion inhibitors.

SIDEBAR 4: The topside corrosion in petroleum tanks is aggravated by sludge, coating failures, debris, water bottoms and scale that sit on the tank bottom. The presence of water is an important mechanism in corrosion. While crude oil tanks have large amounts of water bottoms with corrosive salts in them, even finished fuel tanks have some water on the bottom that settles out due to droplet coalescence. The environmental corrosion conditions vary widely on both the topside and the bottom side of the tank bottom. The diversity of corrosion in tank bottoms matches the diversity of the environment to which the bottom is exposed. There is a gradient of corrosion chemistry conditions on the underside because near the perimeter, water, moisture and salts can migrate under the bottom, but diffusion of these substances is progressively more difficult as we near the centre of the tank. Experience shows that there is often a band of ideal conditions where pitting and corrosion are maximised at some radius less than the radius of the tank, but not always.

to ambient temperature tank bottoms of approximately ¼ inch thickness mild carbon steel in fuel and crude oil tanks. It does not address environmental stress corrosion cracking [Sidebar 3] such as that triggered by ethanol or other chemical environments that promote cracking. Finally, it applies to flat bottom tanks such as those constructed to API 650 or EN14015.

CORROSION

A tank bottom is subject to both topside and bottomside corrosion. [sidebar4] Corrosion can be a mix of relatively uniform thinning but almost always

SIDEBAR 5: API 653 corrosion rate is always less than the linear corrosion rate. It is actually not a corrosion rate at all but part of a larger algorithm to determine the inspection operating interval. It should definitely not be used for any statistical analysis or survival analysis as it will lead to erroneous conclusions and results. Instead, either use the standard linear corrosion rate methodology or else use the enhanced method involving the power law as described in part 2 of this paper. The two graphic panels show the definitions of the standard linear corrosion rate model and the API 653 model differences.

coexists with pitting and variable thinning. The maximum pitting corrosion rate is what usually causes a tank bottom hole and thus a tank bottom leak.

On the soil side of the tank bottom, the conditions are also highly variable. There are some sites where the average corrosion rate over the life of the tank can be over 10 to 15 mils per year (mpy) and others where the corrosion rate is less than 1 mpy.

In most cases the length of the operating service interval is governed by the corrosion rate on the tank bottom (but not always and when damage in other components rises to a dangerous level, then a shutdown is required regardless of the tank bottom condition). This is because all of the nationally recognized recommended practices, guidelines and standards set the maximum interval allowed between the time the tank is inspected to the time that it must again be taken out of service for the next inspection based on the tank bottom corrosion rates.

In this article we show how data should be collected for the purpose of more accurate modeling of tank bottom corrosion rates.

LINEAR MODEL OF CORROSION

API standards such as API 570 Piping Inspection Code or API 510 Pressure Vessel Inspection Code use a linear corrosion rate model. This model simply takes the metal loss divided by the time in service. In other words, corrosion thinning is proportional to time in service. A few important points:

- The corrosion rate is measured at a fixed location both at the beginning and end of the service interval. It assumes that the service has been the same throughout the operating interval (i.e. storage of one type of product). Note that without initial information on the location and thickness of a component, the nominal thickness is often used.
- The measurement of corrosion that is used for determination of the next internal inspection interval is based on the maximum depth of corrosion and some safety factor called the minimum remaining thickness (exception – see Sidebar 5).

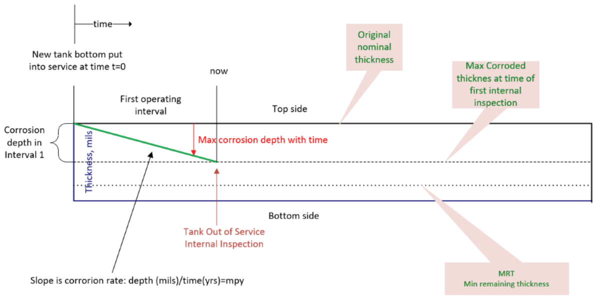
API 653 defines corrosion rate in the definitions this way, but then changes the definition to use the **repair-to thickness** for determination of inspection intervals. Either the linear corrosion rate or the power law corrosion rate should be used for any analysis where survival probabilities are applied such as for Risk Based Inspection, Similar Service, or simply tank bottom life estimates [Sidebar 5].

For more information:

This article was written by Phil Myers, Founder of PEMY Consulting. Part 2 will explain how to model corrosion rates of tank bottoms when using Risk Based Inspection and Similar Service and will appear in the August/September edition of *Tank Storage Magazine*. Myers was past chair of the API Subcommittee on Aboveground Storage Tanks and a current member and his consultance supports the oil and gas industry with advanced engineering, modeling and risk assessment

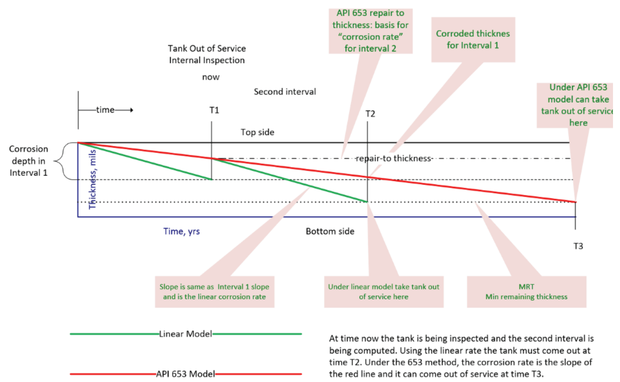
BASIC LINEAR CORROSION RATE DETERMINATION

See Sidebar 5 for explanation



Example: The rectangle represents the tank bottom. Tank interval is 10 yrs. Assume original nominal thickness = 250 mils, MRT=100 mils, max depth of corrosion observed at end of first operating interval is 200 mils. Linear corrosion rate is 200mils/10yr=20mpy. Note we are assuming there is no bottomside corrosion but the principles apply just the same.

DETERMINING THE NEXT INTERVAL #2



At time now the tank is being inspected and the second interval is being computed. Using the linear rate the tank must come out at time T2. Under the 653 method, the corrosion rate is the slope of the red line and it can come out of service at time T3.