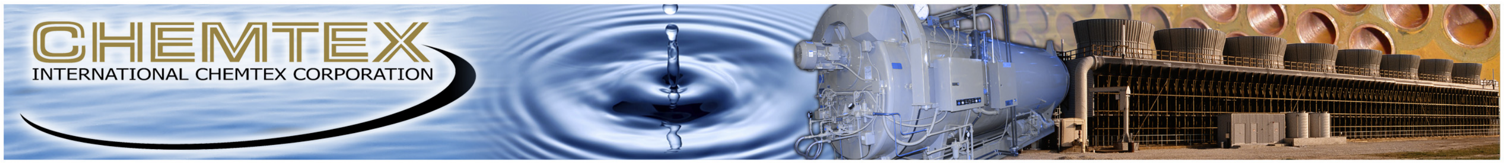

WATER TREATMENT NEWS

Does Your Chemical Program Fit Your Boiler System?

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Most boiler systems today burn natural gas as the primary fuel. Many systems are also set up to burn an alternate fuel if the natural gas supply is curtailed or cut off. In most cases, the alternate fuel is No. 2 fuel oil, a light distillate that is the same as diesel fuel.

Some industrial and utility boilers may use No. 6 oil as the alternate fuel. No. 6 is a heavy residual oil that must be heated to approximately 150°F to be easily pumped. If No. 6 oil were fed to a boiler that was set up to burn No. 2, the burner would not burn the fuel efficiently, and the unit's combustion efficiency would decrease. No. 6 oil is not a good "fit" for a boiler set up to burn no. 2.

Just as the type and quality of the fuel affects a boiler's combustion efficiency, the type and quality of the water treatment chemical program has an impact on the *overall* efficiency of the boiler system. If the chemical treatment program is not a good fit for the system, overall efficiency can be reduced, with a corresponding increase in operational costs. In today's uncertain economic environment, this can put a company or facility at a competitive disadvantage, even threatening its very survival.

How do you know if your water treatment chemical program is a good fit for your facility's boiler system? This question was partially addressed in a past issue of this Newsletter. The Winter, 2002 edition of *The Water Treatment News* explored the use of "one drum" boiler water treatment products in steam boiler systems. That issue evaluated the experience of a plant engineer in a major brewery in using a one drum product in his plant's boiler system. The engineer was initially swayed by the sales presentation of a water treatment salesman who touted the purported advantages of a one drum program for the brewery's boiler system. Use of the one drum program for six months taught the plant engineer an expensive lesson – one drum boiler treatments are not a good fit for systems with varying steam demand or variations in feedwater chemistry. Using the one drum program raised the brewery's treatment costs over the six-month trial period.

Changing steam demand and variations in feedwater chemistry are factors that most boiler systems experience. A good chemical program has the flexibility necessary to respond to these changes and provide complete scale and corrosion control under all operating conditions.

Arguably the most important function of a boiler water treatment program is scale control. Scale results when feedwater hardness precipitates in the boiler and forms a solid material called sludge. The sludge accumulates on the boiler tubes and other internal surfaces and bakes into a hard deposit (scale) that decreases heat transfer, increasing fuel consumption and driving up operational costs. Scale can also result in under-deposit corrosion

To prevent boiler scale, the water treater can use one of two types of treatment approaches – a chelant program or a precipitation program. The word chelant is taken from the Greek word "chela," meaning "claw." The chelant "grabs on," figuratively, to feedwater hardness, keeping it in solution. A correctly applied chelant maintains the hardness in

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solution, thus no sludge forms. With no sludge formation, scale is prevented. However, chelant programs require precise feed control. A slight underfeed will allow scale to form, and even a small overfeed can result in chelant corrosion, which is extremely damaging to boiler internals. For these and other reasons, chelant programs are not well suited for use in most small to medium industrial and heating boiler systems.

In most of these types of systems, precipitation programs are used for scale control. The most commonly used precipitating agents are carbonate and phosphate. Using carbonate, the hardness is precipitated as calcium carbonate and magnesium hydroxide. In a correctly controlled phosphate program, the precipitants are a form of calcium phosphate called calcium hydroxyapatite, and magnesium hydroxide. Unless feedwater hardness is very high [approximately 5-10 parts per million (ppm) or higher], phosphate is preferable to carbonate, because hydroxyapatite is less adherent than calcium carbonate and more easily removed through blowdown.

To assure that the precipitated hardness is completely removed from the boiler, one or more polymers are included in the chemical program. Polymers are long chain organic molecules that adsorb onto sludge particles, and because they are carry a slight negative electrical charge, disperse the particles, preventing them from agglomerating and adhering to the boiler metal, and allowing for their easy removal in the blowdown.

Phosphonates are also often used to keep the sludge particles fluid and non-adherent. With good control of a phosphate/polymer/phosphonate program, the boiler internals can be maintained completely free of scale.

Another important component of a good boiler treatment program is oxygen corrosion control. Oxygen levels as low as one ppm or less in the boiler feedwater can cause pitting type corrosion on boiler tubes and other internal surfaces. Oxygen pits can quickly penetrate a boiler tube, shutting down the boiler and requiring tube repair or replacement.

Some boiler systems have deaerators, which are devices that heat boiler feedwater and drive off most of the oxygen. Other systems have vented feedwater tanks, in which the heat from the returned condensate drives off some of the dissolved oxygen. In either case, the remaining oxygen must be removed from the feedwater to prevent oxygen pitting in the boiler and condensate system.

Chemicals used for this purpose are called oxygen scavengers, the most commonly-used of which is sodium sulfite. Sodium sulfite reacts with feedwater dissolved oxygen to form sodium sulfate, an innocuous salt that is removed in the blowdown. Sodium sulfite is available as a powder or as an aqueous solution.

As sodium sulfite has limited solubility, more concentrated solutions are made with the more soluble sodium bisulfite, which also reacts with oxygen to form sodium sulfate. It should be noted, however, that an additional product of the bisulfite/oxygen reaction is sulfuric acid, which lowers the pH of the feedwater. When a liquid bisulfite oxygen scavenger is used, additional alkalinity builder is usually required to maintain the correct boiler water pH and alkalinity.

An alternative to sulfite or bisulfite as an oxygen scavenger is diethylhydroxylamine (DEHA). While sulfite and bisulfite increase boiler water total dissolved solids (TDS) content, increasing blowdown demand, DEHA does not add solids to the boiler water. In addition, DEHA is volatile, so the excess over that needed for oxygen removal in the boiler carries off with the steam and is available to prevent oxygen corrosion in the condensate due to air in-leakage in condensate receivers and piping.

When the steam leaves the boiler, the water treatment program's job is still not done. When the steam has completed its work of heating a process, product or space, it condenses back into liquid water called condensate. In most systems, the condensate is collected in condensate receivers, from where it is returned to the boiler room and reused to make more steam.

Condensate receivers and piping are highly susceptible to corrosion. The primary type of corrosion that occurs in the condensate system is a generalized type of corrosion caused by acidic condensate. This corrosion is caused by carbon dioxide (CO_2), most of which is generated in the boiler as a result of the thermal decomposition of bicarbonate alkalinity that enters the boiler as a naturally-occurring constituent of system make-up water. The carbon dioxide leaves the boiler along with the steam and, when the steam condenses back into its liquid state, dissolves in the condensate to form carbonic acid. The pH of untreated condensate is typically in the range of 5.5 – 6.5, making the condensate corrosive to condensate piping.

The final component of the chemical treatment program is the condensate return line treatment. Two types of condensate return treatments are available – neutralizing amines and filming amines. Of the two types, by far the most commonly used are the neutralizing amines, which are volatile alkaline liquids. A neutralizing amine is fed to the boiler, where it volatilizes and is carried off with the steam. It can also be injected into the steam line exiting the boiler. When the steam condenses, the neutralizing amine dissolves in the condensate, and, being alkaline, raises the condensate pH. Neutralizing amines are fed at a dosage rate sufficient to raise the condensate pH into the 8.0 to 9.0 range, protecting the condensate system from acidic corrosion.

Filming amines are only slightly soluble, and thus can not be fed into the boiler. They must be injected directly into the steam line using a specially-designed injection nozzle that atomizes the amine into the steam. When the steam condenses, the filming amine coats the condensate piping with a waxy molecule-thin film. The film prevents contact of the acidic condensate with the condensate system metal, thus preventing corrosion of condensate receivers, pumps and piping. Filming amines protect condensate piping against both acidic and oxygen corrosion, but are more difficult to feed and control than neutralizing amines.

Simply put, blowdown is a procedure in which a portion of the boiler water is drawn off and sent to drain. There are two types of blowdown – surface blowdown and bottom blowdown. Each type has a specific function. Bottom blowdown is conducted to remove sludge and other solid material from the mud drum of a water tube boiler or the belly of a fire tube boiler. Bottom blowdown is done on a regular schedule, e.g., once per day, once per shift, three times per week, etc. The frequency of bottom blowdown is established by the water treatment professional, and is a function of boiler feedwater chemistry, boiler internal conditions, steam load and other factors such as boiler type and operating cycle.

The function of surface blowdown is to control the concentration of boiler water dissolved solids, or boiler water cycles of concentration. In conducting surface blowdown, a small amount of boiler water is drawn off from near the surface of the boiler water using a needle valve or other type of flow control valve. Surface blowdown is sometimes automated using an electronic controller that senses the boiler water conductivity and effects surface blowdown by opening an automatic valve such as a motorized ball valve or steam solenoid valve when boiler water conductivity exceeds a pre-determined set-point.

Whether automated or not, surface blowdown plays an integral role in the function of the chemical program by helping control the boiler water chemistry environment. For the chemical program to function properly, the boiler water chemistry must be controlled within relatively tight parameters under what can be constantly changing operating conditions. By maintaining consistent boiler water chemistry, an automatic blowdown controller is an important tool in providing the proper environment for effective scale and corrosion control.

Another important factor in the design of a boiler water treatment program is economics.

Many boiler water treatment chemicals are available in more than one concentration to allow easy and accurate feed control to different sized systems. A typical boiler sludge conditioner, for example, might be designed to be maintained at 200 ppm as product in the boiler water. This would be a good fit, for example, for an 800 horsepower (HP) boiler producing 20,000 pounds of steam per hour at 15 feedwater cycles of concentration. The feed rate of the same product to a 100 HP boiler at 40 cycles of concentration would be so low that it might not be possible to turn down the chemical injection pump low enough to provide accurate dosage control. In this case, a product that contains the same chemical components, but in a formula that required an 800 ppm product residual in the boiler water would be a better fit.

The final factor in the consideration of the suitability of the boiler treatment program is the regulatory requirements. In plants that are governed by the U.S. Food and Drug Administration (FDA) or the U.S. Department of Agriculture (USDA) and in which the steam contacts food or surfaces that contact food, the boiler water treatment chemicals must be formulated using only ingredients that are listed in 21 CFR § 173.310. It is the responsibility of plant personnel to assure that the boiler water chemicals used in their facility are approved for this application. This is usually accomplished by obtaining a letter from the water treatment company that certifies that the chemical products in use in their boiler system meet this approval.

Designing a treatment program that perfectly meets the needs of a plant's steam boiler system is a complicated process. First and foremost, the program must keep the facility's boiler system completely free of scale and corrosion. It must do so economically and, at the same time, comply with all pertinent local, state and federal regulations.

It is the water treatment company's responsibility to provide a chemical treatment program that fits the needs of their customer plant's boiler system, from a technical, performance, economic and regulatory standpoint. It is the responsibility of plant engineering, maintenance and management personnel to choose a water treatment provider that they can trust to design a program that meets those critical needs for their facility. Do you have that trust in your water treatment provider?

Does your chemical program fit your system?

Ask your Chemtex Representative to check it out!