A GUIDE TO OILFIELD TESTING

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Oilfield operations are like an intricate time piece; all gears must be moving in perfect synchronization in order for operations to run smoothly and effectively. When there is deviation from the smooth path from completions through production, how can it be determined where the source of the problem lies? Many issues can be attributed to the slowing or ceasing of flow of production fluid. The culprit can range from water related items such as bacteria or scale to hydrocarbon or gas related issues such as paraffin/asphaltenes and corrosion. Identifying the root cause of the problem can sometimes be difficult. Presented here are various methods of determining how to identify the problems, with a brief introduction to testing methods for the oilfield.

SCALE

The field of scale involves a wide range of compounds that differ in solubility and the conditions that might cause them to precipitate. It is important to know what types of scale are present in the formation, wellbore or flow lines in order to know how to properly remediate the problem. Not only are you initially tasked with determining if the sample is scale but, then you are further tasked with determining what type of scale is present. Historical data for a field can be a good starting place in this determination but it is still best to analytically determine what compounds are present.

A complete water analysis (CWA) is the first step in the analysis of a problematic wellbore. It gives a breakdown of the cations and anions in the sample. This can be used to determine what kind of scale may be present and its severity. The complete water analysis is entered into predictive software that will generate the scaling tendencies for the sample. Care must be taken in selecting the parameters for the scaling tendencies as the pH of the sample and bottom hole temperature can greatly affect the outcome of the predictive software. The Primary downside to this method is that it can not detect what has already precipitated out of the sample downhole; it is only accurate for what is present in the water. This method provides a prediction on what types of scales could be present in order to determine the best treatment options.

In order to obtain a CWA, the sample must be analyzed with an Inductively Coupled Plasma (ICP) instrument. ICP is conducted by misting a small sample of the water through a plasma source that breaks apart the compound and ionizes the atoms. The atoms are then separated by various processes, one of the most common being mass spectrometry. This method separates the ionized atoms by their mass-to-charge ratio before passing into a detector to give a signal proportional to the concentration of the atom. The method is calibrated by a set of known standards for the ions being analyzed, and all samples need to be carefully diluted before testing. The dilution ratio must be recorded in order to back calculate the concentration of the ions in the pure sample.

A solids analysis is conducted in order to determine the percent breakdown of a sample between organic soluble, acid soluble scale, acid insoluble scale, and other solids. The purpose of this test is to ascertain what can break down the solid sample from location in order to determine the best treatment options. It is a multistep process that involves soaking the sample in different solvents followed by filtration and drying. This analysis can also give an estimate on the concentration of acid that should be used for the treatment as well as how long the well needs to stay shut in after treatment to get an effective cleaning. A solids analysis is the best method to determine how to remove scale once it has been formed, but it only gives you an idea of the type of scale depending on the reaction. An exact determination requires running XRD and FTIR.

While a solids analysis will give the breakdown of soluble vs insoluble, an x-ray diffraction instrument will provide the makeup of the solid material being tested and break the compound down to the type of scale present. XRD is conducted by first generating x-rays that are then filtered down to monochromatic radiation. This radiation then bombards the solid sample causing diffractions of the radiation from the 3-D crystalline structure of the sample. These diffractions are then analyzed and compared with known samples to determine the makeup of the solids. One drawback to this method is that you can only identify compounds that you have known standards for. This method can however be used to determine the makeup of the solid sample and give a break down in the concentrations of different type of scales. This method is useful when dealing with acid insoluble scales or scales that might contain different forms of carbonate scale.

The final method for determining scaling issues and selecting a product for treatment is based off of dynamic scale tube blocking (often referred to as PMAC). This method is typically more concerned with scale inhibitor product selection but can also be used to determine how prevalent a scale issue can be downhole. The test is first conducted by running a complete water analysis on the sample to obtain a breakdown of the cations and anions. A synthetic brine is then created for testing in which the cations and anions are separated into two water samples. The synthetic brines are generated so that there is no opportunity for scale to form before being passed through the instrument to limit the interferences in the testing. The synthetic brines are heated in heating columns in an oven chamber to the desired testing temperature before being mixed in a mixing column. The mixing column is going to be the location of any scale formation. Pressure measurements are taken both at the front and back of the mixing column to determine when the small section of tubing starts to block off. This instrument lets you test what conditions will cause scale to form in formation as well as run product testing and evaluation with scale inhibitors in the water.

From time to time you will have a solid sample that gives inconclusive data in the previously mentioned testing methods. These samples are usually polymers or fracture fluid chemicals that remained in the wellbore that require a different method of analysis. One common method is conducting a Fourier transform infrared spectroscopy analysis (FTIR). FTIR is not an exact analysis method but can assist in determining if polymers are present in the sample. An FTIR is conducted by IR radiation being passed through a sample. Some of this radiation is absorbed by the sample while the rest is passed through or transmitted. The radiation that is transmitted to the detector can be interpreted into a spectrum in order to show the function group of a compound. FTIR is typically used when comparing the spectrum of a known compound to that of an unknown in order to try to determine if the spectra are similar or if they match. The downside to FTIR is that you have to already have an idea of what the solid sample is in order to have a baseline for comparison after the analysis. There is also some sample prep time involved in this testing since oil or water that is coating the sample can obscure the data.

It is important to know which test is required to determine the scaling problem since many scales react differently to treatment. You would not want to run an acid job along on a gypsum sample and you would not want to take the time and money to mechanically remove calcite. These testing methods will not only assist in the identification of the scaling problem, but also help recommend the best remediation method available.

PARAFIN AND ASPHALTENES

Paraffins and asphaltenes are naturally occurring in crude oil. Paraffins are long carbon chains that can solidify given the right temperature conditions. Asphaltenes are colloidal solids that are dispersed through the crude oil that can comingle and settle out over time. Both of these types of compounds can give rise to their own problems in oil production, but you also want to keep them in the oil since they can be sold along with the crude. It is important to know which substance you are dealing with so that you can know the proper conditions to limit the problem while maximizing production.

Pour Points are one of the most common analytical tools for determining if paraffin will be problematic in a well. A sample of oil is taken and conditioned in the lab to ensure that all of the paraffin is dispersed throughout the oil sample. The sample is then placed in a chiller where the temperature of the sample is slowly lowered until the sample can no longer flow upon tilting the container. Higher pour point temperatures indicate a larger paraffin problem. Pour Points are increasingly important during winter when it is possible for surface flow lines to reach the temperature at which the paraffin can solidify and restrict or plug the flow line.

Cloud points are temperature measurements taken when the first wax crystal is observed upon chilling the samples. The samples are conditioned in the same way as the pour point samples. This test can give you an estimate for the expected temperature at which paraffin deposition and accumulation is possible.

Cold finger tests are both an analytical tool as well as a screening tool for inhibitors. An untreated oil from the field of interest is collected and conditioned to disperse any paraffin. The oil is then quickly transferred to identical sample containers. The sample containers are either kept as a control or treated with various inhibitor chemicals. The containers are then placed under slight continuous stirring for the remainder of the test to provide flow. The containers are subjected to a constant temperature while a probe is inserted into the sample at a lower temperature. Paraffin slowly adheres to the lower temperature probe throughout the experiment. The probes are then allowed to dry without disturbing the paraffin that has been collected, masses are taken to determine how prevalent the paraffin problem is within the control as well as how efficient the inhibitors worked in the treated sample.

Oil fingerprints combine two separate techniques to give a breakdown of the paraffin and asphaltene impurities. The first method is a solvent extraction method. Initially the paraffin and asphaltenes are forced to precipitate in a sample of known mass. They are then filtered out of the crude sample, dried and weighed to get the mass of the combined solids. The solids are then tested for solubility to remove any paraffin before the remaining asphaltenes are dried and weighed. The mass of paraffin that can precipitate out can be found by subtracting the remaining mass from the original mass. From these masses you can back calculate to the estimated percent paraffin and asphaltenes in the sample. The second procedure involves taking a second sample of the unknown oil and conditioning it to get the paraffin to disperse in the crude oil. A Gas Chromatograph GC is then conducted on the sample to determine what the carbon chain distribution is in the sample.

The final testing method for paraffins and asphaltenes involves using coupons at the wellhead. The coupons are inserted before the flow lines in a position that will allow any passing paraffin a chance to adhere to the coupon. This method allows you to track accumulation of paraffin over a known time so you may determine the severity of the paraffin crystallization. A time log of the mass of paraffin collected on the coupon over the number of days or hours that the coupon has been installed can give an estimated accumulation of paraffin over time for future projections. Care must be taken in the handling, storage, and transportation of coupons since any damage to the coupon or the wax coating will affect the data.

All of the methods for testing paraffin and asphaltenes share one common characteristic, the data obtained from the testing is directly proportional to the quality of the sample that is tested. Samples should be from the same field and formation as the intended new drill, as well as being free from any chemical additives that can affect the crystallization and deposition of paraffin.

CORROSION

While scale, paraffin, and asphaltenes will lead to plugging the wellbore or formation, other problems will arise from ruptures in the tubing. The primary cause of breaks in tubing is due to corrosion in the metal. The corrosion will weaken the tubing or casing causing a failure point that can lead to loss of production. These failures can be observed on the service as drastic drops in pressure and a decrease in production. The only solution to corroded tubing is to pull and replace the section that has been damaged. This is why early detection for corrosion is so important.

One test for predicting the likelihood of corrosion is by determining the concentration of field gasses. The concentration of CO_2 and H_2S can give you an estimate on the conditions downhole and the likelihood of corrosion. It is important to run the test at the wellhead when the samples are collected since the gasses are volatile and will quickly gas off over time.

Coupons can also be used to determine if corrosion is present downhole. A coupon composed of the same material as the tubing is inserted inline with the production flow coming off the wellhead. This coupon is then left in place for a desired amount of time before being removed and returned to the lab that the coupon was obtained from. The lab keeps track of the masses of the coupons before and after field testing in order to determine the percent degradation of the sample overtime. The percent lost can be used to monitor any degradation that is taking place at the location. After determining the percent degradation, tests can be conducted to determine the required concentration of corrosion inhibitor required. A conformation test can then be carried out with the coupon at the wellhead being treated to insure that no degradation is taking place.

The simplest method of determining what type of corrosion is present is also the most expensive method for the customer. This method involves cutting out a section of the pipe that has corroded and examining the failure to determine if the corrosion was due to bacteria or acid. Bacteria induced corrosion will typically have pitting in the failure while acid based corrosion is more of an even failure along the tubing. This is due to the acid passing evenly over the surface of the tubing while the bacteria adhere to a section of the tubing and slowly corrode that section over time.

Most of the common methods for determining if corrosion is present require that some amount of corrosion has already taken place. It is important to know the field history of your location in order to have an understanding of possible problems as well as the different lift systems that have been used in the area. Fields that have been subjected to CO_2 flooding are more likely to have corrosion issues than fields that have undergone water flooding. Historical data can be one of your best tools to prevent corrosion.

BACTERIA

Bacteria can be problematic in the oilfield and cause issues from souring a well by generating H_2S gas to causing corrosion in the pipes. The two predominate types of bacteria of concern in the oilfield are Sulfate Reducing Bacteria (SRB) and Acid Producing Bacteria (APB). The SRB’s take sulfates that are naturally occurring in both fresh and produced water and reduce the sulfates to sulfide. The sulfide can then either combine to form H_2S or Iron Sulfide. H_2S will sour the well and iron sulfide can cause formation plugging/damage. Iron sulfide can be removed with an acid treatment but this treatment will then generate H_2S gas. APB's will produce acid over time that can lead to corrosion. Early treatment of the bacteria and minimizing the introduction of bacteria into the formation can help alleviate problems post completion. The two most common methods for testing of oilfield bacteria are bug bottles and testing for Adenosine Triphosphate (ATP).

The most common method for testing for bacteria is through the use of bug bottles. These bottles contain specific culture media designed to grow and detect a specific type of bacteria (APB or SRB). This method is selective and will give you a logarithmic estimate for the total APB and SRB concentrations. The test is conducted by injecting source water into a bottle filled with a culture media of similar salinity. You then proceed with a serial dilution with the bottles to get a logarithmic estimation on the bacteria concentration. The downside to this test is that it takes up to 28 days to cultivate the samples before an estimate can be obtained. A quicker method that is less accurate is based off of testing for Adenosine Triphosphate (ATP).

ATP testing is conducted when a quick turnaround time is required for the analysis. The testing is not as accurate as bug bottle testing since the ATP test procedure detects all forms of bacteria and not just APBs and SRBs. The test is conducted by passing a sample of the water through a small filter to trap the living bacteria, the bacteria are then broken up to release Adenosine Triphosphate. The chemical is measured by the addition of a luminous agent to produce light. The amount of light given off is then calculated using the instrument to determine the total pictograms per milliliter of ATP in the sample. This value can then give you an estimate for the total concentration of bacteria in the sample. ATP testing is relatively quick to perform and you can have results in ~15 min, but the test is much less accurate in regards to specific types of bacteria.

There are many other methods for testing bacteria in oilfield applications, but this paper focuses on the most common forms of oilfield testing. The described methods should allow you to determine if you have a problem with the most common forms of bacteria and the magnitude of the problem.

While you will encounter vastly different methods of testing for impurities or problems in the oilfield, this paper hopes to explain some of the most common testing that is conducted in order to give a baseline of information for the reader. No matter what problems are encountered, there is a means and a method for determining the root cause and to determine possible remediation or prevention treatments.