IMPROVING PARAFFIN TREATING BY MODERNIZING CHEMICAL APPLICATION VIA PRESSURIZED INJECTION

Greg Darby
Pro-Ject Chemicals, Inc.

INTRODUCTION

Oil from oil and gas wells leads to problematic deposition of paraffin that requires removal through a variety of means. Paraffin remediation from production tubing can be time consuming, difficult, and costly. Flow lines can also plug due to paraffin deposition. This paper describes a novel technology that applies production chemical, including paraffin inhibitor, with a pressurized injection system. The system uses modern electronics and telemetry to apply chemical, integrate chemical injection and flush, and generate reports. Features and benefits as well as field data are discussed.

The application technology described in the paper has been used in various areas of Texas. Over 1,100 pressurized chemical injection systems have been installed on pumping units and ESP systems. The technology uses nitrogen gas to pressurize a chemical reservoir. An electric valve controls the flow of chemical out of the reservoir. The application is typically made to the annulus. A separate electric valve can be mounted on the flow line. The addition of an electric valve to the flow line allows for the integration of the chemical treatment and critical flush operation. A programmable logic controller determines when the electric valves open and how long they stay open. This flexibility in determining when wells are treated and the volume of chemical applied to each application greatly differentiates this system from conventional continuous treating or batch truck treating. A satellite modem can send smart reports to chemical managers and production engineers about system operations, chemical usage, and inventory.

Oil wells produced via pumping unit which use the pressurized chemical system have been able to increase the time interval between well interventions due to paraffin deposition. Overall cost of the chemical injection system is competitive with industry standard positive displacement continuous systems but with many additional standard features. Performance of the treatment and integrated flush improve chemical delivery and improve chemical performance. Pulled tubulars of paraffinic wells treated with the system have been kept free of paraffin or had very little soft wax making stripping and hot oiling unnecessary.

The ability to apply modern electronic circuitry and programmable logic to chemical delivery and improve performance is the primary benefit for a pressurized system. Satellite telemetry allows users to remotely monitor the chemical usage, inventory, and delivery to add a level of confidence and dependability to the system. Improvements have been added recently to tie the pressurized chemical system to either the pumping unit or well PLC/POC to only operate when the well is operating. The system also has the ability to tie into the producer’s internal communication network, further driving down cost and allowing for two way communication.

BACKGROUND

Production chemical applications are a part of life in today’s oilfield. A pressurized chemical injection system has been introduced above. There are other typical applications. Typical applications include continuous application via a positive displacement pump, treater truck batch treatments, or chemical squeezes. Each of these applications has its benefits but each also has significant negative characteristics.

Squeeze applications can be used to provide multi-month chemical residuals via one large reservoir displacement. The downside is that very large liquid volumes are pushed back into the wellbore. Time is required to recover the fluids and reservoir characteristics can be altered with the displacement. Well performance can be negatively impacted.

Treater truck applications are a common chemical delivery method but the treatment is usually sporadic and residual levels are not consistent. For some time frame, there could be a period where chemical residuals are below effective dosage levels. Treater truck applications frequently use a water pill to help flush the chemical treatment through the existing annular fluid column. This water is taken from a produced water tank or other water source different from the well being treated. It is possible the water used for the flush could introduce bacteria or a scaling risk to the well being treated.

Continuous application provides a consistent chemical residual level and efficient chemical delivery. However, it too has some negatives. Chemical pumps move chemical by having to overcome the pressure of the environment where the chemical is to be delivered. Chemical pumps consist of suction and discharge balls and seats which are subject to sticking or failing to seat for any number of reasons. Pump maintenance can be time consuming and costly. Broken and out of service chemical pumps contribute to well problems by not delivering the chemical needed to stop problems.

Continuous applications are frequently used in conjunction with what is known as a slip stream flush. A slip stream flush is a diverted fluid stream from the flow line back to the annulus. This stream is mixed with the chemical application to help disperse the chemical application and help it get through the well fluid level.

Slip stream flush can be effective if it functions properly. Slip streams often fail to consistently operate because pressure differences between the flow line source and the annulus target are often very high or very low. If the pressure difference is high, the slip stream can introduce large volumes of fluids to the annulus. Too much fluid to the annulus can negatively affect well production. A large pressure difference can also lead to having to pinch off control valves, such as needle valves or ball valves. Restricting the flow of fluid through the control valves can easily lead to solids build up, blocking the slip stream flow.

Numerous techniques are available to producers for introducing chemicals into wells for protection and performance but as one can see each technique has significant problems which the chemical industry has been slow to remedy. The rate of new and improved techniques introduced into the industry has been slow. The invention of a pressurized chemical injection introduced to the marketplace within the last 10 years, and greatly improved upon over the last two years, appears to be a much needed industry improvement in chemical application, efficiency, and effectiveness.

PRESSURIZED CHEMICAL INJECTION

Features and Benefits

A pressurized chemical injection system can be built which makes use of modern electronics, computer technology, and satellite telemetry that is cost effective to build versus a continuous injection. A system without satellite telemetry is cheaper to build and install than a traditional continuous injection system while improving chemical performance.

A pressurized chemical injection system consists of a pressure vessel which serves as the reservoir for the production chemical. The vessel is pressurized with nitrogen gas. The pressure of the vessel is the driving force which allows the chemical to move out of the vessel and into the location to be treated, typically a well or production tank. A regulator on the vessel can be used to regulate the pressure to control the pressure difference between the vessel and location to be treated. As the volume of chemical is depleted, the pressure drops. The system can be operated so that the lowest pressure of the tank is higher than the target location. When the pressurized vessel is refilled, the nitrogen is compressed to a higher pressure.

Most conventional chemical injection pumps use pressurized gas or electricity. They typically function by being on all the time. Electric pumps have the ability to be intermittently on or off or to operate with the operability of an oil well but rarely is this utilized. Chemical pumps are either on or off.

Chemical pumps are designed to operate in a range of chemical discharge volumes. Pumps either pump high volumes or low volumes. High volume pumps cannot operate efficiently at low volumes and low volume pumps obviously cannot pump high volumes. An electrically operated valve of a pressurized injection system can be made to control the flow of chemical out of the vessel. The vessel is always pressurized so no additional nitrogen is needed to operate the system once pressurized. The functioning of the valve controls the flow. By not relying on a positive displacement piston to move the liquid through the pump, the pressurized system can be made to either operate as a high volume pump or low volume pump. The frequency and duration of the open electric valve determines the flow. This flexibility in flow provides a very unique ability to fine tune chemical injection rates, especially very low rates. Flowing the chemical allows for consistent delivery of rates less than a quart per day consistently and reliably.

An electric internal float can be installed inside the pressurized tank to provide a level reading. An internal float removes the risk that is inherent in a glass sight glass. Sight glasses are typically made of glass and are prone to breaking and spillage. Continuous chemical injection systems rely on a sight glass to determine the chemical inventory and is also used to determine the flow rate. The typical monitoring of a continuous injection system generally requires a person to physically go by the pump and manually take inventory and injection rate.

A pressurized chemical injection system making use of modern technology can broadcast system parameters remotely. Telemetry methods such as satellite, cellular or mesh networks are available. The typical method is via satellite. Telemetry can broadcast information from the float such as tank level/inventory and injection rate. Chemical injection rate out of the pressurized vessel is determined by inventory or what is in the tank. Most chemical injection rates using continuous injection systems measure chemical rate by what is leaving the chemical tank. A pressurized system uses what is left behind rather than what leaves.

The chemical injection system data can be broadcast via telemetry to give users confidence in the operation of the system. Alarms currently established include low power, low level, or a no flow situation. Alarms provide a level of confidence for wells that are remote, critical, or in difficult to access locations.

Typical continuous injection systems pump continuously. The pumps operate independent of the well they are set up to treat. Wells that are on timers or pump off controllers operate intermittently. The chemical pumps, being independent of the well, operate continuously, whether the well is pumping or not. An electronic pressurized system has the capability to either tie into the well either through dry contacts on the pumping unit motor or via a parallel port into the pump off controller. By acting as part of the well, the chemical injection system can be programmed to only operate when the well is making fluid. If the well is in an “off” cycle, the chemical injection system stops. If it is time to do a treatment but the well is down, the chemical system holds the treatment in reserve and waits until the well is in the “on” cycle. If the well is on a work over of out of service for some other reason, the chemical system shuts down. When down wells are brought back online, the system begins its monitoring of the well again and restarts the programmed chemical injection.

The electronics which control the pressurized injection system require very little power. Power is needed to operate the satellite modem, the electric valves, and read the float. The power supply comes from a rechargeable battery charged by a solar panel. The system keeps track of the battery charge and sends an error message if the battery is not being charged.

Many continuous chemical applications are used in conjunction with a slipstream flush. A slipstream flush is a fluid diversion line run from a producing oil well flow line back to the annular space between the tubing and casing. The flush fluid diverted from the flow line is used to help disperse the chemical injected down the casing to keep it off the casing and tubing walls and help wash it down the well.

Large pressure differences between the flowline and casing often times require the control valves used to regulate the fluid flow, usually a needle or ball valve, to be restricted to prevent flooding the annulus. The restricted valve becomes prone to plugging with scale, sand or other materials. The absence of the flush fluid often times renders the chemical ineffective.

An electronic pressurized chemical system can make use of excess battery power to operate an electric ball valve on the flowline to act as a flushing valve. The outlet of the flush valve can be diverted to the annulus. When the chemical injection valve opens, the flush valve also opens providing flush fluid for the chemical in a controlled and efficient manner. No outside truck is required to deliver the chemical, no outside fluid is required for flush fluid, and wear and tear on lease roads is prevented. The flush valve only operates for a few minutes to flush the chemical and then shuts. The duration of the flush can be programmed to ensure adequate fluid to disperse the chemical but prevent flooding the annulus. The flushing valve is a full open half inch ball valve. A full open valve provides a sufficient volume of flush without a risk of plugging. When the valve opens it sees the full pressure difference between the flowline and casing, minimizing the risk of plugging.

RESULTS

H2S Treatment

Oil wells in Barnhart, TX were producing approximately 1500 ppm H2S in the gas phase. The high H2S was being treated with H2S scavenger on the flowline leaving the casing and with periodic batch treatments down the casing. High H2S content resulting from the poor H2S chemical treatment lead to frequent pipeline shut ins. The pipeline shut ins resulted in well shut ins. The shut in wells would require batch treatment slugs of bactericide and scavenger to knock down the H2S levels so that the wells could be brought back online. The wells would produce until the next pipeline shut in. A new chemical approach was required.

A pressurized chemical system, incorporating all the features and benefits discussed above, was employed to apply H2S scavenger into the annulus. A flushing valve was connected to the flowline to provide flush fluid when the chemical treatment was applied.

The initial test well produced 39 bowp, 63 bwpd, and 19 mscf per day. The well produced 1500 ppm H2S in the gas phase. The pressurized chemical injection system was set up to deliver 8 daily micro batches every 3 hours. The total chemical injection was 6 gallons per day.

Baseline H2S readings at the wellhead prior to starting the pressurized chemical injection system with H2S scavenger was 1500 ppm. 6 gallons per day of chemical were applied daily in micro batches of 3 quarts every 3 hours. H2S readings immediately came down and stayed down with the start of the new chemical application. The 3 quart slugs every 3 hours were enough to keep the H2S levels low until the next micro batch. The system flush was established to flush 5 minutes. The chemical injection application lasted 20 seconds.

H2S readings immediately dropped. H2S tubes pulled at the wellhead confirmed the reduction. The success of the treatment on the initial well prompted additional systems on other wells on the same loop. H2S tubes pulled confirmed the performance at the new injection points. Electronic monitors at the gas sales point also confirmed the decrease. Over time the performance of the pressurized injection system proved to be an improved chemical delivery method. Gas sales valve shut ins stopped and the number of pressurized chemical hook ups increased.

Paraffin Treatment

Paraffin treatment is an expensive problem in the Permian and manifests itself in a variety of ways. Paraffin deposition in the tubing can restrict flow. Secondary lift systems such as rod pump can become stuck. Stuck sucker rods can part, resulting in expensive fishing jobs to retrieve the rods. Wells with stuck sucker rods may need to have the paraffin stripped from the tubing to remove paraffin and retrieve the rods. Stripping jobs can cost over a hundred thousand dollars in extreme cases. Hot oil or hot water treatments provide temporary benefit but over time concentrate high melting point wax. Wax deposition in flowlines creates additional problems. Efficient and cost effective wax management strategies are required.

A field near Patricia, Texas was experiencing extensive paraffin deposition issues on a large number of wells throughout the field. Wells were requiring frequent hot water jobs and many stripping jobs. The produced paraffin created emulsion problems in fluids separation vessels and resulted in a heavy dosage of emulsion breaker to help separate fluids and also prevent tank bottoms. The tank bottoms were resulting in a lot of turndowns from oil haulers. The wax issues resulted in increased costs to operate the wells due to ineffective chemical usage, hot watering, and stripping. The paraffin also contributed to increased costs in chemical treatment at the battery. A field trial was ordered for a pressurized chemical system to see if better paraffin treating was possible.

A pressurized chemical injection system was hooked up to apply a chemical capable of treating multiple phases of the production. The chemical consisted of an additive suitable for treating paraffin in the oil phase and a corrosion inhibitor additive capable of treating the water phase. The initial injection rate of the chemical was set at 3.5 quarts per day. Well production was 26 bopd, 50 bwpd, and 35.5 mcfd. The chemical injection rate was approximately 480 ppm for wax and 125 ppm for corrosion. A small amount of emulsion breaker in the chemical formulation accounted for approximately 40 ppm emulsion breaker in the oil phase.

Wellhead samples taken before starting the pressurized chemical injection system showed a severe emulsion. Wellhead samples taken after the system was started showed a clean oil water interface, indicating the chemical application from the pressurized system was already starting to affect the emulsion treatment at the well.

Treatment costs for the initial trial represented $0.61/BOE and $0.24/Total bbl or $19 per day. Several months of treatment were performed before the well was pulled due to a hole in the tubing. The rod strings were pulled without issue and were clean of paraffin. The pump was pulled without incident and was free of paraffin. The tubing was pulled and evidence of a significant corrosion inhibitor film was present. The tubing OD was black and did not oxidize once water evaporated off the pipe. The tubing section with the hole was cut with a band saw and one could see the reason for the hole was severe rod wear.

The absence of paraffin on the rods and pump during the pull for the hole in the tubing indicated the paraffin chemical performance via the pressurized system was favorable and warranted further review. The trial was expanded to the additional wells on the loop. The loop consisted of 14 wells including the initial test well as well as a treatment tank battery. The fluids entering the tank battery consisted only of the wells on the loop. The chemical application to the other wells consisted of the same chemical as that applied to the initial test well.

Discussions from operations personnel indicated an immediate improvement was seen in pump cards. Also, during the first week of the test it was noticed that the oil quality from primary treating vessels at the battery improved. Wellhead samples and primary separation vessels all showed a reduction in emulsion. Wellhead samples showed rapid oil/water separation when samples were taken.

Prior to starting the pressurized chemical system trial, tank battery chemical treatment included a 40 gallon per day injection of emulsion breaker to aid in fluids separation and help prevent tank bottoms. Wellhead sampling after starting the test showed the oil at the wells was being treated downhole. The battery emulsion breaker was slowly decreased until it was shut off. Primary separation vessel sampling and stock tank monitoring showed that the 40 gallons per day of emulsion breaker at the battery was not required and was eliminated, resulting in a substantial cost savings.

The pressurized chemical injection system has remained in place for 4 months. The initial field trials began in October, 2014. As of mid-March, 2015 no pulling jobs due to paraffin have been required. It is estimated that $133,000 in savings has been realized due to eliminating the emulsion breaker injection at the battery. No turn downs due to bad oil have been experienced. No tank bottoms have had to be vacuumed although some tanks have been rolled to resolve some interfacial emulsion. No additional hot water or stripping jobs have been required since October 2014. No paraffin related pulling jobs have been experienced on the loop since starting treatment with the pressurized injection system. Wells treated with a pressurized chemical injection system have shown to provide a more consistent and effective paraffin treatment program. Emulsion resolution has been shown to be an additional benefit. The resolution of the emulsion at the wellhead has led to a lower overall cost by eliminating added tank battery treatments.

Average well production for the wells on the loop was 22 bopd and 59 bwdp. The chemical treatment costs with the pressurized chemical injection system averaged $16.89/day. Cost per barrel for the loop equated to $0.64/BOE and $0.20 per total barrel. No paraffin related pulls have been experienced in 4 months. Chemical treatment optimization has begun. The target rate at present is to reduce treatment levels to $0.39/BOE and $0.12/total barrel or a little over $10/day per well average.

The pressurized chemical injection system is being used in the Permian Basin for more than just paraffin treating. In the same area as the paraffin treatment study shown above are other wells on other loops. Not all wells suffer from paraffin related issues. Overall costs in this area for all treatments using the pressurized chemical injection system is $0.28/BOE and $0.09/total bbl.

CONCLUSIONS

Over 1,500 wells are being treated with chemical supplied from a pressurized chemical injection system. The data gathered to date indicates the system is a technological improvement over both continuous treatment and truck treating. A pressurized chemical injection system does not necessarily make a chemical better but applies chemical consistently better enabling it to do its intended function.

Pressurized chemical injection has improved well performance by keeping wells running longer. The improvements have shown up in improved pump cards, longer runs between pulls due to paraffin, and reduced H2S levels. Other benefits realized with the system but not discussed in this paper include reduced well failures due to corrosion and scale. Improved application, combined with modern PLC control and telemetry, have the capability to make a pressurized chemical injection system a welcome and needed upgrade to oilfield chemical applications.