BEST PRACTICES IN DIAGNOSTICS TO ADDRESS WELL INTEGRITY PROBLEMS AND REPAIRS

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ABSTRACT
The values that can be obtained from understanding what problems or needs are required in resolving existing well performance are often not taken into account when applying solution treatments. Many times, operators do not perform diagnostics based on past experiences having shown an inability to correctly interpret problems. Costs involved with performing some diagnostic analysis can be rather high and may often times show that what was assumed is correct. Often times, the knowledge and understanding in applying a diagnostic analysis is not capable of obtaining the information needed or addresses the parameters ongoing in a multitude of effects. Many times, providers of solutions give the message that a product will work in any condition and diagnostics are not needed. The operator will readily accept this idea since; there is not a need to spend money to develop necessary criterias and requirements necessary to accomplish a successful solution.[1]

Upfront in Best Practices, Diagnostics may be required to (A) identify well integrity issues, define the various well or reservoir conditions, or they may be needed to (B) define and develop a solution required to fix the various understood problems that may occur. In practice, this compares to the "Chicken or Egg Theory," which came first?

INTRODUCTION
Comprehensively identifying the source of a problem is the first and most important step in solving it. Only after a problem has been properly identified, can it be effectively treated. Just as a medical doctor cannot effectively treat internal bleeding with a bandage, a water-coning problem cannot be effectively treated with a cement squeeze job.

Also, if possible, it is better to foresee a potential problem and take steps to avoid or minimize it than to affect a cure after the problem occurs. Again, it is more effective to get regular medical checkups, eat properly, and exercise rather than ignore one's health until heart by-pass surgery is needed. It is also more effective to gather information on a reservoir, simulate its future behavior, and treat it to minimize or eliminate a future coning problem than ignore the health of a well until it waters out. Understanding the source or potential source of a problem requires thorough investigation of all aspects of well and reservoir parameters.

The ability to diagnose a problem or anomaly that is happening within a reservoir or near a wellbore is not always easy. Development of new generation tools and devices to interpret what is occurring may lead to a better understanding of the proper solution and method that a treatment may be applied. Often, a need to diagnose a treatment while being placed; i.e. in real-time, may be necessary to the successful problem resolution.

Some examples of Diagnostics giving successes are discussed in this paper and are presented showing both the identification processes using proper investigation techniques and how Diagnostics Techniques are employed to determine qualified attributes needed in the solutions, their size (volume), and placement techniques on treatments.
Other Diagnostics utilized by operators may range from defining performance aspects within a Reservoir Model to performing integrity tests with tools. These techniques are not discussed in detail, but are part of the synergized efforts operators must rely on to identify and control well performance.

TREATMENT PLACEMENT AND JOB EXECUTION
The understanding through diagnostics of what may or may not be happening in one's reservoir will give the best practice method(s) in addressing how to place a treatment. Most often, problem identifications addressing conditions and performances in production and/or injection can be qualified. Determinations as to the best solution that may be utilized to modify or change

the reservoir conditions which will lead to a better production should be based on performance properties of the solutions and economics involved.

Often times, the diagnostics being performed to determine the problem(s) may also be utilized to determine the applicable placement technique to best address the cause of poor performance in production or injection. With this same investigation used to determine the problems, one may determine the best suited solution and how it may be placed.

The improved conditions needed to achieve maximization in production is often times limited due to using a limited range of solutions with a misunderstanding of how to properly place the material in the most advantageous portion of the reservoir. Simply dumping in or squeezing a material in a well and justifying placement on a possible misleading pressure response has led to the "reported failure" of Remediation Treatments at 70-80 percent.

Historically, when proper diagnostics are used in the process of Problem Identification, Best Solution Method, and using a proper Placement Technique to solve the poor production or injection performance, desired results have been achieved. Most failures in obtaining a successful result can be attributed to not applying a diagnostically determined "Best Placement Technique." Proper placements have shown to improve results from the norm of 30 percent up to 85-95 percent success[2].

Job execution and onsite knowledgeable interpretation insures the proper placement of solutions. Many operators recognize the need to have this understanding and utilize the available tools and knowledge gained from years of performing these treatments. A synergistic approach using all available technologies; including Coil Tubing, Special Tools, Logging Analysis, Pumping Services, Reservoir Analysis, Pressure Transient Analysis, Production Enhancement, Surface Facilities Development, and Production Services are utilized by successful operators' Production and Reservoir Management groups to focus towards these goals.

Successful operators' focus starts from the beginning understand of what cause and effect may be giving less than desired production or injection performance in the reservoir. The operator's tasks then are to; development and selection of capable products, selecting the methods to address a varied and wide requirement, the designing, and interpreting the placement of these solutions needed to enhance well performance.

PROBLEM SOURCES & DIAGNOSIS METHODS

A list of potential remediation problems follows. The problems are classified as either near-wellbore or reservoir-related. However, some of the problems listed could easily fall into either category. For example, even though barrier breakdown is related to fracturing out of zone and could be considered reservoir-related, it is listed as a near-wellbore problem. Likewise, although coning and cresting occur in the near-wellbore region and can result from a completion too near the water or gas zone, they are considered reservoir-related. For each problem, technologies that can help identify the source are presented. More detailed information on fluid influx into the casing/formation annulus, coning and cresting, channeling, and fingering is referenced in the Manual: "Conformance Technologies," - "Nonconformance Phenomena" section, Chapter 2[1]. "Technologies for Problem Identification and Treatment Evaluation" contains more detailed information on many of the technologies discussed here as they relate to well conformance.[1]

Near-Wellbore & Casing Leaks

Casing leaks are normally detected by an unexpected increase in water or gas production. Production logs, such as temperature, fluid density, hydro, and flowmeter (spinner), can help, singly or in combination, locate where various fluids are entering the wellbore. Thermal Multigate Decay (TMD) and Pulsed Spectral Gamma Test (PSGT) logs help detect water entry and water flow into casing. Casing evaluation logs are used to find holes, splits, and deformities that could allow unwanted fluid entry. The logs also detect corrosion conditions that could lead to leaks.

Downhole video can give a good visual indication of where various fluids enter the wellbore and the condition of the wellbore. Comparison of water analyses between the produced water and those of nearby formations can be used to locate the source of the leak.

CHANNEL BEHIND CASING

This problem of channels behind the casing can occur any time in the life of a well but is most noticeable after initial completion or stimulation of the well. Unexpected water production at that time is a good indication that a channel exists. Channels in the casing-formation annulus result from poor cement/casing bonds or cement/formation bonds.

Cement evaluation logs are used to detect behind-casing channels by examining the degree of bonding between the cement and the casing or formation. These include cement bond logs and pulse echo tools. Temperature logs that exhibit deviation from the geothermal gradient when the well is shut in indicate migration of fluid behind pipe. A zone of abnormally high temperature indicates upward migration of fluid. Abnormally low temperatures indicate downward migration.

TMD and PSGT logs detect and quantify water flow in a channel behind the casing. Borehole Audio Tracer Surveys (BATS) taken with the well shut in help indicate possible fluid movement behind the pipe.

BARRIER BREAKDOWN

Even if natural barriers, such as dense shale layers, separate the different fluid zones and a good cement job exists, the shales can heave and fracture in the vicinity of the wellbore because of the pressure differential across them resulting from production, which allows fluid to migrate through (Figure 1.2). More often, this type of failure is associated with attempts to stimulate the oil zone. Fractures can break through the layer, or acids can dissolve channels through it. Fluid migration through formation channels in the vicinity of the wellbore are detected from temperature logs that exhibit deviation from the geothermal gradient when the well is shut in. A zone of abnormally high temperature indicates upward migration of fluid. Abnormally low temperatures indicate downward migration. TMD and PSGT logs detect and quantify water flow in a formation channel near the wellbore.

DEBRIS, SCALE, AND BACTERIA

Debris, scale, or bacteria deposited on the perforations or in the region around the wellbore of an injector can restrict flow through perforations, decreasing injectivity and possibly diverting fluid into unwanted regions. The presence of debris, scale, or bacteria can also serve as an indication of permeability streaks or crossflow. Water analysis comparison between injection and reservoir fluids is an excellent method to determine the possibility of scale problems. All fluids injected into the well should be evaluated for the possibility of introducing bacteria to the formation face. Scale problems can also be detected with downhole video.

COMPLETION INTO OR NEAR WATER OR GAS

Completion into the unwanted fluid allows it to be produced immediately. Even if perforations are above the original water-oil contact or below the gas-oil contact, proximity to either of these interfaces allows production of the unwanted fluid, through coning or cresting, to occur much more easily and quickly. Core data, the driller's daily report, and openhole logs should be reexamined to determine the cutoff point of moveable water. Data from resistivity and porosity logs, for example, can be combined to determine the location of water and pay zones.

RESERVOIR-RELATED CONING AND CRESTING

Fluid coning, in the case of a vertical well, and cresting, in the case of a horizontal well, is the result of reduced pressure in the vicinity of the well completion drawing water or gas from an adjacent, connected zone toward the completion. Eventually the water or gas can break through into the perforated section, replacing all or part of the hydrocarbon production. Once breakthrough occurs, the problem tends to get worse, with higher cuts of the unwanted fluid produced. Reduced production rates can reduce the problem but not cure it. Fluid density and hydro logs help determine the point of water entry into the wellbore. PSGT and TMD logs can also be used in this regard and can help determine the present location of the water-oil contact before breakthrough, too. Well testing is used to detect encroachment of bottomwater, and reservoir monitoring helps detect the formation of a cone. Detailed calculations to predict potential coning behavior are made with a proper reservoir simulator. Rougher calculations are made from available, simplified correlations.

CHANNELING THROUGH HIGHER PERMEABILITY

High-permeability streaks can allow the fluid that is driving hydrocarbon production to break through prematurely, bypassing potential production by leaving lower permeability zones unswept. As the driving fluid sweeps the higher permeability intervals, permeability to subsequent flow of the fluid becomes even higher, leading to increasing water-oil or gas-oil ratios throughout the life of the project.

Channels are detected through tracer surveys, interference and pulse testing, reservoir simulation of the field, reservoir description, and reservoir monitoring. Tracer surveys and interference and pulse tests verify communication between wells and help determine the flow capacity of the channel. Reservoir description and monitoring can verify the location of fluids in the various formations with reservoir monitoring tracking the fluid movement. The data available through reservoir description allow more accurate modeling of the formations involved, which allows more accurate modeling of fluid movement through reservoir simulation. Additional sources of useful information include coring and pressure transient testing of individual zones to determine permeability variations between zones.

FRACTURE COMMUNICATION BETWEEN INJECTOR AND PRODUCER

Natural fracture systems can provide direct connection between injection and production wells, allowing injected fluid to move through these higher permeability channels, bypassing hydrocarbons within the rock matrix. Even if natural fractures intersecting two wells are not directly connected, fluid can preferentially flow through one fracture until it is in close proximity to another fracture or wellbore, crossing through and sweeping only a small portion of the matrix. Natural fractures serving as flow channels can be confirmed by chloride level comparisons and tracer surveys. Reservoir description should locate the discontinuities, and reservoir monitoring should detect the movement of fluids through the fracture system. A combined analysis of pressure buildup or drawdown data and interference data allows an estimation of properties for both the matrix and the natural fracture system.

Poorly oriented hydraulic fractures can also provide channels that allow injected fluids to bypass much of hydrocarbon production. Although created fractures rarely interconnect two wells, a hydraulic fracture still provides a channel of higher conductivity that allows much of the reservoir fluid to be bypassed. Preferred fracture orientation and the possibility of enhanced recovery operations should be considered in the initial development of a reservoir.
Various technologies, such as microfrac analysis and anelastic strain recovery, exist for determining the expected direction of fracture growth. If the lengths and direction of any hydraulic fractures are known, reservoir simulation is used to model flow through the system and determine the expected sweep efficiency.

LACK OF COMMUNICATION BETWEEN INJECTOR AND PRODUCER

If oil or gas production does not respond to injection, the problem could be a lack of communication between the injector and producer. A natural barrier, such as a sealing fault, can separate the wells, or they can be perforated in different zones. Interference and pulse tests help determine if there is interwell communication. Reservoir description reveals the presence of major heterogeneities, such as faults.

HIGH-PERMEABILITY CHANNELING

Reservoirs containing fractures or high-permeability streaks may suffer from early water breakthrough and poor sweep efficiency. As fluids are produced from a reservoir, zones of higher permeability and correspondingly higher flow rates, create channels for the preferential movement of fluids. In the case of water, this can result in premature communication between a reservoir and an aquifer or between an injector and a producer. In either case, sweep efficiency is diminished.
One possible treatment to eliminate or inhibit channeling is the placement of gels in the high-permeability zones at the injection wells. The gels “plug” the high-permeability zones and force the injected water to sweep the oil-saturated, low-permeability zones. For such gel placements to be successful, an accurate under-standing of the lateral and vertical distribution of the permeability zones is required to identify interwell flow regimes. To reduce or prevent the effects of high-permeability channeling, the lateral and vertical distribution of permeability can be mapped during reservoir description. Knowledge of the distribution of high-permeability zones (potential channels) across the field and/or reservoir allows the operations engineer to plan to avoid or control channeling-related nonconformance.

FINGERING

Unfavorable mobility ratios (>1) allow the more mobile displacing fluid (from either primary or enhanced recovery operations) to finger through and bypass large amounts of oil. Once breakthrough occurs, very little additional oil will be produced as the drive fluid continues to flow directly from the source to the production well.

Information on reservoir and drive fluid mobility's drawn from fluid and core data is probably the most important factor to determine if fingering is a potential problem. Reservoir simulation or available information on ideal systems is used to tell if sweep efficiencies are within range of what would be expected if there were no fingering. Reservoir monitoring is used to determine the position of the fluid interface in the reservoir and show if fingering is occurring.

Viscous fingering is significant in a waterflood environment, especially with high oil-water viscosity ratios, where discrete streamers or fingers of displacing water may move through the reservoir or field. At high oil-water viscosity ratios, instabilities occur at the oil-water interface because of the higher mobility of the driving fluid. The mobility ratio is the driving fluid mobility over the driven fluid mobility (k/m or permeability/viscosity). The driving fluid can be water or gas, with an ideal mobility ratio being less than one to avoid fingering. In a field, there may be several types of reservoirs and the hydrocarbons trapped in each reservoir may not be the same. In some cases, oil gravities may vary substantially from one reservoir to another, even in the same part of the field. Further, the mobility of some hydrocarbons relative to water, for instance, may be different in different parts of a field. In addition, static reservoir properties and heterogeneities may dictate the preferential flow of oil, gas, or water, depending on the placement and number of these fluids. During reservoir description, the fractional flow of fluid phases can be estimated from laboratory tests on core samples to determine relative permeabilities and capillary pressures of the wetting phase. Further, the variation and distribution of fluid types and fluid properties are characterized and modeled. Static reservoir properties are also modeled. The integration of the static and dynamic properties into a reservoir description model makes it possible to predict and plan for zones and/or scenarios in which fingering is likely to occur.

INDUCED FRACTURES - FRACTURING OUT OF ZONE

An improperly designed or performed stimulation treatment allows a hydraulic fracture to enter a water or gas zone. If the stimulation is performed on a production well, an out-of-zone fracture can allow early breakthrough of water or gas. If the fracturing treatment is performed on an injection well, a fracture that connects the flooded interval to an aquifer or other permeable zone can divert the injected fluid to the aquifer, providing very little benefit in sweeping the oil zone. Temperature logs, tracer surveys, and detailed review of the fracturing treatment help identify this problem. Microfrac treatments and long-spaced sonic logs, usually performed before the fracturing treatment, help verify the existence of vertical stress contrasts sufficient to contain fracture height growth.

Injection above formation parting pressure inadvertently creates stresses in the reservoir zone that exceed the tolerance of the reservoir rock. These results in the creation of induced fractures that can modify expected fluid flow patterns. This can produce both positive and negative effects.

If the induced fractures do not extend beyond the reservoir pay zone, then the effect is generally positive (similar to hydraulic fracture stimulation). However, if the induced fractures extend into a gas or water zone, they become high-permeability conduits that allow communication (channeling) between the reservoir and these zones, resulting in diminished sweep efficiency and oil recovery.

In-situ reservoir stresses and rock strength control the initiation, opening, and propagation direction of the induced fractures. An understanding of the in-situ stress field and the mechanical strength of the rock at reservoir conditions allows accurate determination of the formation parting pressure and of the probable intensity, spacing, length, and orientation of any induced fractures. With this information, injection activities can be planned or modified to minimize or avoid nonconformance problems.

NATURAL FRACTURES

Natural fractures are common components of many reservoirs and can provide significant flow paths for fluid movement. Natural fractures may connect oil and water zones and define flow patterns or trends for subsurface fluids. Fractures may also provide a significant portion of reservoir quality, contributing permeability or porosity or both.

Production and injection activities must take into account the influence and effects the fracture system has on hydrocarbon and water distribution and movement. An understanding of natural fractures involves determination of fracture geometry, intensity, and distribution in three-dimensional space.

The reservoir properties of the fracture system, fluid flow interaction or crossflow related to the fracture system, and what the fracture system provides to total reservoir quality, need to be qualitatively or quantitatively determined. For rocks that have a multistage history of deformation, several sets of fractures may be present, each with different characteristics and effects on reservoir performance.

PERMEABILITY BARRIERS

The assumption that there are no horizontal or vertical permeability barriers in a typical reservoir is probably wrong. Intra-reservoir heterogeneities, such as depositional boundaries (unconformities), facies changes, diagenetic effects, sedimentary structures, and irregular pore networks can all produce permeability barriers.

These barriers disrupt predicted fluid flow, resulting in diminished sweep efficiency and nonconformance problems. For example, horizontal permeability barriers may halt or redirect waterflood fronts, while vertical permeability barriers have a direct effect on water coning and could, in some cases, promote a more uniform flood front or prevent gravity segregation.

The influence and effects of permeability barriers is frequently reflected in production tests and in production and injection profiles. Further, field maps of production and injection data (histories) often reflect the influence of reservoir permeability barriers ("dead zones"). However, in most cases, detailed geologic study is required to identify, quantify, and map permeability barriers.

Unfortunately, in cases in which a fluid is injected to stabilize or re-pressure a reservoir, ignorance of the distribution and geometry of the permeability barriers in the interwell space is likely to result in a production plan that is inefficient in both production and injection.

NONCONFORMANCE PHENOMENA

Some of the phenomena that cause remediation and integrity problems along with the methods to alleviate these problems are:

Fluid Influx into Casing/Formation - Annulus (Channel behind Casing)

There are several factors associated with gas or liquid influx into an annulus. To prevent fluid influx, it is paramount to employ proper displacement techniques. Failure to follow proper displacement techniques results in a poor cement-to-casing bond and channels in the annulus. The following summarizes the factors affecting displacement efficiency.

<u>Condition of the drilling fluid:</u> Circulate until maximum circulatable hole is achieved, and increase the mobility of the drilling fluid by controlling filter-cake buildup. In vertical applications, this equates to low gel strength and viscosity. In deviated wellbores, condition the drilling fluid to prevent dynamic settling of solids to the low side of the wellbore.
<u>Pipe movement:</u> Rotate or reciprocate the casing to provide a mechanical means of controlling gel strength buildup. Pipe movement can eliminate a solids-settled channel.

<u>Pipe centralization:</u> Use centralizers to improve pipe standoff and to equalize the forces in the annulus. The result is uniform fluid flow around the casing. In deviated wellbores, a standoff of at least 70% is preferred. Displacement fluid velocity: Displace the fluids from the annulus at the highest rate possible while maintaining wellbore control.

<u>Gas influx or fluid migration</u> that occurs through the unset cement column is caused by the inability of the slurry to maintain overbalance pressure while the cement is in a gelled phase, allowing gas percolation to form a gas channel. Once

cement slurry is in place, it begins to develop static gel strength. Gel strength development inhibits the ability of the slurry to transmit hydrostatic pressure, and when combined with hydration/fluid-loss volume reductions, the result is gas migration. Controlling gas migration during initial phases of cement hydration has been thoroughly researched and several means have been developed to help control gas migration. These include systems that exhibit controlled fluid loss, modified static gel strength development, and compressible systems.

Gas influx can also occur after the cement has set. This type of gas migration, known as "long-term", is thought to occur as a result of poor displacement or de-bonding of the pipe/cement/formation sheath. In the case of poor displacement, gas flow dehydrates the drilling fluid bypassed by the cement and results in a highly permeable flow path for gas migration.

Drilling/production/workover operations can break the cement/casing bond or cause the cement sheath to fail, resulting in a path for fluid migration. Following good displacement practices and using expansive cements help solve "long-term" gas migration problems.

The purpose of a primary cement job is to effectively seal and isolate production zones, to eliminate the production of unwanted fluids, and to support the casing for the life of the well. Once the well has been cemented, it is up to diagnostic sonic tools (Cement Bond and Pulse Echo Tools) to determine the effectiveness of the cement job. The logs generated by these tools must be interpreted, and this interpretation is historically used as the basis for remedial work, such as squeezing off water and gas.

Data from these sonic tools provide information about bonding the cement to the pipe and a qualitative analysis of the ability of the cement to seal the annulus.

APPENDICES

Unique Diagnostic Techniques: *Linked References included*

A knowledge of the path in the reservoir injection and production will traverse is necessary to make wise and efficient operational decisions. Well logs and core permeability data provide some information about the region near the wellbore. A knowledge of prior injection histories can add useful information about interwell communication. Also, pressure transient tests, which may be rather expensive, can supply information about fluid flow between wells. Another source of information of reservoir behavior is the tracing of injected water or EOR injectant such as CO_2 with a chemical that may be observed when and where the chemical is produced. Some of the types and variations of Tracer Chemicals and Techniques/Uses are listed:

Tracers

Radioisotopes
Fluorescent Dyes
Water Soluble Alcohols
Water Soluble Salts

Use of Interwell Tracers

Pilot Stages of New Flood Projects
Unexpected Early Water Breakthrough
Evaluate Volumetric Sweep Efficiency
Identify Problem Injectors
Directional Flow Trends
Delineation of Flow Barriers
Evaluate Efficiency of Injected Fluids
Pilot Stages of New Flood Projects
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Directional Flow Trends
Delineation of Flow Barriers
Evaluate Efficiency of Injected Fluids

Types of Interwell Tracers

Water Phase Tracers

Inorganic Salts

Organic Tracers (dyes, alcohols)

Radioactive Tracers

Water Phase Tracers

Tritiated Water (HTO)

Thiocyanate (CNS)

Bromide (Br^-)

Cobalt Hexacyanide ($(Co(CN)_6)^{-3}$)

Iodide (I^-)

Deuterium (D_2O)

Nitrate (NO_3^-)

Fluorescent Dyes (Fluorescein, Rhodamine-WT)

Alcohols

Hydrocarbon Phase Tracers

Oil and Gas Tracers

Chemical Tracers

Radioactive Tracers

Hydrocarbon Phase Tracers

Tritium ($^3H_2$)

Krypton 85 (Kr-85)

Carbon-14

Sulfur Hexafluoride (SF6)

Freon's

Perfluroinated Compounds

Example: Fluorescent Dyes as Waterflood Tracers

In cases where very rapid communication (≤5 days) is thought to exist between an injector and a producer, fluorescent dyes are considered excellent tracer materials. These dyes are absorbed to some extent on typical reservoir rocks, but even trace amounts can be detected visually in the produced water with no need for elaborate chemical analysis. Detection of water flow communication between wells can confirm the presence of channels and help in sizing and planning corrective treatments.

The usual placement method is to inject a concentrated "slug" of the tracer while maintaining the normal Waterflood. Producers offset to the injection well are monitored for the presence of tracer. Fluorescent dyes are easily detectable to the naked eye at one part per million concentrations, equivalent to one pound in 2850 bbls of water. The use of a "black light" to illuminate the water samples will allow detection of 50 parts per billion dye. This extreme sensitivity of the detection method allows dyes to be used, despite high absorption on rock surfaces, provided residence time in the reservoir is not too long.

The two most readily available fluorescent tracers are sodium fluorescein, also known as Uranine, and Rhodamine B. These show yellow-green and red fluorescence respectively. Uranine in the past was available under Halliburton part number 70.15632 if ordering from them. Another source for either dye was: Pylam Products CO., Inc., 1001 Stewart Avenue, Garden City, NY 11530. (516) 222-1750. Several other sources exist; most laboratory chemical supply houses have these dyes (at higher prices, of course).

Amounts of dye to use in a particular situation depend primarily on how much dilution the tracer will see. A suggested starting point would be a pound of dye in an injection well that takes 200-500 BPD of water. This would provide sufficient dye for some dilution and adsorption, and still be detectable at the end of a channel.

These dyes are readily water soluble, and placement is simple. The dye can be dissolved in water, say 1 lb. in 5 gallons, and placed into an injection well by any convenient method. It can also be added through a lubricator or injected with the Waterflood pump, if desired. If it is necessary to pump the tracer, it would be simpler to use a tracer volume of a few barrels of water to give the pump truck enough fluid to prime the pump. (Everything the truck pumps for a day or two may be dyed after handling these materials.) After placement of the dye, return the well normal injection to displace the tracer.

Offset producers should be monitored fairly often for presence of the dye over the next several days. Tracer will typically "spread out" in the formation, and continue to show up for some time after initial breakthrough. The initial appearance is the piece of data which allows estimation of the shortest path between the injector and offset producer(s).

It is required to do more quantitative calculations, such as mass balances, other non-absorbing tracers should be used. Several are available which require only simple lab (or field) chemical testing.

EXAMPLE: TRACER DYE TESTING FOR RAPID COMMUNICATION ASPECTS [4]

This procedure requires returning the injection well back to injection to reestablish the water injection path with its offset producer(s).

This information is needed to help in designing the conformance procedure for injection wells.

The following is the procedure to be used in pumping the dye test on injection wells. The dye is called *Teremark SPI Dye* and is available in liquid or powder form. The liquid should be used if it is available. This dye can be obtained from Chemical Weed Control suppliers. An MSDS sheet should be obtained from them.

DYE TEST PROCEDURE

1. Return injection well to injection. Rate control the well @ former designed injection rate at least

1 week prior to the die test. The purpose is to reestablish the path the injection water traveled to the offset communicated producer(s).

2. Set the offending injection well on rate control at specified rate (BWIPD) for several hours prior to the test. The well could be on a vacuum in some areas.

3. Mix 50 BBL of water with 64 ounces of Teremark SPI Liquid Dye. (If liquid is not available use 25 packs of powder)

4. Rig up pump truck capable of pumping at 0.25 BPM. (Pumps may only inject @ 0.31 BPM lowest rate achievable. OK for most treatments.)

5. Shut off injection to the well from the injection header and begin pumping the dye solution at approximately 0.25 BPM.

6. Record time that pumping is started. Pump the entire 50 BBL batch of solution and record the time that pumping ends. The wells could be on vacuum during the pumping, but record any pressures should it occur.

7. Return well to injection at the same daily injection rate (BWIPD). Rig down pump truck.

DYE MONITORING PROCEDURE

The dye can be expected to arrive at offset producers between 30 minutes and 6 hours after pumping begins on many wells. Samples should be taken as follows:

30 minutes after pumping begins

1 Hour after pumping begins

Every 15 minutes from 1 Hours until 6 hours after pumping begins

Every hour after that until 10 hours after pumping begins

Every 2 hours thereafter until the dye is no longer coming up to 48 hours

If the dye does not arrive in 48 hours, contact engineer for instructions or information.

NOTE: Continue to take samples until the dye is no longer present and note the time when dye ceases to be present.

Samples should be taken in clear sample bottles and retained until the test is complete and the results are confirmed. The samples should be compared for color to a "control group" of samples and the best color match noted. The "control group": of samples should be made up as follows:

1. Take a 1 gallon sample of the 50 BBL dye mixture.

2. Place 1 teaspoon of 50 BBL dye mixture in a sample bottle and fill the bottle to a total of 8 ounces with water.

3. Repeat No. 2 with the following volumes

1 Tablespoon in 8 ounces of total mixture (1 tablespoon = 0.5 ounces)
1 ounce in 8 ounces of total mixture
2 ounces in 8 ounces of total mixture
4 ounces in 8 ounces of total mixture
6 ounces in 8 ounces of total mixture

8 ounces in 8 ounces of total mixture

4. Note the mixture which best matches each sample taken in the offset producer(s).

If the sample falls between two samples note which two it falls between

Injection Analysis - Pressure Analysis:

Injection/Fall off tests

Injection Profiles - Why?

- Determine where fluids are going. [**best to know where fluids have gone**]
- Check mechanical integrity of well bore.
- Verify conformance to formation porosity.
- Locate channels.
- Check perforations.
- Check fill.
- Find scale and build-up.
- Discover holes or unreported perforations

Injection Profile Log - Components

- Radioactive Tracers
- Spinner Logs
- Temperature Logs
- Caliper Logs
- Collar Logs

Injection Profile Components

- Injection Profile Log - Logs
- Injecting Temperature Log
- Two Radioactive Tracer Logs
- The Intensity Profile
- Series of Stationary Velocity Measurements
- Channel Checks
- Packer Check
- Shut-In Temperature Logs
- Cross-Flow Checks
- Caliper Log

Interference / Pulse Tests- Detailed in Cardinal Surveys Website – *Separate Discussions*[3]

•Oil and gas well tests can be grouped into two general categories based on their primary function

1. pressure transient tests, includes tests that quantify important reservoir rock and fluid properties, such as permeability, porosity and average reservoir pressure, and locate and identify reservoir heterogeneities, such as sealing faults, natural fractures, and layers
2. deliverability tests, includes tests that evaluate a well's production potential under specific operating conditions

Hall Plot – Separate Discussions – Not usually studied as a Diagnostic Tool

Example: Multi-Rate Injectivity Analysis

One aspect in diagnostics that has proven capable in improving successes is associated with placements of sealants or cements in fractures or extremely high permeabilities. Understandings are needed as to where unwanted fluids are being produced from and where injected fluids have gone at different conditions. The conditions under injection that may vary are the pressure changes associated with different injection rates. Most multi-rate analyses are conducted with a logging tool in the hole and equipped with a release device capable of placing a specified amount of radioactive material into the flow stream above the logging tools. There is a required base gamma analysis to determine variations. Normally the testing is performed with both Intensity releases of isotopes placed in segments up through the wellbore and followed with a large shot of isotope placed above the entry zone as a Velocity shot. The process is normally started at a reduced rate that is generally enough to establish entry only into the interval that a desired placement of chemicals or cement is desired. By releasing the Intensity shots and a Velocity shot, the injectivity of the tag can be traced to determine its path and where it has gone. Using both Intensity and Velocity shots, comparison analysis gives a better understanding of injectivity. Combining these with a temperature analysis also leads to a better understanding of injectivities. The following runs for multi-rates are taken at incremented increased rates once given enough time for clearance of the prior shot isotopes and stabilization of fluid entry. These following steps may be taken up to a maximum rate of 1-1/2 to 2 BPM in most cases {wellbore configuration determinate}, higher rates being difficult to follow. The focus is to determine if there is a variation in entries at the different rates and accompanying changes in BHIP if any.

Also there may be determination of a ratio for dual placement control, a maximum injection pressure if bullheading fluids, and an insight as to the type of solution that may be used. Differential pressure responses may give understanding of the tortuosity aspects of fluid entry into specific portions of the reservoir. When rates exceed certain velocities, there may be determined if such materials as cement slurries may be pumped into a portion of the well. With normal permeabilities ranging from 0.01 to 1000 md in Permian Age reservoirs, there is little chance of injecting a gelled fluid or slurry at these rates associated with multi-rate injectivities and only matrix flow. The emphasis of placing a treatment where it develops a blocking effect without entering other portions of a formation may be determined with this analysis. If investigations show that at a specific pressure developed from varying injectivity would cause undesired entry, this information may be used to limit the treatment pressure. The chosen solutions that can be placed under the criterias established in a multi-rate injection analysis are established with this analysis.

Proposed technique and method to perform diagnostics – Multi-Rate Injectivity:

It is suggested to perform an injectivity analysis on wells to determine variables in pressures and placement methods needed to address the shut off of water production [*actually any unwanted production*]. There may be an apparent connectivity within the reservoir between the oil or gas pay portion, communication via fissures, cracks, or loss of integrity, and the portion of reservoir where water is being produced. The high water cut productions may be entering from within the near wellbore radius, casing perforations in lower intervals, or via fractures or vertical permeability within the reservoir at near or far distances from the wellbore. The analysis may be performed via Intensity shots and a Velocity shot and tracking fluid injection into the current sets of perforations or open holes while analyzing at multi-rate injections. Ideally, Temperature analysis [both static base line and under either production or injections] are suggested to develop a better understanding of the fluid movements even deeper into the reservoir.

Set-up for Analysis:

Rig up Tracer Company with intensity and velocity shot analysis capabilities. A base Gamma and analysis Gamma would be recommended. The ability to take up to 5 shots per run may be needed. Rig up an injection unit capable of accurate rate and surface pressure measurements. Availability of sufficient injectant (produced water, etc.) needs to be arranged {usually 250 to 500 bbls.}. The wells current production or injection rates should be utilized to address starting points of injection. An example of performing an analysis with multi-rate investigations with intensity and velocity shots is as follows;

1. ½ Normal Daily Injection Rate — Release tracer and analyze; Allow stabilization and clearance
2. Normal Daily Injection Rate — Release tracer and analyze; Allow stabilization and clear
3. 1-1/2 Normal Daily Injection Rate — Release tracer and analyze; Allow stabilization and clear
4. 2 Normal Daily Injection Rate — Release tracer and analyze; Allow stabilization and clear
5. Shut down and check for any crossflow from above down or from below upward.

Once analysis is made as to controlling the proper placement technique and determining the best solution needed to achieve zonal isolation, a treatment may be designed accordingly.

NOTE: The rates may be performed for matrix injection as well.

Possible results from diagnostics:

If the injectivity is 100% out the lower perforations or open hole and traveling below throughout the analysis; there may exist a way to place more control in the treatment. Often times, the placement of a squeeze retainer may be made above all of the perforations or within the casing shoe for an open hole completion and by having a limiting injection pressure based on analysis, place the entire squeeze treatment into the lower perforations or out the bottom of an open hole without any entry into the upper perfs or portions of the open hole completion. If there is a partial entry in the upper perfs or open-hole completion in the upper rate analysis, the treatment would be done at a rate and BHIP to coincide with the maximum pressure allowable to only enter the lower desired portion. Treatments have been done with annular injection of protective fluid with retainers placed between perforated intervals or in open holes where capability exists. Tests for communication between perfed intervals is needed to insure well control or need to place tubing flapper valves and BOP stripper.

Discussion:

There is a very useful description and animation on the Cardinal Surveys web site [3] - http://www.cardinalsurveys.com showing this process described below:

Example: CONTROLLED INTERFACE TREATMENT LOG - The Interface Treatment. [3]

In order to selectively place fluid loss control agents or sealants (cement, polymer, etc.), sometimes it is necessary to use a well-known and established method of hydraulically placing materials called the controlled interface treatment. The interface placement technique provides a method to direct the treatment solution into the selected interval(s) through simultaneous dual injection of sealing and non-sealing fluids into, respectively, the tubing and annulus. Determination of placement is performed in a real-time analysis utilizing a tagged fluid and a gamma-ray detector tool. During the initial analysis and possibly during the sealant placement, the pump rates (tubing and annulus) are regulated by readings from the gamma-ray detection tool.

In this method, fluids are pumped from two different directions, and the depth at which they meet is the interface depth. In order to quantify the interface depth, a radioactive tracer can be injected with one of the treatment fluids so that the presence of the tracer in only one fluid accurately defines the interface location. The tracing and recording of the interface is known as an interface log.

Applications are generally found in situations where other, more conventional means of isolation are impractical or impossible. Examples include open-hole completions, wells with damaged casing, or wells with poor cement sheath isolation or other uncontrollable channeling problems such as vertical permeability or natural or hydraulically induced fractures. Wells experiencing sever water coning are also potential candidates for the controlled interface procedure. Some well problems are near well bore, and some are further out in the deep formation.

A gamma-ray detection tool is run down the well and suspended in the hole on an electric conductor cable inside of the tubing and is placed at the desired interface between the upper and lower points in the well. The annular fluid is tagged with a radioactive isotope that can be detected by the tool. The exact location of the interface can be adjusted by manipulating the rate at which the two dissimilar fluids are pumped. For example, if the interface location is too high, then the annular injection can be increased while the tubing injection is decreased in order to move the interface down the well.

Normal operations call for the sealing solution to be placed at a rate below fracture pressure into the zone desired to be sealed. The controller on these jobs is rate and not pressure. The only pressure consideration is pressure restrictions of the casing and fracture pressures.

To configure the well for the interface treatment, the tubing must be placed below the interface location, and left open ended. It is permissible to leave the packer on the end of the tubing string with the packer seals released. A pin-collar is recommended on the end of the tubing to prevent the logging tools from exiting the tubing.

Consideration should be made as to the treating chemical's differences in viscosity, density, etc., if it is necessary to begin the treatment without the logging tools in the well.

Spotting the annular fluid down close to the desired interface prior to performing the analysis is usually performed to save time since annular volumes are sometimes large based on the daily injection volume for the upper interval.

The gamma ray logging tools should be moved to locate the interface and track the developing stationary injectivities per each annular rate adjustment. Further, the tools may also be moved to analyze the initial movement when starting the analyses.

A temperature tool is sometimes required when the bottom hole injection temperature is needed for sealant reaction time calculations

It is desirable to use high pressure tracer injection technology (Cardinal Surveys Company's Tagmaster) to prevent any unnecessary contamination of pumping equipment with radioactive materials.

Operating Procedures:

1. Configure well to allow pumping down tubing string and casing-tubing annulus. Set end of tubing near the bottom of the well, or well below the planned interface depth.
2. Rig up two pumps to inject fluid down the tubing and casing-tubing annulus, respectively. Install flow manifold to monitor rate and pressure to each injection point.
3. Connect as example Cardinal Surveys Company's Tagmaster unit to allow tracing of fluid which is injected down the casing-tubing annulus. Normally, a liquid based tracer of I-131 is preferred.

4. Rig up logging unit with gamma ray detector, temperature and casing collar locator tools. Use full lubricator stack. Run correlation gamma ray and collar logs on zone of interest and make necessary depth corrections.
5. Begin injection of fluid down the casing-tubing annulus only. Begin radioactive tracer. Inject fluid at maximum allowable rate and pressure. Use gamma ray detector to monitor injected fluid as it moves down the casing-tubing annulus.
6. As the tracer leading edge nears the planned interface depth, begin injecting down the tubing while reducing injection down the casing-tubing annulus. Maintain total rate and pressures below maximum allowable levels, and adjust total rate to planned treatment rate.
7. Continue to monitor leading edge of tracer using gamma ray detector tool. Adjust individual injection rates while keeping total injection rate constant. Stabilize interface at desired interface depth.
8. Once interface has stabilized, begin pumping fluid control agent (polymer or cement slurry.) COH with logging tools if necessary. Continue to monitor interface depth if possible.

Logging Procedures:

9. Gamma Ray detector is lowered below tracer leading edge, and a recording of gamma ray intensity is made versus depth. The tracer leading edge is indicative of the fluid interface once injection is established down both the casing-tubing annulus and down the tubing. Fluid containing the radioactive tracer will register a significantly higher reading when recorded.
10. Repeated recordings of gamma intensity versus depth are made. The interface depth is reported to pumping personnel after each recording. Pump rates are adjusted as required to position the interface at the desired depth.
11. Continued monitoring is desirable unless the fluid control agent is not compatible with the wireline equipment.

Example and Step Process: Injection Profile applications:

The following procedure represents the fundamental steps needed to accomplish most Injection Profile applications. However, due to the investigative nature of production logging, it must be noted that the following procedure may be modified at any point in order to optimize the definition of events or abnormalities. This procedure should be considered as a general plan of action.

1. Conduct tailgate safety meeting to identify location hazards, review well information, review test objectives, and make necessary plans to maximize safety and test results.
2. Rig up Wireline logging unit on well and conduct the pre-job wellhead radiation survey.
3. Attach Wireline Injection Profile tool string *which as an example* consists of a Rope Socket (1.25" x 15" with a 5/8" fishing neck), Caliper (1.375" x 69"), Collar Locator (1.375" x 28.5"), Scintillation Gammaray Detector (1.375" x 60"), Microprocessor Controlled Ejector (1.375" x 75.5") with UV I-131 as the tracer isotope, and a Temperature Tool (1.375" x 37").
4. Install wireline blow out preventer and tool trap.
5. Install lubricator and test for leaks.
6. RIH with Injection Profile tool string into the tubing.
7. Check well for stable injection rate and pressure.
8. Run Injection Temperature and CCL Logs from ***as an example*** *5,500 to 6,100*.[Example well's injection interval]
9. Run Gamma Ray and Collar Logs from 6,100 to 5,500. Correlate Gammaray and CCL logs to supplied correlation log. Adjust depth measurement from Wireline Depth to Measured Depth.
10. Return Injection Profile logging string to T.D. at 6,100 and run Caliper Log from 6,100 to 5,500.
11. Intensity Profile: Place Injection Profile logging string above the zone of interest 5700 - 6000 and eject Slug #1 of UV I-131. As the slug travels down hole with the flow, attempt 3 passes through the UV I-131 with the recorder set to depth drive before the first point of loss. This will allow for a 100% intensity reading. Note the delta times from peak to peak.
12. Continue to make timed passes through Slug #1 until it has dissipated.
13. Velocity Profile: Eject Slug #2 of UV I-131 below the zone 5700 - 6000 and above T.D. at 6,100. Eject the slug as low as possible if there is no rathole. Place the recorder in 2" Time Drive. Wait 3 - 5 minutes for the UV I-131 slug to travel down to the detector.
14. After the UV I-131 has reached the detector, or the 5 minute waiting period has expired, Make a single pass through Slug #2 (recorder in depth drive) to determine if there was a slug ejected and whether the reaction time (if any) was caused by fluid movement or simple dispersion of material. Slug #2 is referred to as the No-Flow Shot. It helps determine if there is any injection going below T.D. in the wellbore.
15. Break down the areas of loss in the zone from 5700 - 6000 by ejecting slugs of UV I-131 between areas of interest while the tool string is stationary and the recorder is in 2" time drive.

Note: Refer to the Caliper Log so as not to shoot any velocity shots across drastic I.D. changes.

16. Upward Channel Check: Place the gamma ray detector approximately 5 feet above the zone 5700 - 6000 and eject the upward channel check slug. Remain stationary with recorder in 2" Time Drive and monitor slug going past the detector to the zone at 5700 - 6000. Monitor for gamma ray returns for 5 minutes. If gamma ray returns are seen, raise the detector in 5 feet increments to follow channel. If no returns are seen, switch to depth drive and pull a gamma ray log above top of zone in order to check for returns that might have passed outside the detector's range.
17. Eject at least three 100 percent velocity shots above all points of loss so that an average rate may be determined for the Velocity Profile.
18. Raise the logging string up to 5,500 and shut off the injection.
19. Allow well to remain static for approximately one hour.
20. Run a Shut-in Temperature Log from 5,500 to 6,100.
21. Cross Flow Checks, Shoot a series of UV I-131 slugs approximately 50 feet apart across the zone 5700 - 6000 and make timed passes through all the slugs at the same time to determine if there is any cross flow between zones.
22. Run a Shut-in Temperature Log from 5,500 to 6,100 approximately 2 hours after the well has been shut-in.
23. POOH with Wireline Survey's logging tool string.
24. Rig down equipment, return well to injecting status, and conduct the post job wellhead radiation survey.
25. Contact the Your Company, Inc. field representative to give preliminary results and the current status of well.

Example and Step Process: Running a combination of Temperature and Gamma Ray logging - used to determine the placement of well simulations and treatments.

The following procedure represents the fundamental steps needed to accomplish most GAMMA TROL ® [Temperature and Gamma Ray logging] applications. However, due to the investigative nature of production logging, it must be noted that the following procedure may be modified at any point in order to optimize the definition of events or abnormalities. This procedure should be considered as a general plan of action.

1. Conduct tailgate safety meeting to identify location hazards, review well information, review test objectives, and make necessary plans to maximize safety and test results.
2. Rig up Wireline logging unit on well and conduct the pre-job wellhead radiation survey.
3. Attach Wireline Surveys GAMMA TROL ® tool string which for this example consists of a Rope Socket (1.25" x 15" with a 5/8" fishing neck), one or more weight bars, Collar Locator (1.375" x 28.5"), Scintillation Gammaray Detector (1.375" x 60"), and a Temperature Tool (1.375" x 37").
4. Install wireline blow out preventer and tool trap.
5. Install lubricator and test for leaks.
6. RIH with GAMMA TROL ® tool string into the tubing.
7. Run Base Temperature and CCL Logs from **Example Well** perfed interval 5,500 to 6,100.
8. Run Gamma Ray and CCL Logs from 6,100 to 5,500. Correlate Gammaray and CCL logs to supplied correlation log. Adjust depth measurement from Wireline Depth to Measured Depth.
9. POOH with Cardinal Survey's GAMMA TROL ® production logging tool string.
10. Rig down equipment, store lubricator in a safe area, and stand by during well stimulation.

Radioactive tagging information can be found in Cardinal Survey's Webpage - TAGMASTER ®:

11. Record ISIP and 15 minute shut-in pressures.
12. Install wireline blow out preventor and tool trap.
13. Install lubricator and test for leaks.
14. RIH with GAMMA TROL ® tool string into the tubing.
15. Run After Temperature and CCL Logs from for this example 5,500 to 6,100.
16. Run After Gammaray and CCL Logs from 6,100 to 5,500.
17. Allow well to remain static for approximately one hour.
18. Run a Shut-in Temperature Log from 5,500 to 6,100.
19. POOH with Cardinal Survey's GAMMA TROL ® production logging tool string.
20. Rig down equipment and conduct the post job wellhead radiation survey.
21. Contact the Your Company, Inc. field representative to give preliminary results and the current status of well.

Example and Step Process: Production Logging

PROCEDURE - WELL PREPARATION

As an example, Cardinal's TRAC-III logging string consists of a Scintillation Gamma Ray Detector, (micro-processor controlled) Radioactive Ejector, Collar Locator, Capacitance Probe, Caliper, and Temperature Tool. All sensors come in $^{7}/8$" O.D., 1" O.D., 1 $^{1}/4$" O.D., and 1 $^{3}/8$" O.D. cases.

Some benefits of running these production surveys are:

- Document baseline production profile for future references.

- Verify effectiveness of well treatments.
- Discover unwanted water sources for remedial procedures.
- Correlate production results with injection profiles for sweep efficiency of floods.

The following Cardinal Survey procedure represents the fundamental steps needed to accomplish most Production Survey applications. However, due to the investigative nature of production logging, it must be noted that the following procedure may be modified at any point in order to optimize the definition of events or abnormalities. This procedure should be considered as a general plan of action.

1. Conduct tailgate safety meeting to identify location hazards, review well information, review test objectives, and make necessary plans to maximize safety and test results.
2. Rig up Cardinal Surveys logging unit on well and conduct the pre-job wellhead radiation survey.
3. Attach Cardinal Surveys 1 $^{3}/8$" O. D. TRAC-III tool string which consists of a Rope Socket (1.375" x 15" with a 5/8" fishing neck), Capacitance Tool (1.375" x 40"), Caliper (1.375" x 69"), Collar Locator (1.375" x 28.5"), Scintillation Gammaray Detector (1.375" x 60"), Microprocessor Controlled Ejector (1.375" x 75.5") with I-131 as the tracer isotope, and a Temperature Tool (1.375" x 37").
4. Install 5,000# lubricator and test for leaks.
5. Pressure up lubricator and secure wellhead.
6. RIH with TRAC-III tool string into the tubing.
7. Run Flowing Temperature and CCL Logs from **Example well** - 5,400 to 6,100.
8. Run Gammaray and CCL Logs from 6,100 to 5,400. Correlate Gammaray and CCL logs to supplied correlation log. Adjust depth measurement from Wireline Depth to Measured Depth.
9. Return TRAC-III logging string to T.D. at 6,100 and run Capacitance Log from 6,100 to 5,400.
10. Return TRAC-III logging string to T.D. at 6,100 and run Caliper from 6,100 to 5,400.
11. Place TRAC-III logging string above the zone of interest 5600 - 6000 and eject a slug of radioactive material. As the slug travels up hole with the flow, make at least 3 passes through the material with the recorder set to depth drive. Note the delta times from peak to peak. This will allow for a 100% velocity reading.
12. Repeat step 11 two more times.
13. Repeat step 11 in areas between perforated intervals or between areas of interest in the openhole section. Please refer to the caliper results from 5600 - 6000 when placing the radioactive slugs. Try to avoid areas of drastic I. D. change to minimize the error in the velocity measurements.
14. Eject a slug of radioactive material below the zone 5600 - 6000 and above T.D. at 6,100. Eject the slug as low as possible if there is no rathole. Make several passes through the material to determine if there is any flow coming from below T.D. in the wellbore.
15. Shut-in production at wing valve.
16. Allow well to remain static for approximately one hour.
17. Run a Shut-in Temperature Log from 5,400 to 6,100.
18. Cross Flow Checks, Shoot a series of radioactive slugs approximately 50 feet apart across the zone 5600 - 6000 and make timed passes through all the slugs at the same time to determine if there is any cross flow between zones.
19. Run a Shut-in Temperature Log from 5,400 to 6,100 approximately 2 hours after the well has been shut-in.
20. It may be desirable to pull a Shut-in Capacitance Log at this point from 6,100 to 5,400.
21. POOH with Cardinal Survey's TRAC-III production logging tool string.
22. Rig down equipment, return well to prior status, and conduct the post job wellhead radiation survey.
23. Contact the field representative to give preliminary results and the current status of well.

Well Preparation - Location:

Logging company must be able to back their logging unit up to within 2 to 3 feet of the wellhead. Please remove any tubing, B.O.P., etc. from the location.

Stabilization:

Stable producing conditions are crucial to running a TRAC-III that will give insight to the wells normal production characteristics. This is important when the test objective is to see the well's production profile. It is also important for determining the effects of a past stimulation that has not performed as expected.

If we run a TRAC-III immediately after the well has been worked over, it will only tell us what the well does at that particular point in time. You want to allow the production to stabilize, unless (drum roll) you have had a sudden, big increase in your water production.

It does not matter if this increase of water production was brought on by stimulation, direct channel from an offset injector, or natural causes. Get busy, prepare your well for a TRAC-III and call Cardinal. Time is critical. Don't wait for stabilization.

There is a strong possibility this new water is from a higher pressure source than anything you've been producing. In these situations we regularly see crossflow into the proven oil zones. We need to find the water source so that you can take remedial action. Remember, you will have to recover all those barrels of water that cross flowed in before you will get your production back.

Example and Step Process: Annulus Production Logging

PROCEDURE - WELL PREPARATION

Production logs have long been used as a reliable source of information to optimize profits on flowing wells. Cardinal's TRAC-III has made this proven service available to a large number of wells that could not have been logged in the past. Annular production logging is possibly the best means of acquiring "real time" data of dynamic producing conditions in wells with rod pumps.

Cardinal Survey's TRAC-III System was designed from conception to maximize operational success and data quality. The TRAC-III logging string consists of a Scintillation Gamma Ray Detector, (micro-processor controlled) Radioactive Ejector, Collar Locator, Capacitance Probe, Caliper, and Temperature Tool. All sensors are housed in 7/8" O.D. cases to facilitate passage down the tubing annulus.

Some benefits of running TRAC-III's are:

- Document baseline production profile for future references.
- Verify effectiveness of well treatments.
- Optimize pump placement.
- Discover unwanted water sources for remedial procedures.
- Correlate production results with injection profiles for sweep efficiency of floods.

The TRAC-III System has been designed for wells with 5½" casing and $2^{7}/8$" tubing. The system can also be used on any combination of bigger casing or smaller tubing.

It is possible to run the tools down the annulus between 4½" casing and $2^{3}/8$" tubing. No pressure control can be used at surface with this configuration and the well preparation is quite entailed. However, it is not impossible. Wells have been successfully logged down with a 4½" and $2^{3}/8$" to 13,100' in Crane County Texas.

The following procedure represents the fundamental steps needed to accomplish most TRAC-III ® applications. However, due to the investigative nature of production logging, it must be noted that the following procedure may be modified at any point in order to optimize the definition of events or abnormalities. This procedure should be considered as a general plan of action.

1. Conduct tailgate safety meeting to identify location hazards, review well information, review test objectives, and make necessary plans to maximize safety and test results.
2. Rig up logging unit on well and conduct the pre-job wellhead radiation survey.
3. Attach as example Cardinal Surveys 7/8" O. D. TRAC-III ® tool string which consists of a Rope Socket (.875" x 15" with a 5/8" fishing neck), Capacitance Tool (.875" x 40"), Caliper (.875" x 69"), Collar Locator (.875" x 28.5"), Scintillation Gammaray Detector (.875" x 60"), Microprocessor Controlled Ejector (.875" x 75.5") with I-131 as the tracer isotope, and a Temperature Tool (.875" x 37").
4. Shut down pump jack and lock in place.
5. Determine means of pressure control (hand packoff or lubricator) and implement.
6. RIH with TRAC-III ® tool string into the tubing annulus.
7. Release and activate pump jack.
8. Run Pumping Temperature and CCL Logs from 5,500 to 6,100.
9. Run Gammaray and CCL Logs from 6,100 to 5,500. Correlate Gammaray and CCL logs to supplied correlation log. Adjust depth measurement from Wireline Depth to Measured Depth.
10. Return TRAC-III ® logging string to T.D. at 6,100 and run Capacitance Log from 6,100 to 5,500.
11. Return TRAC-III ® logging string to T.D. at 6,100 and run Caliper from 6,100 to 5,500.
12. Place TRAC-III ® logging string above the zone of interest 5600 - 6000 and eject a slug of radioactive material. As the slug travels up hole with the flow, make at least 3 passes through the material with the recorder set to depth drive. Note the delta times from peak to peak. This will allow for a 100% velocity reading.
13. Repeat step 12 two more times.
14. Repeat step 12 in areas between perforated intervals or between areas of interest in the openhole section. Please refer to the caliper results from 5600 - 6000 when placing the radioactive slugs. Try to avoid areas of drastic I. D. change to minimize the error in the velocity measurements.

15. Eject a slug of radioactive material below the zone 5600 - 6000 and above T.D. at 6,100. Eject the slug as low as possible if there is no rathole. Make several passes through the material to determine if there is any flow coming from below T.D. in the wellbore.
16. Shut down pump jack and shut-in production.
17. Allow well to remain static for approximately one hour.
18. Run a Shut-in Temperature Log from 5,500 to 6,100.
19. Cross Flow Checks, shoot a series of radioactive slugs approximately 50 feet apart across the zone 5600 - 6000 and make timed passes through all the slugs at the same time to determine if there is any cross flow between zones.
20. Run a Shut-in Temperature Log from 5,500 to 6,100 approximately 2 hours after the well has been shut-in.
21. It may be desirable to pull a Shut-in Capacitance Log at this point from 6,100 to 5,500.
22. POOH with Cardinal Survey's 7/8" O.D. TRAC-III ® production logging tool string.
23. Rig down equipment, return well to pumping status, and conduct the post job wellhead radiation survey.
24. Contact the operator field representative to give preliminary results and the current status of well.

Well Preparation

The one key factor in rigging up for an Annulus TRAC-III is that you must have strict, vertical clearance above the annulus valve. The logging company must be able to lower the logging sonde directly into the valve.

Diagnostics - Success Ratios – from Database 1964-2004 – Permian Basin & SE New Mexico[2]

Problems Observed & Identified:

Near wellbore integrity
Deep reservoir sweep problems
Interwell communication problems
High Permeability Streaks
Fractures, Fissures, Vugular Rocks, etc.
Edge Water and Cone-in Problems

Pre-Diagnostics and Diagnostics Utilized	Success Percentage
Historical Data Defining Problems	84.60
Injection Profiles - Tracers	87.09
Multi-rate Injectivity Analysis with Profiles	93.06
Logging Analysis - Defining Problem	92.00
Production Analysis -Production Testing	80.96
Production Logs - Analysis	89.14
Reservoir Model Development - Profiles - Placement	93.82
Tools & Testing Diagnostics - Determinants	87.35
Unknown Diagnostics	79.00

No Diagnostics or Analysis Performed	Success Percentage
None*	51.62

*Treatments were recommended based on:

1. Customer not desiring to perform the diagnostics or analysis - wanted best guess of what to do
2. Designers used the sales literature and product performance attributes to address assumed problems
3. Past knowledge and localized performance of products indicated possible solution capability
4. Problems were clearly identified from current information available, data from well files, past diagnostics and analysis, and ease of correcting the problems

CONCLUSIONS

The Oil & Gas Industry has sought a quantitative analysis where the value of performing diagnostics can be shown. Historically, if there is the ability to diagnose problems, the solutions can show a greater success. What this means in dollars has been noted through collected well workover databases as significant improvements in remediation successes and solutions to integrity problems.

Expectations for future developments are that the oil and gas industry decisions may lead to a better qualification in the methods used to diagnose well conditions and problematic anomalies. A general consensus may not be derived, but understanding what experiences have been and what types of diagnostic analysis have been utilized will qualify best practices in evaluations for problem remediations.

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