UNITED STATES
ENVIRONMENTAL
PROTECTION AGENCY
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SUBJECT: **GROUND WATER SECTION GUIDANCE NO. 36**
Completing, operating, monitoring, and testing wells that have tubing cemented in place.

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This guidance is for UIC permit, compliance, and enforcement personnel to use when conducting permit, compliance, and enforcement actions on wells that have tubing cemented in place.

STANDARD WELL COMPLETIONS vs. CEMENTED TUBING COMPLETIONS

Injection wells should be designed and operated to prevent fluid from entering any formation other than the designated injection formation. One of EPA's duties is to monitor and test injection wells to make sure that injection occurs only into authorized formations. In a well with a tubing/casing annulus, EPA can (by monitoring and testing the pressures in the annulus) maintain a high degree of assurance that no injected fluid is lost through leaks in the well. For wells where the annulus is filled with cement, EPA loses this simple test to monitor for leaks in the well. Therefore, we need to take special precautions in dealing with wells where the tubing is cemented in place.

Standard Completions

The standard well completion (an annulus between the long-string casing, tubing, and packer) allows for two features that are very important to the safe operation and monitoring of injection wells:

1) **MONITORING** - By comparing the pressure relationship between the tubing and the annulus, an inspector can "look" into an injection well and assess the tubing/packer integrity. The inspector can use this "look" to determine if any injected fluids are lost through leaks in the well (i.e., leaks which may contaminate USDWs). Since the operator usually maintains the annulus at zero (0) psi, any pressure evident on an annular pressure gauge suggests a

potential problem with the well. When the annulus and tubing gauges show similar pressures, a tubing/packer leak may be the cause.

2) **MITs** - The standard well completion allows for a simple mechanical integrity test (MIT). A typical MIT consists of adding pressure to the annulus, and then monitoring that pressure for a certain time period. A drop in pressure indicates a leak in the annulus.

<u>Cemented Tubing Completions</u>

When an operator cements the tubing in the hole, we lose the monitoring and testing features described above. At first glance, it seems that cementing the injection tubing in the casing would provide additional protection against USDW contamination. The opposite is true, however.

We generally think of tubing as a string of pipe <u>that can be run in and out of the hole</u> as conditions and workovers warrant. When we cement the tubing in the hole, the tubing can no longer be retrieved; thereby making it a slim-hole casing string. The well should be considered just that: a slim-hole casing injection well.

Any string that is cemented in place may develop leaks. For example, leaks are common in a <u>casing</u> string that is fully cemented. Also, leaks may develop in a <u>tubing</u> string cemented in the hole. These leaks may allow injected fluid to exit the wellbore and to contaminate USDWs.

Since the annulus is full of cement, an inspector (either the operator or an EPA inspector) is unable to "look" into the well to find a leak by simple surface monitoring.

Also, cementing the tubing inside the casing prevents a straight-forward mechanical integrity test. We must now design an alternate MIT that may be more costly to the operator, which may not provide the same assurance that we would get from a standard annular pressure test.

Besides the limits described above, there may be other serious drawbacks to cementing the tubing string in the hole. With such a small wellbore, any problem with the well becomes much more serious than with a conventional completion. For example, we may not be able to run conventional logging tools for monitoring or testing due to the reduced I.D. of the tubing. Any mechanical problems with the well (i.e., scale buildup, internal corrosion, buckled pipe, etc.) may prevent proper logging or plugging. Also, workover procedures that require entering the well may cause tools to become stuck or lost. If the stuck or lost tools happen to bridge the hole, the only alternative may be to abandon the well. If we must plug the well, the stuck tools may make it impossible to place cement in the proper interval(s) necessary to prevent flow into and between USDWs. Again, slim-hole completions do pose a greater environmental risk.

Cementing the tubing inside a bad string of casing should not become standard practice. Cementing a tubing string in the hole should be considered only as a last resort necessary to keep a vital well in service.

ADVISING OPERATORS WHO WISH TO CEMENT THE TUBING IN PLACE

To ensure that a well with tubing cemented in place will protect all USDWs, one must carefully plan the well completion, operation and testing program. A well that has tubing cemented in the hole is usually more costly to complete and to test. Therefore, the operator wishing to convert a well by cementing tubing in place must consider many factors before proceeding with the operation. Some of these factors include:

1) Consider the location of USDWs. If the operator cannot run tubing through all USDWs, a MIT may be difficult or impossible to conduct. Make sure that all USDWs are covered by tubing.

2) Consider the P&A plan. How will the recompletion affect the P&A plan? If we cement the tubing inside another casing string, it may be difficult to place a plug outside the casing string during the P&A operation. In this situation, we may want to squeeze cement outside the casing **before** cementing tubing in place. This step should not compromise the integrity of the well since the squeeze perforations will be covered by the cemented tubing.

   Will the operator be able to plug the well properly if there are any obstructions in the tubing? Any stuck tools or wireline may prevent a proper P&A. The operator may be forced to conduct an expensive fishing or milling operation prior to the P&A in order to place cement in the required intervals.

3) Consider the MIT. How will the MIT be conducted once the tubing is cemented in place? What type of tubing will be run? Operators may wish to reduce corrosion problems by using tubing that has a corrosion resistant internal coating. This type of tubing may require that the operator conduct a very expensive MIT if the completion is not properly designed. Also, check the pressure ratings of different tools to see that they can withstand the pressure

test at or above the maximum permitted injection pressure.

The operator must also know that the well will be subject to more frequent MITs. Cost may quickly become a limiting factor for an operator considering to re-complete a well by cementing the tubing in place.

4) Consider the finality of the recompletion. Since there is no way to pull tubing, a simple problem in the well may require that the well be plugged and abandoned.

MIT METHODS FOR WELLS WITH TUBING CEMENTED IN PLACE

If you must conduct a mechanical integrity test on a well where the tubing is cemented in place, you have several options. Each method has pros and cons as explained below.

Seating Nipple

Description:

A seating nipple is a mechanical device which is installed on the tubing string before it is cemented in the hole. The seating nipple is a polished bore receptacle (PBR) that accepts a slickline conveyed tool. With the tool seated, pressure can be applied to assess the integrity of the tubing.

Pros:

Pressure test is a reliable indicator of mechanical integrity of the tubing above the tool.

The tool is widely available.

With the tool seated, the tubing can be pressure tested in much the same way as with a standard MIT.

The cost of running the test is low (1994 prices run from $1300/well for single wells, with multi-well discounts pushing the cost down into the $700/well range).

Low "down-time" required for the MIT (approximately 1 hour).

Cons:

The seating nipple must be made up on the tubing string before the string is cemented in the hole.

The up-front cost is higher since tubing must be pulled, and the seating nipple installed in the lower tubing string before cementing the tubing in the hole.

The tool may not provide a positive seal in wells that have scale problems or that are highly corrosive. Scale or corrosion buildup on the seating nipple may not allow the wireline tool to seat properly.

If scale or trash falls onto the wireline tool after it is set, we may experience problems pulling the tool out of the PBR.

The tool is not drillable; thus, it must be milled if it is stuck.

The pressure test must be conducted at a pressure equal to or greater than the maximum permitted injection pressure.

Coiled-tubing conveyed packer

Description:

For wells that have internally coated tubing, but do not have seating nipples installed, a small-bore inflatable packer may be run and set near the lower end of the tubing. When set, this packer allows us to test the tubing in a manner much the same as with a standard completion.

Pros:

Pressure test is a reliable indicator of mechanical integrity.

The rubber packer elements will not damage a tubing's internal coating when the tool is set.

The tool can be used in rough tubing since the inflatable packer elements will expand to fill voids in the tubing wall.

With the tool seated, the tubing can be pressure tested in much the same way as with a standard MIT.

Cons:

This method is expensive (1994 prices are roughly $7,000 - $10,000/well), and tools is not widely available.

Down-time runs about 6 hours per well.

The pressure test must be conducted at a pressure equal to or greater than the maximum permitted injection pressure.

Slick-line conveyed plug

Description:

This method is intended for wells that do not have seating nipples installed. The tool is run in (and out) in two separate runs. The first run sets either a collar stop (set in the tubing collars), or a slip stop (sets in the middle of a joint). After the stop is run and set, the test tool is run in and is set on top of the stop. The test tool seats against the tubing wall and provides the seal. The tubing can then be pressure tested.

Pros:

Pressure test is a reliable indicator of mechanical integrity.

The tool is widely available.

The tool may be used where no seating nipple was installed.

Low cost (1994 prices approximately $800/well).

Low down-time (approximately 2 hours/well since tool must be run-in (and retrieved) with two separate runs).

Cons:

May not provide a seal on rough-walled or pitted tubing.

Cannot be used with internally coated tubing since the tool mechanically engages the tubing wall.

The pressure test must be conducted at a pressure equal to or greater than the maximum permitted injection pressure.

Radioactive Tracer Survey (RTS)

Description:

There are several methods (drag, velocity shot, and slug area) for using tracer logs. However, only the drag method has been approved for use in determining Part I (internal) mechanical integrity.

The drag method involves injecting successive "slugs" of tracer material into the wellbore, and following these slugs down-hole with the detector. As the tool follows a tracer slug down-hole, it detects any tracer material that has passed through a hole in the tubing. This indicates a mechanical integrity failure.

Pros:

The tracer logging tools are usually widely available.

Cons:

The drag method may be unreliable for determining Part I (internal) mechanical integrity.

The limited depth of investigation may limit the detection of leaks (90% of the gammas registered by the tracer tool originates from within a foot of the detector).

The survey must be run at the highest permitted injection pressure so as to detect leaks that would occur while the well is operating. Consequently, the survey may not be applicable for wells with small-bore tubing since fluid velocity may be too fast to track.

Tracer material that may "hang up" at the collars between tubing joints suggests a leak, and may require the operator to run another type of MIT.

May not be reliable in wells where the tracer material may "hang-up" in pits or scale on the tubing wall.
A specific tracer survey must be designed for each well since tubing size(s) and the corresponding fluid velocity (at maximum permitted pressure) dictates how we conduct the test.

Temperature Survey

Description:
The temperature survey when used properly may be used to determine if any injected fluids are exiting the tubing above the approved injection interval. Several log passes are required to detect leaks in tubing - one pass while the well is injecting, and several passes made with the well shut in. For specific procedures, refer to Section Guidance #38 - "Using temperature surveys to determine Mechanical Integrity (MI) for a Class II injection well."

Pros:

Temperature tools are widely available.

Temperature tools are available in sizes applicable for most tubing strings.

Resolution is adequate to detect leaks in the tubing.

Cons:

The well must be shut-in to run the complete set of log passes. This down-time may be considerable, and may be impractical for some operators.

Interpretation is often made more difficult since many factors can affect the logging results.

The survey must be run at the highest permitted injection pressure so as to detect leaks that would occur while the well is operating.

CHOOSING A TEST METHOD

Since injection wells are completed in many different ways, you must choose a test that fits the well's completion. If one of these tests described above will not fully demonstrate the integrity of the tubing, a combination of two or more tests may be necessary. In addition, one of the tests listed above may be used with another test - one that may not be listed above - to prove the integrity of the tubulars through the USDWs.

CONDUCTING MECHANICAL INTEGRITY TESTS

Frequency of Testing

For wells that have tubing cemented in place, the operator needs to conduct MITs more often than for a well with a standard completion. More frequent testing is required since the well's completion makes it impossible to assess mechanical integrity during a surface inspection. Unless it is tested more frequently, a well with a cemented tubing completion could operate up to 5 years with a hole in the tubing - a hole that could allow contamination of USDWs.

The frequency of conducting mechanical tests is based on the location of USDWs containing less than 3000 mg/l TDS. If all USDWs containing water with TDS # 3000 mg/l occur behind cemented surface casing, then the well may operate for up to two years between MITs. If any USDW containing water with # 3000 mg/l TDS occurs below the surface casing, the well must be tested once per year.

Test Pressure

Wells that have tubing cemented in the hole must be tested at a pressure equal to or greater than the maximum permitted injection pressure. This is required so that EPA can assess the condition of the tubing under operating conditions.