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Injection Well Mechanical Integrity

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Abstract

Underground injection control regulations of the U.S. Environmental Protection Agency (EPA) require that all injection wells demonstrate mechanical integrity, which is defined as no significant leak in the casing, tubing or packer; and no significant fluid movement into an underground source of drinking water through vertical channels adjacent to the injection well bore.

This initial research project, examining the question of mechanical injection well integrity, was conducted by the Robert S. Kerr Environmental Research Laboratory and funded in 1981. The three-phased project determined the state-of-the-art methods available for mechanical integrity testing of injection wells and field tested specific analysis methods to determine their adequacy as mechanical integrity tests.

The first phase of the project resulted in a separate report entitled, "Methods for Determining the Mechanical Integrity of Class II Injection Wells," EPA 600/2-84-121. The report represented state-of-the-art methods available for determining mechanical integrity of Class II wells. The technology described may also be applied to other classes of injection wells.

The second and third phases of study involved test wells constructed for mechanical integrity testing: "Logging Well No. 1" to test for channels in the cement behind the casing; "Logging Well No. 2" to test for channels in the cement behind the casing and to evaluate cement behind fiberglass casing; "Fiberglass Calibration Well" for use in calibrating tools to free fiberglass casing; "Leak Test Well" for developing methods for testing the integrity of the tubing, casing and packer as well as locating fluid movement in channels behind the casing; and three monitoring wells to determine fluid movement and pressure buildup as a result of injection.

Channels covering 90, 60, 30, and 6 degrees of the 360 degree circle described by the casing were built into the cement of Logging Well No. 1, and channels covering 30, 25, 20, 15 and 10 degrees of the 360 degree circle described by the casing were built into the cement of Logging Well No. 2. Three generations of logging tools were run in the logging wells: the "cement bond" tool and the "cement evaluation" tool, in addition to prototype tools that are not yet available for commercial use.

None of the logging tools presently commercially available located any of the 6 degree channels in Logging Well No. 1. The "second generation" tools located all of the 30, 60, and 90 degree channels and a calibrated "cement bond" tool with dual receiver 3-foot/5-foot spacing located all but one of the 30 degree and all of the 60 and 90 degree channels.

Results of tests in Logging Well No. 2 indicate that none of the presently available tools are capable of evaluating cement behind fiberglass pipe. Initial indications are that some prototype tools are able to identify 10 degree channels on the steel casing; however, this is based on preliminary data and much more testing must be done before definitive conclusions can be reached.

The tools must be calibrated prior to their use. Industry is encouraged to continue research to increase the sensitivity of the tools for mechanical integrity determinations.

The Leak Test Well was designed to correspond generally to a typical salt water disposal well used by the petroleum industry. It incorporates the use of surface casing, long string, tubing and packer. Additional modifications included two packers, a sliding sleeve on the injection tubing and a 2 3/8-inch tubing attached to the outside of the long string running to the surface. Flow into the well can be controlled so that the injected fluids are directed into the 2 3/8-inch injection tubing, or to the 2 3/8-inch leak string. Return flows can be controlled from the 2 3/8-inch leak string and also from the annulus of the 5 1/2-inch casing.

A number of tests have been performed on the Leak Test Well. These include hydraulic conductivity of the injection zone; radial differential temperature log; temperature log; differential temperature log; radioactive tracer survey; noise log; flow meter survey; oxygen activation techniques; volume-pressure relationships; effect of mud in the long string/surface casing annulus; down-hole TV; and pressure tests using compressed gas. Tests planned for the well include helium leak test, annulus pressure changes resulting from temperature variances and a "mule tail" test.

Three monitoring wells have been constructed to observe each of the zones open to the Leak Test Well. Tests have been conducted with pressure transducers in the zones as injection was conducted to determine lateral and vertical movement within the zone and well bore.

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Acknowledgments

This report reflects the work done to date on unique research wells designed for testing methods of determining the mechanical integrity of injection wells. The successful design of the wells is due to the time and effort which an unusually able advisory panel was willing to devote to the project.

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Introduction

Underground injection control regulations of the United States Environmental Protection Agency (U.S. EPA) require that new injection wells demonstrate mechanical integrity prior to operation and all injection wells demonstrate such integrity at least every 5 years.

The regulations state that an injection well has mechanical integrity if:

(1) There is no significant leak in the casing, tubing or packer.

(2) There is no significant fluid movement into an underground source of drinking water through vertical channels adjacent to the injection well bore.

The initial research project to examine the question of mechanical integrity was funded July 1, 1981. The three-phased project was to determine the state-of-the-art for mechanical integrity testing of injection wells and to test specific field methods to determine their adequacy.

The first phase of the project resulted in a report, "Methods for Determining the Mechanical Integrity of Class II Injection Wells." Although this report represented the state-of-the-art for determining mechanical integrity for Class II wells, the technology described may be applied to other classes of injection wells.

Mechanical Integrity Test Wells

The second and third phases of the project involved construction and testing of wells designed to evaluate various tools and techniques used to determine mechanical integrity of injection wells. The test wells – two "logging wells," a "leak test well," a "calibration well," and three "monitoring wells" – were designed for developing methods testing the integrity of the tubing, casing and packer; locating fluid movement in channels behind the casing; and testing for channels in the cement behind the casing. The wells are located on a 110-acre site approximately 11 miles west of Ada, Oklahoma.

Logging Well No. 1

The purpose of this well is to determine the present capability in the industry for evaluating the cement bond between the cement/casing and cement/formation coupling in injection wells, and to provide a test facility for evaluating new tools developed for cement evaluation.

After much discussion among members of the advisory group, it was determined that the best method to simulate poor cement bonding, or channels in the cement, would be to attach water-filled polyvinyl chloride (PVC) pipes to the outside of the casing. Thus, PVC pipe was attached to the outside of the casing to cover either 90, 60, 30 or 6 degrees of the 360 degree radial surface of the pipe (Figure 1).

Having installed the "channels" on the casing, attention was turned to a second vital factor in the completion of this well, the quality of the cement job. The planned cementing program was designed to provide the most favorable conditions for obtaining excellent bonding of the cement to the casing and coupling of the cement to the formations, so that the "channels" identified by the logging tools would be those purposely created for the project.

A thorough review of the logs run to evaluate the cement bonding indicates that about 60 percent of the well has good cement bonding and provides an excellent facility for determining the sensitivity of various down-hole cement evaluation techniques. The other 40 percent of the well provides an opportunity for testing techniques for repairing channels in cement, and for evaluating the success of the repair efforts.

The well specifications, along with a detailed description of the installation process, are provided in Appendix A.

Cement Evaluation

With the completion of the well, the actual testing portion of the project, determining the present capability for evaluating the cement,

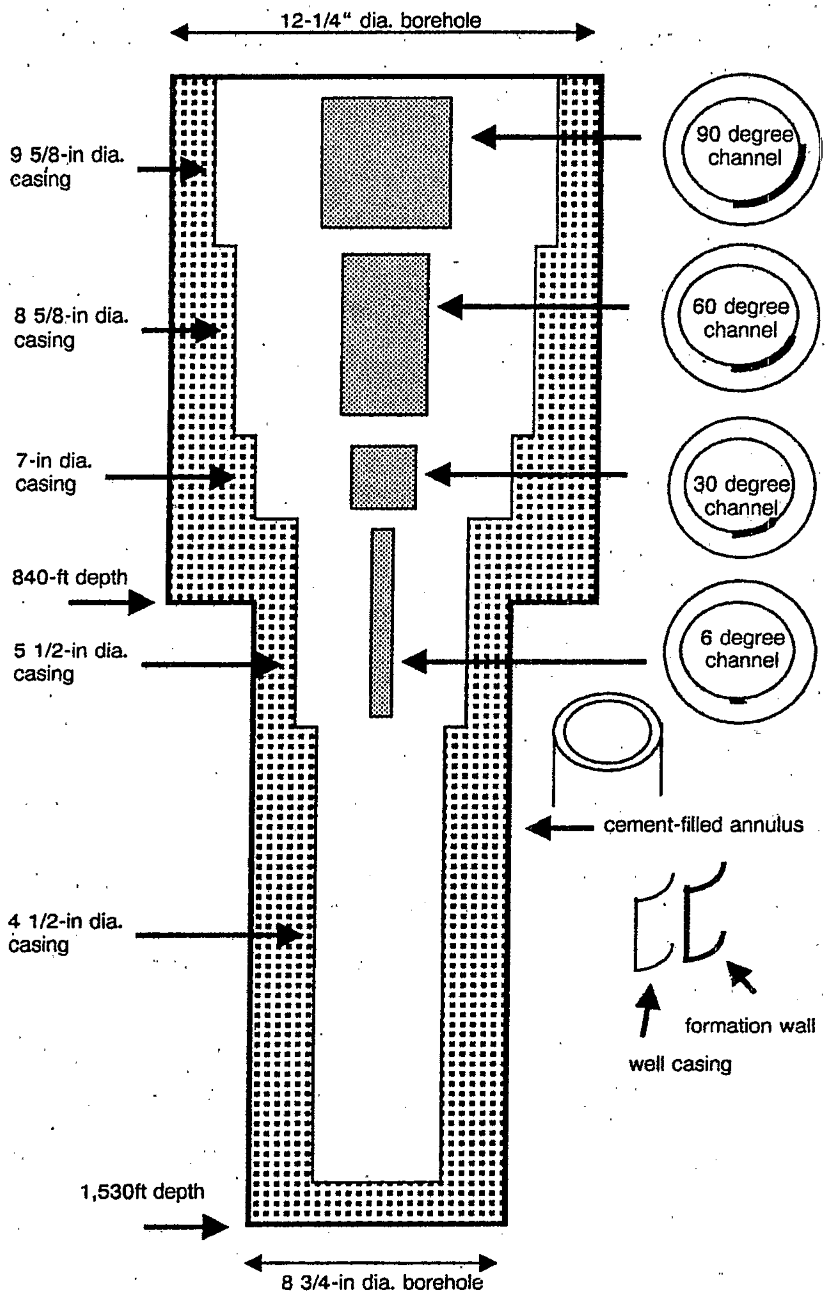

Figure 1. Logging Well No. 1.

was ready to proceed. Contact was made with as many logging companies as possible to determine the types of tools that are being used for evaluating cement in a well and to run as many different tools as possible in the well. At the initial contact with each company contracted to log the well, the construction and purpose of the well were fully explained, except for the location of the manmade channels. Each company representative was also asked to provide a complete interpretation of the condition of the cement in the well, based on the information from the company's log, prior to their leaving the site.

Nine companies have produced 16 logs on the well. Two companies have refused to run a log on the well.

Logging Tools

Basically, two generations of logging tools have been run in the well: the "cement bond" tool, consisting of single transmitter/single receiver or single transmitter/dual receivers; and the "cement evaluation" tool which has eight ultrasonic transducers.

The typical cement bond tool presents a log with the following data: gamma-ray and casing collar locator (CCL), which are included for depth control; transit time (TT), which measures the time it takes for a certain level sound wave to travel from the transmitter to the receiver; amplitude, which measures the strength of the first compressional cycle of the returning sound wave; and a graphic representation of the wave form, which displays the manner in which the received sound wave varies with time. This representation is called variable density log (VDL), seismic spectrum, or micro-seismogram, and is a function of the property of the material through which the signal is transmitted.

There are various transmitter/receiver spacings available, the most common being a single transmitter with a single receiver located 3 feet away (Figure 2). Other tools include the single transmitter/single receiver with 4-foot or 5-foot spacing, or a single transmitter/dual receiver with 3-foot/5-foot spacing (Figure 3).

The "second generation" tools for determining the adequacy of cement bonding include a tool having eight ultrasonic transducers spiraled around it to survey the circumference of the casing (Figure 4). The information presented on the log from these tools includes casing ovality; average casing I.D.; casing collars; hole deviation; fluid velocity; eccentering of the tool; rotation of the tool; gamma-ray, maximum and minimum cement compressive strength; average of the energy returned to all eight transducers; and cement distribution around the casing.

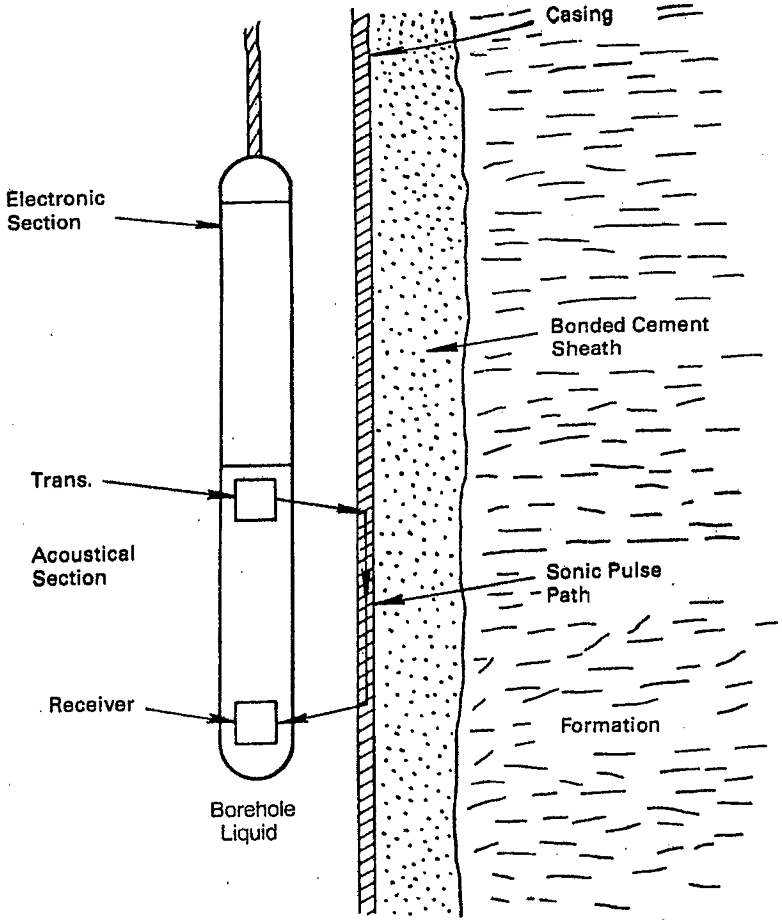

Figure 2. Cement bond tool - single transmitter/receiver.

Log Interpretation

The bonding of cement to casing can be measured quantitatively, but the bonding, or rather the coupling, of cement to the formation is only a qualitative estimate. Therefore, when attempting to evaluate cement in a well, it is extremely important to obtain as much information as possible.

The components of the sound wave that are of primary interest when analyzing a "bond log" are the casing, formation and fluid (mud) signals. Each medium has different characteristics, thus the

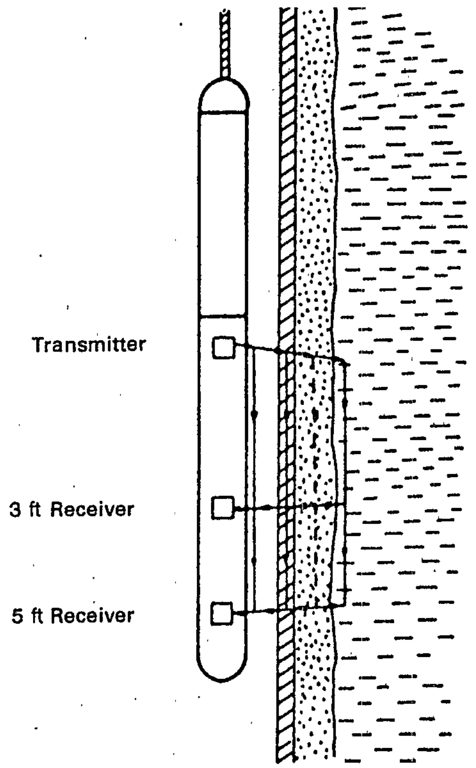

Figure 3. Cement bond tool - single transmitter/dual receiver.

sound waves will have different amplitudes and velocities. Figure 5 indicates these wave forms and a composite signal.

A recommended approach to evaluating the cement bond log is to first determine the information available from the graphic representation of the wave form (VDL), then examine the amplitude curve to see if the two are in agreement. For example, if the casing diameter and transmitter/receiver spacing are known, the transit time for the casing arrivals can be predicted. Figure 6 is a chart that, for practical field or reference purposes, gives an idea of the approximate transit time for the casing signal for various tool spacing and casing I.D. By examining the VDL, the time, in microseconds of the first arrival, can be determined. This time can then be checked against the chart to determine if it is a casing signal.

The fluid, or mud, wave has a velocity of about 189 microseconds/foot, and its arrival can be predicted, if the tool spacing is known, by multiplying the tool spacing by 189. The fluid wave has a

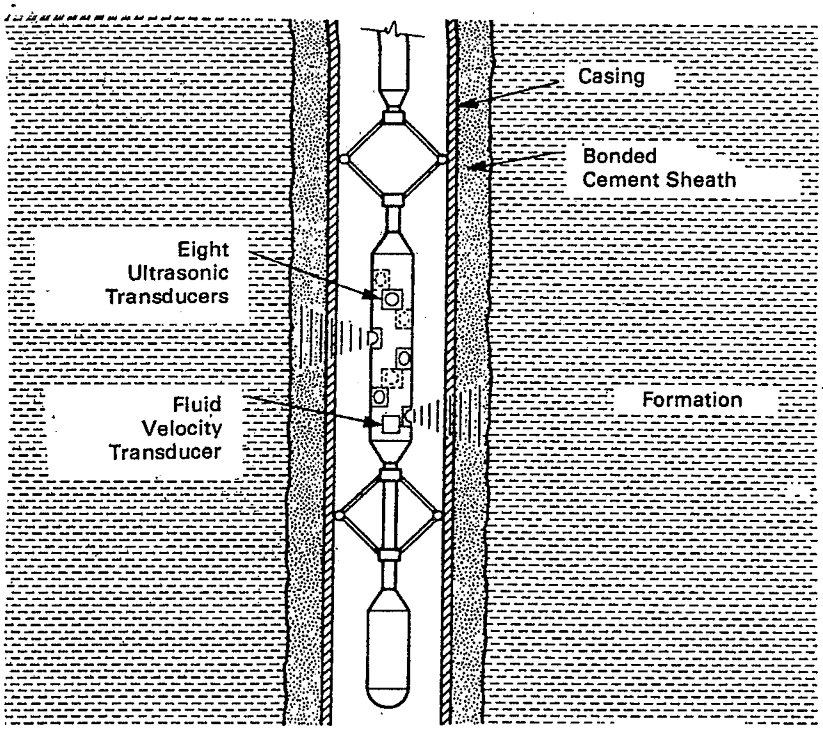

Figure 4. Second generation tool.

destructive interference; thus when it enters the receiver, distortion of the wave occurs. Because of this, the only part of the VDL that is useful for interpretive purposes is that part that reaches the receiver prior to the arrival of the fluid wave.

The "second generation" tools generate a pulse of ultrasonic energy from each of the eight focused transducers that are arranged around the circumference of the tool. The strength and duration of the echoes reflected from the casing and cement are used to form an image of the cement distribution and quality around the casing. This information and the cement compressive strengths are two very useful pieces of data for evaluating the casing/cement bonding in a well.

As stated earlier, 16 different logs have been produced from the well. Appendix A contains a detailed comparison of specific sections of the well that have been logged by "first generation" tools with single transmitter/receiver, 3-, 4- or 5-foot spacing; and the second generation ultrasonic logging tool.

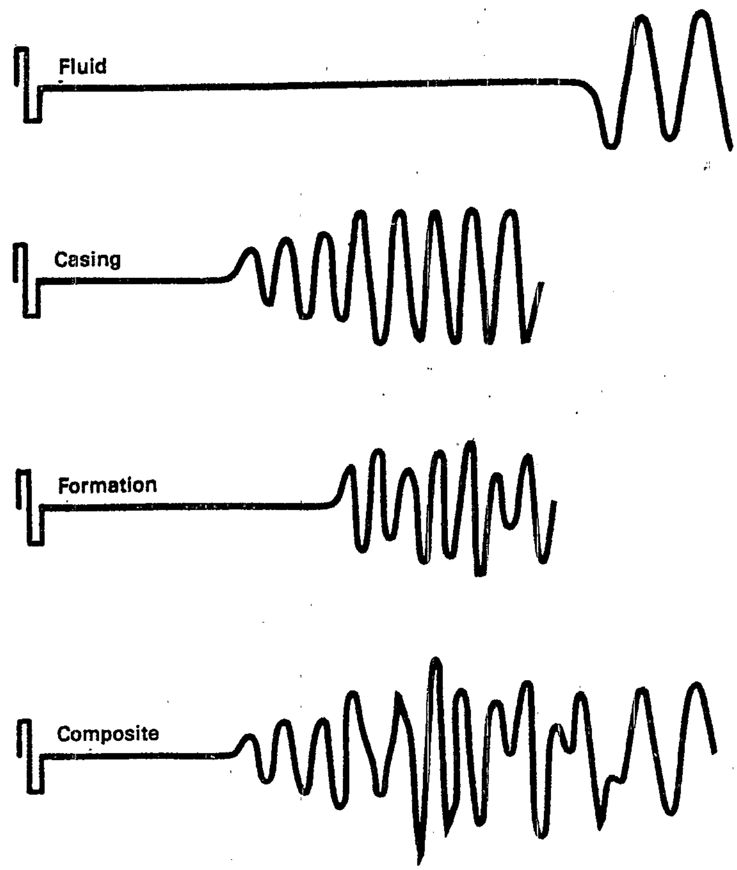

Figure 5. Composite wave form.

Logging Well No. 2

Analysis of the tests completed on Logging Well No. 1 identified two areas that needed further investigation. As has been stated, certain logging tools located all of the 90 and 60 degree channels, all but one of the 30 degree channels, but none of the 6 degree channels. Thus, the detection limit for the tools is somewhere between 30 and 6 degrees. The second area of concern relates to the inability of presently available equipment to evaluate cement behind fiberglass pipe.

To address these concerns, Logging Well No. 2 was designed and constructed with both steel and fiberglass pipe and with channels

	A ft 3	4	5
D in 4	235	292	349
5	250	307	364
6	265	322	379
7	280	337	394

A ft - Receiver spacing
D in - Casing diameter

Figure 6. Field reference transit time.

on the steel pipe covering 30, 25, 20, 15 and 10 degrees of the 360 degree radial surface of the pipe (Figure 7).

The well specifications, along with a detailed description of the drilling and completion process, are provided in Appendix A.

Cement Evaluation

With the completion of the well, the process of determining the capability for locating channels on steel pipe and evaluating cement behind fiberglass pipe was ready to begin. Only those logging tools that produced satisfactory logs in Well No. 1 were run on Well No. 2, with the exception of some experimental tools that have been run in the well but are not yet available for general use.

Ten logs have been produced on the well. Of these, four were produced from experimental tools.

Logging Tools

Three generations of logging tools have been run in the well. The "cement bond" tool consists of a single transmitter/dual receiver with the receivers spaced 3 feet and 5 feet from the transmitter. The "cement evaluation" tool has eight ultrasonic transducers spiraled around a 2-foot section of the tool. Prototype tools are not yet in commercial use.

Well Logging Conclusions and Recommendations

Well Completion

Greater care must be exercised in planning the cement job and in carrying out that plan when cementing injection wells, especially Class I wells where cement is to be circulated to the surface around the long string. The plan should include equipment and activities that will enhance the possibility for obtaining the best cement bonding possible. This should include the use of a caliper log to determine exact hole size to better estimate the volume of cement necessary to

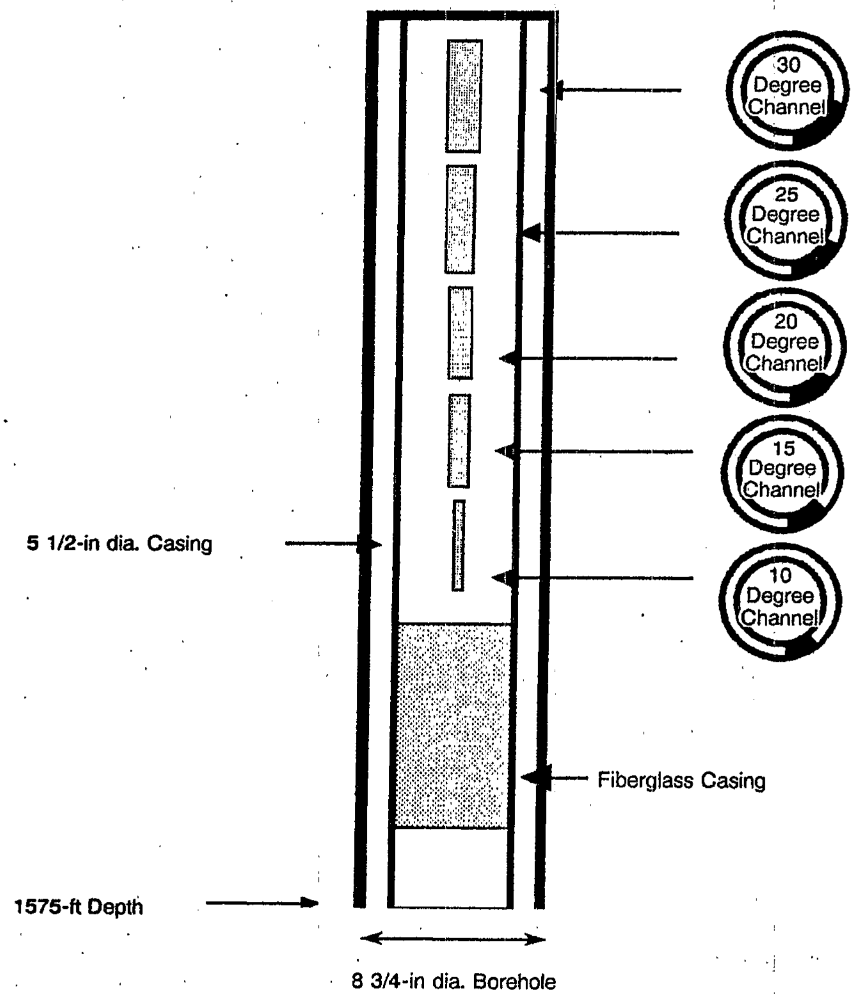

Figure 7. Logging Well No. 2.

complete the well; properly conditioned drilling mud prior to beginning the cementing operation; centralizers, to ensure that the casing is centered in the hole; pre-flush, to help clean out the hole prior to pumping cement; rotating and/or reciprocating the pipe during the cementing operation to further aid in cleaning out the hole; and at least 100 percent excess cement. The experience in cementing Logging Well No. 1 indicates that those areas where the greatest volume of cement flowed past had cleaner holes and better cement bonds, thus the use of 100 percent excess cement will enhance the probability of a good cement job throughout the casing length.

In Logging Well No. 1, although cement was circulated to the surface, after the cement set for 72 hours, the top of the cement behind the casing was 132 feet below land surface. This "fall back" of the cement behind the casing must be monitored and corrected so that there is cement fill-up behind the casing to the surface of the ground.

Because of the problems encountered in cementing Logging Well No. 1, extreme care was taken to ensure that a good cement job was obtained in Logging Well No. 2. The top of cement behind the casing was 42 feet below land surface in this well, as opposed to 132 feet in No. 1. Approximately 1,075 sacks of cement were used to cement Well No. 2 with about 500 sacks circulated to the surface during the cementing operation.

Logging Equipment

None of the logging tools presently available located any of the 6 degree channels in Logging Well No. 1. The second generation tools located all of the 30, 60 and 90 degree channels that were designed into and could be identified in the well. A calibrated single transmitter/dual receiver cement bond tool with 3-foot/5-foot spacing located the 60 and 90 degree channels and all but one of the 30 degree channels. The other cement bond tools with single transmitter/single receiver 3-foot, 4-foot, or 5-foot spacing presented very inconsistent results.

The 3-foot spacing is the best currently available for measuring and evaluating the amplitude of the first compressional arrival and the attenuation of this signal is a measure of the bonding of the cement to the casing. However, this spacing is not satisfactory for determining data on or evaluating the relationship of the cement to the formation. Five-foot spacing between the transmitter and receiver is the best currently available for evaluating the relationship of the cement to the formation, but it is not accurate for determining bonding to the casing. Four-foot spacing is being used; however, it does not have satisfactory resolution for evaluating the relationship of the cement to either the casing or formation.

The significant fact remains that none of the tools located channels smaller than 30 degrees in the well. Such channels represent a significant avenue for movement of fluid and methods must be developed to locate these and even smaller channels. It is recommended that the logging industry continue research efforts toward increasing the sensitivity of the logging tools.

The research conducted on Logging Well No. 1 indicates that with the presently available tools, the ideal approach for evaluating the cement in an injection well is to run both the second generation tool and a calibrated cement bond tool with single transmitter/dual receiver

3-foot/5-foot spacing. This combination gives the most information for interpretive purposes.

An alternative to this approach is the use of either the second generation tool or a calibrated "bond tool" with single transmitter/dual receiver 3-foot/5-foot spacing. The second generation tool gives no information on the cement/formation coupling, but gives excellent information on the cement/casing bonding and its presentation allows for easy interpretation. The "cement bond" tool provides information on both casing/cement bonding and coupling to the formation, but is somewhat harder to interpret and may be less sensitive in some specific situations.

Calibration of both tools is imperative for reliable data to be produced. The size and weight of the casing must be available for use with the second generation tool. A standard shop calibration of the cement bond tool is essential to its use and must be included for there to be any chance of obtaining reliable information. Quality control on the "cement bond" tools can be included, to some degree, on site, in that certain checks can be made to determine whether or not the tool is working properly.

Some of the checks that can be made include:

1. If the well contains free pipe, the chevron effect must be obvious. The chevron effect is the "W" seen opposite casing collars in free pipe. Figure 8 indicates a bond log with free pipe. Note the well-developed chevron effect opposite the casing collars.

2. In free pipe, certain casing diameters call for certain amplitude readings. For example, for 5-inch (I.D.) casing the amplitude should read about 74 millivolts (mv); 7 inch - 60 mv; 8 inch - 55 mv; 9 inch - 30-35 mv. Such information can be used to determine if the tool has been calibrated. Figure 8 indicates an amplitude reading of over 60 mv in 9-inch free pipe. This indicates that the tool was not calibrated.

3. In free pipe, the transit time from a properly centered tool should be constant, except for the influence of the casing collars. In Figure 8, the decrease in transit time (immediately below the arrow) and the corresponding decrease in amplitude, indicates a slightly eccentered tool. Figure 9 also indicates free pipe. Note, however, the wavy free pipe signal on the VDL and the significant drift of the transit time (over one-half of a chart division). This indicates an improperly centered tool.

4. The fluid wave should be visible on each wave form presentation (VDL). If the fluid wave is not visible, this indicates a low response tool and its use should be questioned.

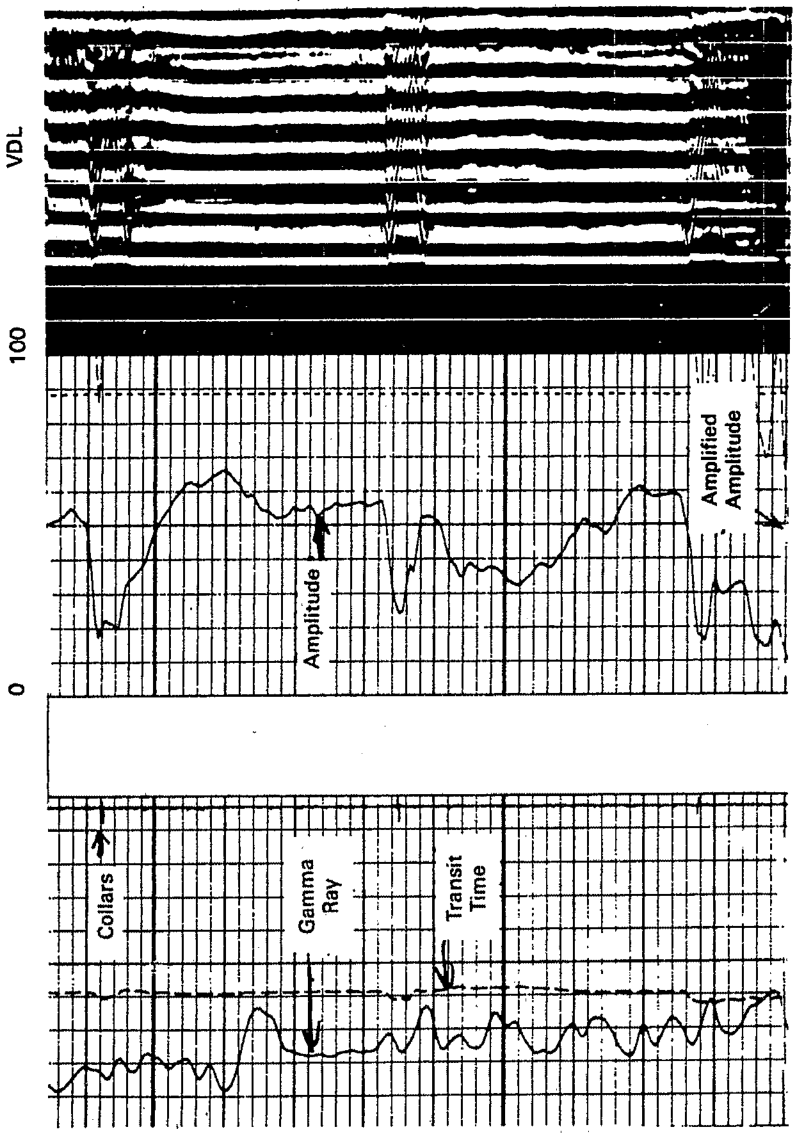

Figure 8. Amplitude, chevron and free pipe.

An API committee is presently working on standardizing a calibration system. This work should be encouraged and continued until an adequate system is developed that can be used throughout the industry.

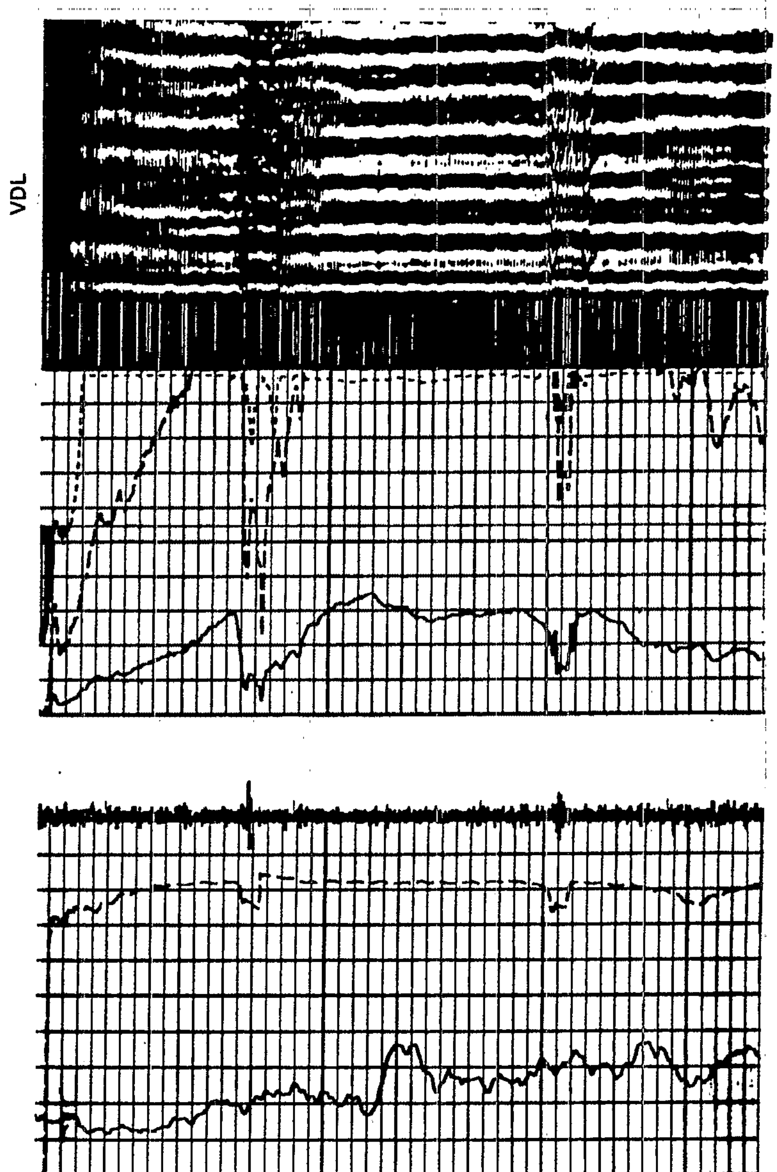

Figure 9. Tool not centered.

The cement bond tools and second generation logging tools run in Logging Well No. 2 located the 30, 25, 20 and 15 degree channels. However, none consistently located the 10 degree channels on the casing. A 10 degree channel on the 5 1/2-inch casing represents about 1/2 inch.

One of the prototype tools consistently located the 10 degree channels. This is very encouraging; however, much more research needs to be completed on these new tools to be assured of their capability for locating channels in cement.

Only one tool presented data that could be used to evaluate the cement behind fiberglass casing. This second generation tool had been modified to respond to the resonance of fiberglass and seemed to work well in the test well. However, the tool is not available commercially and will not be available in the foreseeable future.

Additional research will be done in these two areas during the next 3 years of the mechanical integrity research project.

Log Interpretation

A significant problem that became apparent during the research efforts, especially on Logging Well No. 1, was the inability of some logging company personnel to interpret the logs they produced. Several companies had good equipment, but onsite personnel apparently did not have sufficient knowledge of the equipment to properly operate the system or interpret the log. This is a critical concern if these tools are to be used to evaluate the cement in an injection well. The logging company, injection well owner, or regulatory agency must have trained personnel that are capable of evaluating a log to determine as much information as possible on the quality of the cement behind each casing string.

Leak Test Well

The purpose of the Leak Test Well is to provide a facility to develop methods for testing the integrity of the tubing, casing and packer and for testing the capability of various down-hole tools to detect fluid movement behind the casing.

The design of the well generally corresponds to a typical salt water disposal well used in the oil and gas industry. That is, it includes the use of surface casing, long string, tubing and packer. The deviation from the norm in this well includes two packers and a sliding sleeve on the injection tubing and a 2 3/8-inch tubing attached to the outside of the long string and running to the surface (Figure 10). Detailed discussion on well design and installation is provided in Appendix B.

Flow into the well can be controlled so that the injected fluids are directed into the 2 3/8-inch injection tubing, or to the 2 3/8-inch leak string. Returned flows can be controlled from the 2 3/8-inch leak string and also from the annulus of the 5 1/2-inch casing (Figure 11).

Monitoring wells have been constructed to each of the zones open to the Leak Test Well (Figures 12, 13, and 14). These are multipurpose wells that are being used to monitor pressure changes

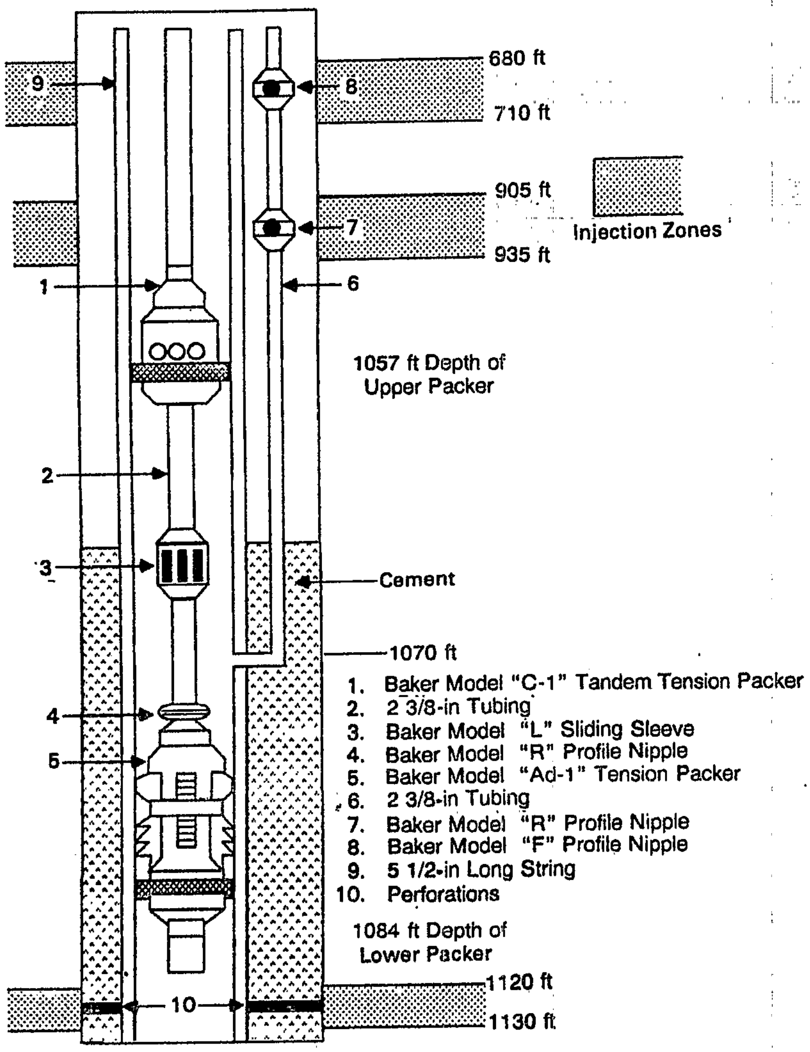

Figure 10. Leak Test Well.

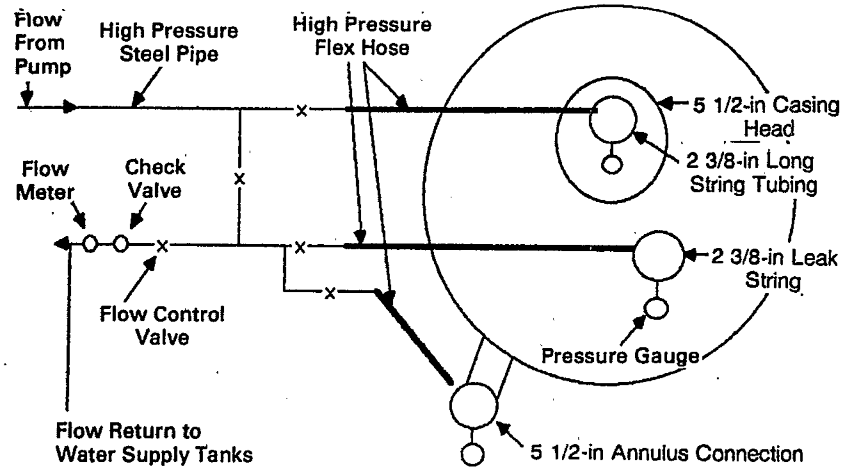

Figure 11. Injection well head and flow lines.

in the respective zones during injection and to determine the capability to evaluate certain types of cement. Well No. 1 was cemented using a latex cement, No. 2, a spherelite cement, and No. 3, a foam cement. Detailed discussions on monitoring well design and installation are provided in Appendix B.

A number of tests have been conducted or are planned for the Leak Test Well. In addition to a test to determine the hydraulic conductivity of the injection zone, such tests include:

Test	Date Completed
1. Acoustic Cement Bond Tool	1/13/87
2. Nuclear Activation Technique	1/24/87
3. Testing for Hole in Casing	2/02/87
4. Ada Pressure Test	12/04/85
5. Nuclear Activation (PDK-100)	4/08/87
6. Radial Differential Temperature	4/27/87
7. Nuclear Activation Technique (Oxygen Activation)	8/31/87
8. Mechanical Integrity Research	2/22/88
(Mud in Annulus)	
(Pressure Monitoring)	
(Standard Pressure Test)	
(Volume vs Pressure/Monitoring Wells)	
(Volume vs Pressure/Hole Size)	
9. Noise Survey	2/15/88
10. Temperature Survey	9/10/85
11. Continuous Flow Survey	10/13/87

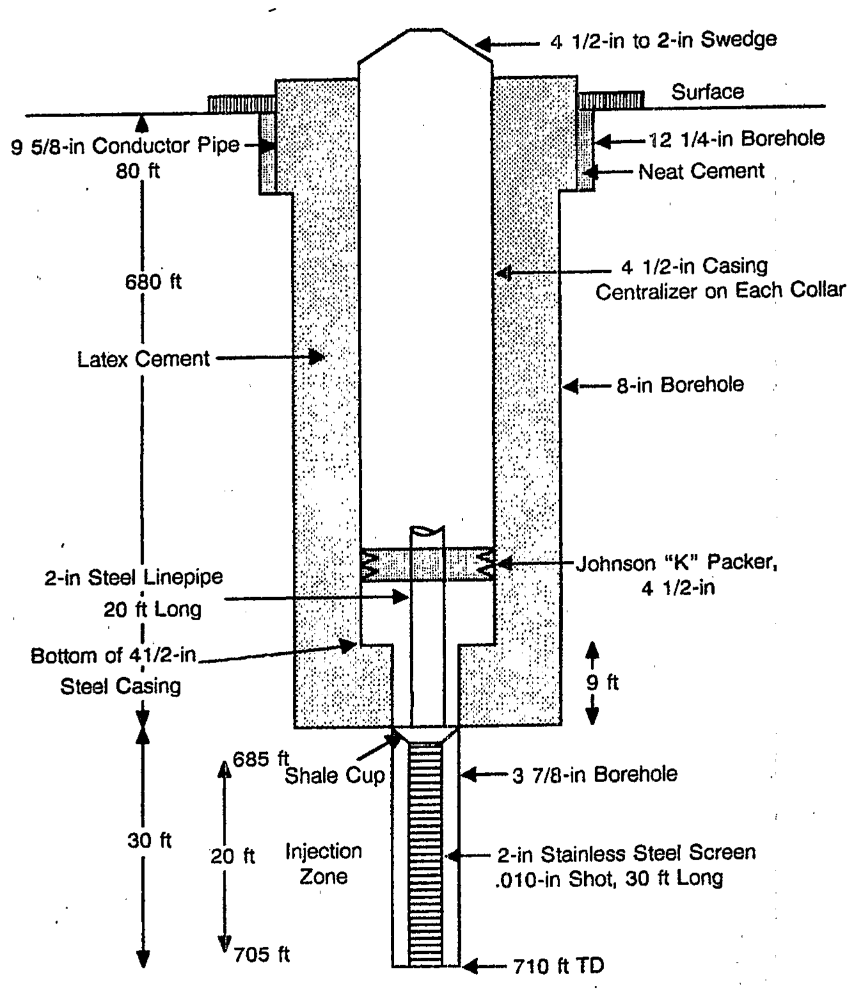

Figure 12. Monitoring Well #1.

12.	Radioactive Tracer Survey	5/19/88
13.	Differential Temperature Survey	11/04/87
14.	Annulus Pressure Changes Due to Temperature	Planned
15.	Helium Leak Test	Planned
16.	"Mule Tail" Test	Planned
17.	Tracers Involving Monitoring Wells	Planned
18.	Oxygen Activation (Water Quality and Flow)	Planned

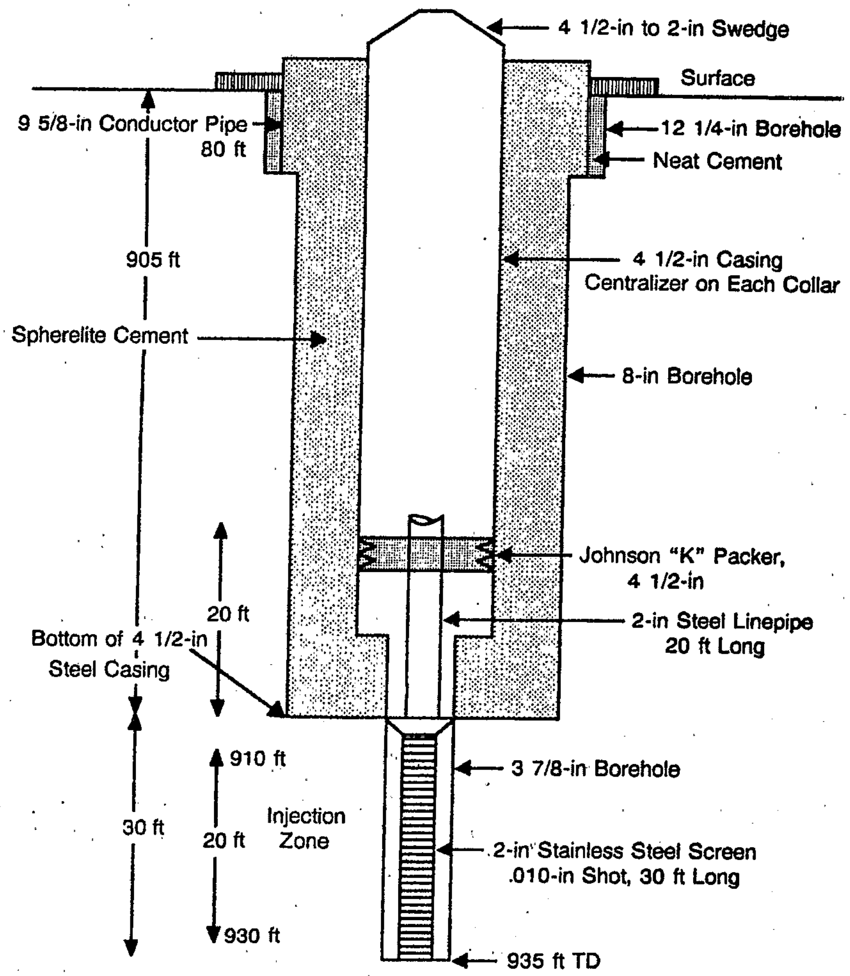

Figure 13. Monitoring Well #2.

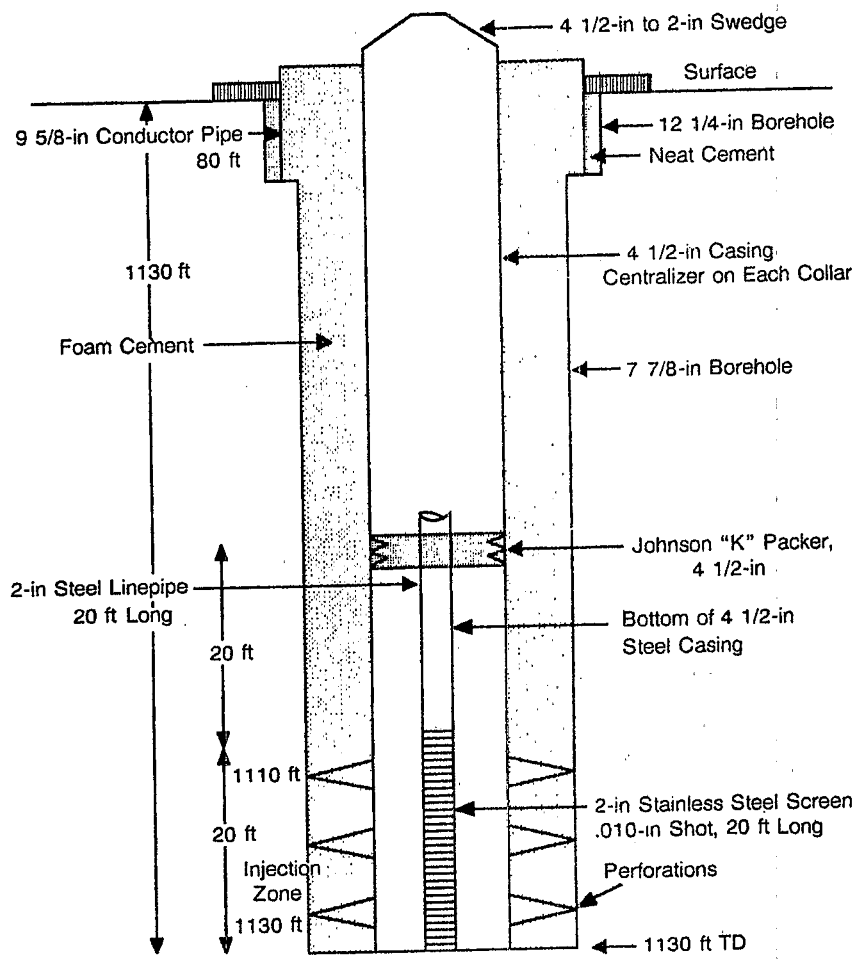

Figure 14. Monitoring well #3.

Conclusions

The viability of deep well injection as a waste management alternative rests on the ability to emplace wastes in geologic formations beneath and isolated from underground sources of drinking water. Wastewater injected into wells may escape through leaks in the well casing caused by mechanical failure within the well or by migration of wastewater between the well's outer casing and well bore because of faulty cementing. Although technology is available to construct and operate injection wells that meet mechanical integrity criteria, technology for determining injection well mechanical integrity must be tested and proven to ensure that sound decisions are made and that underground sources of drinking water are protected.

No one test provides sufficient information to make a determination of the mechanical integrity of an injection well. This determination is made from a combination of tests which individually provide pieces of information that must be evaluated together to provide a basis for making an informed judgment regarding the mechanical integrity of an injection well.

The research facilities described in this document offer industry, state regulatory agencies and EPA a unique capability to test and evaluate a variety of methods for determining mechanical integrity. Such testing can improve the confidence of industry and permitting agencies in approved methods and can speed the acceptance of new methods that may be developed.

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APPENDIX A

Logging Well Design Specifications and Installation Procedures

Logging Well No. 1

Logging Test Well Material Specifications

Casing	Weight	Grade
3 joints of 9 5/8-inch	53.5#/ft	N-80
3 joints of 9 5/8-inch	36.0#/ft	K-55
8 joints of 8 5/8-inch	24.0#/ft	J-55
4 joints of 7-inch	23.0#/ft	K-55
2 joints of 5 1/2-inch	23.0#/ft	N-80
3 joints of 5 1/2-inch	17.0#/ft	J-55
3 joints of 5 1/2-inch	15.5#/ft	J-55
2 joints of 4 1/2-inch	13.5#/ft	N-80
4 joints of 4 1/2-inch	11.6#/ft	J-55
5 joints of 4 1/2-inch	9.5#/ft	J-55

Equipment	Size	Grade
Swage nipple	5 1/2-inch x 4-1/2-inch	K-55
Swage nipple	7-inch x 5 1/2-inch	J-55
Swage nipple	8 5/8-inch x 7-inch	J-55
Swage nipple	9 5/8-inch x 8-5/8-inch	J-55
Swage nipple	9 5/8-inch x 5-1/2-inch	J-55
10 centralizers	4 1/2-inch	
7 centralizers	5 1/2-inch	
3 centralizers	7-inch	
7 centralizers	8 5/8-inch	
5 centralizers	9 5/8-inch	

Detailed Description of Well Construction

On August 14, 1984, the process of preparing the "channels" was begun. PVC pipe, either 3/4 or 1/2 inches in diameter, was sealed on one end, filled with water saturated with boric acid and capped. The next step was to attach the PVC pipe to the outside of the casing so that the channel would cover either 90, 60, 30 or 6 degrees of the 360 degree radial surface of the pipe (Figure A-1). This was accomplished by attaching the PVC pipe to the surface of the casing, which had been sandblasted to remove mill varnish, using fiberglass cloth and epoxy resin. Three layers of fiberglass were used to ensure that the PVC pipe was securely sealed and attached to the casing (Figures A-1 to A-4). This phase of the project was completed on September 17, 1984.

The casing was then wrapped with heat tape and insulation to prevent freezing of the channels while awaiting the availability of the drilling rig.

The driller began moving the rig to the site on December 13, 1984. Rigging up continued on the 14th and 15th and drilling began at 2:30 p.m. on December 15, 1984. The procedure followed and the date each step was accomplished are indicated below:

	Activity	Date Completed
1)	Prepare site (Baulch Drilling Company)	12/13/84
2)	Move in rig and rig up	12/15/84
3)	Drill 15-inch hole to 40 feet, set 13 3/8-inch conductor pipe (OK Cement, 35 sx)	12/15/84
4)	Drill 8 3/4-inch hole to 1,530 feet. Collect drill cuttings every 10 feet starting at 100 feet	12/18/84
5)	Condition hole for logging	12/18/84
6)	Run Dual Induction Laterolog, Gamma Ray, Compensated Neutron, Compensated Density, and B.H.C. Sonic Log (Gearhart)	12/18/84
7)	Ream 12 1/2-inch hole to 758 feet	12/20/84
8)	Clean out hole to TD, condition for setting casing	12/20/84
9)	Set casing	12/20/84
10)	Run 2 3/8-inch tubing and string into Baker Duplex Cement shoe. Condition hole for cementing.	12/20/84
11)	Cement casing (Halliburton, 700 sx. 50/50 Posmix)	12/20/84
12)	Remove tubing, flush out hole	12/20/84
13)	Weld steel plate between 9 5/8-inch and 13 3/8-inch casing. Install 9 5/8-inch x 5 1/2-inch swage nipple on 9 5/8-inch casing. Screw locking cap on swage.	12/27/84
14)	Install rock pad and cement slab	9/10/85

Figure A-1. Preparing fiberglass with epoxy resin.

Figure A-2. Applying initial fiberglass layer.

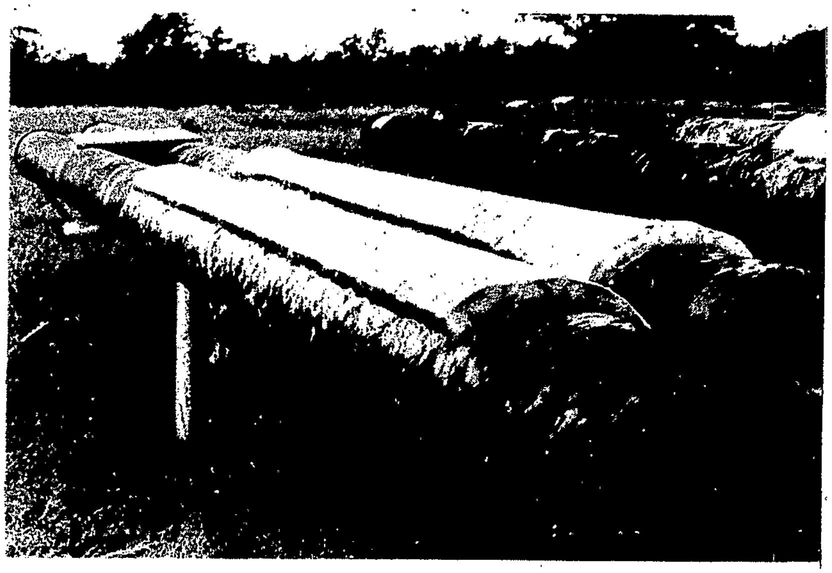

Figure A-3. Completed channel - prior to using wire brush to remove excess.

Figure A-4. Removing excess fiberglass with wire brush.

The design of the Logging Well presumed that the channels would remain in place during the process of setting and cementing the casing. The driller took special precautions when moving the pipe from the pipe racks to the rig, and during the pipe setting process to ensure that this was the case. No problems were encountered during the entire casing setting and well cementing operation, thus there was a high degree of confidence that the channels were not damaged and were in place as designed. Later review of logs run on the well reinforced this confidence.

Log Interpretation

Figures A-5, A-6 and A-7 are portions of logs from the Logging Well that compare single transmitter/single receiver with either 3-, 4-, or 5- foot spacing; single transmitter/dual receiver with both 3-foot and 5-foot spacing; and the second generation logs. Each interpretation is based solely on information from the log.

Figure A-5a indicates a log section from a tool with single transmitter/single receiver, 3-foot spacing. The fluid wave should enter the receiver at about 567 microseconds; however, it is indistinguishable on this log. Casing signals are present in the upper part of the VDL, but no other interpretation can be made. The amplitude curve indicates poor bonding in the upper part of the section, which seems to agree with the VDL, and casing/cement bonding throughout the remainder of the section.

Interpretation: Excellent casing/cement bonding throughout the section with a possible channel or micro-annulus in the upper part of the section. Coupling to the formation cannot be determined.

Figure A-5b is the same section from a single transmitter/single receiver tool, with 4-foot spacing. The fluid wave should enter the receiver at about 756 microseconds, as indicated on the log. Casing signals may be present in the upper part of the section, although the signals are weak. The amplitude curve indicates a problem in the upper part and casing/cement bonding for the remainder of the section.

Interpretation: Excellent casing/cement bonding throughout the section with a possible channel or micro-annulus in the upper part of the section. No coupling to the formation.

Figure A-5c is the same section from a tool with single transmitter/single receiver, 5-foot spacing. The fluid wave should enter the receiver at about 945 microseconds. In this case, the fluid wave is pushed far enough to the right to allow the formation signals to be seen. The VDL indicates formation signals throughout the section, and some casing signals in the upper part of the section. The

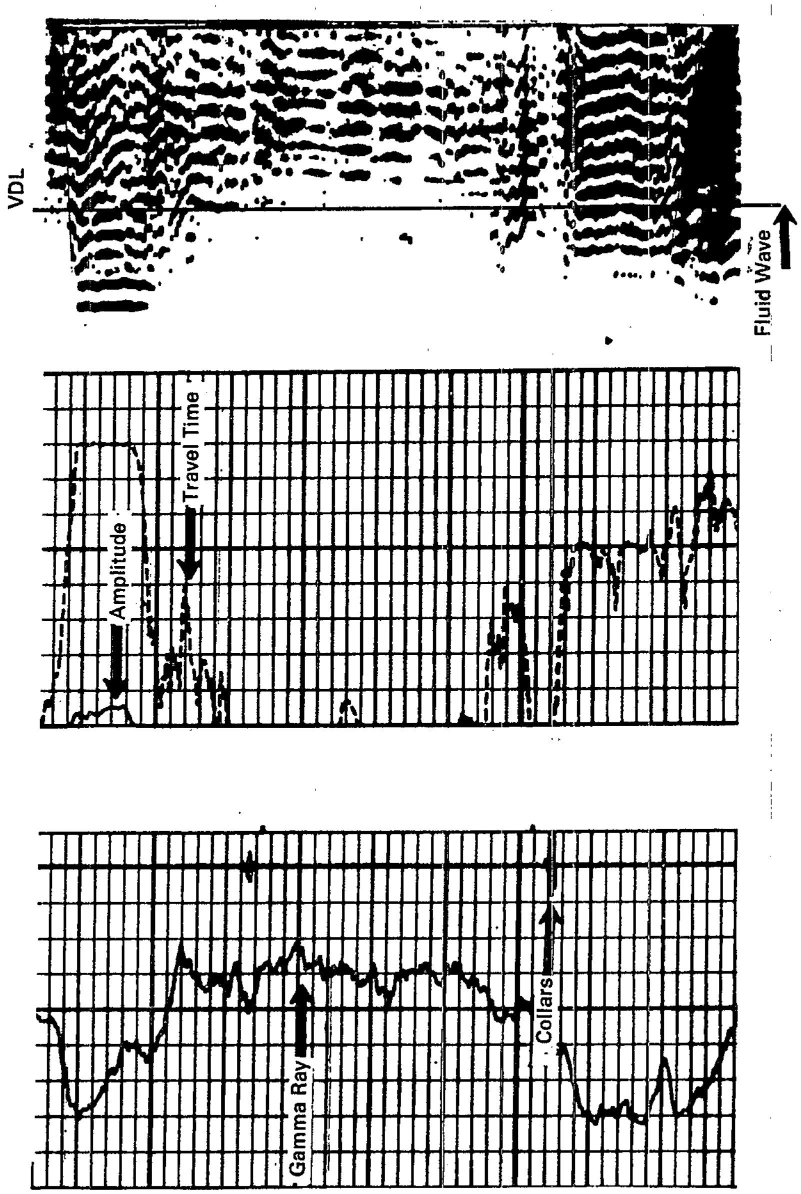

Figure A-5a. Single receiver 3-foot spacing.

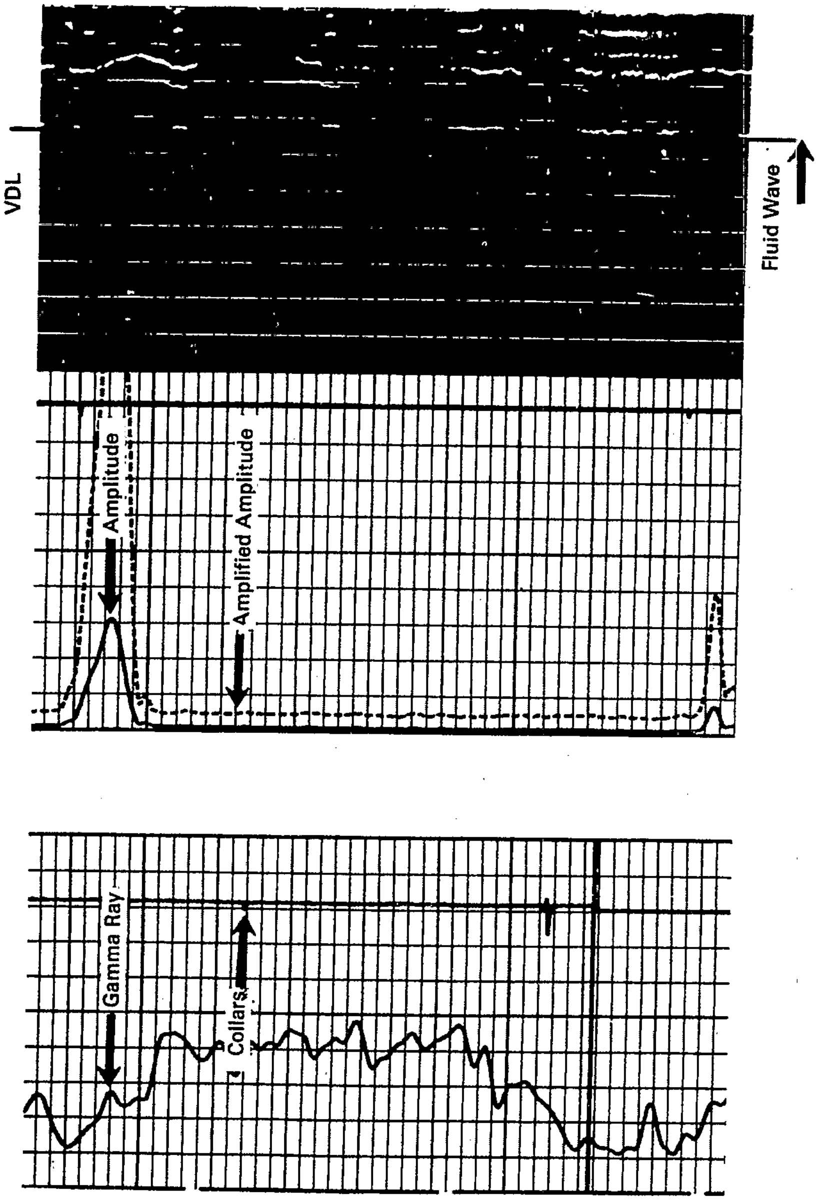

Figure A-5b. Single receiver 4-foot spacing.

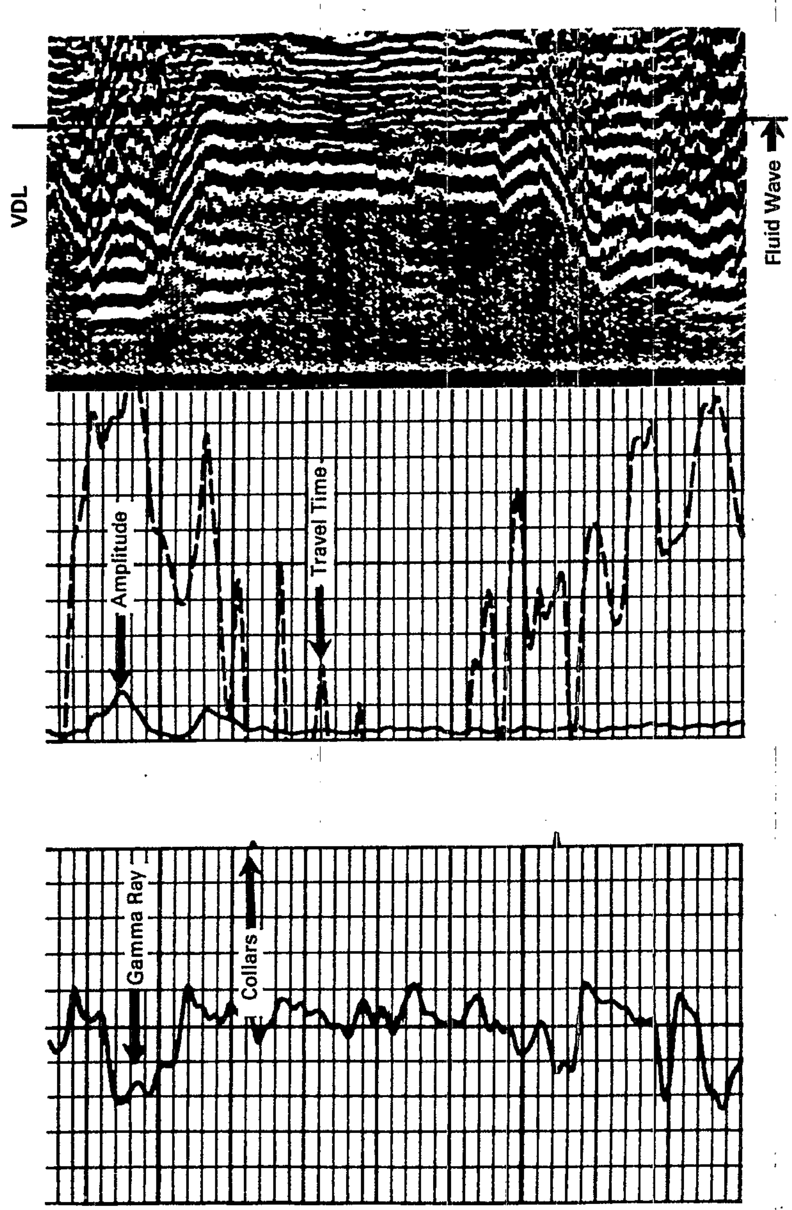

Figure A-5c. Single receiver 5-foot spacing.

amplitude curve indicates a problem in the upper part with casing/cement bond throughout the remainder of the section.

Interpretation: Excellent casing/cement bonding throughout the section with a possible channel or microannulus in the upper part of the section. Possible coupling of cement to the formation.

Figure A-5d is the same section from a tool with single transmitter/dual receivers and a 3-foot/5-foot spacing. The VDL shows formation signals throughout the section and casing signals in the upper and lower parts of the section. The amplitude curve indicates a problem in the upper part with casing/cement bonding indicated throughout the remainder of the section.

Interpretation: Excellent casing/cement bonding throughout the section with either channels or microannuli in the upper and lower parts of the section. Possible coupling to formation.

Figure A-5e is the same section from one of the second generation logs. The white areas on the bond image portion of the log indicate the presence of poor casing/cement bonding. The minimum compressive strength curve also indicates some problems in three areas that coincide with the white areas on the bond image portion of the log.

Interpretation: Excellent casing/cement bonding with three channels or microannuli in the upper, middle and lower parts of the section. No information is available on formation coupling.

A second comparison of the different logging tools run in the Logging Well is shown in the Figure A-6 series. Figure A-6a is a log section from a tool with single transmitter/single receiver, 3-foot spacing. The fluid wave should enter the receiver at about 567 microseconds; however, it is not distinguishable on this log. There may be formation signals in the presentation; however, they are not distinctive, making it difficult to determine the character of the log. The amplitude curve only registers in two places on the log, and the transit time curve is not definitive.

Interpretation: Excellent casing/cement bonding throughout the section.

Figure A-6b is the same section from a tool with single transmitter/single receiver, 4-foot spacing. The fluid signal is very strong, with the VDL indicating casing/cement bonding but no formation coupling. The amplitude curve indicates casing/cement bonding.

Interpretation: Excellent casing/cement bonding, no formation coupling.

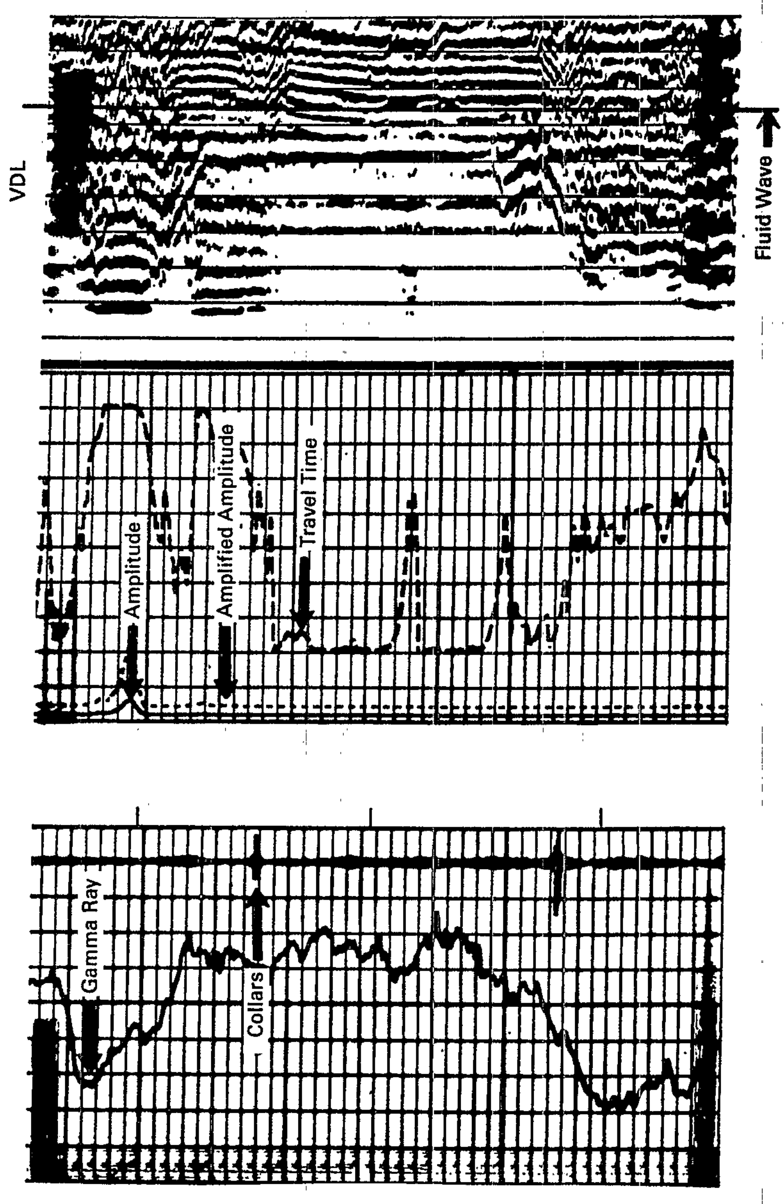

Figure A-5d. Dual receiver 3-foot/5-foot spacing.

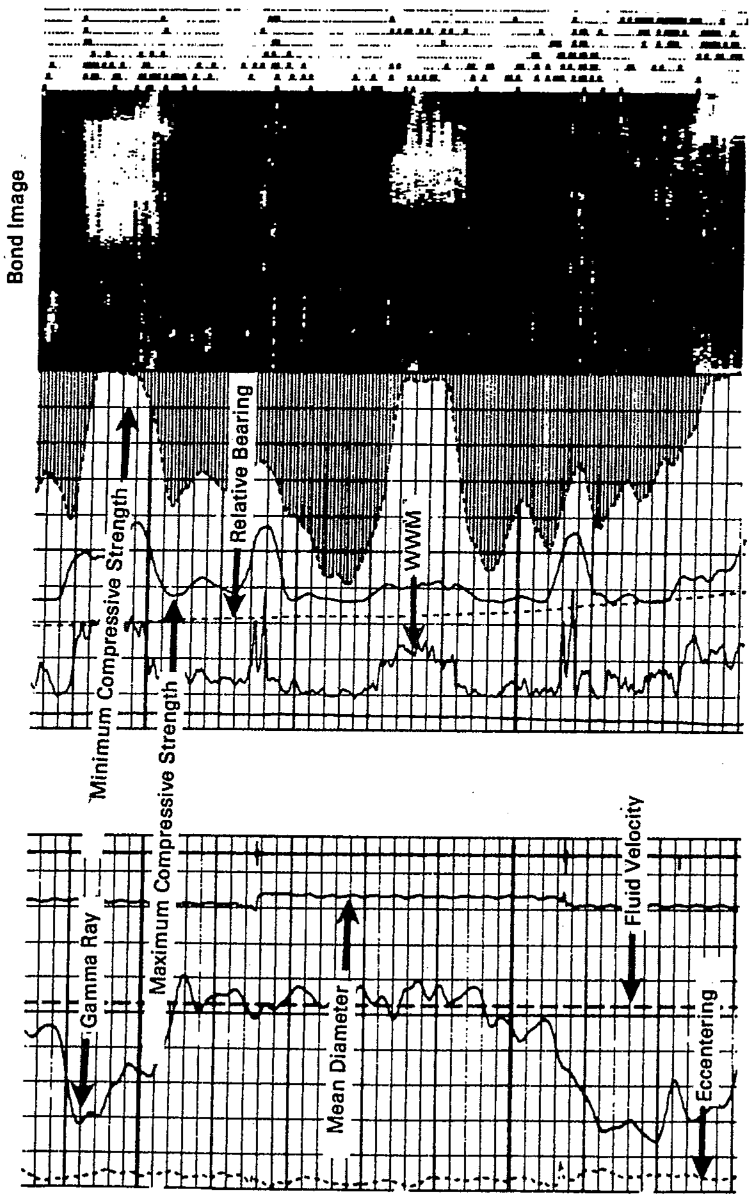

Figure A-5e. Second generation log - Company A.

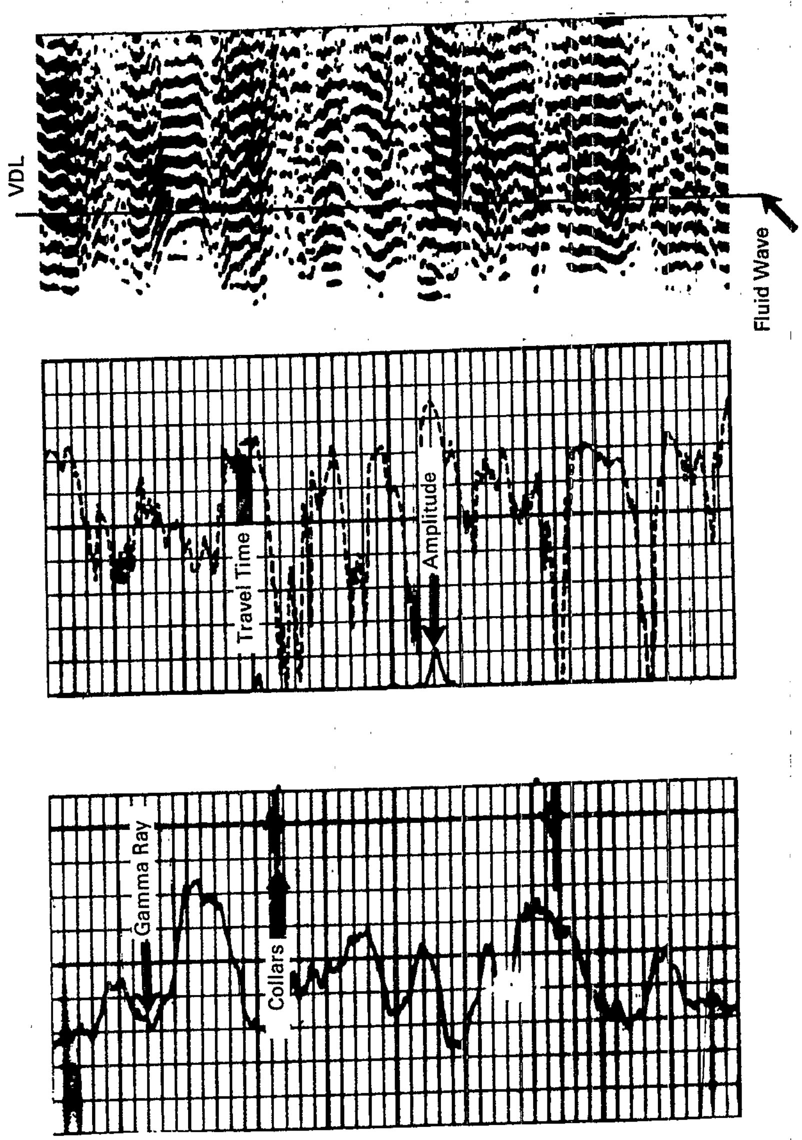

Figure A-6a. Single receiver 3-foot spacing.

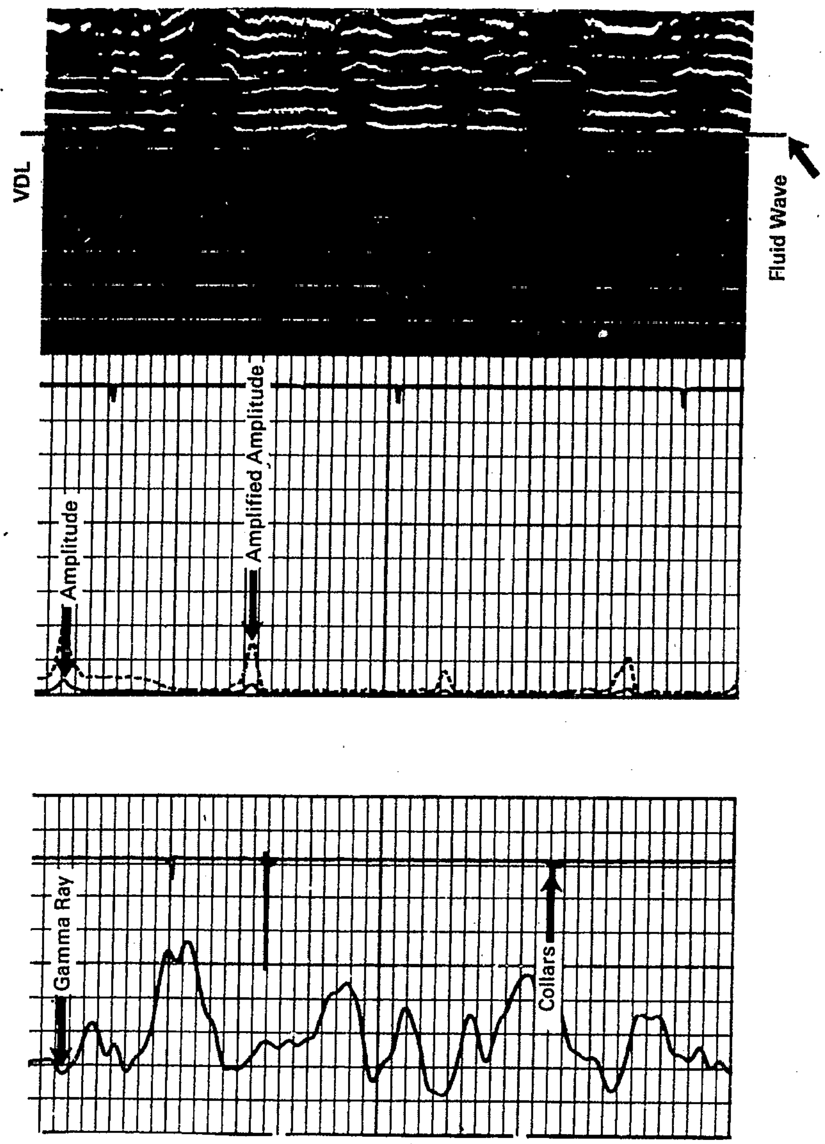

Figure A-6b. Single receiver 4-foot spacing.

Figure A-6c represents a log from a tool with single transmitter/single receiver, 5-foot spacing. It shows very clear formation signals on the VDL, with one area near the center of the section showing casing signal. The amplitude curve shows casing/cement bonding, with a possible problem in the center of the section.

Interpretation: Good casing/cement bonding with the possibility of a channel or microannulus in the middle of the section. Formation signals indicate coupling to the formation.

Figure A-6d represents a log from a tool with single transmitter/dual receivers with 3-foot/5-foot spacing. The VDL shows formation signals throughout the section and definite casing signals near the middle and in the lower part of the section. The amplitude curve indicates cement/casing bonding, with a very slight response in the middle of the section.

Interpretation: Excellent casing/cement bonding with the possibility of channels or microannuli in the middle and lower parts of the section. Formation signals indicate coupling of the formation to the casing.

Figure A-6e is a log of the same section of the hole from a second generation tool. The bonding display indicates two channels or microannuli, one in the middle and one in the lower section. The average cement strength curve correlates with the bonding display.

Interpretation: Excellent casing/cement bonding with the exception of two channels or microannuli in the middle and lower part of the section. No information on formation coupling.

The third comparison of results from various logging tools involves the occurrence of "fast formations," those formations that exhibit a travel time that is equal to or faster than the travel time for casing.

Figure A-7a is a section from a tool with a single transmitter/single receiver with 3-foot spacing. The VDL indicates what appears to be casing signals in the upper part of the section and formation signals in the lower part of the section. The VDL signal in the lower part is called formation signal because no chevrons are visible opposite the casing collars. The amplitude curve indicates some casing signals in three parts of the section.

Interpretation: Poor casing/cement bonding in the upper part. The amplitude curve and VDL are contradictory in the lower part of the section. The VDL indicates casing/cement bonding and the amplitude indicates poor bonding in one area.

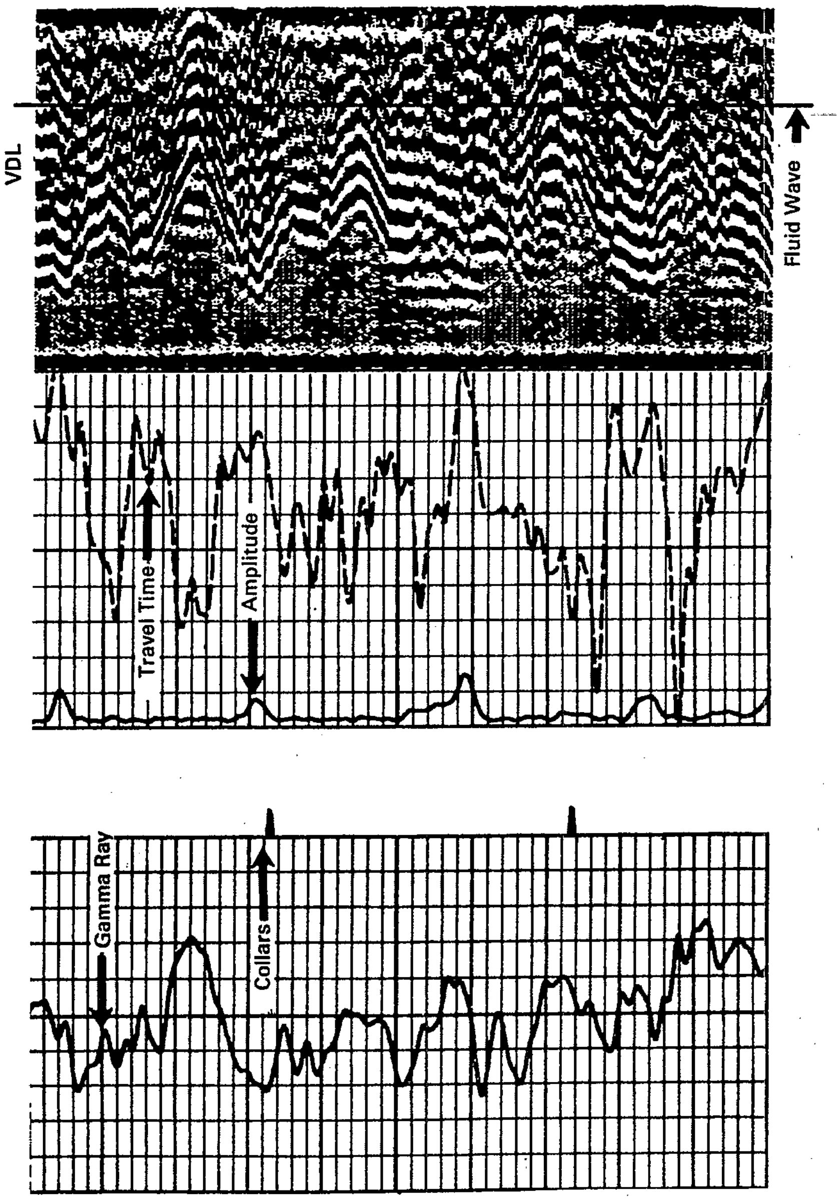

Figure A-6c. Single receiver 5-foot spacing.

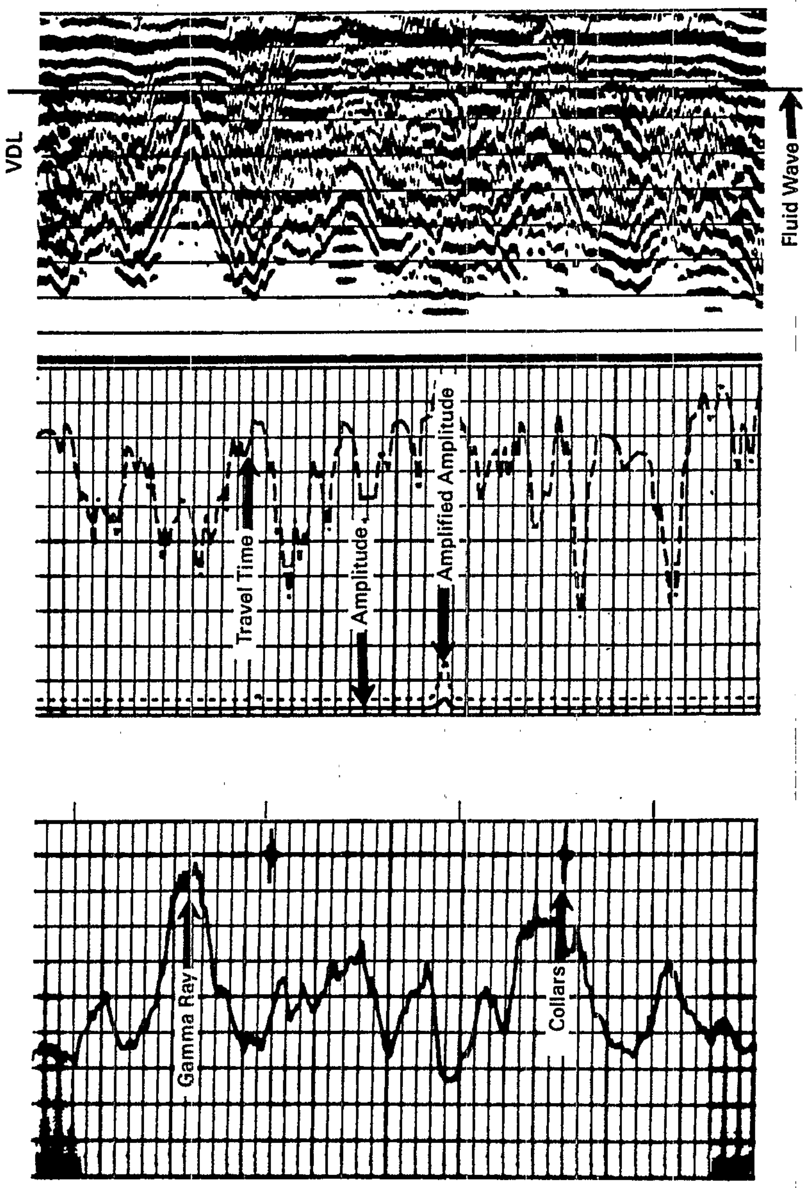

Figure A-6d. Dual receiver 3-foot/5-foot spacing.

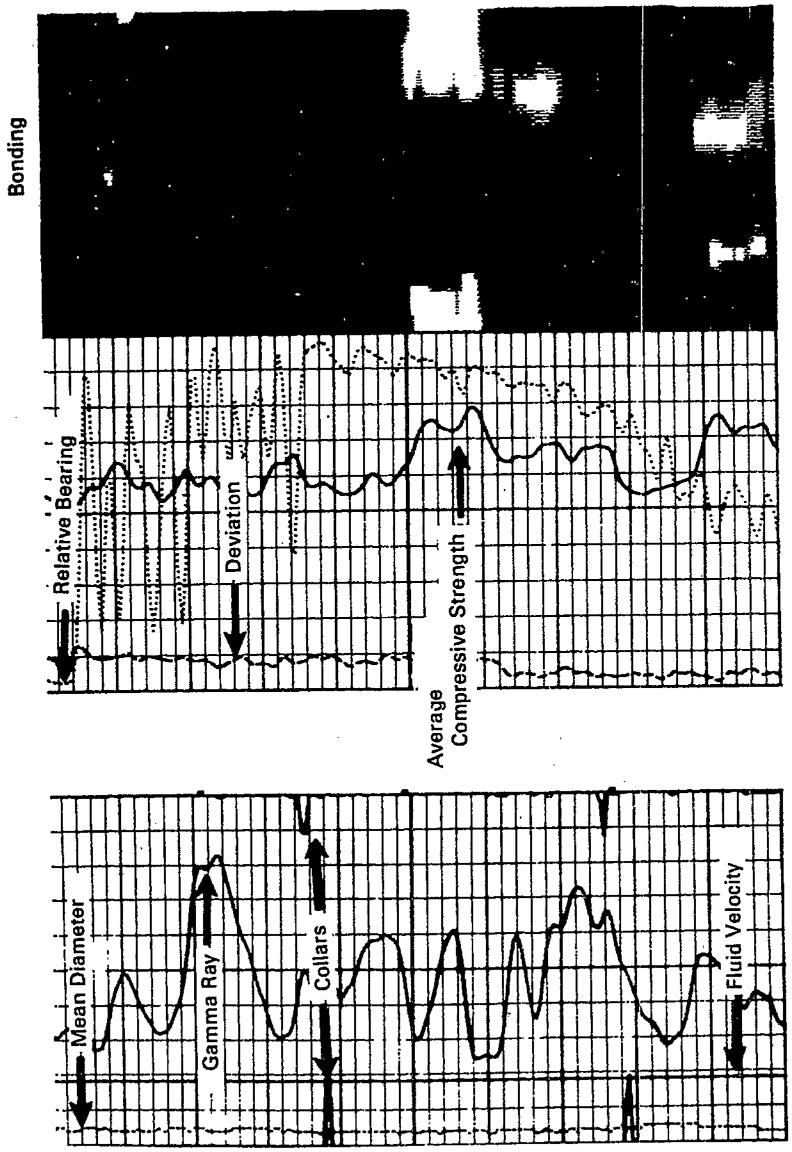

Figure A-6e. Second generation log - Company B.

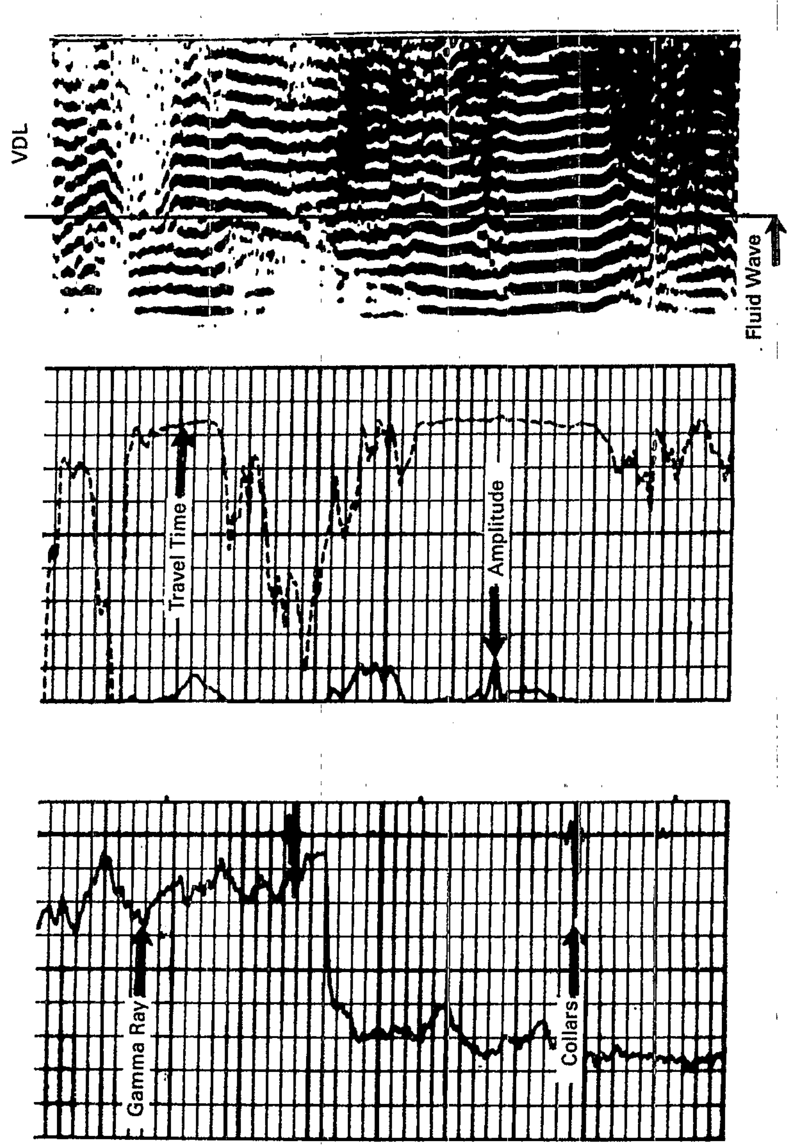

Figure A-7a. Single receiver 3-foot spacing.

Figure A-7b is a log of the same section with a tool with single transmitter/single receiver, 4-foot spacing. The VDL indicates casing/cement bonding in most of the section with one area of formation signal in the lower part. The amplitude curve indicates casing signal in the lower part.

Interpretation: Good casing/cement bonding in the upper part of the section. No formation coupling in the upper part. The amplitude curve and VDL are contradictory in the lower part of the section.

Figure A-7c is a log of the same section from a tool with single transmitter/single receiver, 5-foot spacing. The VDL indicates formation signals throughout the section with possible casing signals in the upper part. The amplitude curve indicates poor casing/cement bonding throughout most of the section except for about 10 feet in the upper part and the lower 20 feet.

Interpretation: Poor cement/casing bonding throughout the section except for about 10 feet in the upper part and the lowermost 20 feet. The amplitude curve and VDL are contradictory in the lower part. The amplitude curve reads over 70 mv, which indicates free pipe.

Figure A-7d indicates a log of the same section from a tool with single transmitter/dual receiver with 3-foot/5-foot spacing. The VDL indicates formation signals throughout the section with casing signals in the upper part. The amplitude curve indicates cement/casing bonding with one possible problem in the upper part of the log.

Interpretation: Excellent cement/casing bonding throughout most of the section. Possible channels or microannuli in the upper part of the section. Formation coupling throughout most of the log.

Figure A-7e is the same section from one of the second generation logs. The bond image part of the log indicates three channels or microannuli in the upper two-thirds of the log. The minimum compressive strength curve supports that some problem exists in these areas.

Interpretation: Excellent cement/casing bonding with three channels or microannuli. No information on formation coupling.

As can be seen from these examples, casing signals and formation signals are very difficult to differentiate when a fast formation is involved.

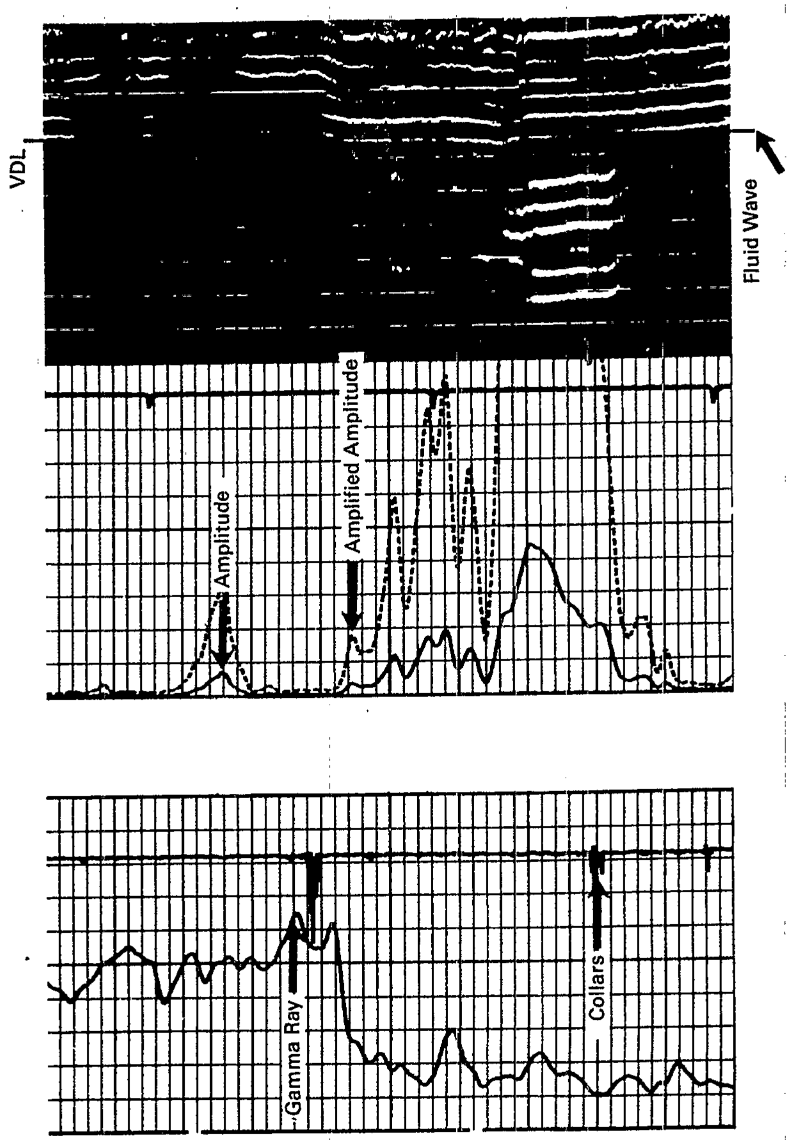

Figure A-7b. Single receiver 4-foot spacing.

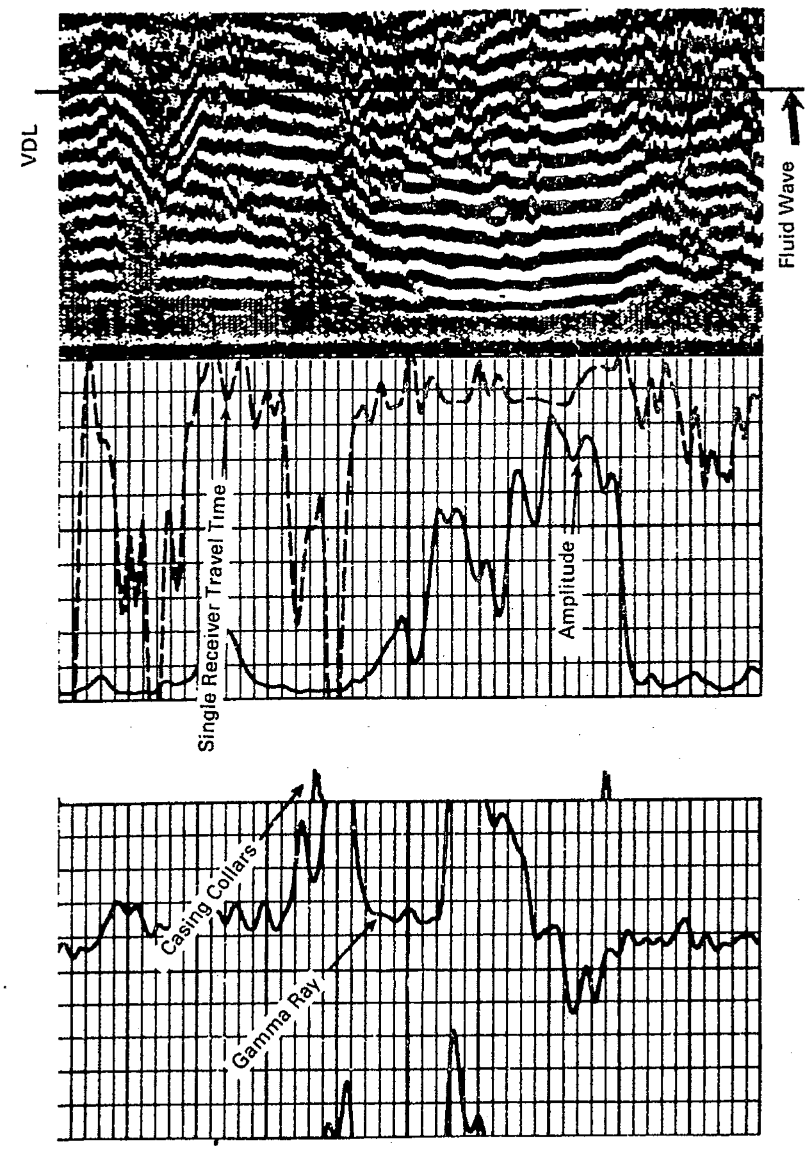

Figure A-7c. Single receiver 5-foot spacing.

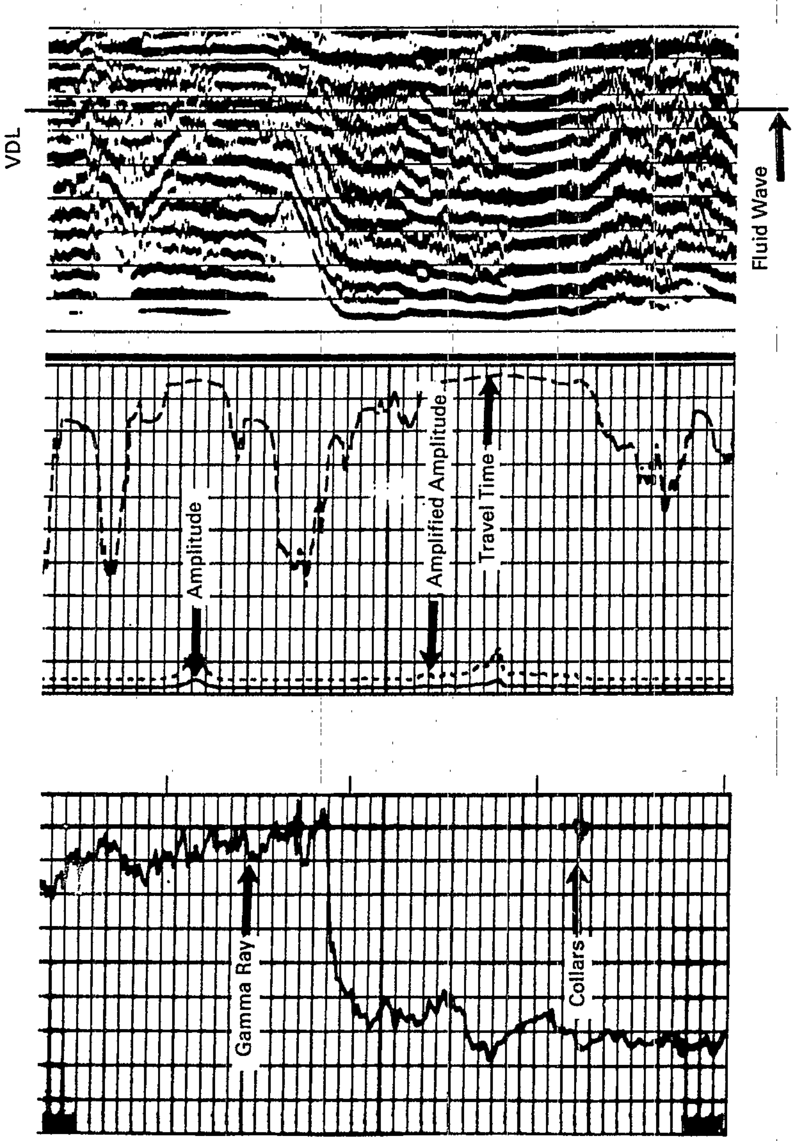

Figure A-7d. Dual receiver 3-foot/5-foot spacing.

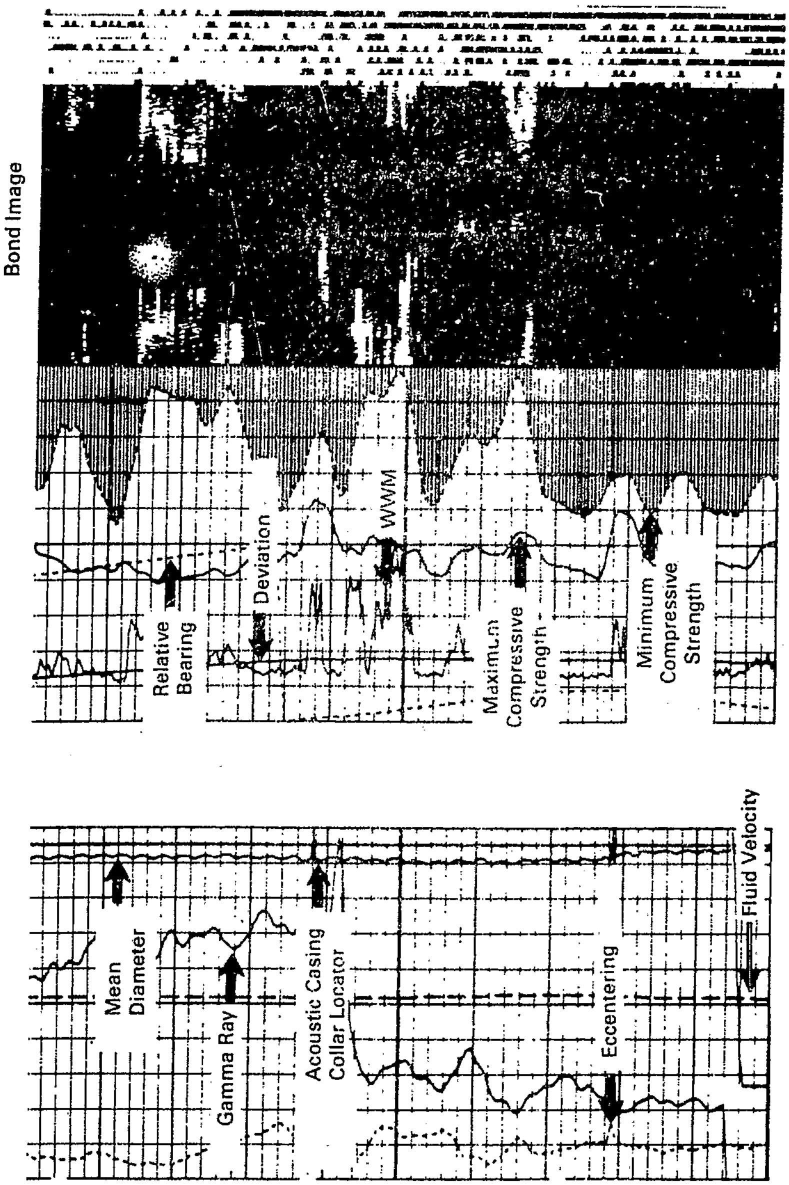

Figure A-7e. Second generation log - Company A.

Logging Well No. 2

Logging Test Well Material Specifications

Casing	Weight	Grade
2 joints of 8 5/8-inch	conductor pipe	
39 joints of 5 1/2-inch	17.0#/ft	J-55
5 joints	fiberglass with steel in collars	

Equipment

43 centralizers

Detailed Description of Well Construction

On May 26, 1987, the process of preparing the channels was begun. Essentially the same process that was used on Logging Well No. 1 was repeated, with the exception of the size of channel material. PVC pipe, 1/4-inch polyethylene tubing, and fiberglass were used to create the 30, 25, 20, 15 and 10 degree channels. The excess resin and fiberglass were sandblasted to ensure that the channels were the correct size, and the completed work was moved to the drilling rig on June 25, 1987.

The driller began moving to the site on June 22, 1987, and began drilling the rat hole on June 23, 1987. The procedure followed for this well included:

	Activity	Date Completed
1)	Prepare site (Baulch Drilling Company)	6/22/87
2)	Move in rig and rig up	6/22/87
3)	Drill 12 1/4-inch hole to 80 feet: set conductor pipe	6/24/87
4)	Drill 8 3/4-inch hole to 1,575 feet	6/26/87
5)	Condition hole for logging	6/26/87
6)	Run Dual Induction - SFL and Microlog (Schlumberger also ran some experimental open hole logs. They logged the well from 1:00 a.m. until 9:15 p.m.)	6/26/87
7)	Set casing	6/27/87
8)	Cement casing (Halliburton, 1,075 sacks 50/50 Posmix)	6/27/87
9)	Install rock pad and cement slab	7/08/87

No significant problems were encountered in completing the well, and the first log was run on July 14, 1987.

APPENDIX B

Leak Test Well Design and Testing Criteria and Test Summaries

Leak Test Well

The purpose of the "Leak Test Well" is to provide a facility to develop methods for testing the integrity of the tubing, casing and packer and for testing the capability of various down-hole tools to detect fluid movement behind the casing.

The design of the well generally corresponds to a typical salt water disposal well used in the oil and gas industry. That is, it includes the use of surface casing, long string, tubing and packer. The deviation from the norm in this well includes two packers and a sliding sleeve on the injection tubing and a 2 3/8-inch tubing attached to the outside of the long string and running to the surface (Figure 10).

The depth to which surface casing was set was based on Oklahoma Corporation Commission regulatory requirements to extend below the occurrence of ground water having 10,000 mg/L or less total dissolved solids. The selection of the depth for locating the profile nipples and the injection zone was based on porosity data from Compensated Density and Compensated Neutron logs from the Logging Well.

The 2 3/8-inch tubing, outside the 5 1/2-inch long string, extends from a 1/4-inch hole in the long string at 1,070 feet below land surface to the surface of the ground. The hole was drilled using a 1/4-inch bit, and a 2 3/8-inch elbow was welded to the casing so that the tubing could be attached. Profile nipples were placed in the tubing opposite the 680- to 710-foot sand at 700 feet and the 905- to 935-foot sand at 920 feet. These nipples will control the leakage of fluid from the tubing, in that fluid can exit the tubing at either of the nipples or be brought to the surface.

Casing and equipment for the Leak Test Well include:

571 feet of 13 3/8-inch casing
1,215 feet of 5 1/2-inch long string
1,070 feet of 2 3/8-inch tubing outside the long string
1,120 feet of 2 3/8-inch tubing inside the long string
Baker Model "L" Sliding Sleeve
Baker Model "AD-1" Tension Packer

Baker Model "C-L" Tandem Tension Packer
Baker Model "R" Profile Nipple 1.78
Baker Model "RW" Profile Nipple 1.81
Baker Model "F" Profile Nipple 1.87
Baker 5 1/2-inch Float Shoe
Hinderliter 10FSF Wellhead for dual completions (5 1/2-inch and 2 3/8-inch)
3 centralizers 5 1/2-inch

The surface equipment for the Leak Test Well consists of two 100-barrel fiberglass tanks, a 10-horsepower electric powered injection pump, high pressure injection flow lines and schedule 40 plastic return flow lines (Figure 11). The water supply is from the City of Ada, Oklahoma. The control accessories are an air chamber, which smooths out the pumping actions of the pump pistons; a pressure control valve, which can be set to any predetermined pressure from 10 to 600 psi; a check valve which prevents back flow in the injection line; a strainer to catch foreign material that may be pumped into the line; a flow meter to record the number of barrels of liquid pumped; a flow outlet pipe used to calibrate the flow meter; a control valve to regulate the flow to the injection well; a thermometer to determine the temperature of the injected fluids; and pressure gauges to indicate the injection pressure (Figure B-1).

Flow into the well can be controlled so that the injected fluids are directed into the 2 3/8-inch injection tubing, the tubing/casing annulus or to the 2 3/8-inch outside tubing. Returned flows can be controlled from the 2 3/8-inch outside tubing and also from the annulus of the 5 1/2 inch casing.

Three monitoring wells were constructed around the Leak Test Well to depths of 710, 935 and 1,130 feet. The casing and equipment for the monitoring wells included:

No. 1

15 Baker Centralizers, 4 1/2-inch
Halliburton Super Seal Float Shoe
671 feet of 4 1/2-inch steel casing, 10.6 #/ft
2-inch Johnson stainless steel well screen, .010-inch slot with bottom plate
20 feet of 2-inch line pipe on top of screen
2- to 4-inch shale cup
Johnson "K" type packer, 4 1/2-inch
80 feet of 9 5/8-inch conductor pipe, 36 #/ft
4 1/2- to 2-inch steel swage/cap

No. 2

21 Baker Centralizers, 4 1/2-inch
Halliburton Super Seal Float Shoe
905 feet of 4 1/2-inch steel casing, 10.6 #/ft

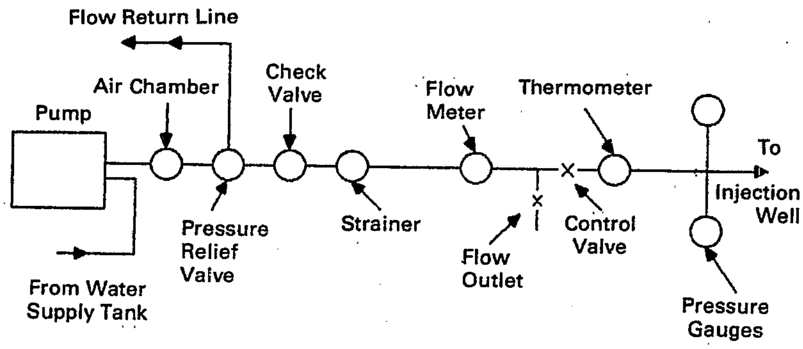

Figure B-1. Injection pump and control accessories.

2-inch Johnson stainless steel well screen, .011-inch slot with bottom plate
21 feet of 2-inch line pipe on top of screen
Johnson "K" type packer, 4 1/2-inch
80 feet of 9-5/8" conductor pipe, 37 #/ft
4 1/2- to 2-inch steel swage/cap

No. 3

27 Baker Centralizers, 4 1/2-inch
Halliburton Super Seal Float Shoe
1,130 feet of 4 1/2-inch steel casing, 10.6 #/ft
2-inch Johnson stainless steel well screen, .010-inch slot with bottom plate
20 feet of 2-inch line pipe on top of screen
80 feet of 9 5/8-inch conductor pipe, 36 #/ft
4 1/2- to 2-inch steel swage/cap

Wells No. 1 and 2 were drilled using air rotary to prevent contamination of the zones to be monitored by drilling fluids. Well No. 3 could not be completed using air so it was drilled with mud rotary.

The procedure followed for drilling the wells and the dates involved are indicated in Table B-1.

Table B-1. Procedure for Drilling the Monitoring Wells

Activity	Date Completed
Monitoring Well No. 1	
1. Rig up, air drill 9-inch diameter hole to 82 feet, ream 12 1/2-inch hole to 82 feet, set and cement 9 5/8-inch conductor pipe	11/17/87
2. Drill 8-inch hole to 680 feet, run 4 1/2-inch steel casing with centralizer on each collar, cement with latex cement (Halliburton)	11/24/87
3. Drill remaining 30 feet with 3 7/8-inch bit	11/28/87
4. Set 2-inch by 30-foot Johnson stainless steel screen	11/28/87
Monitoring Well No. 2	
1. Rig up, air drill 12 1/4-inch diameter hole	11/30/87
2. Cement conductor pipe	12/01/87
3. Drill 8-inch hole to 905 feet, run 70 sacks of gel to stabilize hole	12/03/87
4. Run 4 1/2-inch steel casing with centralizer on each collar	12/04/87
5. Cement with spherelite cement (Halliburton)	12/08/87
6. Drill to 935 feet with 3 7/8-inch tricone bit, set 2-inch by 30-foot stainless steel screen with bottom plate	12/21/87
Monitoring Well No. 3	
1. Rig up, drill 12 1/4-inch diameter hole to 80 feet, set and cement 9 5/8-inch conductor pipe	12/01/87
2. Dig mud handling pit	12/08/87
3. Drill 7 7/8-inch hole to 1,130 feet, run 4 1/2-inch steel casing with float shoe	1/09/88
4. Cement with foam cement (Halliburton)	1/10/88
5. Perforate zone from 1,120 to 1,130 feet, 21 shots	1/14/88
6. Swab casing, set 2-inch by 20-foot stainless steel screen	1/14/88

Test Summaries

A number of specific tests are planned for the Leak Test Well. As the tests are completed, brief summaries are prepared and forwarded to the Underground Injection Control Program Offices in EPA Headquarters and the regions. Summaries of those tests completed to date are included as follows:

Test No. 1: Acoustic Cement Bond Tool Test for Flow Behind Casing

Introduction

In November 1986, personnel from Regions IV and V witnessed a demonstration of the use of an acoustic cement bond tool for detecting fluid movement behind casing. The demonstration was conducted by Dresser Atlas personnel at their field office in Olney, Illinois, and involved pumping water through the annular space between two concentric pieces of pipe while holding the bond tool stationary in the inner pipe.

EPA personnel suggested that the tool(s) be tested in the Leak Test Well at the Robert S. Kerr Environmental Research Laboratory (RSKERL) to get a better definition of the sensitivity of the tool and the conditions under which it will or will not work.

C.D. "Mac" McGregor, a log analyst for Dresser Atlas, contacted RSKERL personnel, and plans were made to run the tests on January 23, 24, and 25, 1987.

Test Well Conditions

The purpose of the test was to determine if flow of water at various rates could be detected behind pipe using the data presented by the fluid wave from a cement bond tool. The test was developed in two phases: Phase I looked at flow immediately behind casing under free-pipe conditions, and Phase II looked at flow in tubing behind casing under conditions which would possibly simulate flow in a channel in cement.

Figure B-2 indicates the configuration of the Leak Test Well for the initial test. In this configuration, water was pumped down the tubing/casing annulus into the injection zone. This represents flow in the free-pipe condition, i.e., no cement behind the pipe (2 3/8-inch tubing in this case).

Figure B-3 indicates the well configuration for the second test, which was designed to simulate flow in a channel in cement. The section of the well between 1,070 and 950 feet has cement behind the 5 1/2-inch casing and thus around the 2 3/8-inch tubing. Thus the tubing in that area represents, to some degree, a channel in the cement. In this phase, water was pumped down the 2 3/8-inch tubing, into the 5 1/2-inch casing and out the perforations.

Test - Phase I

The test was conducted with a 1 11/16-inch OD Acoustic Cement Bond Tool with a single transmitter/single receiver with 4-foot spacing. The tool was placed in the injection tubing at 57 feet and the oscilloscope was viewed in the no-flow and flow conditions.

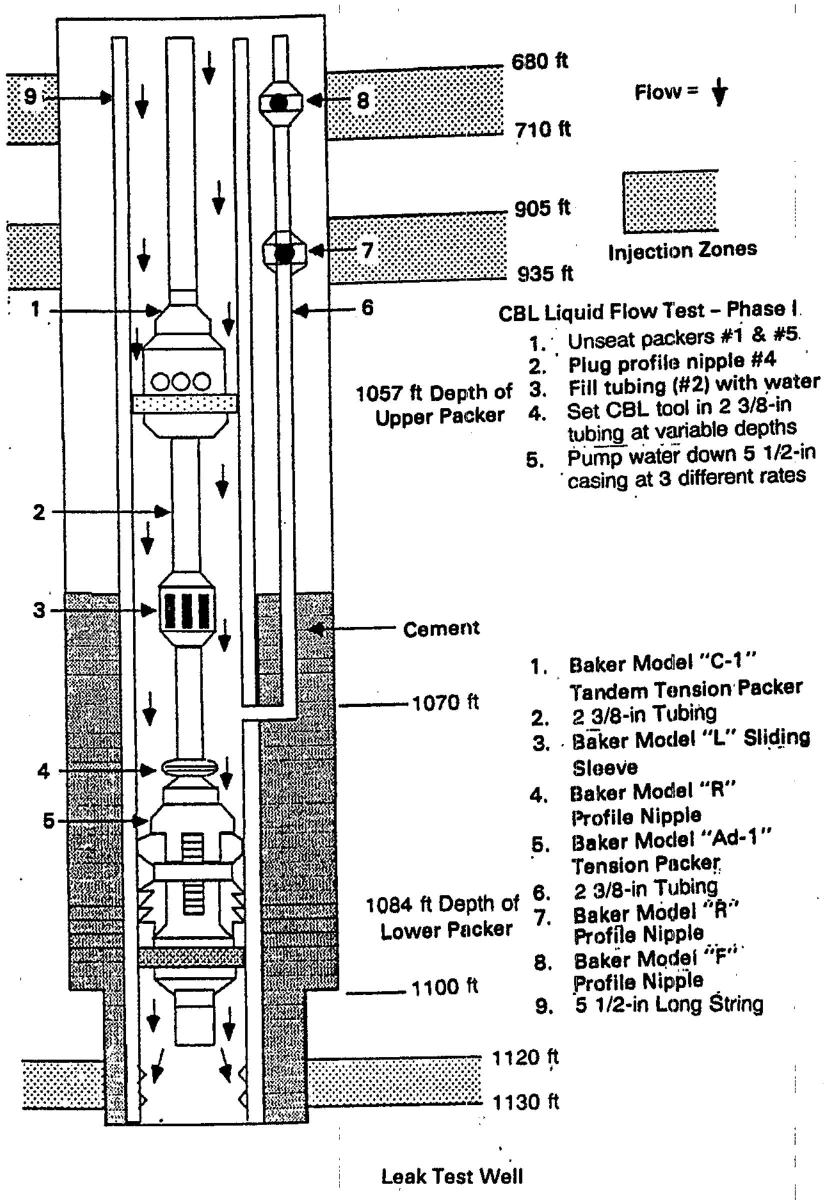

Figure B-2. CBL liquid flow test - Phase I.

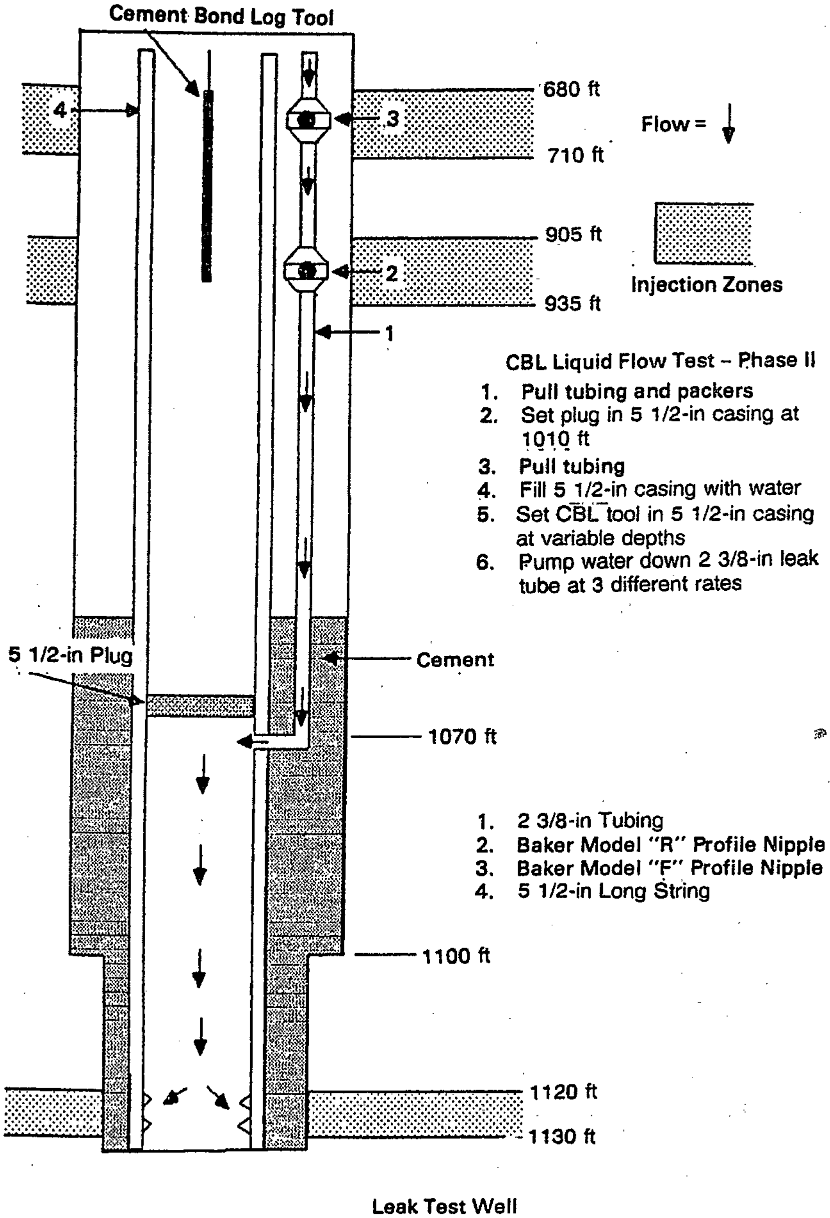

Figure B-3. CBL liquid flow test - Phase II.

Test - Phase I

Time	Flow Rate	Oscilloscope Response
1:50 p.m.	No flow	None
2:00 p.m.	8 gpm	Yes
2:03 p.m.	4 gpm	Yes
2:17 p.m.	0.78 gpm	Yes
2:20 p.m.	0.78 gpm + air	Yes
2:24 p.m.	6 gpm + air	Yes
2:30 p.m.	Stopped injection	Yes

The test was repeated with the tool at various depths in the well, with the same results; that is, the oscilloscope indicated no distortion of the fluid wave in the no-flow condition and distortion at all three flow rates. The distortion was greater when air was added to simulate gas movement behind the pipe.

Test - Phase II

The second test was conducted with the tubing and packers removed and a bridge plug set, as indicated by Figure B-3. The Acoustic Cement Bond Tool used for this test was a 3 5/8-inch OD tool with single transmitter/single receiver with 5-foot spacing.

Test - Phase II

Tool Depth (feet)	Flow Rate (gpm)	Oscilloscope Response
600	8	None
700	8	None
800	8	None
900	8	None
1,000	8	None

The tool was initially set immediately above the bridge plug and the oscilloscope viewed in the no-flow condition. Water was then pumped down the outside tubing at a rate of 8 gpm. No distortion of the fluid wave was evident on the oscilloscope. The tool was then moved up the hole in 100-foot increments. No distortion of the fluid wave was evident at any depth, thus no flow was detected in the tubing.

Conclusions

The Phase I test results indicate that the fluid wave of the Acoustic Cement Bond Tool responded to fluid movement behind the tubing in a free-pipe condition, that is, with no cement behind the pipe. A response was evident with flow as low as 0.78 gpm.

The tool used in the Phase II test did not pick up flow in the 2 3/8-inch tubing either within or above the cemented section of the well. Thus, flow in the manmade channel behind the 5 1/2-inch casing could not be detected under the test conditions.

One explanation for the responses observed under the test conditions previously outlined is that under free-pipe conditions, the paths for movement of the sound wave are through the casing and fluid. Thus, under static conditions, where the tool is not moving and there is no movement of fluid in or behind the pipe, the fluid wave, as presented on the oscilloscope, is also static. On the other hand, flow of fluid behind the pipe while the tool is stationary affects the sound wave as it moves through the fluid, causing a distortion of the wave. This distortion shows up as rapid changes in amplitude in the display of the fluid wave on the oscilloscope and indicates movement of the fluid. Thus, under free-pipe conditions, the fluid wave has the capacity to reflect fluid movement behind pipe.

The presence of cement behind pipe presents a much more difficult set of conditions for identifying fluid movement with the cement bond tool. The paths for the sound wave under these conditions are movement along the casing and cement (small signal because of the attenuation effect of the cement behind the casing), movement through the formation and movement through the fluid. The heterogeneity of the formation, the size of the channel, and type and amount of fluid movement will all affect the ability of the tool to identify fluid flow in channels in cement. Thus, the capability of the Acoustic Cement Bond Tool to identify fluid flow in channels is unproven, though certainly not impossible.

Recommendations

Field data should be accumulated to determine the capability of this type of tool for detecting flow behind casing in varying well conditions, i.e., free pipe and channels in cement.

When running other tools, such as temperature or noise surveys for detecting flow behind pipe, service companies should run the bond tool for comparison purposes to determine if flow in channels can be detected.

Test No. 2. Nuclear Activation Technique for Detecting Flow Behind Casing

Introduction

On January 23 and 24, 1987, personnel from the Robert S. Kerr Environmental Research Laboratory (RSKERL) and Dresser Atlas conducted a series of tests for determining flow behind pipe using two neutron activation tools.

The purpose of the tests was to determine if flow of water at various rates could be detected behind pipe using the data presented by a pulsed neutron lifetime logging system (PDK-100) and a Cyclic Activation Tool.

Tools Tested

Two tools were tested during the 2-day period:

- A 1 11/16-inch diameter PDK-100 Tool
- A 3 5/8-inch diameter Cyclic Activation Tool

The operation of both tools is based on a nuclear activation technique in which flowing water is irradiated with neutrons emitted by a logging sonde. These neutrons interact with oxygen nuclei in the water to produce nitrogen-16 (^{16}N), which decays with a half-life of 7.13 seconds, emitting gamma radiation. The flow is then computed from the energy and intensity response of two gamma ray detectors mounted in the logging sonde.

Test Well Conditions

The tests were developed in four phases, the first three using the PDK-100 Tool and the last using the Cyclic Activation Tool.

Figure B-4 indicates the configuration of the Leak Test Well for the initial test. In this configuration, water was pumped down the tubing/casing annulus into the injection zone with the 1 11/16-inch diameter PDK-100 Tool held stationary in the 2 3/8-inch injection tubing. This condition represented flow in the free-pipe condition, i.e., with no cement behind the pipe (2 3/8-inch tubing in this case). A valve at the surface on the outside 2 3/8-inch tubing was closed so that circulation was not possible up that tubing.

Figure B-5 indicates the well configuration for the second test, which was designed to simulate upward flow in a channel in cement. Water, pumped down the tubing/casing annulus, moves through a 1/4-inch hole in the 5 1/2-inch casing at 1,070 feet and up the 2 3/8-inch outside tubing. The section of the well between 1,070 and 950 feet has cement behind the 5 1/2-inch casing and thus around the 2 3/8-inch tubing. The tubing in that area represents, to some degree, a channel in the cement.

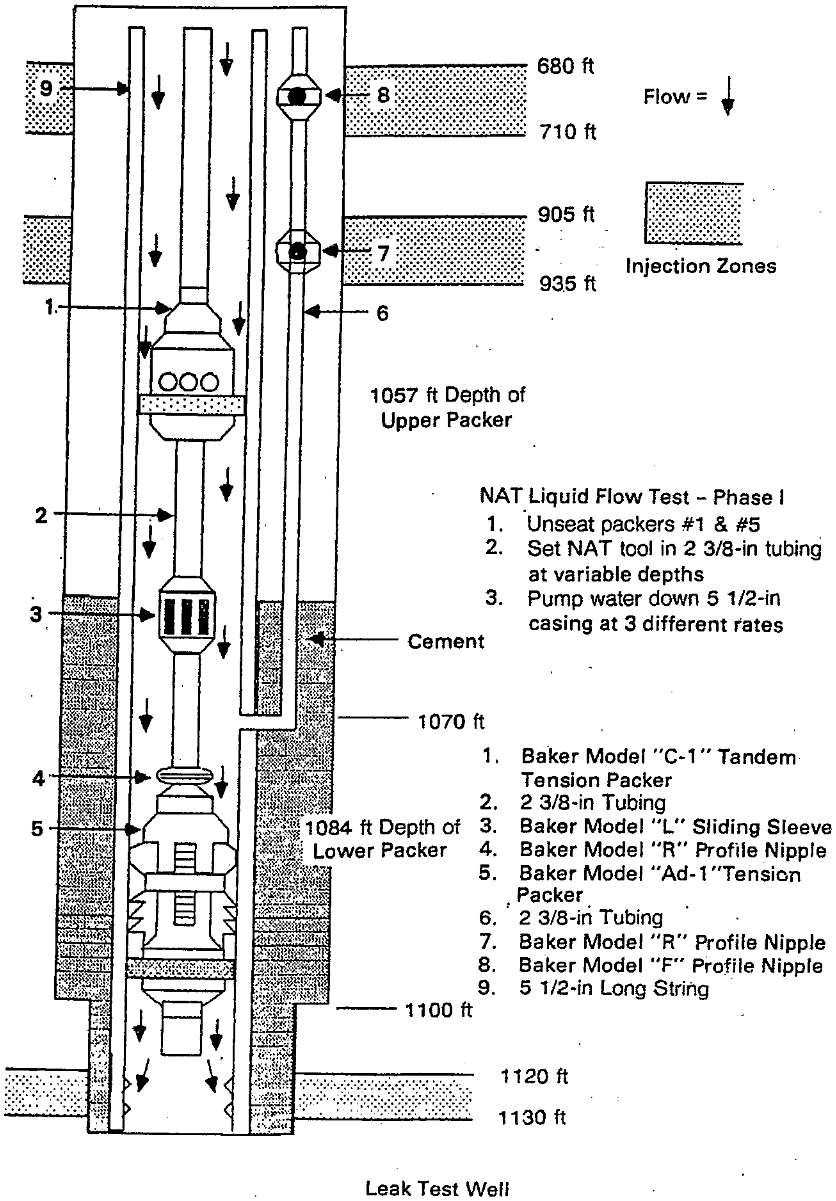

Figure B-4. Neutron activation tool liquid flow test - Phase I.

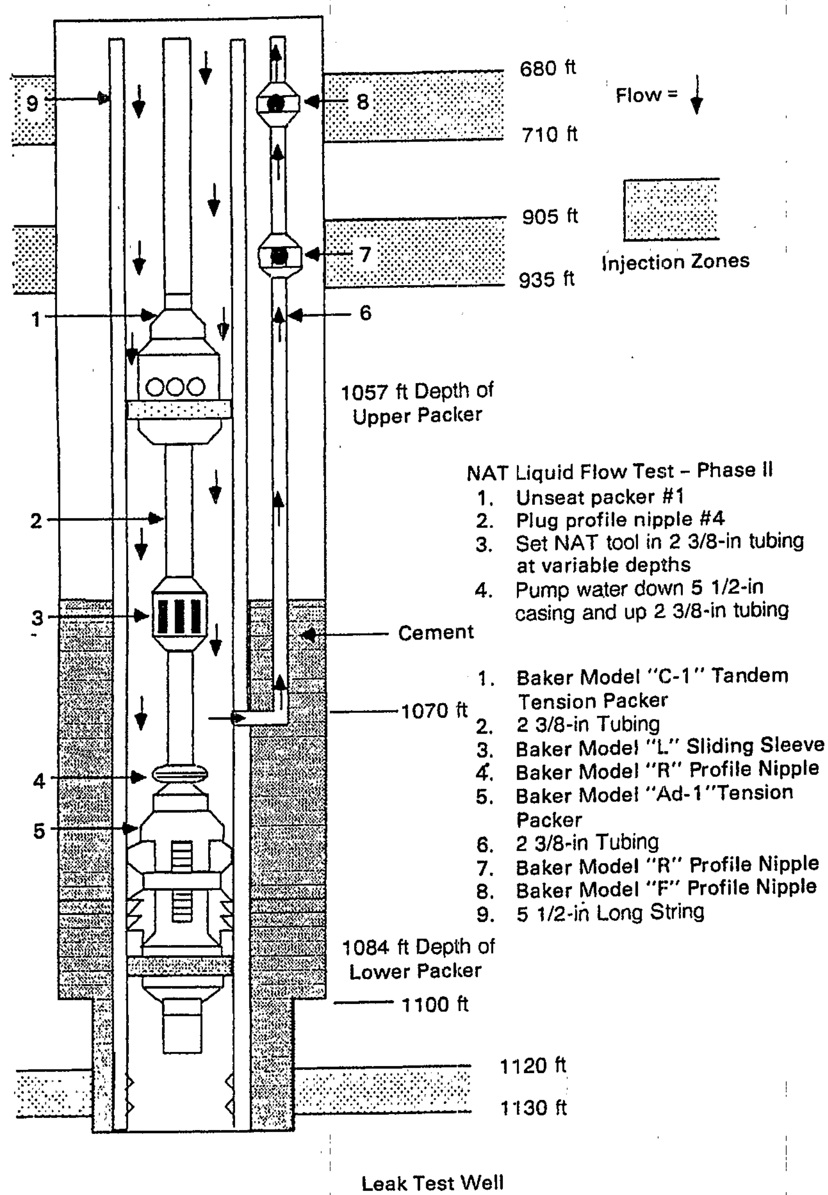

Figure B-5. Neutron activation tool liquid flow test - Phase II.

Figure B-6 indicates the well configuration for the third test, which was designed to simulate downward flow in a channel in cement. Water, pumped down the 2 3/8-inch outside tubing, moves through the 1/4-inch hole in the 5 1/2-inch casing at 1,070 feet and up the 5 1/2-inch casing to the surface.

Figure B-7 indicates the well configuration for the final test, which was designed to simulate downward flow in a channel in cement using the larger Cyclic Activation Tool. Water, pumped down the 2 3/8-inch outside tubing, flows into the 5 1/2-inch casing through the 1/4-inch hole and out through perforations into the injection interval from 1,120 to 1,130 feet.

Test - Phase I

This test was conducted with the PDK-100 Tool with the two detectors located below the neutron generator so that downward flow could be detected. With the tool located at 300 feet inside the 2 3/8-inch injection tubing, data was obtained under conditions of no flow and flow of 8, 4 and 1 gallon per minute (gpm). Two replications of these flow rates were conducted and flow was detected by the tool in all instances.

Test - Phase II

This test was conducted with the PDK-100 Tool with the two detectors located above the neutron generator to determine if flow up the outside 2 3/8-inch could be detected. With the tool located at 600 feet, data was obtained under no flow, and 8 gpm flow conditions. Flow up the outside 2 3/8-inch tubing could not be detected.

Test - Phase III

This test was conducted with the PDK-100 Tool at 600 feet with the generator-detector configuration identical to the Phase II test. Water was pumped down the 2 3/8-inch outside tubing and up the 5- 1/2" casing at three different rates (8,4 and 1 gpm). Upward flow was detected in the 5 1/2-inch casing at all three flow rates.

The tool configuration was then changed with the detectors below the generator to determine if downward flow in the outside tubing could be detected. Flow down the outside 2 3/8-inch tubing could not be detected.

Test - Phase IV

This test was conducted using a 3 5/8-inch diameter Cyclic Activation Tool. The detectors were located below the generator for detecting flow in the 2 3/8-inch tubing as water moved down the tubing, through the 1/4-inch hole into the 5 1/2-inch casing and out the perforations into the injection interval. Flow rates for this test were 7.8, 6.1 and 0.79 gpm. All three flow rates were detected by the tool,

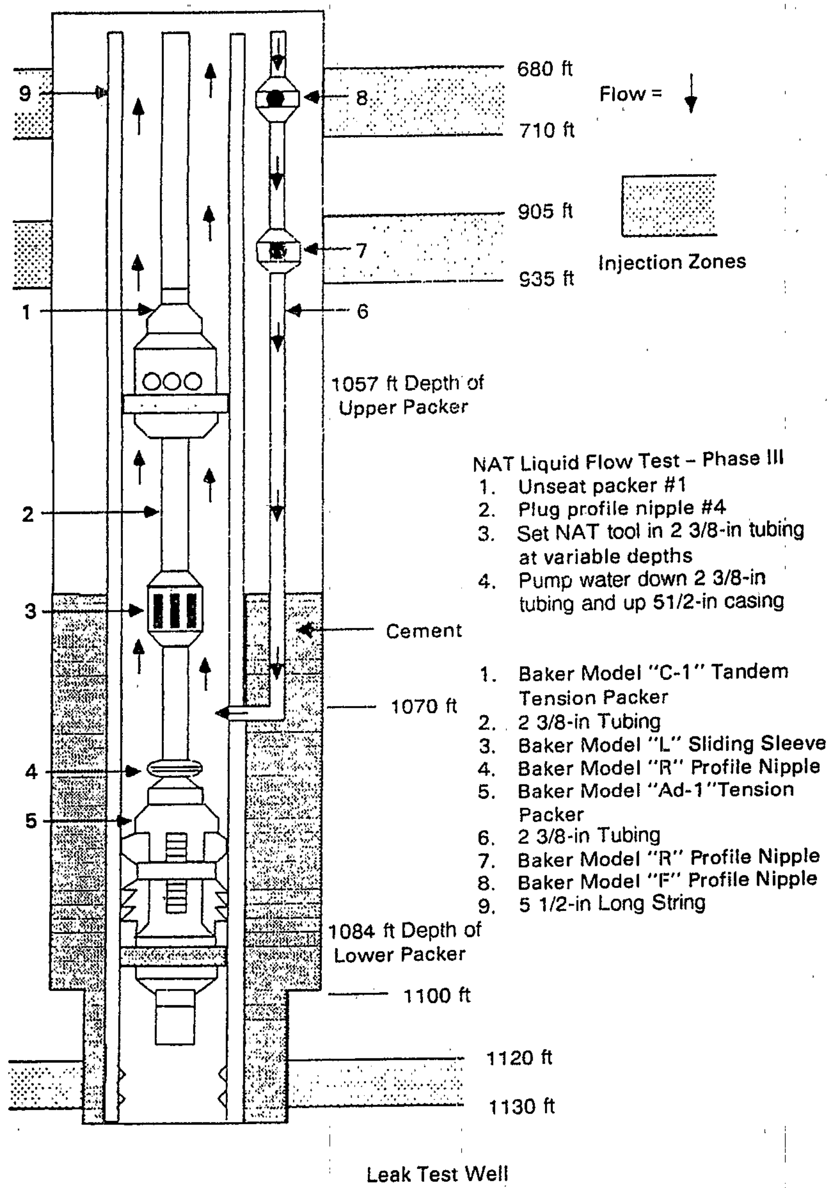

Figure B-6. Neutron activation tool liquid flow test - Phase III.

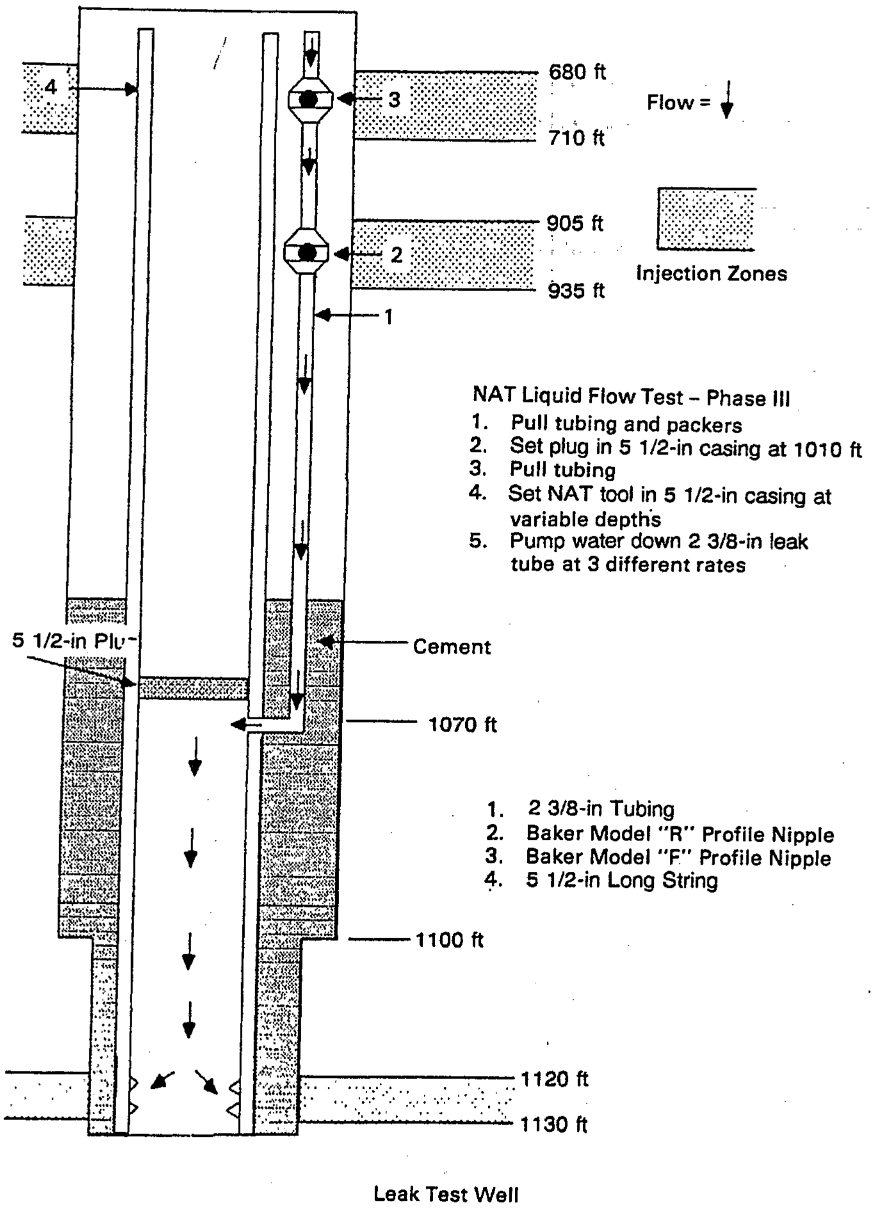

Figure B-7. Neutron activation tool liquid flow test - Phase IV.

and flow velocities were calculated from the data collected by the tool.

Conclusions

The PDK-100 Tool was able to detect all three flow rates when flow was up or down the 5 1/2-inch casing. The tool did not detect any flow up or down the outside 2 3/8-inch tubing.

The Cyclic Activation Tool was able to detect all three flow rates in the outside 2 3/8-inch tubing. In addition, the computer associated with the tool has the capability to compute a velocity of flow for each flow rate.

Recommendations

Additional work should be done to increase the sensitivity of the PDK-100 Tool. It should be noted here that since the tests were conducted, Dresser Atlas personnel have made some modifications to the PDK-100 Tool and have been able to detect flow in outside tubing in a well constructed very similarly to the Leak Test Well. The adjusted tool will be retested at the RSKERL Test Facility as soon as it can be arranged. In the meantime, Dresser Atlas personnel will run the tool in several wells owned by Mobil, and will make those results available to RSKERL personnel.

The Cyclic Activation Tool should be tested under "real well" conditions to verify the results seen during the tests on the Leak Test Well.

The capability of this equipment to locate flow behind pipe could be a significant breakthrough for mechanical integrity testing. Especially the PDK-100 Tool, which can be run in tubing filled with water or with only air present. Thus, no workover costs would be involved in testing a well, i.e., setting plugs, pulling tubing, etc.

Test No. 3: Testing for a Hole in the Long String

Introduction

On January 23, 24 and 25, 1987, test results from testing tools for detecting flow behind casing indicated a possible hole in the 5 1/2-inch long string of the research well. A series of tests was conducted on the well on January 25 and 27, and February 2, 3, 10, 11 and 12 to determine whether there was a hole in the pipe.

Test Well Conditions

Figure B-8 indicates the well configuration during most of the tests to be discussed. Any changes in the well will be noted as the various tests are discussed.

During testing of an Acoustic Cement Bond Tool (ACBT), the 5 1/2-inch casing was full of fluid above a bridge plug and water was being pumped down the outside 2 3/8-inch tubing at about 8 gpm. Pumping had been in progress only about 5 minutes when water began flowing out of the 5 1/2-inch casing at about 2 1/2 gpm.

The immediate thought was the bridge plug was leaking; however, the Baker Packer representative was confident that the bridge plug could not leak. In checking the setting depth for the plug it appeared possible that it was located opposite a casing collar. The plug was reset to ensure that it was properly set between collars.

Acoustic Cement Bond Tool

A plan was developed to systematically check the well to determine where the leak was in the system. The first approach was to use the ACBT to determine if flow in the 5 1/2-inch casing was occurring. The tool was set immediately above the bridge plug, which was set at 1,010 feet, and readings were taken to determine if flow would be reflected by the fluid wave. The tool was then moved up the well at 100 foot increments and readings taken, with the following results:

Depth (feet)	Flow Indicated
1,000	No
900	No
800	No
700	No
600	No
500	No
400	No
300	Yes
250	Yes
200	Yes

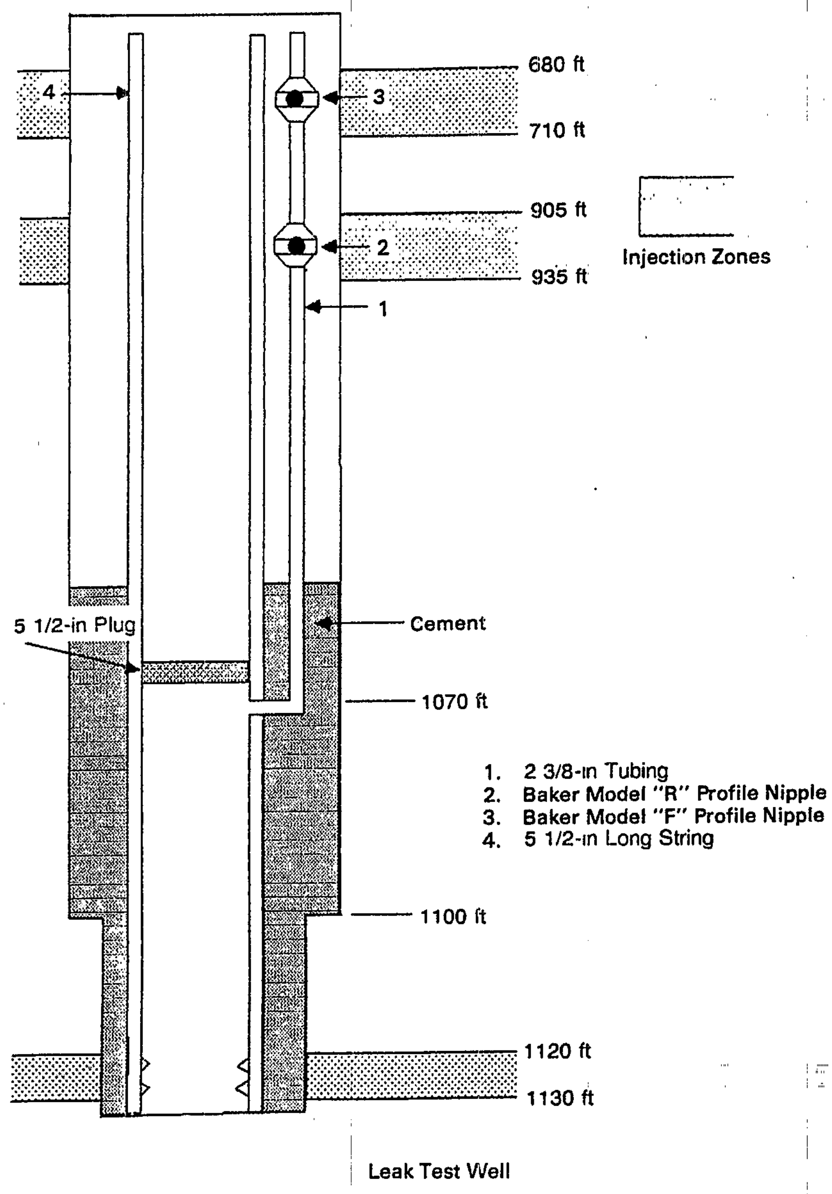

Figure B-8. Testing for a hole in the long string.

The tests were rerun with the same results. Thus, the ACBT data indicated that flow might be coming into the casing at around 300 feet.

Down-Hole TV

On January 27, 1987 Layne-Western Company brought their down-shot camera to survey the well, to locate any hole that might be present. The regular lens would not give a good image, so a lens that must be used in air rather than water was tried. First the well was swabbed so that the water level was about 870 feet below land surface.

The camera, which had never been run in 5 1/2-inch casing, provided an excellent picture of the casing as it was lowered down the casing. An anomaly was seen at about 240 feet that could possibly be a damaged area of the casing.

Pressure Test - Gas

The next test was to pressure the well with nitrogen and shut it in to determine if any loss of pressure would occur over time. The well, with the bridge plug still intact at 1,010 feet, was pressured to 185 psi with nitrogen and shut in. There was no loss of pressure evident after 1 hour.

Pressure Test - Water

The gas pressure was relieved and the injection pump hooked up to fill the 5 1/2-inch casing with water. After filling, 150 psi pressure was added to the weight of the water column and the well was shut in for 1 hour. No pressure drop was noted.

Pressure was relieved and water was pumped down the outside 2 3/8-inch tubing at about 8 gpm. After pumping for only 5 minutes, water began flowing out of the 5 1/2-inch casing at a rate of about 2 1/2 gpm.

Pressure Test - Packer

Next, Baker Packer, using a full-bore packer on tubing performed a series of pressure tests with the packer set at various depths in the casing, as follows:

Packer Depth feet	Pressure psi	Drop in Pressure after 5 Minutes
115	92	None
295	115	None
595	100	None

Ada Pressure Test

The final test was a modified "Ada Pressure Test." After removing the bridge plug, nitrogen was used to move the static water level toward the hole in the 5 1/2-inch casing. A pressure of 380 psi was placed on the fluid in the casing and held overnight with no loss of pressure.

Conclusions

The series of pressure tests performed on the well clearly indicated no hole is present in the 5 1/2-inch casing. The differential pressure bridge plug apparently did not have sufficient pressure differential to set securely, thus allowing the plug to leak when injection was taking place down the outside tubing.

The ACBT and down-hole TV were inconclusive in that a doubt still existed after reviewing data from the tests.

Test No. 4: Ada Pressure Test

Introduction

Early in the mechanical integrity test program, it was discovered that some wells could not be tested using the standard pressure test. For example, a number of wells in Osage County, Oklahoma, could not use the standard pressure test because of perforations in the long string above the packer. EPA regional personnel suggested that a procedure similar to the air line method for determining the water level in a producing water well should be explored as an alternative for testing those wells whose "special" construction would not permit the use of standard pressure tests.

Development of Test

A possible alternative to the standard pressure test is to use compressed air or nitrogen to depress the static water level below the point to be tested and hold the pressure for a specific period of time. If the pressure holds, the tubular goods above the fluid level have no leaks.

Table B-2 indicates theoretically what would take place in the well as pressure is added to the tubing to depress the water. With a static fluid level of 360 feet below the land surface, the hydrostatic head at the perforations would be 760 feet. The tubing gauge pressure and the pressure at the fluid level would both be zero. This hydrostatic head would exert 307 psi at a depth of 1,070 feet, and 329 psi at a depth of 1,120 feet. As pressure is added from cylinders of compressed gas, the gauge pressure increases and depresses the fluid level, thus reducing the hydrostatic head by a corresponding amount. The pressure at the gauge and pressure at the fluid level remain equal throughout the procedure. Thus, the pressure at the point of consideration remains constant in that the hydrostatic pressure is replaced by gas pressure during the test.

Table B-2 Effects of Adding Pressure to Depress Water

Tubing Gauge Reading (psi)	Depth to Fluid Level (feet)	Hydrostatic Head Above Perforations (feet)	psi @ Fluid Level	psi @ Hole (1,070 feet)	psi @ Perf. (1,120 feet)
0	360	760	0	307	329
100	591	529	100	307	329
200	822	298	200	307	329
300	1,053	67	300	307	329
307	1,070	50	307	307	329
329	1,120	0	329	329	329

Implementing the Tests

On December 4, 1985, two tests were implemented to determine if pressure testing with compressed air was a viable option for testing special wells. The configuration of the Leak Test Well was altered slightly for each of the tests to represent real world situations as closely as possible (Figure B-9).

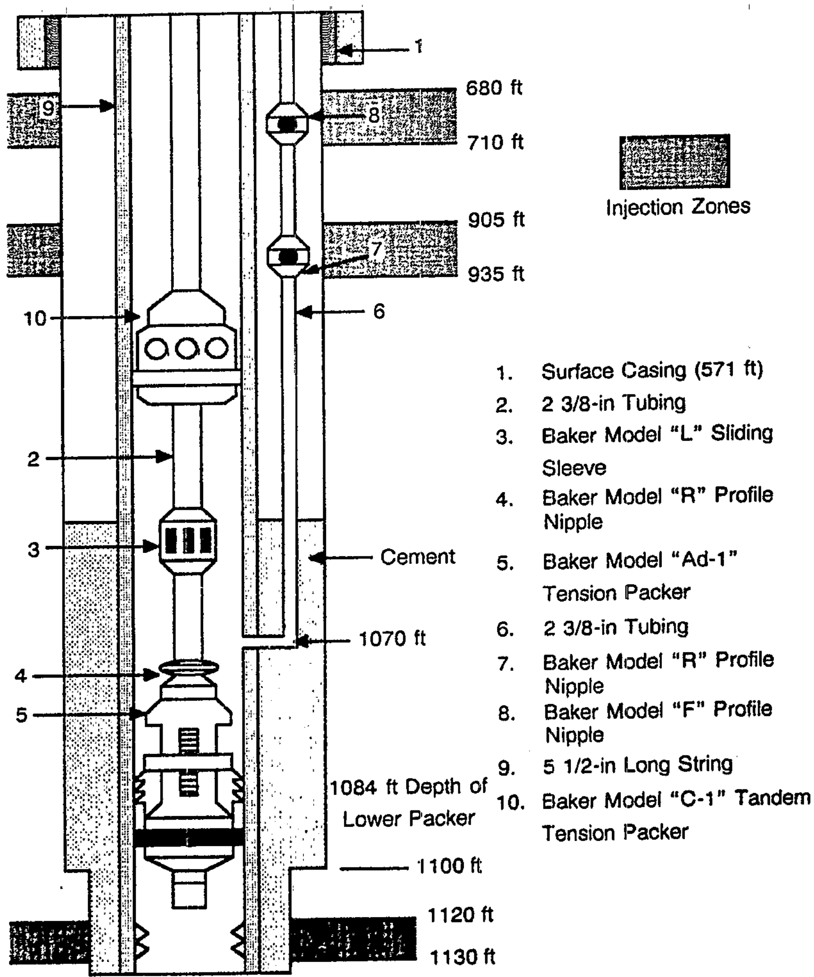

Figure B-9. Leak Test Well.

The first test was conducted with the sliding sleeve closed, to represent no leak in the system, and the second test was conducted with the sliding sleeve open, to represent a leak in the tubing at a depth of 1,070 feet. The fluid level in the injection tubing as measured with an Echo Meter was 360 feet below the land surface. That provided a hydrostatic head of 710 feet at the hole at 1,070 feet and 760 feet of head at the perforations at 1,120 feet. Assuming 2.31 feet per psi, it would require 307 psi to depress the water level to a depth of 1,070 feet and 329 psi to depress the water level to a depth of 1,120 feet.

Test 1

In the first test, with the sliding sleeve closed, the pressure should have reached 329 psig before the pressure could not be increased. This would indicate that the fluid level was at the top of the perforations at 1,120 feet, and with the gas source closed the pressure gauge should continue to read 329 psig.

A pressure of 380 psig was added without reaching the point anticipated. When the cylinder was closed the pressure dropped below 329 psig, and repeated attempts to increase the pressure gave the same results. The source of compressed gas was exhausted and the test was stopped without reaching the point of stabilization at 329 psi.

This behavior seems to indicate that the permeability of the injection zone was low and the formation would not accept the water fast enough to depress the water level as quickly as anticipated. Thus, during the time of the test, the fluid level in the tubing was still being depressed but had not had time to reach the desired level.

Test 2

In the second test, with the sliding sleeve open, 307 psig should have depressed the water level to a depth of 1,070 feet, and it should have been impossible to add additional pressure because pressure was lost through the hole in the long string at that depth. However, an inability to increase the pressure was reached at a pressure of 300 psig. The pressure remained at 300 psig after shutting off the compressed gas source.

On May 1, 1986, the well was acidized and injectivity tests indicated a permeability of 125 millidarcies (md). The second series of tests was run with the results comparable to those predicted in the table. Nitrogen was used to eliminate any explosion hazard that might have been presented by using compressed air.

The test was rerun on February 11, 1987, using nitrogen, and the results confirmed the response seen in May 1986.

Conclusions

The test results indicate that an annulus pressure test can be run on certain wells that have special conditions that prevent the running of standard pressure tests. The following conditions are recommended to assure that the test has validity for a specific well:

1. The fluid level in the zone being tested must have reached static conditions before the test is run.
2. The specific gravity of the injected water must be known to calculate the pressure required to depress the fluid level to a specific depth.

Test No. 5: Nuclear Activation Technique for Detecting Flow Behind Casing

Introduction

On April 8, 1987, personnel from the Robert S. Kerr Environmental Research Laboratory (RSKERL) and Dresser Atlas conducted a series of tests to determine flow behind pipe using the PDK-100 Flow Tool.

The purpose of the tests was to determine if flow of water at various rates could be detected behind pipe from data presented by a pulsed neutron lifetime logging system (PDK-100). The 1 11/16-inch diameter tool had been tested on January 23 and 24, 1987, and could detect flow immediately behind the injection tubing but could not detect flow in the outside 2 3/8-inch tubing. The tool had been modified for the new series of tests.

Test Well Configuration

Figure B-10 indicates the configuration of the Leak Test Well for the test. Both packers were set, the sliding sleeve was open and injection was maintained down the outside tubing at varying injection rates.

Tool Testing

For each flow rate the PDK-100 was held stationary at a depth of 300' in the injection tubing. After taking two background checks, flow was initiated down the outside tubing at a rate of 8 gallons per minute (gpm), 6, 4, 2, and 0.105 gpm. The results of the tests for detecting flow are as follows:

Flow Rate (gpm)	Flow Detected
8	Yes
6	Yes
4	Yes
2	Yes
0.105	No

Readings were taken three times at each flow rate.

Conclusion

The PDK-100 was able to detect four of the five flow rates with no problem. Movement was detected for the 0.105 gpm flow but it was probably the column of water in the tubing moving toward static conditions, since at this extremely low flow the fluid level in the tubing could not be maintained.

The capacity of this tool to locate flow behind casing looks very promising. The next phase should be field testing under "real well" conditions.

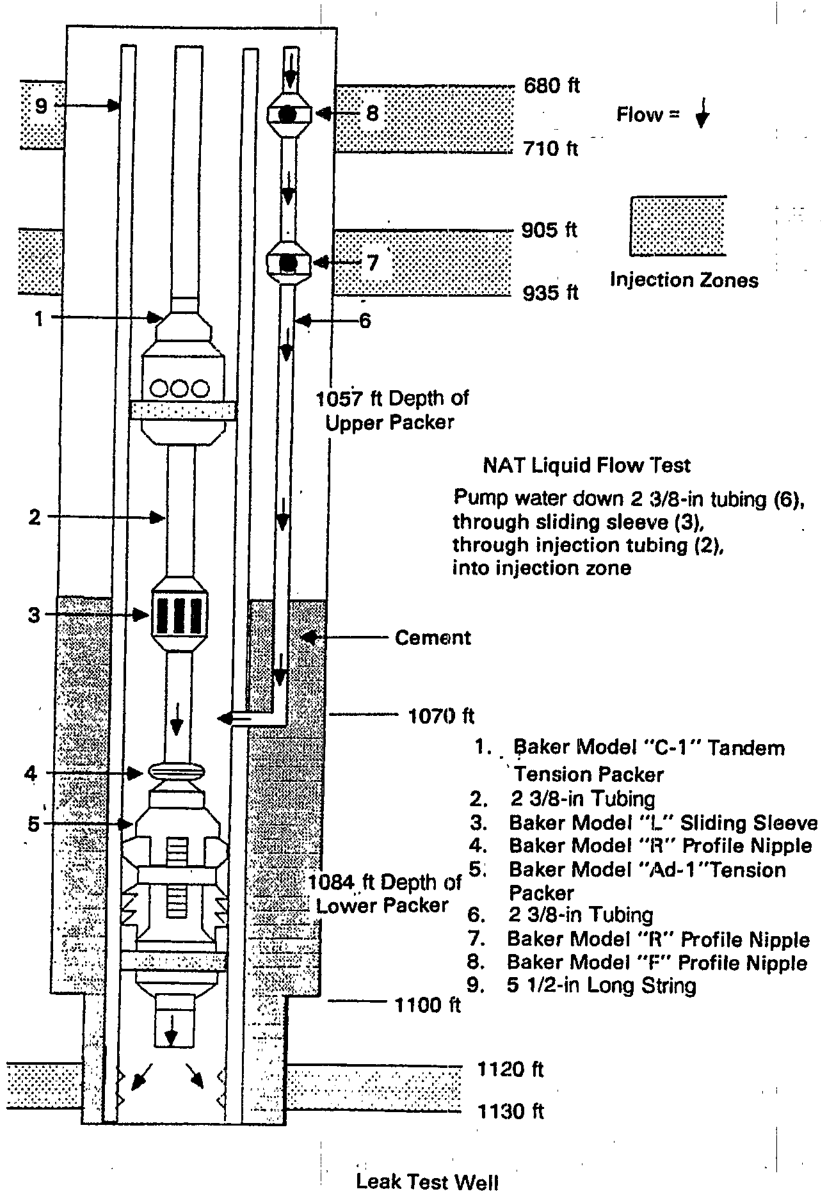

Figure B-10. Neutron activation tool liquid flow test.

Test No. 6: Radial Differential Temperature Survey

Introduction

On April 27, 1987, Gearhart Industries, Inc., was contracted to run a Radial Temperature Survey on the Leak Test Well to determine the capability of this tool to detect vertical flow behind casing.

The Radial Differential Temperature (RDT) tool employs two highly sensitive temperature probes which extend from the centralized 1 11/16-inch O.D. housing to contact the casing. As these probes are rotated, they measure any difference in temperature at two points on the casing 180 degrees apart.

Well Configuration

Figure B-11 indicates the Leak Test Well configuration for the RDT survey. The fluid level in both the 5 1/2-inch casing and the 2 3/8-inch tubing was 190 feet below the surface of the ground.

Radial Differential Temperature Survey

The procedure for running the RDT in the Leak Test Well was to run a conventional temperature profile, take RDT readings at five depths under no-flow conditions, then repeat the RDT readings at the five depths after beginning injection down the outside 2 3/8-inch tubing.

The temperature profile indicated that the fluid level in the 5 1/2-inch casing was at 190 feet below land surface. RDT scans at 1,050, 1,025, 1,000, 975, and 850 feet, under no-flow conditions, showed the same temperature for both probes as they were rotated at each depth. (See Figure B-12.)

Injection down the outside 2 3/8-inch tubing was started at 10:57 a.m., and the RDT surveys at 11:05 a.m. The scan at 975 feet began to show a temperature difference as a result of the injection down the tubing. The temperature differential is easily seen at 1,025 feet (Figure B-13).

A final scan at 850 feet indicated the temperature variation one would expect with cooler fluid flowing in a channel outside the long string.

Conclusion

The Radial Differential Temperature tool easily identified cooler water flowing in the outside tubing in the Leak Test Well.

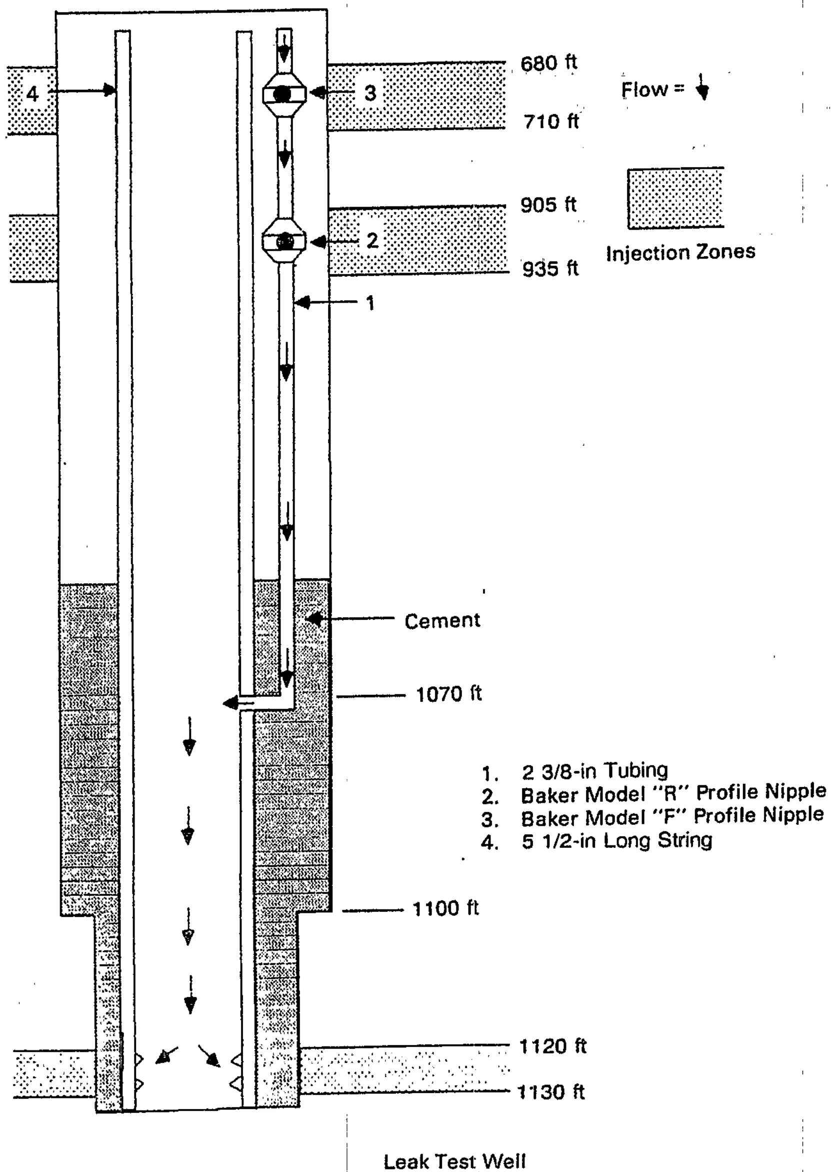

Figure B-11. Radial differential temperature survey.

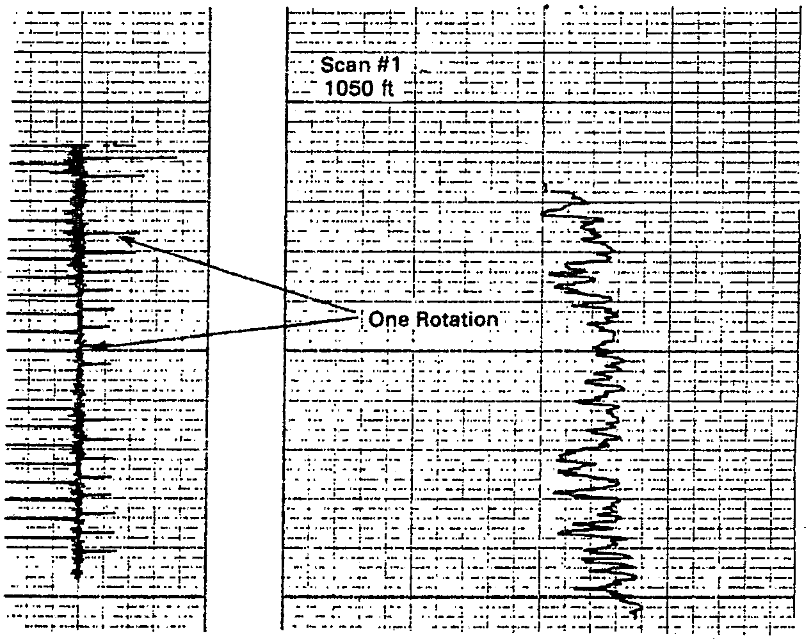

Figure B-12. RDT scan no-flow condition.

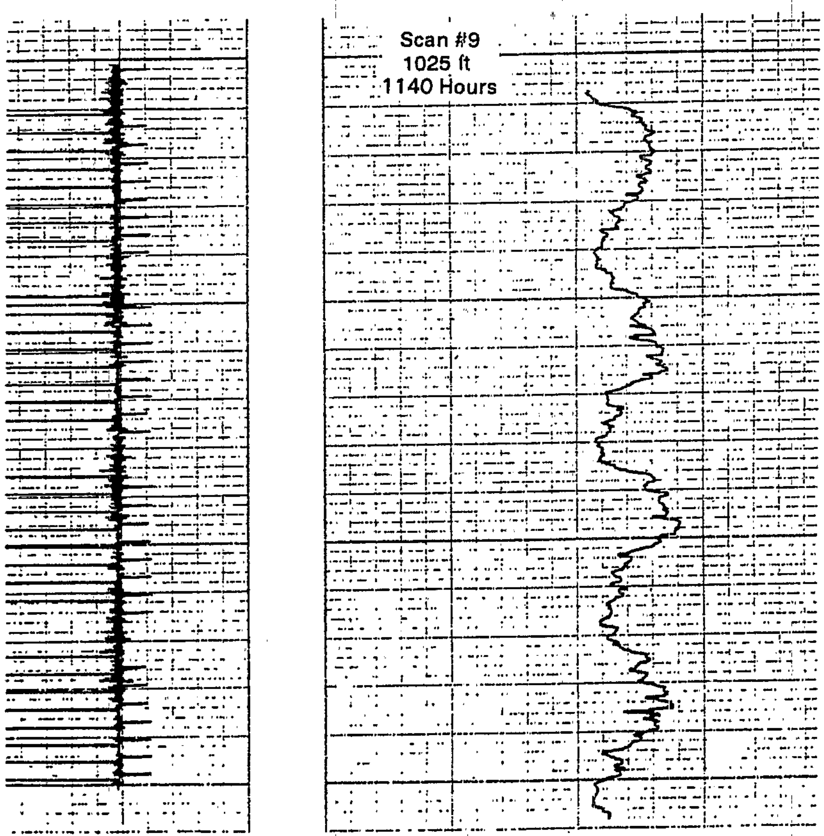

Figure B-13. RDT scan flow condition.

Test No. 7: Nuclear Activation Technique for Detecting Flow Behind Casing

Introduction

On August 28 and 29, 1987, personnel from the Robert S. Kerr Environmental Research Laboratory (RSKERL), EPA Region IV, Atlas Wireline and Shell Western E & P conducted a series of tests to determine flow behind pipe using the PDK-100 pulsed neutron logging system.

The purpose of the test was to determine if flow of water at two different rates could be detected behind pipe in a "real world" well. Shell personnel had agreed to the use of an abandoned 10,600-foot gas well in which a 100+ foot channel had been identified using a radioactive tracer survey.

Test Well Conditions

The well, Little Creek 2-6A, has 5 1/2-inch long string which had been cleaned out to perforations at 4,163 feet. The test was then conducted in two stages: with a packer set at 4,000 feet and the PDK-100 located below the packer in the long string, and with the packer set at 4,125 feet and the PDK-100 located within the tubing.

Test Procedure

The first objective was to determine if the previously identified channel was still present behind the casing. This was done with a radioactive tracer survey as follows:

A. Tracer FloLog

1. Rig up Atlas Wireline Services and go into the hole with 1 11/16-inch O.D. dual detector tracer instrument. Place instrument 5 feet above perforations.
2. With the instrument stationary, start water injection into the perforations at 4,162 feet with the pump truck operating at a rate of 1/2 barrels per minute (BPM).
3. When the injection rate stabilizes, eject a slug of radioactive iodine-131 into the flow and verify its mode of travel. The material should travel downward past the two radiation detectors and into the perforations. If upward channeling exists, the material should travel up behind the casing within the channel, passing the detectors again, but in reverse order.
4. After channeling has been detected and the radioactive material has moved past the instrument, move the instrument upward rapidly, catching and recording the travel path of the radioactive material. (The instrument is

moved up and down past the slug repeatedly to accomplish this.)

5. Reposition the FloLog instrument 5 to 10 feet above the perforations and repeat steps 2 through 4 to verify all previous measurements.

6. Stop water injection and remove the Tracer FloLog instrument from the well.

This procedure established that a channel existed behind the casing from 4,162 feet to about 4,020 feet. Having established this fact, the following procedure was used to test the PDK-100:

1. Configure the PDK-100 with the pulsed neutron source beneath the radiation detectors so that upward flow may be identified.

2. Go into the hole and locate tool 5 to 10 feet above the perforations but below the tubing and packer.

3. Turn the PDK-100 instrument on and record the no-flow response.

4. Start the water injection at the rate of 1/2 BPM.

5. Turn the PDK-100 on and record the results. Adjust the flow to 1/4 BPM and record the results.

6. Move the PDK-100 to the mid-range of the channel.

7. Turn on and record the results at both 1/2 and 1/4 BPM.

8. Move to the top of the channel and record the results at both flow rates.

9. Move out of the channel area and record the results. If no movement is present, stop the water injection and remove tool from the well.

10. Reset packer at 4,125 feet and rerun surveys with the PDK-100 within the tubing.

11. Rig the wireline unit down and review results of both surveys.

Conclusions

The first series of tests, with the tool below the tubing and packer, included stations at 4,180, 4,150, 4,100, and 4,050 feet. The second series, with the tool located within the tubing, included tests at 4,100, 4,050, 4,000, 3,990, and 3,950.

The PDK-100 detected both flow rates with the tool either in the casing or within the tubing. The top of the channel was determined to be between 4,000 and 4,050 feet.

The PDK-100 has the potential for providing an excellent method for detecting flow behind pipe. However, additional work needs to be done to determine specific applications for the tool.

Introduction

During the week of February 22, 1988, a series of tests was conducted on the Leak Test Well at the Mechanical Integrity Test Facility at Ada, Oklahoma. The series included pressure tests, monitoring well response, and volume versus pressure tests. Each test was designed to provide information on mechanical integrity of injection wells and to determine whether or not flow from a leak in an injection well could be identified in an adjacent monitoring well.

Well Configuration

The Leak Test Well was configured as shown in Figure B-14: surface casing set at 571 feet and cemented to the surface; long string set at 1,215 feet and cemented to 925 feet; injection tubing set on a packer at 1,084 feet; sliding sleeve in injection tubing closed; profile nipple at 700 feet in outside tubing open; profile nipple at 920 feet in outside tubing closed. The profile nipple has three 3/16-inch openings to allow flow from the outside tubing.

Two pressure gauges and two flow meters were installed in the flow line between the pump and the injection well so that an accurate determination of the injection pressure and flow to the well could be obtained.

Three monitoring wells are located around the Leak Test Well in a radial pattern 20 feet from the Leak Test Well (Figure B-15). Table B-3 indicates the depths of the monitoring wells and the depth to water in each well. The water table was measured using a weighted steel tape and was corrected to depth below land surface.

On Monday, February 22, 1988, pressure transducers were installed in the 710-foot and 935-foot wells to monitor any water-level changes that might occur prior to and during the tests. The pressure transducers were used in conjunction with an SE200 Hydrologic Analysis System which is marketed by In-Situ, Inc. The transducers are 0.85-inch diameter stainless steel and the SE200 was programmed to record data (in this case water levels) every 10 minutes for 10,000 minutes.

Mud in Annulus

The Leak Test Well was completed in January 1985 with the long strong/surface casing annulus full of native drilling mud above the top of the cement around the long string. The mud weight was recorded as 9.7 lb/gal upon completion of reaming the well, prior to setting and cementing the long string. The gel strength was 3 lb/100 ft^2 at 10 seconds and 4 lb/100 ft^2 at 10 minutes.

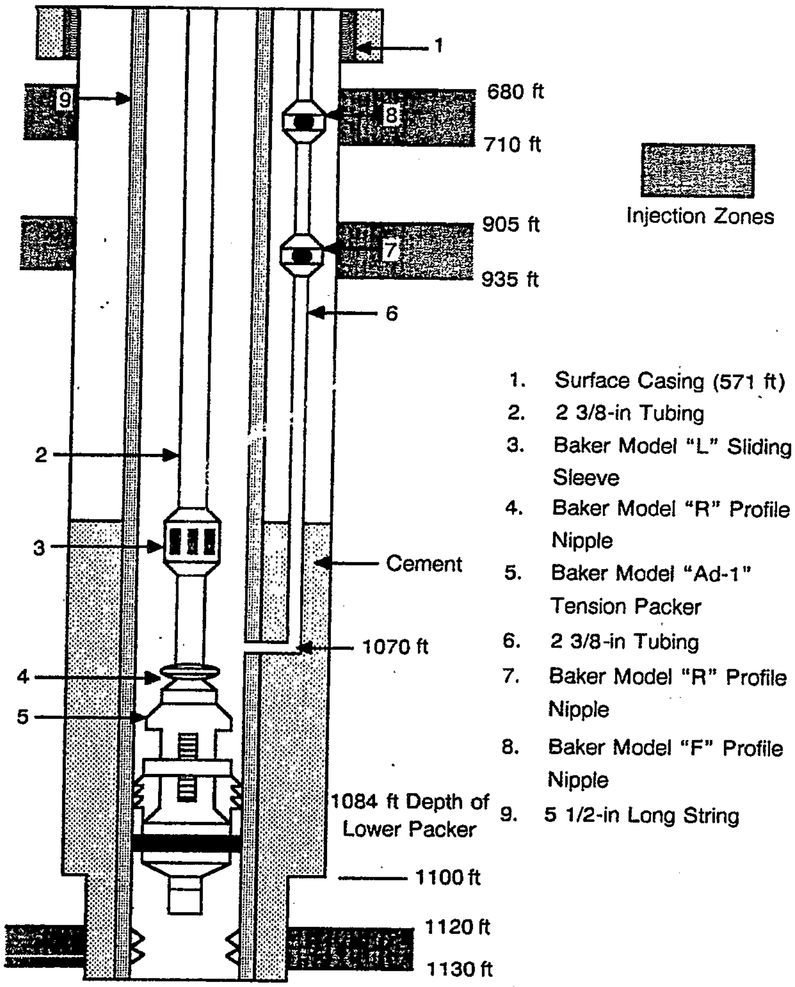

Figure B-14. Leak Test Well.

The purpose of this test was to determine if water, injected into the well and out the profile nipple at 700 feet, would move into a zone open to the well bore or move up the well bore through the drilling mud to the surface. Water was to be injected down the outside tubing while a surface valve on the tubing/long string annulus was open so that the flow would discharge at the surface, thus removing any air in the system as the outside tubing and tubing/casing annulus filled with water. In addition, a bull plug was removed from the surface casing

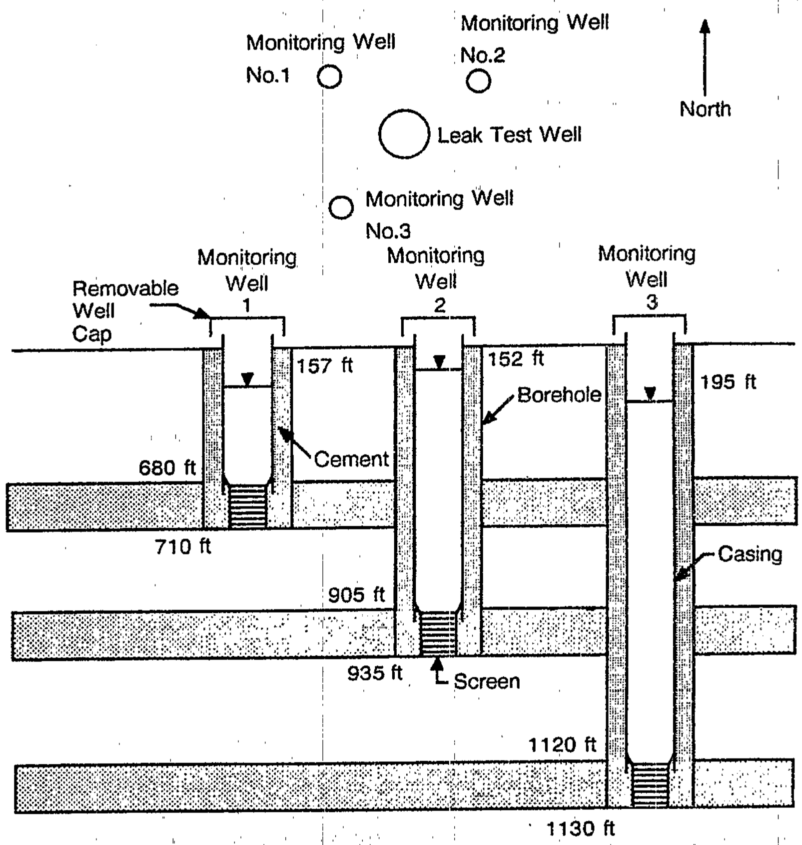

Figure B-15. Monitoring wells.

Table B-3. Depth to Water in Monitoring Wells

Monitoring Well	Depth (feet)	Water Level Below Land Surface (feet)
1	710	157
2	935	152
3	1,130	195

so that the surface casing/long string annulus was open to the surface.

At 1:05 p.m. the pump was turned on to begin pumping water into the outside tubing. In 8 minutes water began flowing out of the tubing/long string annulus at the surface. At that time the valve on the tubing/long string annulus was closed so that the flow into the outside tubing would exit only through the profile nipple at 700 feet.

At 1:46 p.m. a significant pressure drop was noted on the pressure gauge (from 300 psig to 70 psig), and water began flowing at the surface through the bull plug opening in the surface casing. The water flowing from the surface casing was clear, indicating channeling through the mud rather than displacement of the mud.

On Friday, February 26, after all the other tests were completed, an attempt was made to determine how much pressure would be necessary to reopen the apparent channel in the mud and establish flow at the surface. The bull plug in the surface casing was removed and injection begun down the tubing/long string annulus at a pressure of 30 psig and a flow of 3.3 gpm. Within 1 minute flow of clear water appeared at the surface from the bull plug opening in the surface casing. The pressure was gradually reduced and the flow decreased. Even when the pressure gauge showed zero pressure, there was a trickle of water flowing from the surface casing. The low pressure necessary to induce flow indicates that the channel created on February 22 remained open.

The fact that a channel was created in the mud initially and the channel did not "heal" over the 5-day test period is of concern when considering abandoned wells and wells with inadequate casing through underground sources of drinking water. In a report titled, "Determining the Area of Review for Industrial Waste Disposal Wells," Stephen E. Barker investigated mud strengths and the pressure required to initiate flow in abandoned wells. He stated that in addition to the pressure required to overcome the hydrostatic head of the borehole mud, the pressure necessary to displace the mud varies directly with the gel strength and well depth and inversely with borehole diameter.

$$P = \frac{0.00333\,(GS)\,(h)}{D}$$

GS = gel strength, pounds/100 ft^2

h = height of mud column or depth of well, feet

D = hole diameter, inches

P = displacement pressure, psi

The constant 0.00333 has the units ft/inch

The resistance to flow in the long string/borehole annulus of the Leak Test Well includes the mud column in the long string/borehole annulus (mud gradient .499 psi/ft), and the gel strength of the mud (assume 25 lb/100 ft^2)

Mud Column

$$.499 \text{ psi/ft} \times 700 \text{ ft} = 349 \text{ psi}$$

Gel Strength

$$\frac{.00333 \text{ ft/in} \times 25 \text{ lb/100 ft}^2 \times 700 \text{ ft}}{6 \text{ in}}$$

Thus, the resistance to flow is the sum of the mud column and the gel strength: 349 psi + 9.7 psi = 358.7 psi.

The inducement to flow includes the water column in the long string above the 700-inch zone and the pump pressure:

Hydrostatic pressure	=	.434 psi/ft × 700 ft = 303.8 psi
Pump pressure	=	300 psig
Inducement to flow	=	603.8 psi

Thus, the differential pressure available to cause flow in the long string annulus is 245.1 psi (603.8 psi - 358.7 psi).

If the gel strength of the mud in the annulus had reached 120 lb/100 ft^2, the displacement pressure due to the gel strength would have only been 46.6 psi and the differential pressure to cause flow in the annulus, 208.2 psi.

It appears that at shallow depths, the probability of fluids from leaks in the system being able to move through the mud, either to the surface or into permeable zones, is very high when injection pressures are additive to the hydrostatic pressure.

Pressure Monitoring

This test was designed to establish if monitoring a positive pressure, without an initial pressure test, could detect the same leak in the system that could be detected with a pressure test. To perform the test a 5 1/2-foot standpipe was attached to the tubing/long string annulus to provide the positive pressure for the test (Figure B-16). The plastic standpipe was graduated into 1 foot increments and each foot of the standpipe held 1 gallon of water. The base of the standpipe was located 3.2 feet above the land surface.

The standpipe was attached to the well on Wednesday morning and the system was filled with water to the 5-foot level. The water-level decline was then measured every hour for 7 hours, until the

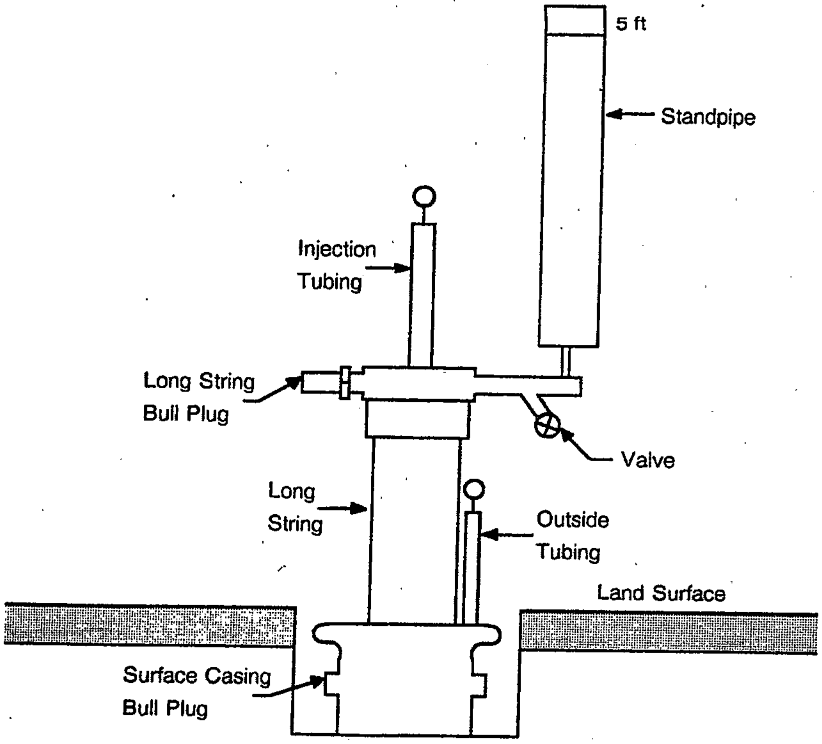

Figure B-16. Standpipe.

Table B-4 Water-Level Decline in Standpipe

Time (24 hours)	Elapsed Time (hours)	Water Level (feet)	Decline/Hour (feet)
0810	0	5.0	0.0
0910	1	4.3	0.7
1010	2	3.7	0.6
1110	3	3.1	0.6
1210	4	2.4	0.7
1310	5	1.8	0.6
1410	6	1.2	0.6
1510	7	0.5	0.7
1610	8	Below base of standpipe	

water level fell below the base of the standpipe. Table B-4 indicates the water-level decline in the standpipe over the period of the test.

At 1:45 p.m. on February 25, 1988 (about 29 hours after start of the test), the bull plug in the long string was removed and a water-level measurement was taken. The water level in the tubing/long string annulus was 16.1 feet below the base of the standpipe.

The average decline in the standpipe was .64 ft/hour, slightly slower than the tubing/casing annulus decline of .76 ft/hour. This is due to the fact that the standpipe contained 1 gallon per foot and the tubing/casing annulus contained only .7938 gallons per foot. The decline noted calculates to a .01 gpm, .6 gpd or .34 bpd leak.

The data indicate that the monitoring system can detect a leak of this size. The amount of positive pressure is not significant, it is just a means of putting the fluid level above the surface where the water-level decline can be readily observed. The pressure differential created by the hydrostatic column in the casing/tubing annulus and the formation pressure is what controls the rate of decline and rate of volume lost. Had the test been allowed to run long enough, the rate of decline and volume of fluid lost would have steadily decreased until equilibrium was reached.

Standard Pressure Test

The standpipe was removed and the well was subjected to the standard mechanical integrity pressure test to determine effects of different pressures and length of tests on the capability for detecting leaks. Table B-5 indicates the pressures applied and pressure decline over time.

In some UIC programs, if a well does not lose more than 10 percent of the pressure in 30 minutes, it passes the pressure test. The Leak Test Well failed the test in less than 2 minutes at all pressures (Figure B-17). In each of the tests (50, 100, 200 and 400 psig), more than 75 percent of the initial pressure was lost within 15 minutes.

The water-in-annulus test, in which a well passes the mechanical integrity test (MIT) if the water level does not decline more than 5 feet per hour, is of concern. A water-in-annulus test would have indicated that the Leak Test Well had mechanical integrity. As the monitoring showed, the water-level decline was only 0.76 ft/hour. Thus, under the pressure differential (70 psi) created during this test by the hydrostatic column in the annulus, the fluid loss was .01 gpm, 0.6 gph, 14.4 gpd or .34 bpd. However, a tubing or packer leak, sufficient to create only a 120 psi differential (equivalent to the 50 psig test on Table B-6) between the annulus and the receiving formation, would lose 0.8 gpm, 48 gph, 1,152 gpd or 27.4 bpd through the same holes.

Table B-5 *Pressure Decline Over Time*

Pressure Applied	50 psig	100 psig	200 psig	400 psig
Pressure Differential (700 ft sand)	120 psi	170 psi	270 psi	470 psi

Time (min)	Pressure Decline (psig)			
0	50	100	200	400
5	25	43	77	225
10	15	22	35	117
15	10	13	18	60
20	5	7	13	34
25	3	5	7	23
30	0	3	6	15

Injected Volume Versus Pressure/Leak Detection through Monitoring Wells

The next test run on the well involved evaluating injected volume versus pressure, to determine whether or not a monitoring well can detect an increase in pressure as a result of flow through a leak in the system.

While injecting at pressures of 50, 100, 200 and 400 psig for 30 minutes, the flow into the profile nipple at 700 feet was measured (Table B-6). At the same time the injection-volume relationship was being determined, the In-Situ Hydrologic Unit was recording the changes in water level in the two monitoring wells every 10 minutes (Tables B-7 and B-8).

Injection began at 3,892 minutes elapsed time at 50 psig; 100 psig at 3,922; 200 psig at 3,952; and 400 psig at 3,982. Injection was stopped at 4,012 minutes.

The data from the transducers clearly demonstrate that the water level in the 700-foot sand is responding to the different rates of injection (Table B-7, Figure B-18) while that in the 900-foot sand (Table B-8, Figure B-19) is not. The water-level drop during the 400 psi injection probably indicates that some other zone began taking water, since in this test the pressure was maintained as a constant, rather than the flow rate. Additional "injection volume versus pressure" tests need to be conducted over a longer period of time to establish more data for determining the reason for the water-level drop.

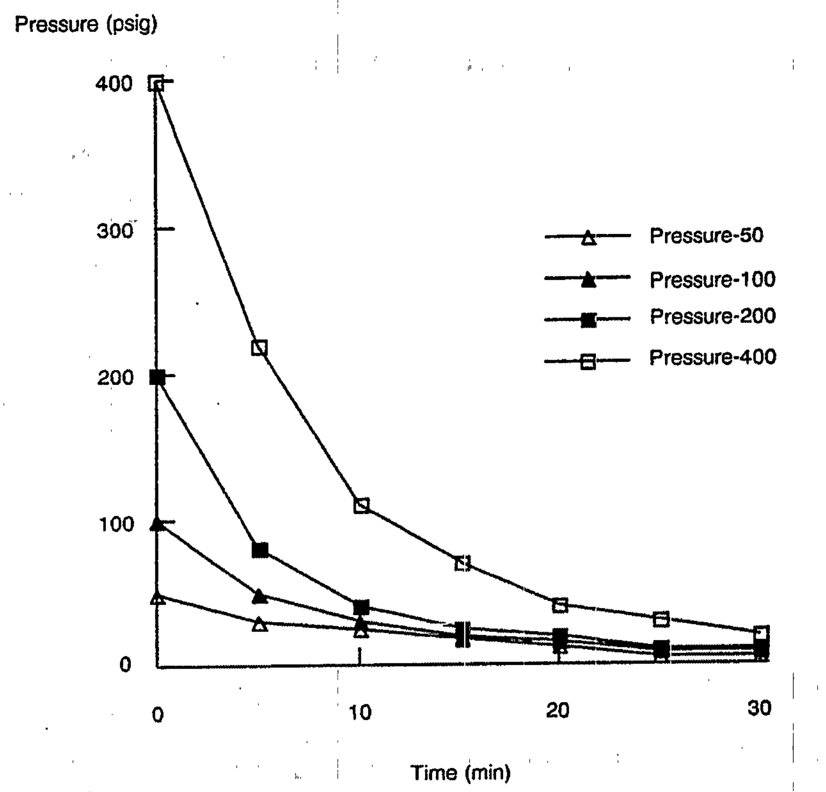

Figure B-17. Pressure decline over time.

Table B-6. Flow through Profile Nipple

Time	Elapsed Time (min)	Injection Pressure (psig)	Differential Pressure (psi)	Injection Volume (gpm)
Start Test	3892	0	70	0.01
0800	3892-3922	50	120	0.8
0830	3922-3952	100	170	1.0
0900	3952-3982	200	270	1.2
0930	3982-4012	400	470	2.7

Volume Versus Pressure–Hole Size

The next test performed was to determine the volume of water which could be pumped through a 1/32-, 1/16-, 1/8-, and 3/16-inch orifice at varying pressures. Orifices of these sizes were drilled into caps fitted onto the injection line. With all valves closed to the well, different pressures were applied and the flow rate was measured a stopwatch and a graduated bucket.

Table B-7. Changes in Water Level – Monitoring Well No. 1

Elapsed Time (min)	Water Level (ft)	Change in Water Level (ft)
3810	157.06	0.06
3820	157.06	0.06
3830	157.06	0.06
3840	157.06	0.06
3850	157.06	0.06
3860	157.06	0.06
3870	157.05	0.05
3880	157.05	0.05
3890	157.04	0.04
3900	157.05	0.05
3910	157.07	0.07
3920	157.07	0.07
3930	157.08	0.08
3940	157.07	0.07
3950	157.11	0.11
3960	157.12	0.12
3970	157.12	0.12
3980	157.12	0.12
3990	157.17	0.17
4000	157.05	0.05
4010	157.02	0.02
4020	157.06	0.06
4030	157.10	0.10
4040	157.09	0.09
4046	157.11	0.11

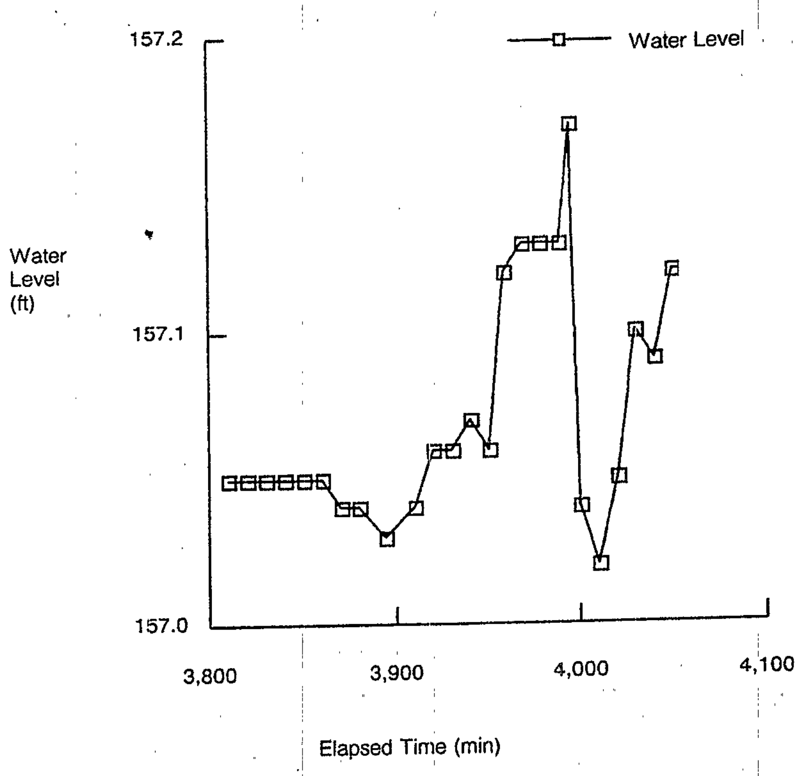

Figure B-18. Changes in water level – 700-ft zone.

Table B-9 indicates the results of this test. It should be noted that the differential pressure between the casing/tubing annulus (gauge pressure + hydrostatic pressure) and the formation pressure opposite the hole determines the volume of a flow through a certain size hole in a well casing.

Table B-8. Changes in Water Level – Monitoring Well No. 2

Elapsed Time (min)	Water Level (ft)	Change in Water Level (ft)
3810	152.04	0.04
3820	152.04	0.04
3830	152.04	0.04
3840	152.04	0.04
3850	152.04	0.04
3860	152.04	0.04
3870	152.04	0.04
3880	152.04	0.04
3890	152.04	0.04
3900	152.04	0.04
3910	152.04	0.04
3920	152.04	0.04
3930	152.04	0.04
3940	152.04	0.04
3950	152.04	0.04
3960	152.04	0.04
3970	152.04	0.04
3980	152.04	0.04
3990	152.04	0.04
4000	152.04	0.04
4010	152.03	0.03
4020	152.03	0.04
4030	152.04	0.03
4040	152.03	0.03
4046	152.04	0.04

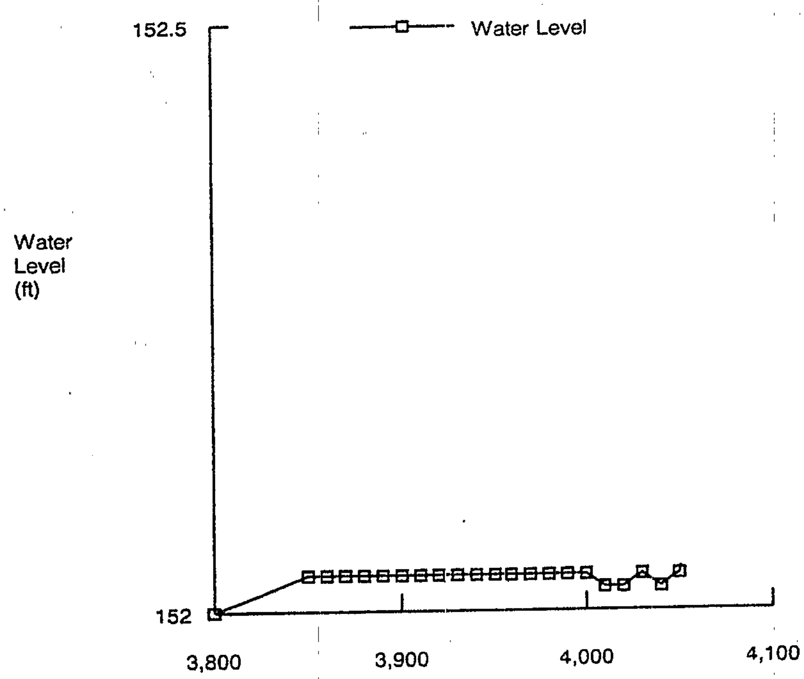

Figure B-19. Changes in water level – 900-ft zone.

Table B-9. Flow of Water (gpm) through Holes at Different Pressures

	Hole Size (inch)			
Pressure (psig)	1/32	1/16	1/8	3/16
50	0.075	0.65	2.45	5.5
100	0.088	0.85	3.31	*
200	0.115	1.13	4.50	
400	0.160	1.60	**	

* Barely reached 50 psi
** Could not get above 220 psi

Conclusions

The tests run during this week provide a number of points that need to be considered in determining mechanical integrity of injection wells:

1. A channel was created in the mud in the long string/well bore annulus on Monday and the channel was still open on Friday.
2. Data from the monitoring system (standpipe) were sufficient to detect a leak in the Leak Test Well.
3. The Leak Test Well failed the standard pressure test in less than 2 minutes.
4. The Leak Test Well would have passed a water-in-annulus test even though it failed the standard pressure test. The water-in-annulus test needs more study to determine if it is indeed a valid test.
5. The water level in the 700-foot zone clearly responded to the injection rates in the Leak Test Well, while the water level in the 900-foot zone showed no response to the injection.

Test No. [illegible]: Noise Logging

Introduction

On February 15, 1988, personnel from Atlas Wireline Services conducted a noise survey on the Leak Test Well at the Mechanical Integrity Test Facility. This survey, termed SONAN, was conducted to determine if flow through the outside tubing in the well could be identified.

Well Configuration

The well was configured as shown in Figure B-20, with injection maintained down the 2 3/8-inch outside tubing. The noise tool was located inside the 2 3/8-inch injection tubing.

Noise Survey

The tool used by Atlas Wireline has an outside diameter of 1 11/16 inches, a length of 3 feet, a bottom hole temperature rating of 350 degrees and a bottom hole pressure rating of 15,000 psi. The tool has the capability to take data at seven frequencies as shown on Table B-10. On the table, HPO1 relates to 200 HTZ, HPO2 to 600 HTZ, HPO3 to 1,000 HTZ, HPO4 to 2,000 HTZ, HPO5 to 4,000 HTZ, HPO6 TO 6,000 HTZ and HPO7 to 8,000 HTZ. On this particular test, readings were taken only through 2,000 HTZ, thus the numbers recorded for HPO5, 6 and 7 are meaningless.

Data was taken at 25 stations in the well (Table B-10). At least four readings are taken at each station to identify the frequency character of the sound sources.

The curves presented on Figures B-21 and B-22 and the data on Table B-10 are developed by recording the peak millivolt reading for each frequency at each station. The readings for HPO1 represent the noise levels for 200 HTZ and up; HPO2 for 600 HTZ and up; HPO3 for 1,000 HTZ and up; and HPO4 for 2,000 and up.

Conclusions

The attached copies of the Sonan Log (Figures B-21 and B-22), present data indicating increased noise at the hole in the long string at 1,070 feet. However, two noise anomalies (980 and 860 feet) have not been fully explained.

R.M. McKinley, Exxon Production Research, Houston, Texas, is one of the foremost authorities on the noise tool. He has stated that extraneous sources of sound are the greatest impediment to noise log quality control. These extraneous sources may be surface equipment noise or inadvertent flow past the sonde or continued movement of the logging tool during measurement.

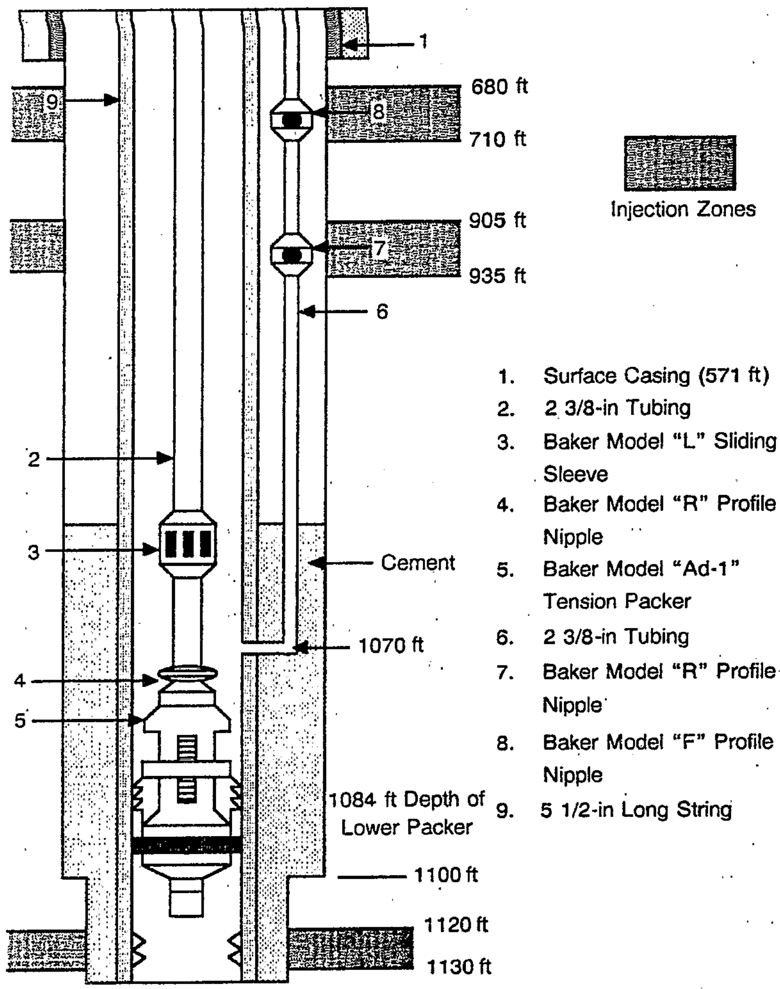

Figure B-20. Leak Test Well.

Another interesting aspect of the log interpretation relates to single versus multiphase flow. Multiphase flow is characterized by lower frequency sound than single phase flow, and is indicated by the separation of the 200 HTZ curve from the other curves. This phenomenon seems to be quite vividly portrayed on the log. Thus, air was apparently being pumped down the well along with the water.

Much additional testing is necessary to fully understand the capabilities of the noise tool in mechanical integrity testing and to fully

Table B-10. Leak Test Well – SONAN Data

Depth	Corrected Data for Line Length, Size						
	HPO1	HPO2	HPO3	HPO4	HPO5	HPO6	HPO7
650.00	58	13	10	9	3	2	1
700.00	48	20	13	7	3	2	1
750.00	51	10	9	6	3	2	1
800.00	74	16	12	4	3	2	1
860.00	132	11	9	7	3	2	1
900.00	83	22	12	7	4	2	1
940.00	106	11	10	7	3	2	1
980.00	144	12	11	7	3	2	1
1000.00	101	17	11	7	3	2	1
1020.00	90	11	8	6	3	2	1
1040.00	59	10	9	7	3	2	1
1050.00	135	29	7	4	3	2	1
1055.00	119	16	11	6	3	2	1
1060.00	137	13	8	7	3	2	1
1065.00	14	16	8	7	3	2	1
1070.00	136	9	8	6	3	2	1
1075.00	86	14	10	9	3	2	1
1080.00	89	11	8	7	3	2	1
1090.00	64	11	9	7	3	2	1
1100.00	73	10	8	7	3	2	1
1120.00	62	14	13	8	3	2	1
1140.00	35	20	17	7	3	2	1
1160.00	26	8	8	7	3	2	1
1180.00	20	15	7	4	3	2	1
1200.00	17	7	6	4	3	2	1

interpret data presented on the noise log. It is strongly recommended that the following articles be made a part of a library for assistance when dealing with noise surveys:

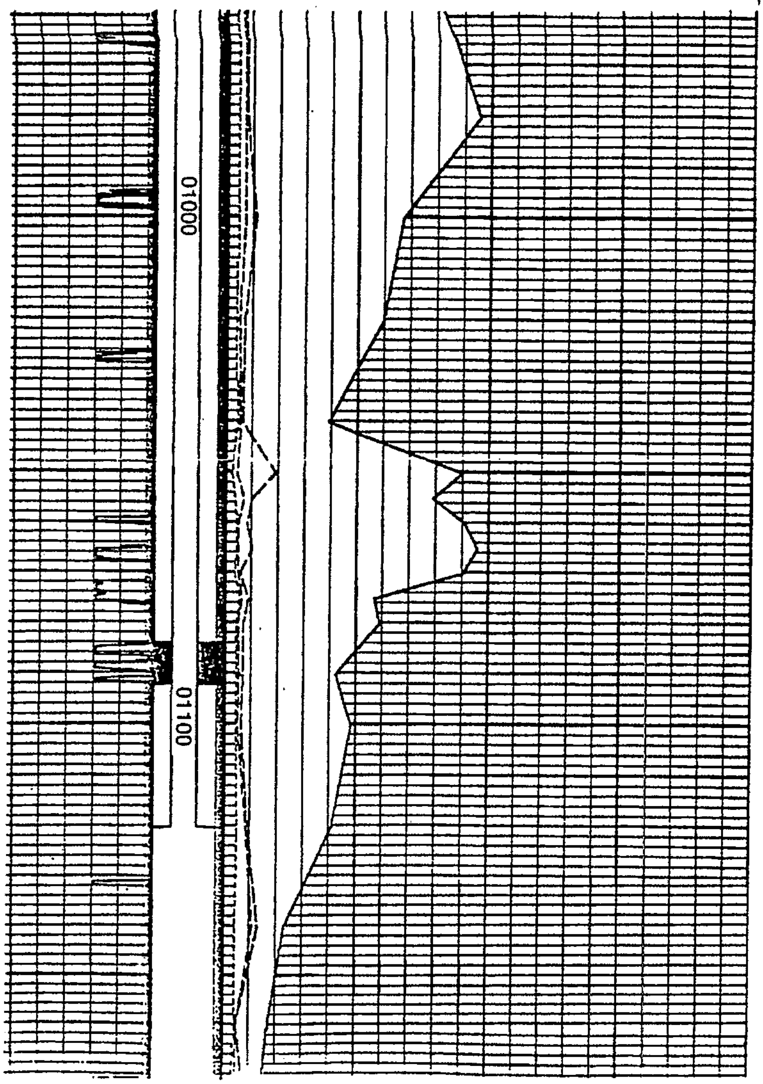

Figure B-21. Atlas Wireline Services SONAN Leak Test Well.

McKinley, R.M., Bower, F.M., Rumble, R.C., "The Structure and Interpretation of Noise from Flow Behind Cemented Casing," *Journal of Petroleum Technology* (March 1973), pages 329-338.

McKinley, R.M.; Bower, F.M., "Specialized Applications of Noise Logging," *Journal of Petroleum Technology* (November 1979), pages 1387-1395.

McKinley, R.M., "Production Logging," SPE Paper 10035, undated.

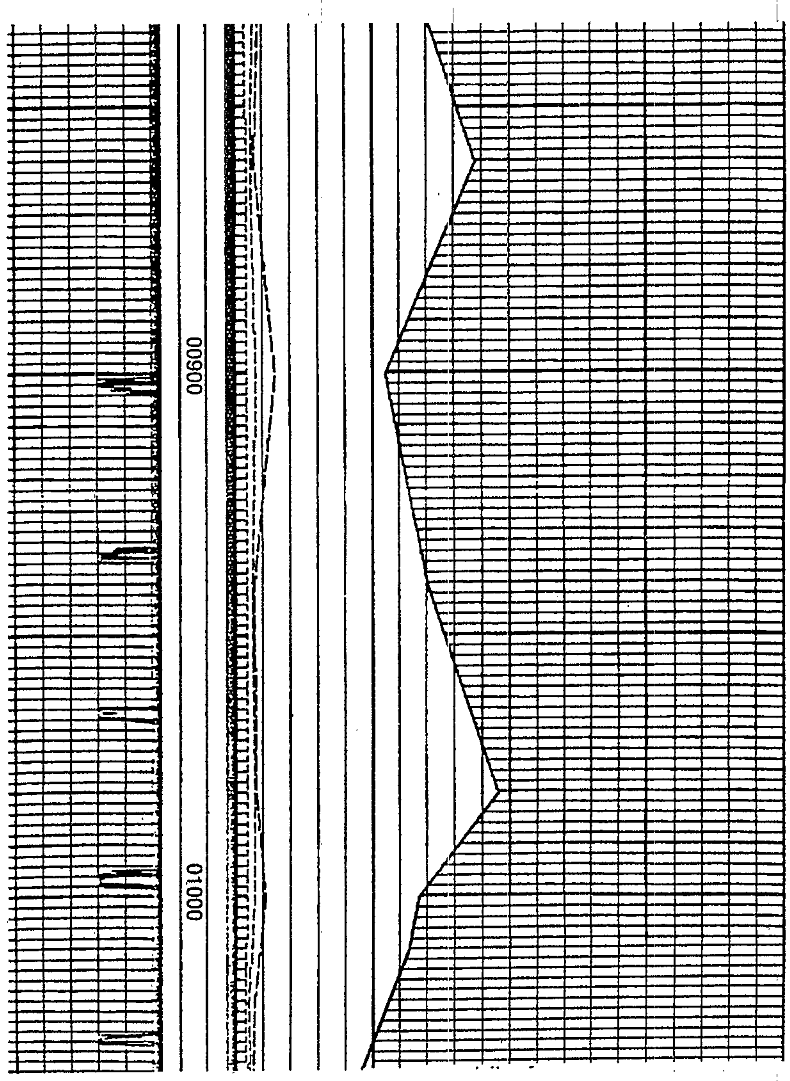

Figure B-22. Atlas Wireline Services SONAN Leak Test Well.

Test No. 10: Temperature Survey

Introduction

On September 10, 1985, personnel from the Tom Hansen Company ran a temperature survey in the Leak Test Well. The purpose of the survey was to determine the geothermal gradient, the fluid level, and, by including a casing collar locator, the location of the casing collars, packers and sliding sleeve in the well.

Well Configuration

The well had surface casing set at 571 feet and cemented to the surface, and long string set to 1,215 feet with the top of the cement at about 920 feet. When the injection tubing was set, calculations indicated the upper packer should be at 1,057 feet, and the lower packer at 1,084 feet, with the sliding sleeve at about 1,070 feet (Figure B-23).

Temperature Survey

The sequence of events leading to the temperature survey included:

9-5-85 The 5 1/2-inch casing was filled with water and the zone 1,120-1,130 perforated with 2 shots per foot (SIEDP – deep penetrating shot). The average hole size should be .411 inches and the average depth of penetration of the shot, 19 inches. The water level was measured and was 20 feet below the land surface.

9-9-85 The water level was 46 feet below the land surface. The well was swabbed before setting tubing and packers. Operators set the tubing and packers and prepared to run the temperature survey.

Two runs were made in the well, each run taking about 35 minutes. A geothermal gradient could not be obtained since the work done in setting the tubing (swabbing, etc.) resulted in moving fluid from the casing into the injection zone. As a result, the log reflected the results one would expect after injection has taken place.

The temperature went from 76°F at the surface to 75.5°F at total depth in the first run. The second run indicated a surface temperature of 80°F and a bottom hole temperature of 73.5°F. The fluid level in the second run was about 474 feet below the land surface.

A very interesting part of the log presentation was the casing collar locator. It indicated the upper packer at a depth of 1,054 feet, sliding sleeve at 1,066 feet and the lower packer at 1,084 feet. This compares favorably with the calculated locations made prior to setting the tubing and packers.

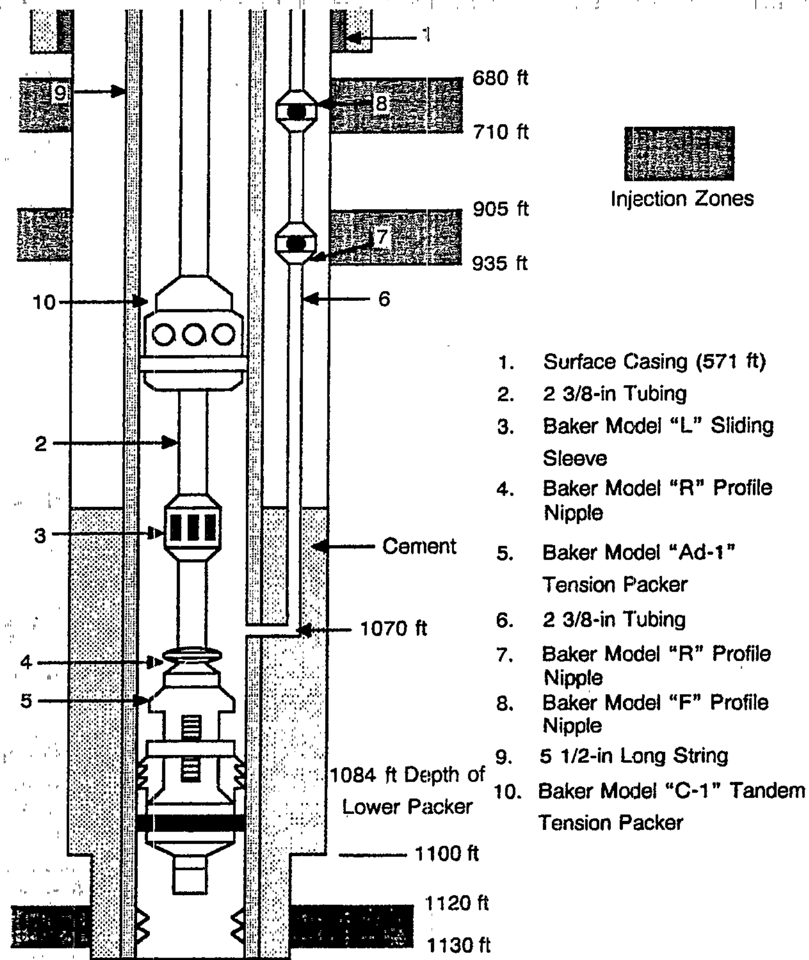

Figure B-23. Leak Test Well.

Conclusions

The CCL portion of the log was good for comparing the calculated location of both packers and the sliding sleeve. The temperature log gave no significant information since a geothermal gradient was not obtained. A base log to establish the geothermal gradient is extremely important for developing a meaningful log. Temperature, differential temperature and radial differential temperature logs will be run on the well at a later date.

Test No. 11: Continuous Flow Survey

Introduction

On October 13, 1987, personnel from Gearhart Industries, Inc., ran a continuous flow survey on the Leak Test Well. The purpose was to determine whether or not the survey could identify leaks in the well, and, in turn, whether or not flow was exiting through the perforations.

Well Configuration

The well was configured as shown in Figure B-24. The sliding sleeve was closed so that all flow down the injection tubing went to the perforations at 1,120 to 1,130 feet.

Flow Meter Survey

The survey was run by pumping water down the injection tubing at different rates and checking those rates with calculations of flow from data collected by the flow meter. Also, readings were taken at specific intervals to determine if flow was leaving the injection tubing. Flow rates from the pump were about 7, 6, 1 and 1/2 gallons per minute. However, accurate determinations of flow rates were not possible owing to a malfunction of the flow meter in the flow line to the well.

Twenty-one different "runs" were made in the well under flow and no-flow conditions. Each run was indicated on a log as a file with the following information presented: speed of tool movement, either up or down in feet per minute; depth interval; average revolutions/second of the spinner in a clockwise and a counterclockwise direction; and the flow rate, in revolutions per second, in the clockwise and counterclockwise direction.

In the initial test (File 1), the tool was held stationary at 193 feet and water was injected down the injection tubing at a rate of about 7 gpm. The calculated flow rate past the tool was 265 barrels per day (7.7 gpm).

The flow was changed to about 6 gpm, and the tool (File 2) indicated a flow of 221 bpd (6.4 gpm) (Figure B-25).

For File 3, the flow rate was changed to about 1 gpm and the tool indicated a flow of 44 bpd (1.3 gpm).

The flow rate for File 4 was about .5 gpm and the calculated flow from the tool data was 15 bpd (.43 gpm).

The remaining runs (files) involved moving the tool up or down in the tubing under no-flow conditions to check the flow meter, stop checks above and below the sliding sleeve to determine whether

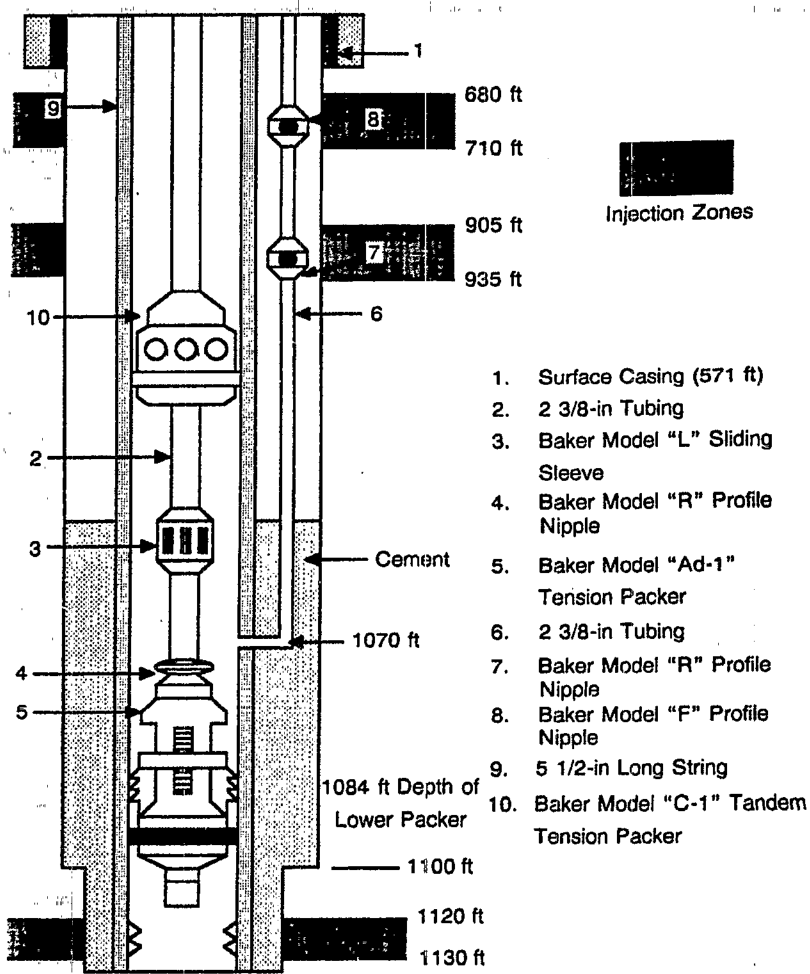

Figure B-24. Leak Test Well.

leakage was occurring out the sleeve and a check of the flow out the perforations.

Figures B-25 to B-28 indicate specific runs and comments of the operator based on data provided by the survey.

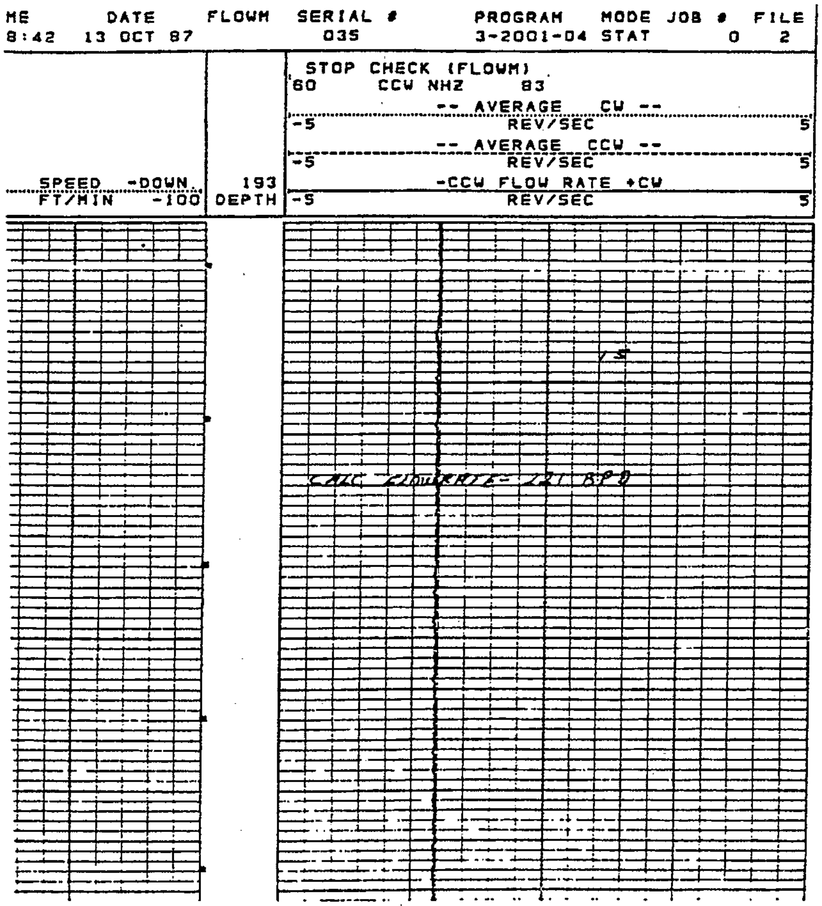

Figure B-25. Gearhart Industries, Inc., continuous flow survey.

Conclusions

The continuous flow survey indicated that there was a possible slight loss of fluid through the sliding sleeve and the flow was going out the perforations about equally.

Continuous flow surveys are a useful tool for determining leaks in tubing, casing or packers. Additional tests will be done to correlate more accurately the flow rate from the pump with the estimate from the tool.

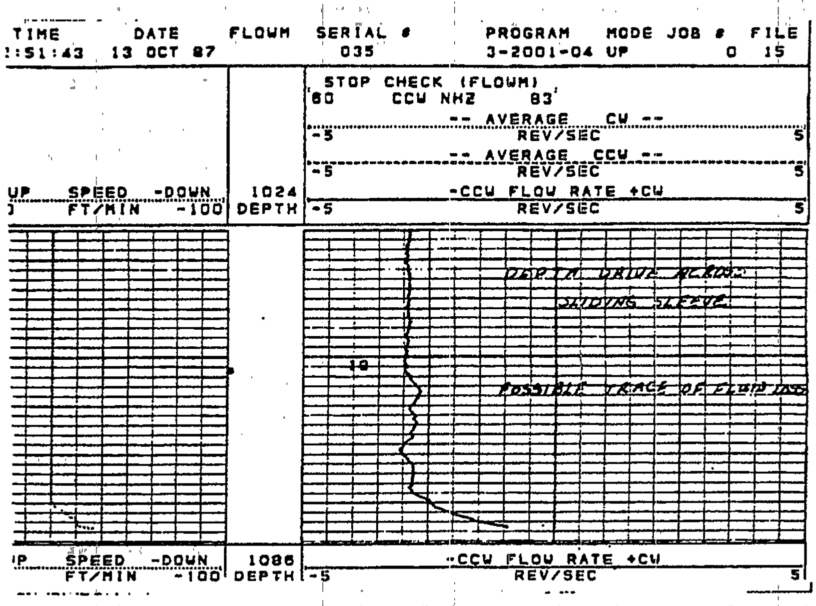

Figure B-26. Gearhart Industries, Inc., continuous flow survey.

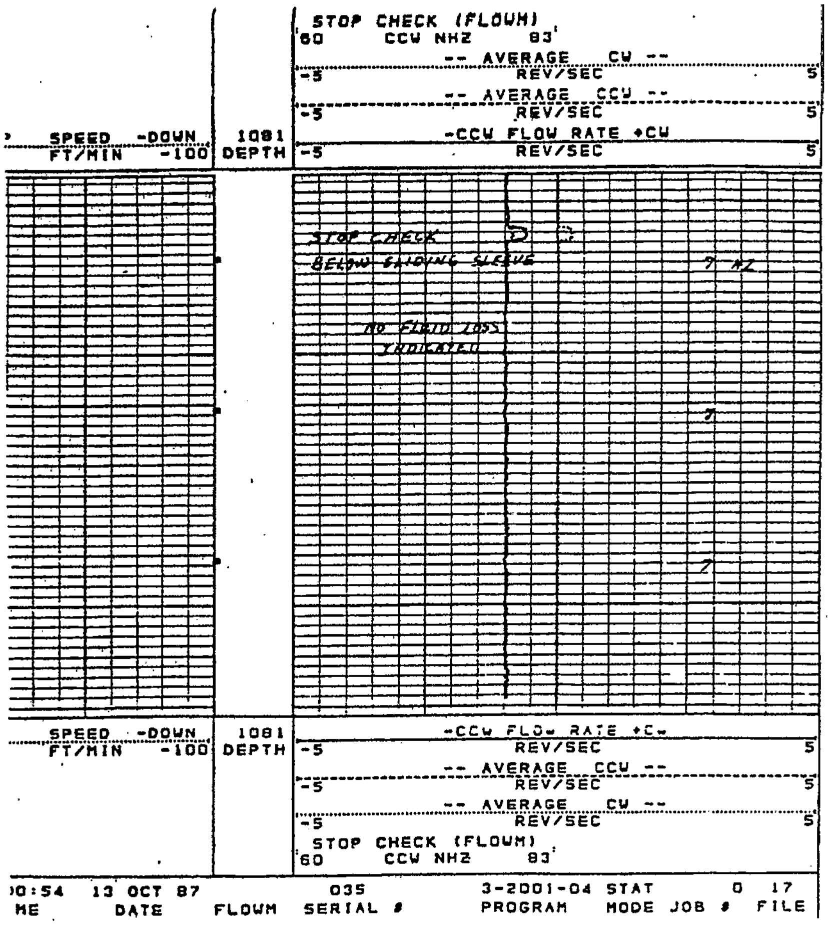

Figure B-27. Gearhart Industries, Inc., continuous flow survey.

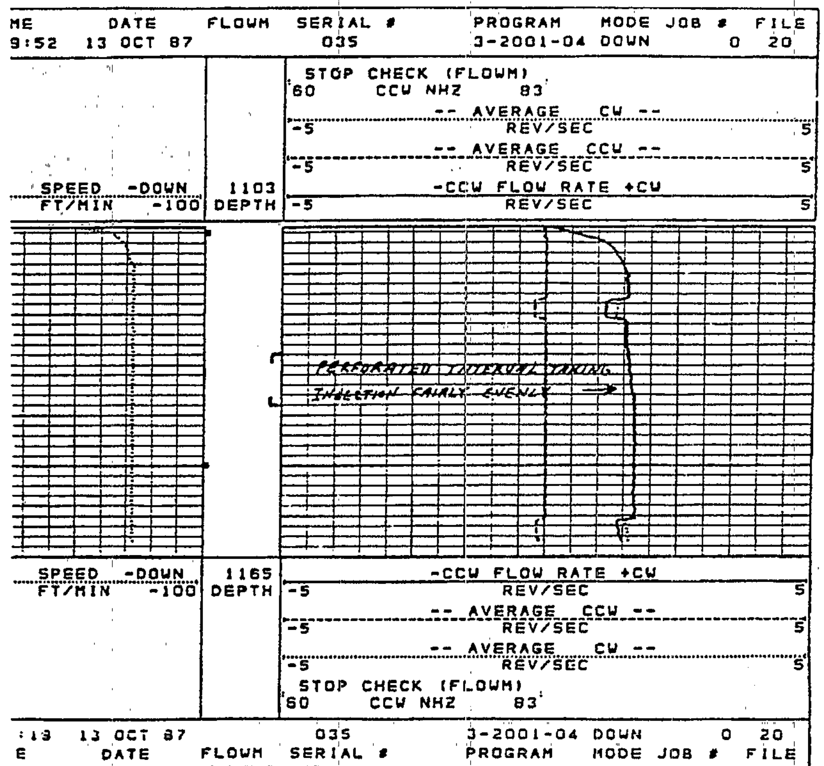

Figure B-28. Gearhart Industries, Inc., continuous flow survey.

Test No. 12: Radioactive Tracer Survey

Introduction

On May 19, 1988, personnel from the Tom Hansen Company conducted a radioactive tracer survey on the Leak Test Well. The purpose of the survey was to determine if there were leaks in the tubing, casing or packer, or channeling in the cement in the area of the perforations in the long string.

Well Configuration

The well was configured as shown in Figure B-29. The sliding sleeve was closed so that material injected down the injection tubing would exit through the perforations from 1,120 to 1,130 feet.

Radioactive Tracer Survey

The first run was to determine a background. The tool used to develop the base log included a casing collar locator and low-sensitivity gamma ray.

The survey was conducted while pumping approximately 1/2 bpm at 300 psig, as follows:

1. Ejected tracer at about 1,000 feet and followed it down the tubing and out the perforations. Most of the material went out the lower part of the perforations. Eight runs were taken to trace the material (Figure B-30).
2. Ejected tracer at 1,125 feet and checked for movement with a detector at 1,139 feet. No channeling detected (Figure B-31).
3. Ejected tracer at 1,125 feet and checked for movement with a detector at 1,135 feet (time drive). Some of the material was detected (Figure B-32), which indicates a channel in the cement below the perforations.
4. Ejected tracer at 1,107 feet with a detector at 1,115 feet. No leak indicated.
5. Ejected tracer at 1,102 feet with a detector at 1,110 feet. No leak indicated.
6. Ejected tracer at 1,066 feet with a detector at 1,076 feet. No leak indicated.
7. Ejected tracer at 1,052 feet with a detector at 1,060 feet. No leak indicated.
8. Ejected tracer at 1,042 feet with a detector at 1,050 feet. No leak indicated.

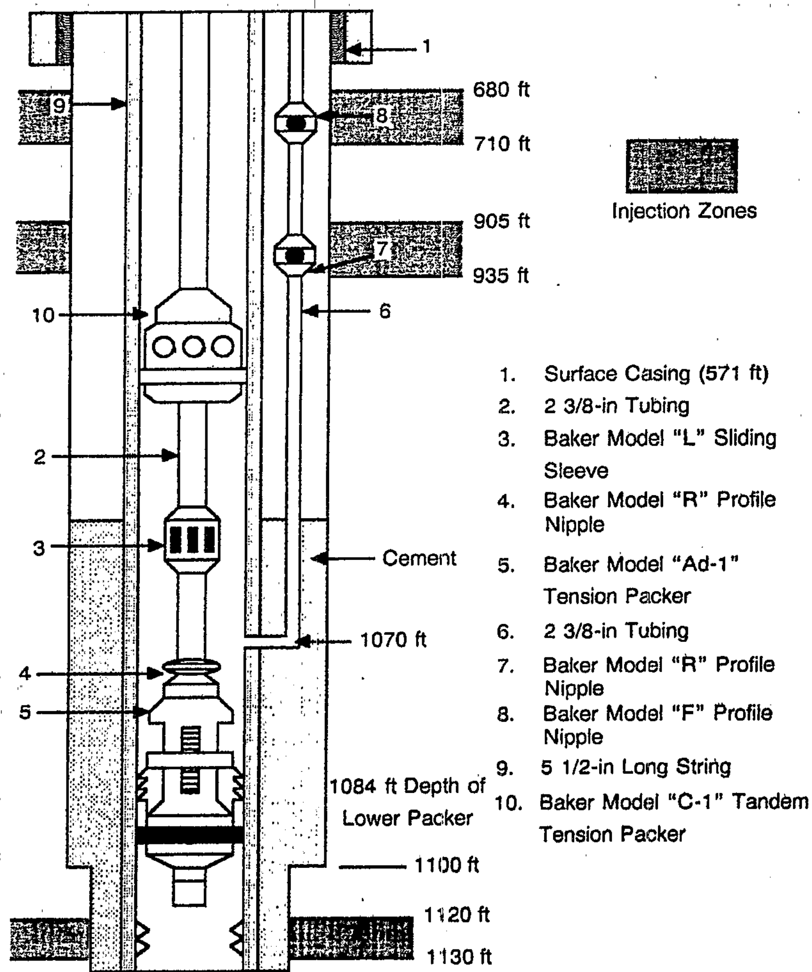

Figure B-29. Leak Test Well.

Conclusions

The radioactive tracer survey indicated a slight channel down from 1,130 to 1,135 feet. There was no indication of channeling at 1,139 feet. There were no indications of leaks in the tubing or packer or channels above the perforations.

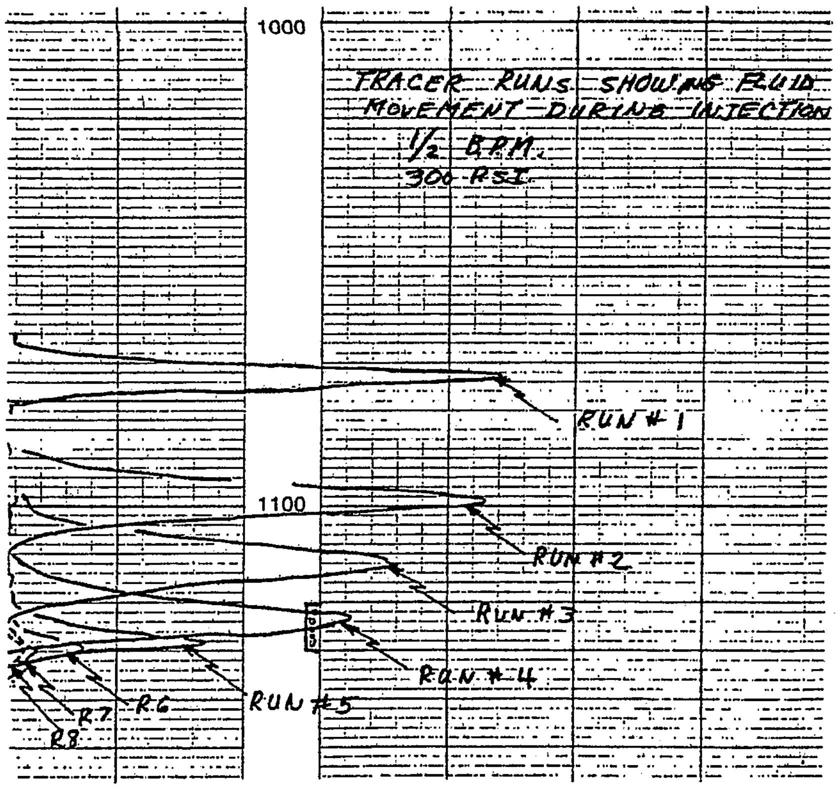

Figure B-30. Tracer runs showing fluid movement during injection at 1/2 bpm 300 psi.

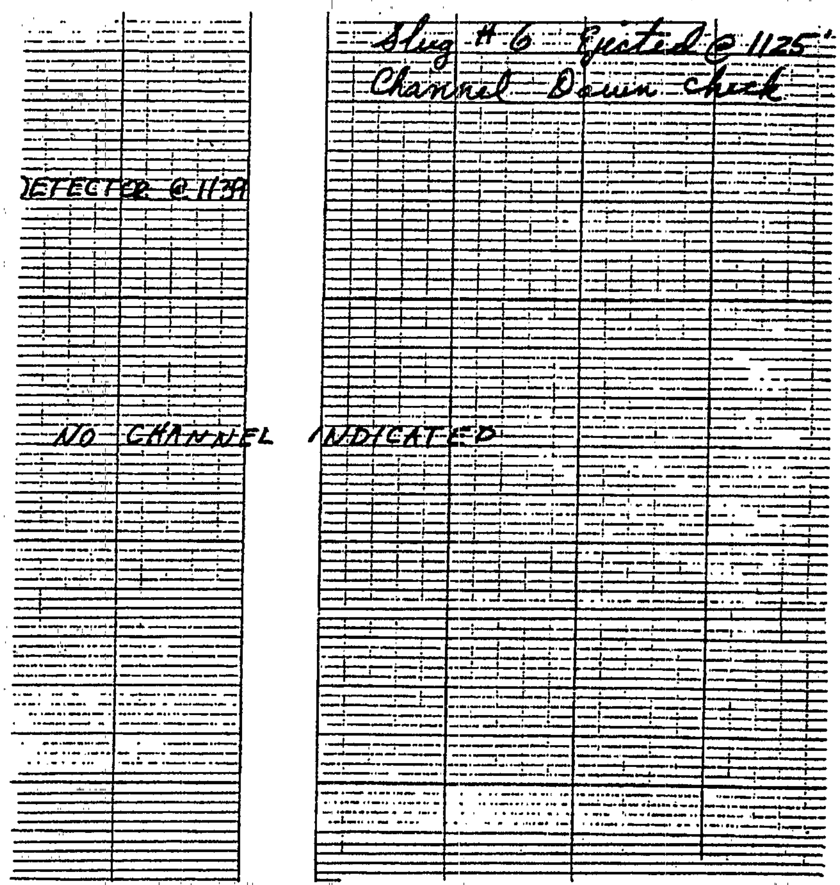

Figure B-31. Slug #6 ejected at 1,125-ft channel down check.

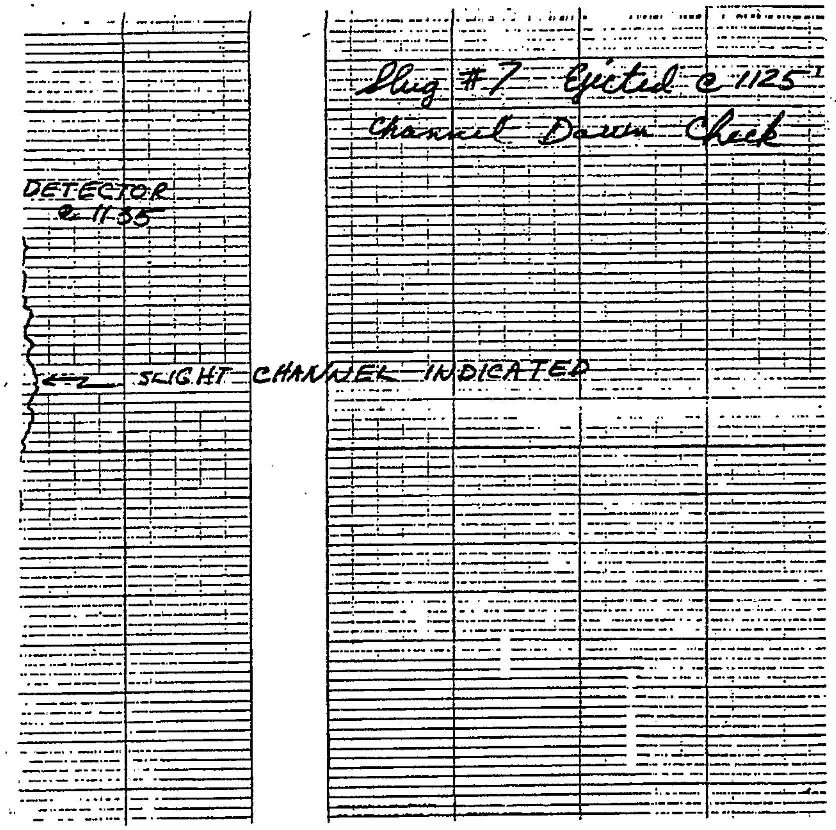

Figure B-32. Slug #7 ejected at 1,125-ft channel down check.

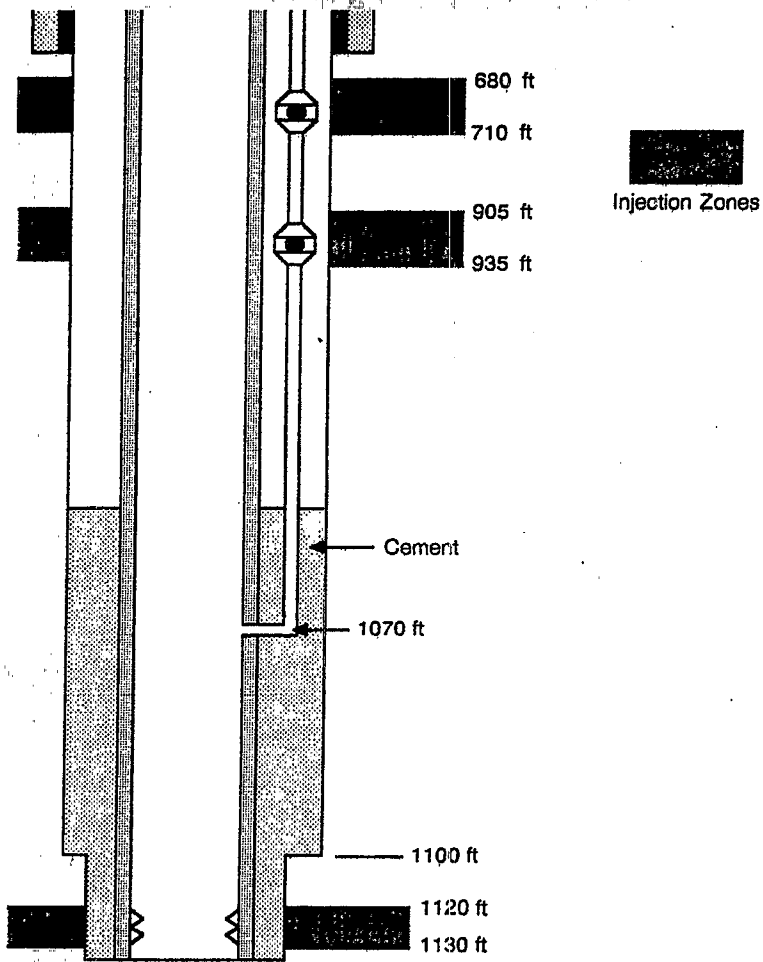

Figure B-33. Leak Test Well.

Test No. 13: Differential Temperature Survey

Introduction

On November 4, 1987, personnel from Schlumberger Well Services ran a differential temperature survey in the Leak Test Well. The survey was run after injection had been ongoing for about 5 hours and the well had been shut in for 16 hours.

Well Configuration

The well was configured as shown in Figure B-34. The injection tubing had been pulled and injection was taking place down the long string into the perforations at 1,120 to 1,130 feet. The surface valve on the outside tubing was closed so that no fluid could move through this area.

Differential Temperature Survey

The log presentation included curves for gamma ray, casing collars, temperature gradient and differential temperature.

The temperature gradient was from 65.5°F at about 200 feet to 73°F at 1,215 feet. The differential temperature curve indicated a slight (0.2°F) change in temperature at the base of the injection zone. The fluid level was indicated at about 173 feet below land surface by the temperature gradient curve.

Conclusion

The differential temperature log indicated there are no leaks in the long string.

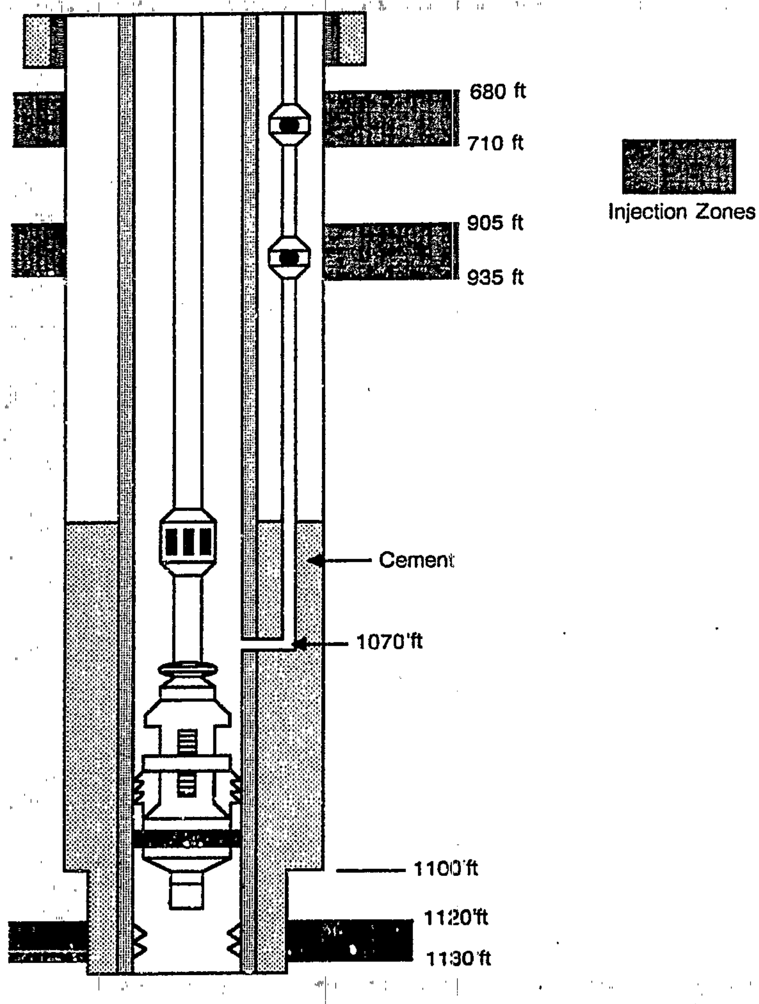

Figure B-34. Leak Test Well.

Test No. 14: Nuclear Activation Technique for Detecting Flow Behind Casing

Introduction

On November 3, 1987, personnel from the Robert S. Kerr Environmental Research Laboratory (RSKERL) and Atlas Wireline Service conducted a series of tests to determine flow behind pipe using an oxygen activation tool.

The purpose of the tests was to determine if flow could be detected behind pipe in the Leak Test Well and, if possible, the detection limit of the tool.

Well Configuration

Figure B-35 indicates the configuration of the Leak Test Well. A packer was set at 1,084 feet and a profile nipple was open at 700 feet. Injection was maintained down the injection tubing/long string annulus, out the 1/4-inch hole in the long string and up the outside tubing.

Tool Test

The test was conducted with the Atlas Wireline 1 11/16-inch diameter oxygen activation tool (Serial No. 24334) located in the 2 3/8-inch injection tubing. Stationary "no flow" background gamma ray count rates were taken for both the long spaced (LS) and short spaced (SS) detectors at depths of 300, 800 and 1,000 feet.

A background count rate was computed for each depth of investigation by determining the inelastic gamma ray and oxygen count rates for three no-flow measurements at each station. For each no-flow measurement, the ratio of the oxygen count rate to the inelastic count rate was computed, and the average of these ratios was determined. The result of this activity gives a long-space factor and short-space factor that are then multiplied times the measured inelastic long space and inelastic short space count rate, respectively, to compute the proper background.

After determining the background factors for each depth investigated, the tool was moved down the well at speeds of 15 feet per minute and 30 feet per minute to check the velocity calculations. The final part of the test involved injecting water down the tubing/long string annulus at different flow rates and determining what flow could be detected coming up the outside tubing. Flow measurements were taken at depths of 1,000, 800 and 660 feet.

Table B-11 is a summary of specific data taken at a depth of 1,000 feet. The determination of interest during this investigation was a flow or no-flow indication. The velocity data are also of interest, although not critical to this series of tests.

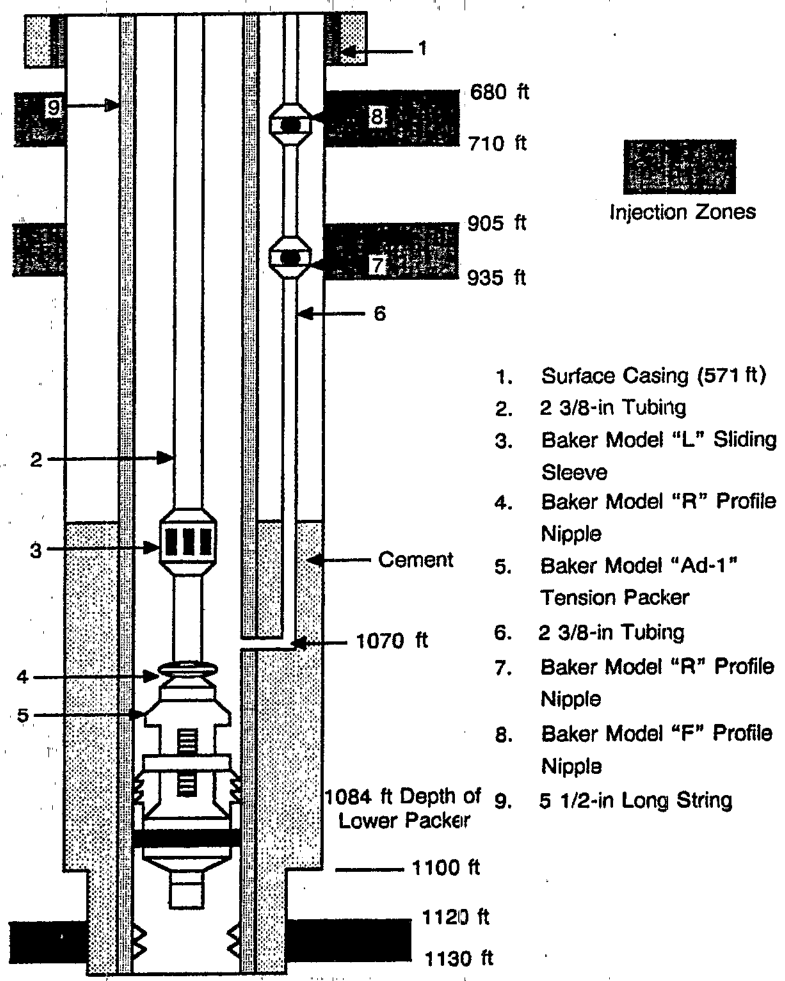

Figure B-35. Leak Test Well.

The criterion for flow indication is that the long space count rate must be greater than 1.0 counts/second after subtracting the background reading. Thus, from Table B-10 flows were indicated at stations 17 through 26, 36, and 37.

Table B-11. *Oxygen Activation Log Data,* Leak Test Well – November 3, 1987

Depth (feet)	Station	Flow Ind.* SS	Flow Ind.* LS	Velocity	Comments
1000	11	.35	.19	None	Not injecting
1000	12	-.01	.16	None	Not injecting
1000	13	.05	.11	None	Not injecting
1000	17	5.18	3.02	14 ft/min	Injecting .86 gpm
1000	18	3.52	3.35	155.88 ft/min	Injecting .86 gpm
1000	19	3.68	2.60	21.88 ft/min	Injecting .86 gpm
1000	20	3.17	3.36	0	Injecting .86 gpm
1000	21	5.24	4.32	39.43 ft/min	Injecting 4 gpm
1000	22	6.29	3.73	14.69 ft/min	Injecting 4 gpm
1000	23	4.50	3.91	54.65 ft/min	Injecting 4 gpm
1000	24	5.46	2.88	11.97 ft/min	Injecting 1.5 gpm
1000	25	6.36	3.16	10.94 ft/min	Injecting 1.5 gpm
1000	26	5.59	2.60	9.98 ft/min	Injecting 1.5 gpm
1000	28	.26	.43	0	Injecting .46 gpm
1000	29	.80	.24	0	Injecting .46 gpm
1000	30	1.99	.51	5.67 ft/min	Injecting .46 gpm
1000	31	.95	.32	0	Injecting .46 gpm
1000	32	1.33	.17	0	Injecting .32 gpm
1000	33	.02	.04	0	Injecting .32 gpm
1000	34	-.49	.004	0	Injecting .32 gpm
1000	35	3.47	.99	6.09 ft/min	Injecting .75 gpm
1000	36	3.02	1.19	8.18 ft/min	Injecting .75 gpm
1000	37	2.82	1.05	7.78 ft/min	Injecting .75 gpm
1000	38	.60	.45	0	No injection
1000	39	-.11	.12	0	No injection
1000	40	.05	.29	0	No injection

*With background subtracted

As previously stated, the velocity measurements are interesting but are not significant in the use of the tool for determining flow behind pipe at this point in the development of the tool, with one exception: one must determine the sensitivity of the tool, i.e., the slowest velocity the tool can identify as flow. The criteria for a valid velocity measurement are:

1. The flow indication signal for the SS must be at least three times the error bar.
2. The flow indication for the LS must be at least two times the error bar.
3. The LS signal must be less than the SS signal.
4. Neither signal can be zero.

If any of these criteria is not met, the velocity should be shown as zero in the data listing. A review of the data sheets from this test indicates that the velocity measurements meet these criteria.

Conclusions

The 1 11/16-inch oxygen activation tool was successful in detecting flow up the outside tubing in each of the tests while injecting at .86, 4, 1.5 and .75 gallons per minute. The tool did not detect flow at the .46 or the .32 gpm rates.

The minimum velocity the tool was able to detect during the tests was 3 ft/min. The results of this and other tests indicate that the velocity range of the tool in its present configuration is approximately 3 to 100 ft/min.

Test No. 15: Nuclear Activation Technique for Detecting Flow Behind Casing

Introduction

On September 14, 1988, personnel from the Robert S. Kerr Environmental Research Laboratory (RSKERL) and Atlas Wireline Service conducted a series of tests to determine flow behind pipe using an oxygen activation tool.

The purpose of the tests was to determine if flow could be detected behind pipe in the Leak Test Well, both in 2 3/8-inch tubing and in a channel in the mud system, and, if possible, the detection limit of the tool.

Well Configuration

Figure B-36 indicates the configuration of the Leak Test Well. A packer was set at 1,084 feet and a profile nipple was open at 700 feet. Injection was maintained down the injection tubing/long string annulus, out the 1/4-inch hole in the long string and up the outside tubing, out the tubing through the profile nipple at 700 feet and through a channel in the mud to the surface of the ground.

Tool Test

The test was conducted with the Atlas Wireline 1 11/16-inch diameter oxygen activation tool located in the 2 3/8-inch injection tubing. Stationary "no flow" background gamma ray count rates were taken for both the long spaced (LS) and short spaced (SS) detectors at a depth of 1,075 feet, which was below the injection activity. Readings were taken during injection at depths of 300, 600 and 1,000 feet to determine both flow/no-flow and velocity.

A background count rate was computed for the 1,075 feet depth by determining the inelastic gamma ray and oxygen count rates for three no-flow measurements at this station. For each no-flow measurement, the ratio of the oxygen count rate to the inelastic count rate was computed, and the average of these ratios was determined. The result of this activity gives a long-space factor and short-space factor that are then multiplied times the measured inelastic long space and inelastic short space count rate, respectively, to compute the proper background.

After determining the background factor, the final part of the test involved injecting water down the tubing/long string annulus at different flow rates and determining what flow could be detected coming up the outside tubing, and through the channel in the mud from 700 feet to the surface of the ground.

Table B-12 is a summary of specific data taken during the test. The determination of interest during this investigation was a flow or

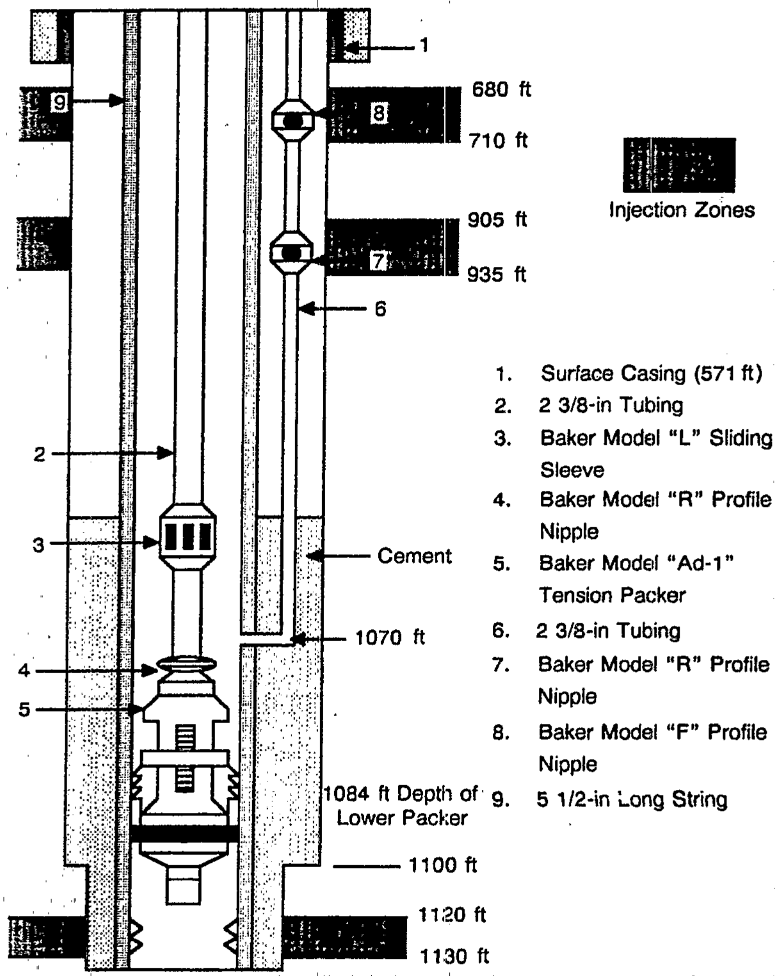

Figure B-36. Leak Test Well.

no-flow indication within both the outside tubing and the channel in the mud. The velocity data are of interest, although not critical to this series of tests.

The criterion for flow indication is that the long space count rate must be greater than 1.0 counts/second after subtracting the background reading. Thus, from Table B-12, flows were indicated at stations 3 (1,000 feet) and 4 through 9.

Table B-12. Oxygen Activation Log Data,, Leak Test Well – September 14, 1988

Depth (feet)	Station	Flow Ind. SS	Flow Ind. LS	Velocity	Comments
1075	0	-.61	.03	None	Below injection
1075	1	.16	-.01	None	Below injection
1075	2	.51	-.02	None	Below injection
1000	3	1.24	1.72	0	Tubing flow
1000	4	.89	1.68	0	Tubing flow
600	5	71.70	29.10	8.49 ft/min	Channel flow
600	6	71.17	26.19	7.66 ft/min	Channel flow
300	7	93.87	23.76	5.57ft/min	Channel flow
300	8	57.01	10.05	4.41 ft/min	Channel flow
300	9	62.19	10.07	4.20 ft/min	Channel flow

The tests began with a flow of approximately 20 gpm coming from the pump. Stations 3, 4, 6 and 7 were taken at that flow rate with the stations opposite the 2 3/8-inch outside tubing (stations 3 and 4) and the channel in the mud (stations 5, 6 and 7). Although flow was detected at each station, a much higher flow indication was seen at stations 5, 6 and 7. Stations 8 and 9 were taken opposite the channel but at a flow rate of about 10 gpm. A reduced flow indication is evident for these stations.

Conclusions

The 1 11/16-inch oxygen activation tool was successful in detecting flow at all stations, although the flow indication was much lower at the stations opposite the 2 3/8-inch outside tubing than in those stations opposite the channel in the mud system. This was probably due to the larger size of the mud channel.

Additional tests should be run with this tool in real wells to provide data for evaluating the total capability of the tool for detecting flow behind pipe.

*US GOVERNMENT PRINTING OFFICE:1990-748-159/20487 REPRINT