Engineering Report

INVESTIGATION TESTING AND REPAIR OF THE DEEP INJECTION WELL IW-1

At The
City of Margate Wastewater Treatment Plant

CITY OF MARGATE DEPARTMENT OF UTILITIES
Margate, Florida

Prepared By

CH2M HILL

June 1985

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Engineers
Planners
Economists
Scientists

CH2M HILL

Copy of:
Ron Reese

June 6, 1985

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U.S. Geological Survey
Florida Integrated Science Center
3110 SW 9 Avenue
Ft. Lauderdale, FL 33315

Mr. Jerry David
Director of Utilities
City of Margate
5790 Margate Boulevard
Margate, Florida 33063

Dear Mr. David:

Subject: Investigation, Testing, and Repair of the Deep Injection Well, IW-1, at the City of Margate Wastewater Treatment Plant

We are pleased to submit to you this engineering report on the investigation, testing, and repair of the deep injection well, IW-1. The repair has been completed in accordance with the requirements of Chapter 17-28 of the Florida Administrative Code, and the Technical Advisory Committee chaired by Mr. John Guidry of the Florida Department of Environmental Regulation. This report has been prepared to document the methods of investigation and repair that were performed to return the deep injection well to service.

This has been a most challenging project, and it has been completed in a satisfactory and economical manner. Our success in completing this project at a cost of approximately one half the amount originally bid by the Deepwell Construction Contractor is attributable to your personal interest and assistance in the management of this project. After months of investigations, planning, and meetings, and all the legal considerations, the actual repair was conducted smoothly and was completed within ten hours.

We would like to thank the Contractors involved, Messrs. Morton Tiley and Mark Tiley of Morton Well Drilling, Messrs. David Onan and Bruce Thomas of Halliburton Services, and those members of your staff who assisted in the execution of the work, Ms. Terry Tapley, Mr. Kipton Lockcuff, and Mr. Jack Brown.

The unusual nature of this project resulted in a great deal of involvement on the part of the City's management. Their assistance and understanding were essential to the effective and economical repair of the well. Our thanks to Mr. Tom Hissom, City Manager; Mr. Gene Steinfeld, City Attorney; Mayor Benjamin Goldner; Former Mayor Leonard Weisinger; and Commissioners Donohue, Starr, Anton, and Varsallone.

Very truly yours,

Thomas M. McCormick
Project Manager

J. I. Garcia-Bengochea
Project Director

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ENGINEERING REPORT

INVESTIGATION, TESTING, AND REPAIR OF THE DEEP INJECTION WELL IW-1 AT THE CITY OF MARGATE WASTEWATER TREATMENT PLANT

Prepared for

CITY OF MARGATE DEPARTMENT OF UTILITIES
Margate, Florida

Prepared by

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June 1985
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ACKNOWLEDGMENTS

The successful completion of this project, the first of its kind in south Florida, is the direct result of careful investigation and preparation on the part of many individuals. The foresight, understanding, and patience displayed by the members of the regulatory agencies were crucial to this success in that it allowed the time necessary for a careful approach to the problem. Those who played a key role in this achievement included:

- Mr. Roy Duke, District Manager, Florida Department of Environmental Regulation (FDER)
- Mr. John Guidry, Chairman of the Technical Advisory Committee
- Mr. Richard Deuerling, Ms. Leslie Bell, and Mr. Gardner Strasser, Hydrogeologists from FDER
- Mr. Jerry David, Director of Utilities, and Mr. Tom Hissom, City Manager, City of Margate
- Dr. Leslie Wedderburn, Deputy Director, and Mr. David Butler, Hydrogeologist, Resource Control Department, South Florida Water Management District
- Mr. Bruce Kester, Chief, Wastewater Section, Broward County Environmental Quality Control Board
- Mr. Morton Tiley and Mr. Mark Tiley of the Morton Well Drilling Division of Morton Pump and Supply
- Mr. Bruce Thomas, Division Engineer, and Mr. David Onan, Senior Chemist, from the Halliburton Services Company

Section 1
SUMMARY AND PURPOSE

This report describes the investigations, tests, modifications, and repairs that were performed on the City of Margate's deep injection well IW-1 following the determination in January 1983 that effluent had been detected in the annular monitor system. The injection well is located on the City of Margate WWTP site, as shown in Figure 1, Project Location, and Figure 2, Site Plan.

The initial investigations were completed in February 1983 and concluded that there was a small leak (10 to 15 gpm) through the cement surrounding the injection casing between 2,309 feet in depth and the bottom of the casing at 2,457 feet. A copy of the Phase I investigations report entitled, "Modifications to Deep Injection Well," is presented in Appendix A.

The Technical Advisory Committee (TAC), comprising representatives of the Florida Department of Environmental Regulation (FDER), the Broward County Environmental Quality Control Board (BCEQCB), the South Florida Water Management District (SFWMD), the Environmental Protection Agency (EPA), and the United States Geological Survey (USGS), met to review the data and the recommendations presented for the repair of the well. The TAC felt that any repair attempt would represent a substantial risk to the well and should not be undertaken without an environmentally acceptable backup system for effluent disposal.

In response to this concern and in consideration of a projected increase in plant capacity, the City of Margate elected to construct a new injection well and a new monitor well before attempting to repair the existing well.

Construction of the new injection well system, Margate injection well IW-2 and monitor well MW-2, by the Alsay Pippin Corporation commenced in March 1984 under FDER Permit No. UD 06-74984. The work performed under that project is detailed in the engineering report entitled, "Drilling and Testing of the Deep Well Injection and Monitoring Wells at the City of Margate Wastewater Treatment Plant," dated December 1984.

Preliminary testing of the selected repair method, the bullhead injection technique, was performed in October 1984. The repair of the well was completed in April 1985 under FDER Permit No. UC 06-066992. The selected bullhead injection technique has proven safe and effective. The City of Margate injection well IW-1 has been successfully repaired and may be returned to service.

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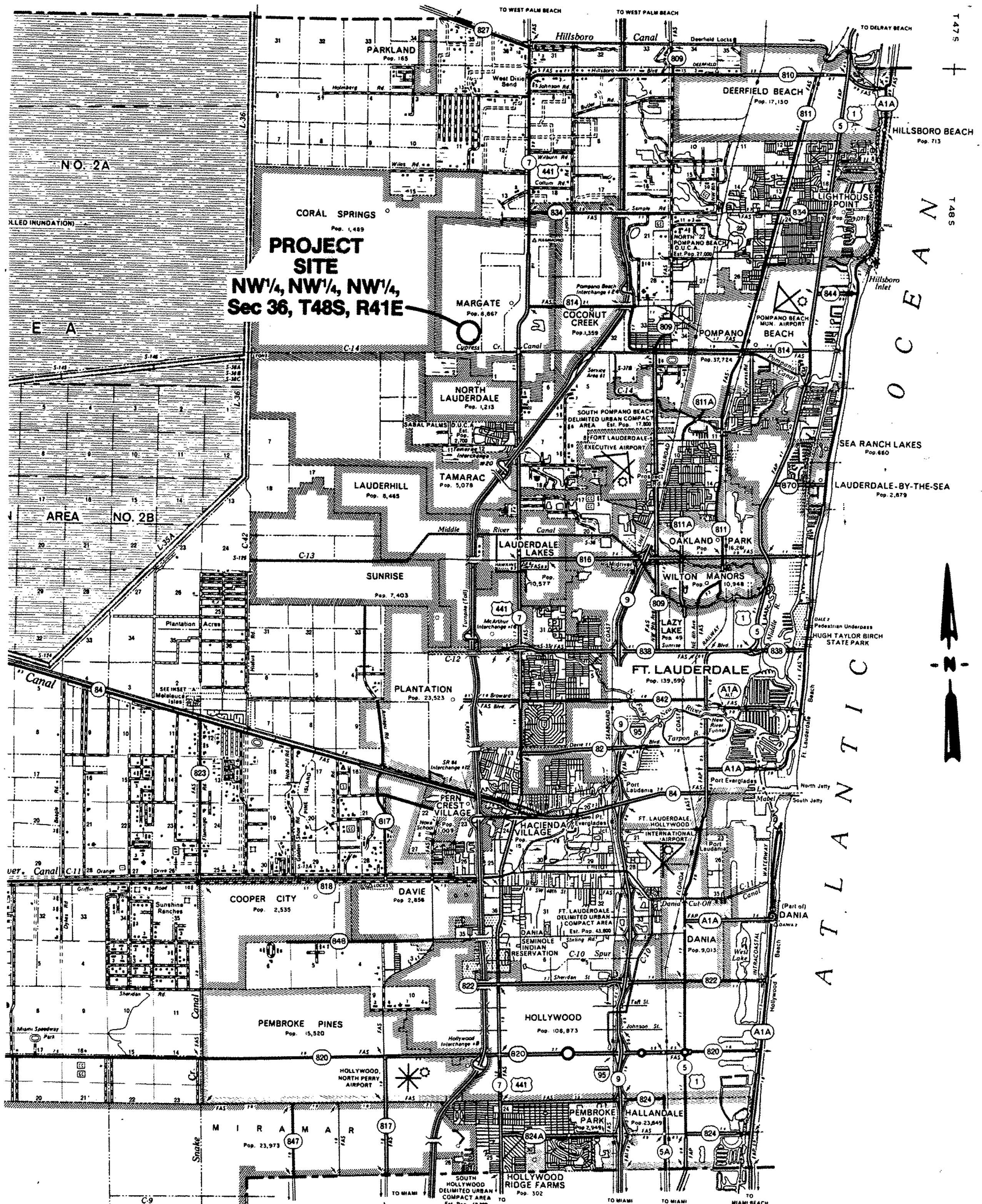

FIGURE 1.
Project Location.

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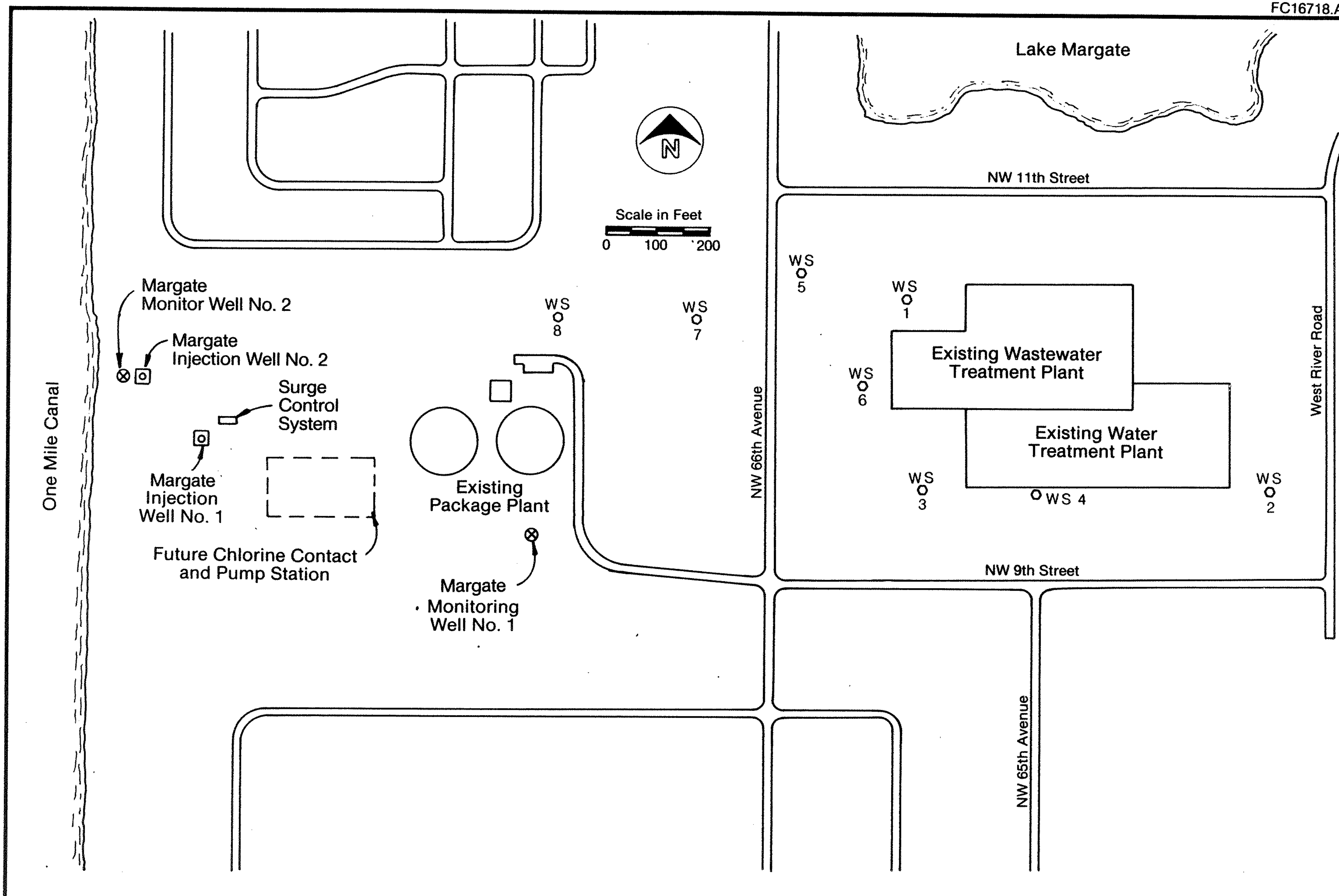

FIGURE 2.
Site Plan. CH2M HILL

Section 2
PROJECT BACKGROUND

The Margate Utility Authority System was constructed under Permit No. 6-453-73A issued by the Department of Pollution Control on September 6, 1973. The original system consisted of one 24-inch injection well, drilled to a depth of 3,200 feet, and one 9-5/8-inch-diameter deep monitoring well with monitor zones at 2,000 feet and 3,200 feet.

Construction of the original injection well, Margate IW-1, was completed in October 198~~4~~73. Following a period of sporadic operation to allow calibration of instruments, the injection well was first put into continuous service on February 12, 197~~5~~4. This was the third deep injection well constructed in south Florida for wastewater treatment plant disposal. However, two events occurred after completion that required modification of this system.

In July 1975, the effluent front arrived at the 3,000-foot zone of the monitor well. Freshening of the waters in the 2,000-foot zone also occurred. This phenomenon was identified as a result of a leak around the packer separating the two monitor zones within the monitoring well itself. Flowmeter logging performed in August 1975 confirmed the presence of a packer leak.

During investigations of the leak around the packer, evidence was gathered that indicated that there might also be active flow between the 2,000-foot zone and the monitor zone at 1,150 feet.

The decision was made to abandon both the 2,000-foot zone and the 1,150-foot zone and convert the well to monitor only 2,110 to 2,120 feet in depth. This work was performed in January 1978. The injection well system then operated without incident until January 1983 when a significant reduction in the conductivity of the annular monitor commenced.

The City immediately initiated investigations on the cause of and a remedy for the phenomenon. On January 26, a color video survey was run to a depth of 2,380 feet, the total depth possible with the survey equipment at that time. This video survey showed no defect in the casing, and no evidence of fluid exit from the casing to the annulus above 2,380 feet. Since the recorded cement top for the well was at 2,309 feet, it was determined that the logical path of fluid migration was around the bottom of the inner casing and through or around the cement seal at the base of the casing. The lower portion of the casing and the surrounding cement sheath was known to have been subjected to milling operations during construction.

Must be in IW-1 ?

A dye test was run by mixing 200 gallons of Rodamine WT dye into the effluent and injecting it into the well. Annulus withdrawals were visually monitored for 30 days thereafter with no visible fluid color change. This test provided further evidence that the effluent was not escaping through a casing failure.

The TAC then proposed to perform a second, more rigorous dye test to provide evidence of a direct connection to the annulus. Since the first test had been inconclusive, the TAC later decided that a second test would have little effect upon their decision to repair the well, and the requirement for performing a second dye test was dropped.

After the collected data had been reviewed, a report was presented to the TAC that concluded that the casing was intact, and that the most effective way to eliminate the leak was to plug the annular monitoring system, thereby restoring the integrity of confining beds between the next casing stage at 1,102 feet and the existing cement top at 2,309 feet (see Appendix A).

Section 3
DESIGN CONSIDERATIONS

Because the structural strength of the casing was in question, there was substantial concern that the repair attempt might result in damage to the well. The worst case consideration was the collapse of the well casing and loss of the well.

Since the injection well represented the main effluent discharge for the Margate wastewater treatment plant, it could not be taken out of service for any length of time to effect a repair. Providing for the discharge of the effluent in the event a casing failure occurred during the repair attempt became a major consideration in the analysis of the proposed repair techniques.

City review of the alternatives available resulted in the decision to construct a second deep injection system that would be placed in service before attempting the repair. This would ensure that an acceptable effluent disposal system would be available in the event of damage to the well during the repair attempt. It would also provide needed additional disposal capacity for a proposed plant expansion.

Three methods for sealing the annulus were available: cementing by tremmie, casing perforation and squeeze cementing, or cementing by the bullhead injection technique wherein cement is placed by pressure injection from the surface down and trapped fluids are displaced into the formation.

At the time the original well was constructed, vertically aligning the centralizers installed with casings was not standard practice; therefore, access to the annular space for a tremmie line was virtually eliminated. In addition, a substantial risk is associated with handling tremmie tubes in that they can be dropped or become stuck in the annulus, thus complicating the process of achieving a complete seal.

Casing perforation and squeeze cementing was eliminated from consideration because of expense and uncertainties concerning the structural strength of the casing. If a casing collapse occurred, the drill string and the squeeze tools could be trapped downhole, substantially complicating any attempt at repair.

Bullhead injection was selected as the repair technique posing the least risk to the well. Bullhead injection does not require the insertion of anything other than the plugging material into the annular space, but it also does not readily allow for the installation of intermediate stages of cement. Thus, the structure being cemented must be capable of withstanding the hydrostatic pressures generated by the placement of the full column of cement.

Because of this requirement, the condition of the 24-inch casing became a critical factor in the planning of the repair. This steel casing had been submerged in a saline environment for 10 years and there was no effective way to determine the actual ring strength remaining. To reduce the potential for casing collapse, a surface pressure restriction during cement injection into the annulus of 60 psi was established. This pressure was selected by assuming a loss of one-fourth of the thickness of the steel casing to corrosion and calculating the collapse pressure for a 3/8-inch thick steel casing.

To reduce the hydrostatic head imposed by the cement column, the lightest possible cement slurries were investigated. Low density coupled with low transmissivity were the qualities sought.

Spherelite cement met the design requirements and was initially recommended as the appropriate material for sealing the annular space. While estimating the cost for the material required, the selected Cementing Contractor, Halliburton Services, recommended that nitrogen foamed cement be considered because of economy, reduced cement losses, and the ability to produce a foamed cement of very low density and transmissivity.

The other basic requirement for successful bullhead injection of cement is that the downhole formations be sufficiently transmissive to receive the waters displaced from the annulus during cementing. This was assumed to be the case, based on data collected during the drilling of the original well.

After a presentation to the TAC, CH2M HILL prepared contract documents for the construction of a new deep injection well and for the repair of the existing injection well, Margate IW-1, by the bullhead injection of nitrogen foamed cement.

Copies of the meeting summaries from the relevant Technical Advisory Meetings are included as Appendix B.

Section 4
REPAIR OF THE INJECTION WELL

CH2M HILL prepared contract documents for the construction of a new deep injection well system and for the repair of the existing well. The project was bid on November 16, 1983, and a contract for the construction of the new injection system was awarded to the low bidder, the Alsay-Pippin Corporation.

The City of Margate felt that the prices submitted for the repair portion of the contract were not acceptable and the City chose to wait until construction of the new injection system was complete before attempting to negotiate a price, or rebidding the repair portion of the contract.

Drilling of the injection well commenced on March 23, 1984, and was completed on June 18, 1984. Installation of instrumentation and surge control systems was completed in August 1984. The layout of the effluent disposal system is shown in Figure 2.

At the time, an unsuccessful attempt was made to negotiate a change order for the repair of the well with the Alsay-Pippin Corporation. Rebidding the work was considered but rejected because of the time involved and the urgent desire of the regulatory agencies to have the repair completed as quickly as possible. The City then considered acting as its own prime contractor, but encountered resistance from both the subcontractors that were to perform portions of the work and from DER, which insisted that the repair work be performed by a licensed water-well contractor. To avoid further delay of the repair, CH2M HILL contracted with Halliburton Services to perform initial testing of the repair technique for the City.

In October 1984, 10 microcuries of Lanthium 130, a radioactive tracer, were mixed in 20 barrels of fracturing gel (used to approximate the density and consistency of the proposed cement mix), injected into the annulus, and followed by water to drive the mixture down the annular space. Movement of the tracer was tracked with a gamma tool. Copies of the logs performed during this test are included in Appendix C.

This test yielded important information about the well. The annulus was open to fluid flow to a depth of 2,230 feet, and the 60-psi pressure constraint established to protect against casing collapse was approached at very low pumping rates. The first item verified the potential for success of the bullhead injection technique, while the second caused considerable concern on the part of the cementing subcontractor, Halliburton Services.

In response to the concern expressed, CH2M HILL asked Halliburton to carefully review their calculations and procedures to ensure that the cement foam would not degenerate at the anticipated low rates of injection. Halliburton Services subsequently reviewed their cementing proposal and determined that they could not use a nitrogen foamed cement and stay within the 60-psi injection pressure constraint.

Because of the compressibility of the gas, nitrogen foamed cement behaves like a dynamic density fluid until it ceases to move within the hydrostatic column. The density of the fluid injected at the surface varies considerably from that of the fluid once it reaches its intended point in the annulus. Increasing hydrostatic pressure as the cement moves down the annulus compresses the gas and increases the density of the cement. To achieve the design density of the cement at a given depth, one must initially inject a cement mixture that is much less dense. The calculations to determine the appropriate density of cement to inject at any given point in the process are complex because the hydrostatic pressure exerted by the cement column itself varies considerably with depth and the amount of nitrogen entrained in the cement foam.

With bullhead injection, the native fluids in the annular space are displaced from the bottom of the column into the formation and the energy necessary to perform this work is reflected at the surface as pressure. As the fluid being pumped into the annular space decreases in density, there is a corresponding increase in pressure.

The glass beads used as the primary weight reduction material in spherelite cement are relatively insensitive to density distortion due to hydrostatic pressure. As a result, both the rate of injection and the injection pressure can be more closely controlled.

The City of Margate, Halliburton Services, and CH2M HILL met to review the available options and decided to proceed with the bullhead injection technique using a spherelite light weight cement in lieu of the nitrogen foamed cement. This decision substantially increased the cost of materials for the repair but allowed more accurate control of the rate of injection and the annular pressure.

Following this decision, the City then began negotiations with the Morton Drilling Division of Morton Pump and Supply

Company of Fort Lauderdale, Florida, for the repair of the well. These negotiations concluded in March 1985 and the repair of the well began on April 3, 1985.

The artesian head of both the annulus and the injection well was suppressed with brine. A cement bond log was performed on the inner casing to establish a basis for comparison. At the same time, the contractor commenced modification of the well head, cutting two additional valved cement ports into the annulus.

When this work was complete, the injection well was flushed with potable water, and a TV survey and caliper survey were performed to confirm the good condition of the casing. The annular space was flushed with potable water to displace the brine from the well to reduce any potential for flash set of the cements.

On April 8, 1985, Halliburton Services began onsite operations. Three lines were installed to the well, two to the pumping unit for injection of the cement, and the third to a mud pit to accommodate a pressure recorder and pressure relief valve system. Two pressure relief rupture disks designed to rupture at 58 psi were installed downstream of the pressure relief valves. During cementing, one of the valves was open and one closed. In the event of excessive pressure, the disk would rupture and cement would discharge into the mud pit. When pressure had been sufficiently reduced, that valve could be closed, the other system opened, and cementing continued.

A two-stage pumping system was used. One recirculating pump truck drawing from a series of bulk tankers discharged to a blending tanker. A second recirculating pump truck drew from the blending tanker and injected into the annular system. This allowed an accurate control of the density of the fluid and uniform distribution of the radioactive tracer. A recording densometer and a flowmeter in the discharge line from the second pump truck were used to control density and flow rates. In addition to the instrumentation, periodic grab samples from the mixing bins were checked for consistency and viscosity with an IMCO mud lab.

Four thousand gallons of bentonite spacer were injected into the annulus to flush any brine from the system. Ninety-eight sacks of neat cement tagged with 10 millicuries of Gold 198 radioactive tracer was then placed as a lead cement by the bullhead injection technique, followed by approximately 475 sacks of spherelite cement as a tail cement.

After an initial rise to 38 psi during the placement of the bentonite spacer, the pressure in the annulus stabilized at 19 psi. The pressure stayed constant until the injection of the lead cement commenced. At that time the annulus went on vacuum and the injection rate was stabilized between 6 and 7 barrels per minute. After 10,000 gallons of slurry had been placed, the annular pressure began to rise. The rate of injection was adjusted to maintain a low annular pressure. After 36,000 gallons of slurry had been placed, the annular pressure ceased to respond to a reduction in injection rate. Cementing was halted when annular pressure exceeded 50 psi. A total of approximately 38,000 gallons of cement slurry was pumped into the annular monitor system. Well head pressures, injection rates, and volumes recorded during the repair are presented in Figure 3.

Gamma logging during the injection showed a steady downhole progress of the tagged neat cement and the spherelite cement to a total recorded depth of 2,400 feet, 100 feet below the cement top indicated by the cement bond log.

The migration of the gamma peak to the 2,400-foot depth is shown in Figure 4. The peak was displaced past the gamma probe at 2,400 feet, and shortly thereafter, annular pressure began to rise rapidly. This may be interpreted as evidence that a channel existed in the cement sheath surrounding the base of the casing, as concluded two years earlier, and that the spherelite cement displaced a portion of the tagged neat cement through that channel. The rapid rise in annular pressure after the neat cement had been displaced through the channel is consistent with the superior lost circulation properties of spherelite cements.

A gamma log of the complete well run after cementing had been completed showed an increase in gamma activity above 2,260 feet in depth. The presence of unidentified debris in the wellbore at 2,447 feet restricted further downward movement of the gamma probe.

On the following day, the gamma, caliper, and TV survey were run to confirm the good condition of the casing. The spherelite cement was then allowed to stand undisturbed for 30 days to maximize its compressive strength and the bond to the casing. After 30 days, the cement bond log and the variable density log were run again.

The cement bond log run on May 8th, after the repair, shows an increased bonding between 2,300 feet and 2,175 feet in depth. This corresponds with the gamma log performed just after placement of cement. The gamma count indicated that neat cement was present to a depth of 2,150 feet. Above 2,175 feet, the signal travel time becomes erratic and the cement bond log appears to conflict with the response shown

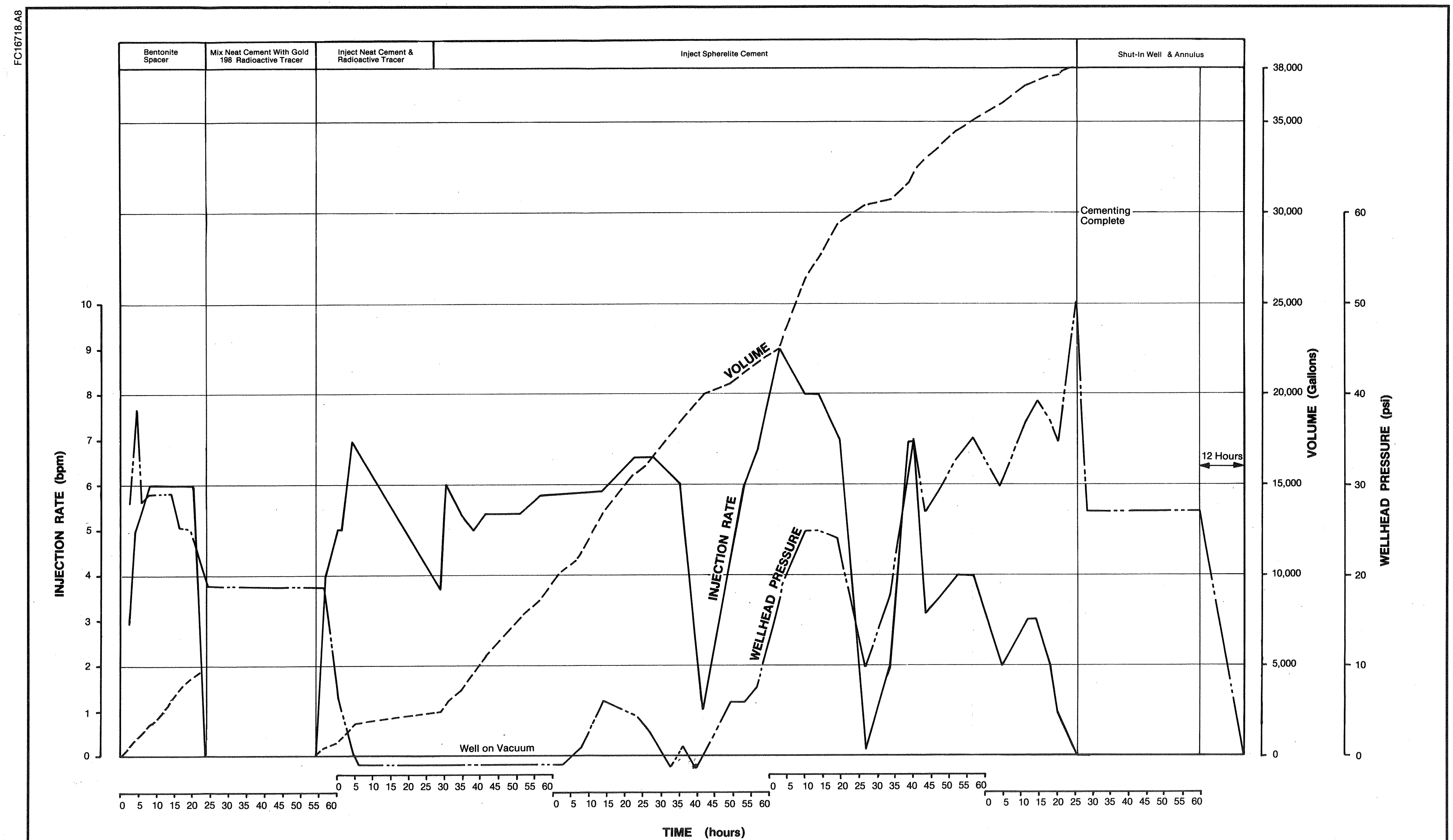

FIGURE 3.
Volume, Pressure, and Rate During Placement of Cement.

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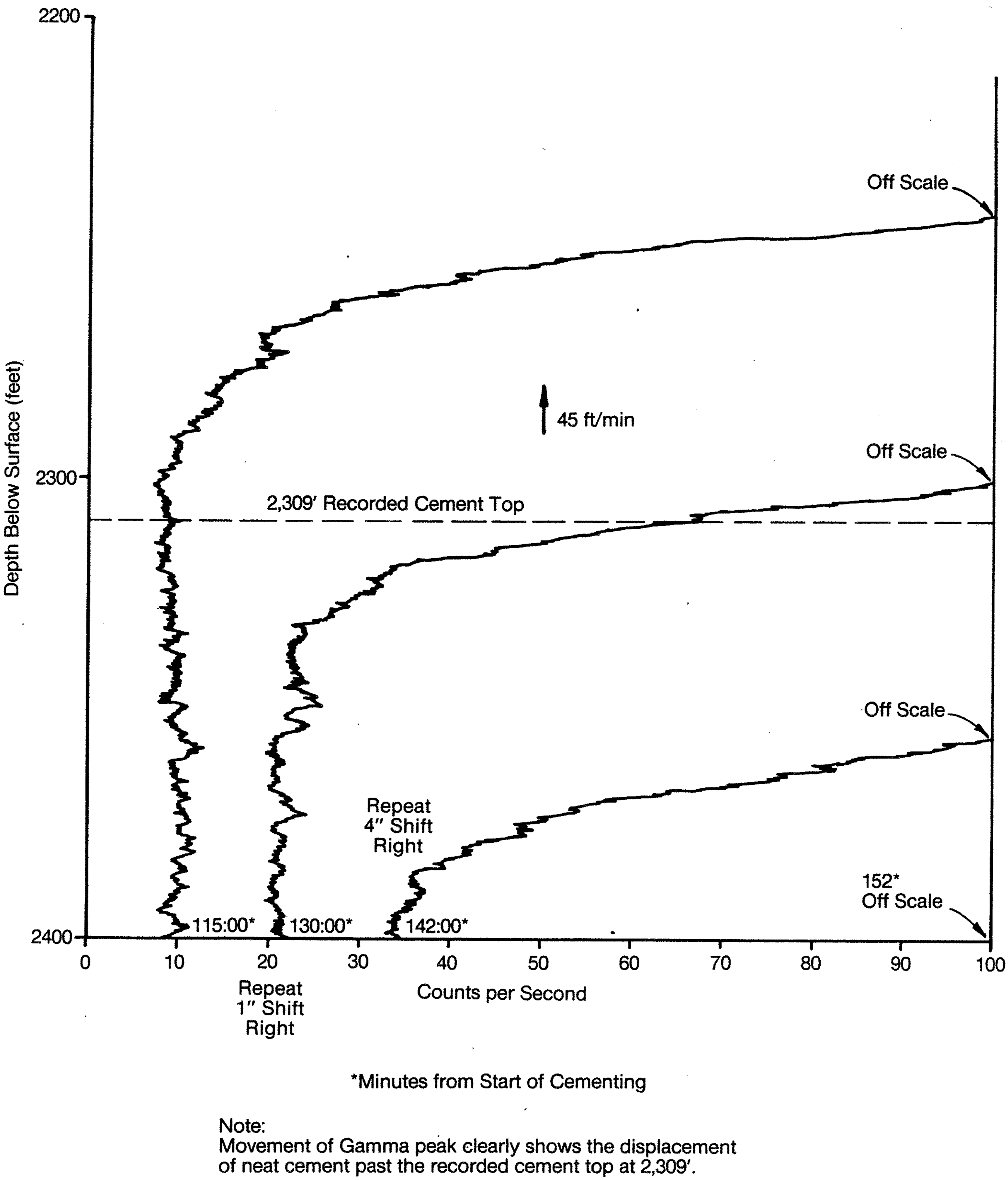

FIGURE 4.
Gamma Trace During Cementing.

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by the variable density log. The strong attenuation of the signal may be attributed to the high volume to solids ratio of the spherelite cement. Schlumberger noted a similar effect, strong attenuation of the signal, when logging through muds that contain gas.

By exhibiting this strong attenuation of signal throughout the cement column, the variable density log gives positive evidence that the spherelite cement has completely filled the annular space, including the pathway of the leak to a depth of 2,400 feet. Again, due to the unidentified debris in the well bore, it was not judged safe to run the tool below 2,400 feet.

The geophysical logs performed before, during, and after the repair are presented in Appendix D and confirm the success of the repair. The caliper and TV surveys show no damage to the casing, and an examination of the cement bond log and variable density log confirms the presence of the neat and spherelite cements in the annulus.

Margate Injection Well IW-1, as shown in Figure 5, may now be returned to normal operation. The Margate injection well system is now configured as shown in Figure 6. Operation and maintenance of the complete Margate Injection and Monitoring Well system should be performed in accordance with the guidelines presented in the Operation and Maintenance Manual for the Deep Injection and Monitoring Wells at the City of Margate Wastewater Treatment Plant, dated December 1984.

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NOTE: Unidentified pipe or casing fragment lodged in the well above at 2447′ below pad level represents a hazzard to the safe passage of logging tools. The well bore is not blocked.

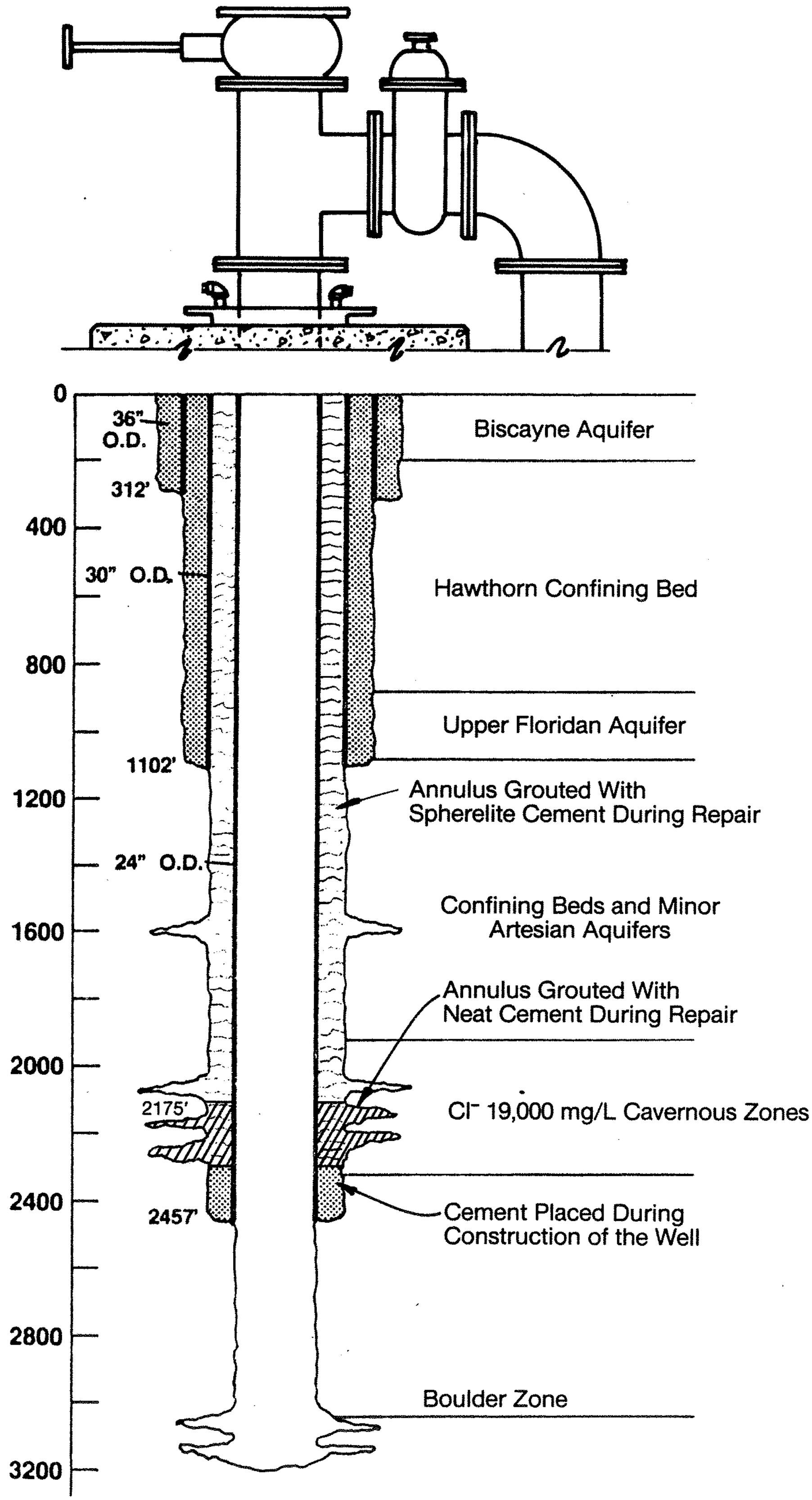

FIGURE 5.
Details of Repair, Margate Injection Well IW-1.

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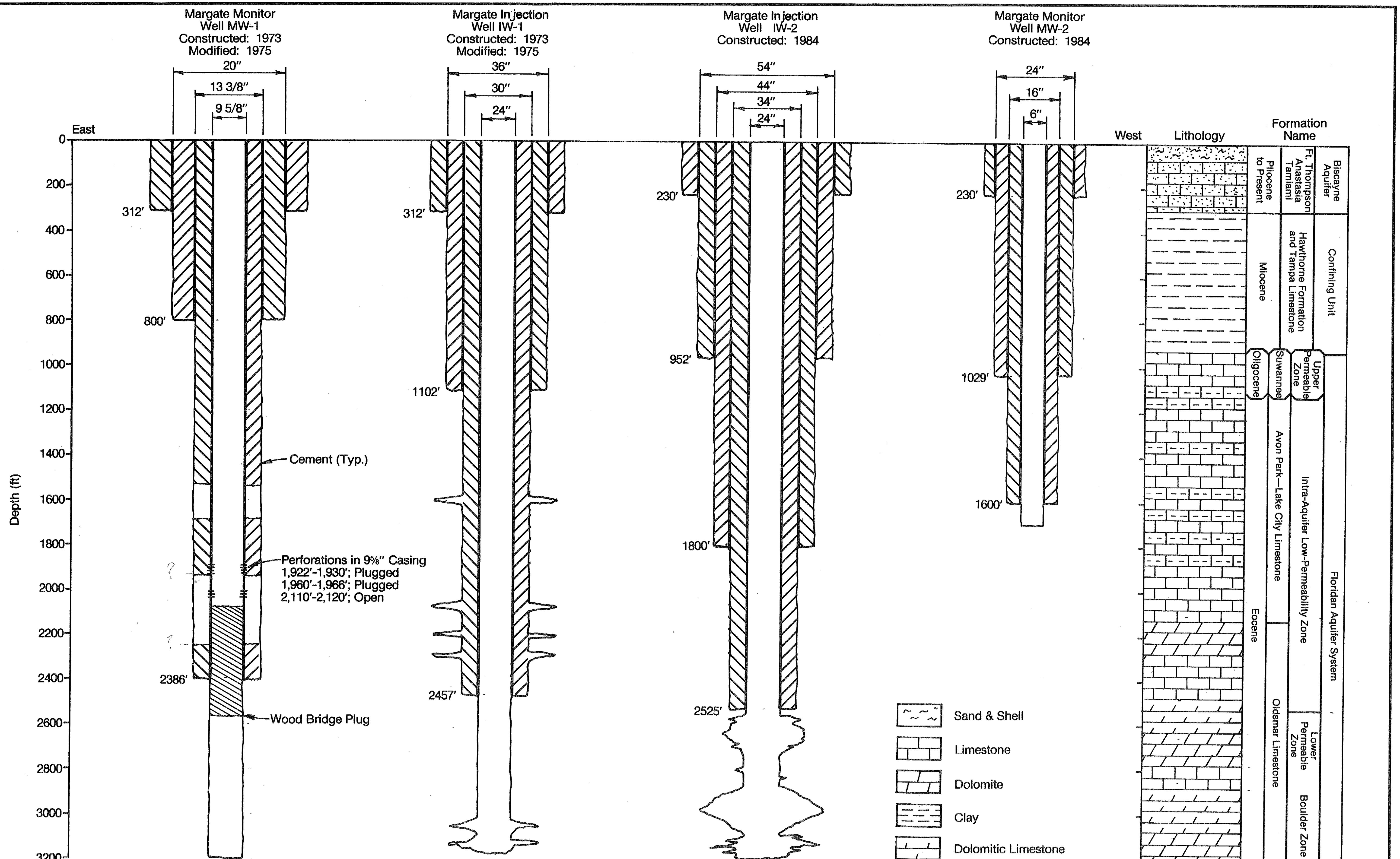

FIGURE 6.
City of Margate Injection and Monitoring Wells, Summary of Construction Details.

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Section 5
SUMMARY

Since the problem was first confirmed in January 1983, a great deal of thought and effort has gone into the development of an effective procedure for the abandonment of the annular monitoring system of Margate IW-1.

The selected bullhead injection technique has proven to be safe and effective. The City of Margate injection well IW-1 has been successfully repaired and may be returned to service.

Two conclusions may be drawn from the success of this project:

1. Annular monitoring systems are effective at early detection of small volume leaks.

2. If the need arises, such systems can be safely and economically abandoned by plugging via the bullhead injection technique.

Appendix A

REPORT ON INVESTIGATIONS FOR THE MODIFICATIONS TO THE DEEP INJECTION WELL

REPORT ON THE INVESTIGATIONS FOR MODIFICATIONS TO THE DEEP-INJECTION WELL

Prepared for

City of Margate, Florida

Prepared by

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February 1983

CH2M HILL
engineers
planners
economists
scientists

February 4, 1983

FC16718.A0

Mr. Jerry A. David
Director of Utilities
City of Margate
6441 N.W. 9th Street
Margate, Florida 33603

Dear Jerry:

Subject: Modifications to Deep-Injection Well
Phase I Investigations
City of Margate, Florida

This letter reports our findings from the referenced investigations authorized by your City Commission January 26, 1983. The project objectives and scope are stated in our letter proposal of January 24, 1983.

The results of the investigations are summarized as follows.

INNER CASING TELEVISION SURVEY

This survey was run the night of January 26 to 27, 1983 in accordance with the program included in Appendix I. This appendix also includes the video log recorded by us that night. We were able to reach a depth of 2,380 feet with the camera, the maximum depth possible with the available color equipment. That depth is within the zone where the inner casing is cemented, as indicated on the attached figure showing a diagram of your injection and monitoring wells. We could have gone deeper with black-and-white equipment but, as discussed at the Florida Department of Environmental Regulation Technical Advisory Committee (TAC) meetings of January 20 and 27, the color survey is much more informative.

The video survey does not show any defect in the casing down to 2,380 feet in depth, nor any transfer of water between the inner casing and the annulus above that depth. The video tapes are in our possession and are available for viewing any time.

MONITORING DATA REVIEW

We have reviewed the relevant monitoring data from both the monitoring annulus and your monitoring well. These data include the annulus pressure and conductivity and the monitoring well conductivity.

Appendix 2 shows a plot for the last 3 years (1980, 1981, and 1982) of the annulus pressure and the annulus conductivity from the continuous plant recording equipment.

Appendix 3 summarizes the annulus conductivity and the monitoring well conductivity data (from water port holes between 2,110 and 2,120 feet in depth) from May 1977 to December 1982 as determined by the City's wastewater laboratory.

Appendix 4 gives the daily annulus conductivity data for the month of January 1983 as determined by the City's wastewater laboratory.

Appendix 5 shows the E. coli variations from samples collected from the annulus since January 14, 1983, the first day the annulus had shown positive E. coli presence.
An evaluation of the above data indicates the following:

1. A freshening trend in the annulus (reduction in conductivity) began in May of 1982 and was accentuated on January 3, 1983. Appendix 3 seems to indicate a gradual freshening since the beginning of record in May 1977; however, this is misleading, because the annulus conductivity for the first year of continuous operation (1975) varied between 11,000 and 15,000.

2. The conductivity of the monitoring well after the 1978 modification and its stabilization around the 30,000 range has remained in that range. (Salt brine was pumped into the well during June and July 1978). There seems to have been a freshening of the well between December 1981 and September 1982, but the conductivity returned to the 30,000 range thereafter.

The freshening of the monitoring annulus and the E. coli results since January 14, 1983 indicate that a small amount of effluent is entering the annulus. This migration seems to be small, as there is a substantial difference in pressure between the inner casing (32 to 45 psi) and the annulus, which remains at 22 psi regardless of the rate of injection and the corresponding inner casing pressure. The pressure in the annulus has increased from an original level of around the lower teens due to the decrease in conductivity and consequent increase in density.

The logical path of this migration seems to be around the bottom part of the inner casing, where there is only 148 feet of cemented casing, the lower part of which was subjected to strenuous milling during construction approximately 10 years ago.

MEETINGS WITH TAC

Two meetings have been held with the Florida Department of Environmental Regulation Technical Advisory Committee (TAC). The purpose of the January 20, 1983 meeting was to inform the TAC members of the possibility of effluent migration; the purpose of the January 27, 1983 meeting was to present the results of the inner casing television survey and the preliminary evaluation of the above monitoring data. Summaries of these meetings are included in Appendix 6.

At both meetings it was pointed out that the migration does not threaten the quality of the potable water aquifer (Biscayne Aquifer) because of the double casing and cement sheath protecting it.

At the last meeting, we recommended that the monitoring annulus be cemented to stop the upward effluent migration and also to comply with the new FDER regulations (Section 17-28) which require total cementing of the inner casing to ground surface. Methods to accomplish this task were discussed and are detailed below.

Members of the TAC, at the meeting and during subsequent conversations, have indicated their desire to have a back-up system for effluent disposal. They suggested that a second well be constructed in accordance with Section 17-28 and that the present one (after cementing the annulus) be used as a standby and to record peaks.

WELL MODIFICATIONS

Two basic methods are available to cement the annulus: (1) emplace the cement by a tremie line, and (2) inject the cement slurry through an existing porthole at the top of the annulus between the 24- and 30-inch casings. These methods are discussed below. As noted by the TAC, these modifications need to be performed without discharging any effluent into the surrounding surface waters.

Tremie Method

This method would consist of the following:

1. Overcoming the annulus pressure by injecting heavy slurries with salt brine into the annulus.

2. Substituting the present well head tee with a temporary elbow to allow for the introduction of tremie lines in the annulus while the well is operating.

3. Lowering tremie lines into the annulus and gradually injecting layers of cement into it until the entire depth is filled.

4. Replacing the temporary wellhead elbow with the permanent T to allow for cement bond and other types of logging which would confirm that the entire annulus is full of cement.

We have discussed this method with potential contractors and estimate that it would cost between $200,000 to $250,000 and would require 45 to 60 days.

Cement Injection

The cement injection method from a top porthole (also known in the oil fields as the "bull head" method) would consist of the following:

1. Confirming the flow path of injected fluids from the top of the annulus all the way to the cavernous zone between approximately 2,309 and 2,000 feet in depth.

2. Injecting an ultra-lightweight cement slurry (±8.5 pounds per gallon) into the annulus to fill it completely from bottom to top.

3. Running a cement bond or equivalent geophysical log to confirm that the entire annulus is full of cement.

We have discussed this method with the Halliburton Company, which specializes in all types of well cementing worldwide. They recommended the use of either "Spherelite" cement or "foam" cement. Of the two, the foam cement seems advantageous over the Spherelite in terms of both cost and flexibility. It is estimated that this procedure would cost between $100,000 and $150,000 and would require approximately 5 and 10 days for completion.

Technical and commercial information on both the spherelite and the foam cement is included in Appendix 7.

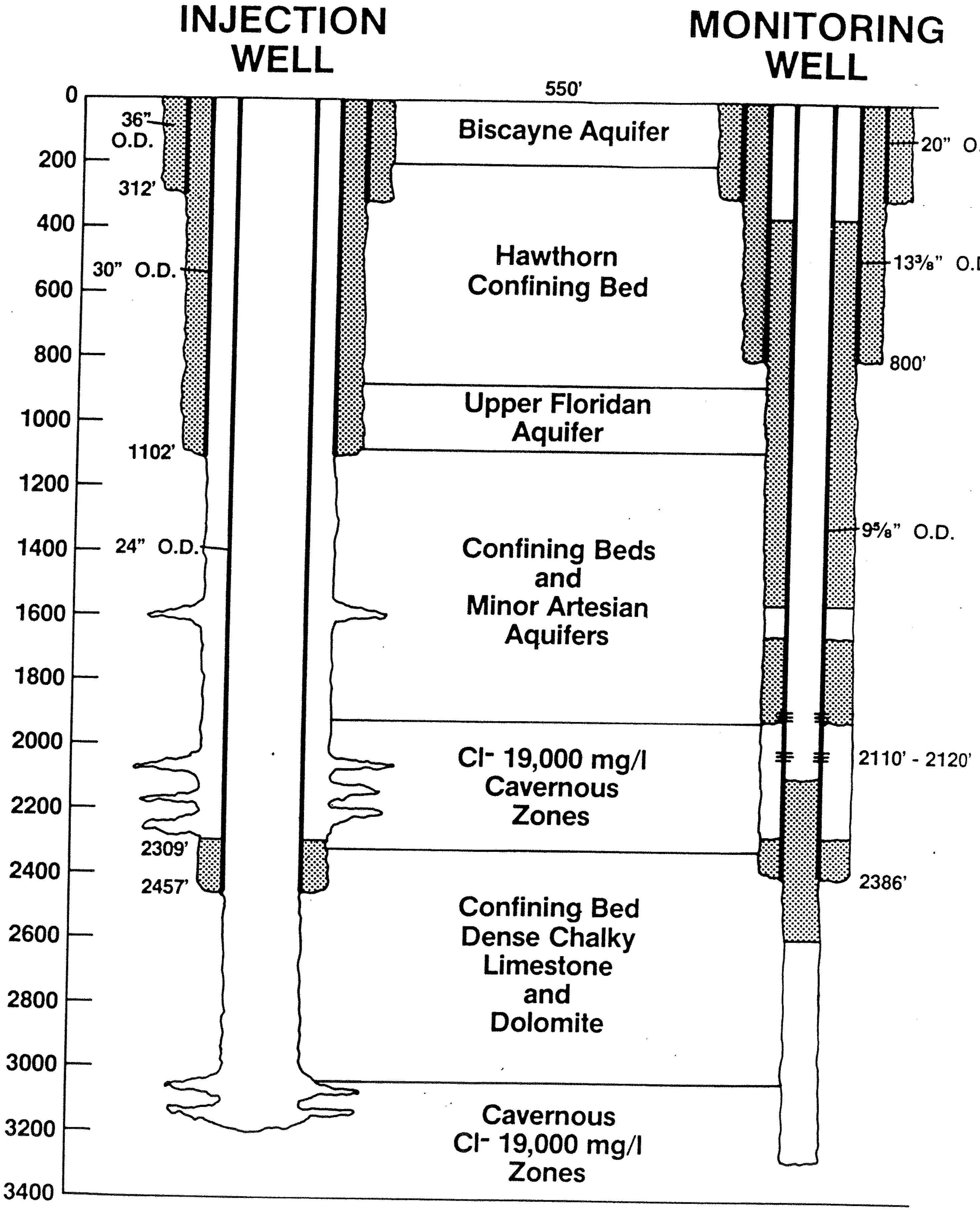
It is our recommendation that you review this letter report before its submittal to TAC indicating our preference for using injection of the foam cement for the required well modifications. A detailed set of specifications will be required for the program, clearly describing the work to be done.

We wish to commend your personnel for their promptness, speed, and effectiveness in preparing the well to be televised. The task required the acquisition and installation of heavy fittings, piping, and valves and was accomplished in 3 days. They also were most helpful during the television survey.

Sincerely,

J. I. Garcia-Bengochea, P.E.

gad/GNLR2
xc: Tom Hissom



MARGATE DEEP INJECTION AND MONITORING WELLS

1/24/83

INVESTIGATIONS FOR MODIFICATIONS
TO THE
DEEP-INJECTION WELL
CITY OF MARGATE, FLORIDA

APPENDIX 1
TELEVISION SURVEY OF 24-INCH INNER CASING

February 4, 1983

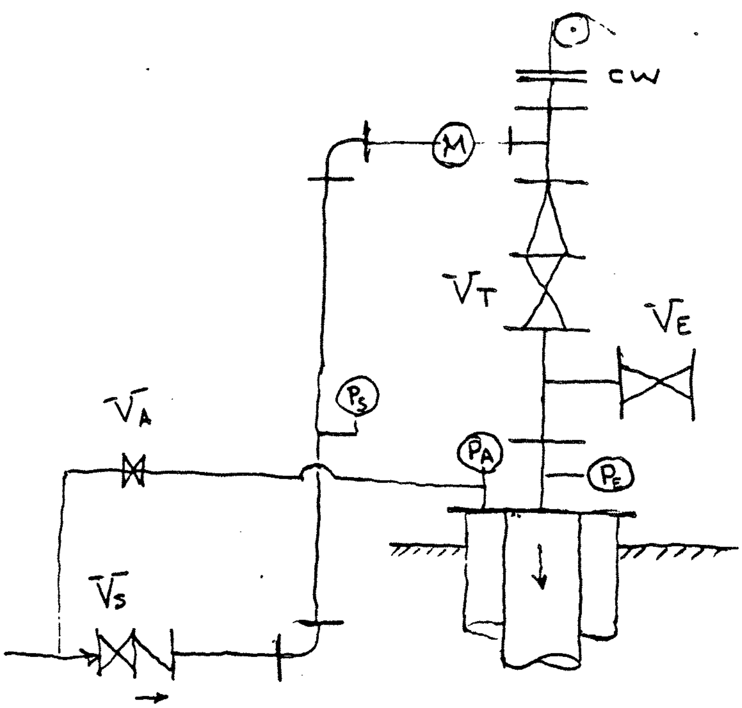
APPENDIX 1

FE16718.AD

CITY OF MARGATE
TELEVISION SURVEY OF DEEP-INJECTION WELL[1]
by

Larry and Jim Hayden, Operators
Deep Venture Divin Service
Perry, Florida.

Started 3[30]PM
January 26, 1983
Completed 4[20]AM
January 27, 1983



Program: Start with V_A, V_S and V_T closed, V_E open. Then:

1. Lower TV Camera between Cable Wipe (CW) and Valve V_T
2. With V_E open & V_T closed, normal op $P_A = 21.8$ $P_E = 41.5$ psi (2 pumps
3. Check CW by cracking V_S with V_T closed. $P_S = 80$ psi
4. When WWTP flow goes down (10[30]PM). stop injection pumps. $P_E = 31.5$ psi (5 bbl
5. Close V_E, equalize P_S with P_E by cracking V_S again & closing it.
6. Open V_T, lower camera to ground level. (G.L.)
7. Start opening V_S until Water meter (M) indicates ± 1000 gpm (2)
8. Waite ± 10 min, check clarity of TV picture. If OK start survey 10[15] AM
going down. $P_A = 22$ $P_E = 32$ psi
9. When reach end of survey (2:45AM), open V_a to bring P_a to approximately 40 psi. (Could not get it above 33 psi)[3]
10. Waite 15 minutes and start bringing camera up.
11. When camera reaches G.L. close V_a and V_S (4[20] AM)
12. Bring camera above V_T Close V_T. Open V_E.
13. Disconnect V_a from P_A
14. Resume injection (± 5[00] AM)
15. End of survey (5[30] AM)

(1) See all foot notes at bottom of page 3/3 of this Appendix 1.

CITY OF MARGATE
TELEVISION SURVEY OF DEEP-INJECTION WELL

VIDEO LOG by JICB & CRS

Depth in Feet		Reel Counter Reading		
From	To	From	To	Remarks
0	0			Ground level
0	99	0	165	Casing with sealing(4) - Joint @99'
99	139	165	214	" " " - Joint @139'
139	179	214	270	" " " @179'
179	214	270	300	" " " @214
214	249	300	333	" " " @249
249	290	333	371	" " " @290
290	332	371	405	" " " @332
332	375	405	434	" " " @375
375	419	434	463	" " " @419
419	463	463	495	" " " @463
463	504	495	557	" " " @504
504	548	557	598	" " " @548
548	590	598	653	" " " @590
590	631	653	677	" " " @631
631	671	677	710	Very hard to see joint(5). @671
671	710	710	737	Casing with sealing Joint @710
710	752	737	759	@752
752	766	759	766	Light bulb blew up @ 11^{45} PM Pulled out & went back 1^{10} AM
766	794	766	787	Casing with sealing, joint @ 794
794	832	787	814	" " " " 832
832	868	814	833	" " " " 868
868	910	833	855	" " " " 910
910	952	855	873	" " " " 952
952	994	873	890	" " " " 994
994	1037	890	908	" " " " 1037
1037	1079	908	947	" " " " 1079
1079	1124	947	955	Problems with TV depth numbers 1124
1124	1251	955	1020	ABEA - depths from cable " 1251
1251	1291	1020	1046	ABIA " " " " 1291
1291	1329	1046	1075	ACBI " " " " 1329
1329	1412	1075	1108	" " " " 1412
1412	1500	1108	1137	" 1500
1500	1600	1137	1174	PPPI " " "
1600	1624	1174	1184	PPCC " " " " 1624
1624	1662	1184	1204	Casing with sealing & joint at 1662
1662	1703	1204	1226	" " " joint @ 1703
1703	1747	1226	1242	" " " joint @ 1747
1747	1788	1242	1258	" " " joint @ 1788
1788	1830	1258	1273	" " " joint @ 1830
1830	1868	1273	1287	" " " joint @ 1868
1868	1905	1287	1302	" " " joint @ 1905

CITY OF MARGATE
TELEVISION SURVEY OF DEEP-INJECTION WELL

VIDEO LOG by JIGB & CRS

Depth in Feet From	Depth in Feet To	Reel Counter Reading From	Reel Counter Reading To	Remarks
1905	1939	1302	1316	Casing with scaling (4), joint at 1939
1939	1981	1316	1334	" " " " " 1981
1981	2021	1334	1348	" " " " " 2021
2021	2063 ✓	1348	1364	" " " " 2063
2063	2097 ✓	1364	1388	Large white marks on scaling
2097	2106 ✓	1388	1400	Joint looks diffrent. Will check it up.
2106	2150	1400	1429	Casing coated with scaling, joint @ 2150
2150	2185 ✓	1429	1452 ✓	" " " " " 2185
2185	2228 ✓	1452	1473	" " " " " 2228
2228	2267 ✓	1473	1493	" " " " " 2267
2267	2303 ✓	1493	1509	" " " " " 2303
2303	2336 ✓			" " " " " 2336
2336	2374	1509	1547	" " " " " 2374
2374	2380	1547	1561	2:45 AM End of cable

At 2:50 AM gave annulus $P_A = 33$ psi Opened 2" through 1" pipe & brought $P_E = 20$ psi
At 3:10 AM starte going up.
Checks above are with figures going down (same depths). Put new tape

	2149		317	No difference observed coming up
	2106		350	
	0000		1186	4:20 AM reached GL. Pulled camera above V_T Closed V_T, started injection at approximately 5:00 AM

Dissambled CW and pulled camera out
Left site at 5:30 AM

NOTES

(1) Witnessed by Jerry David, C.R. Sproul & J.I. Garcia-Bengochea

(2) Flow went way above 1000 gpm (+ 6000 gpm) very quickly after started opening V_S, started closing it back. At 11:15 PM it was checked at 3520 gpm, closed V_S further and at 11:25 PM it was 2200 gpm. Left it at this rate, V_S was open then 3½ turns

(3) At that time 2:45 AM. Totalizer of meter was read and total volume of potable injected had been 149,000 gallons. Decided to bleed inner casing and brought P_E to 20 psi

(4) Scaling seems white soft coating with darker spots, similar to that one observed in Sunset Park, Dade County, 1978. Which was $CaCO_3$.

(5) Joint almost covered by white coating

INVESTIGATIONS FOR MODIFICATIONS
TO THE
DEEP-INJECTION WELL
CITY OF MARGATE, FLORIDA

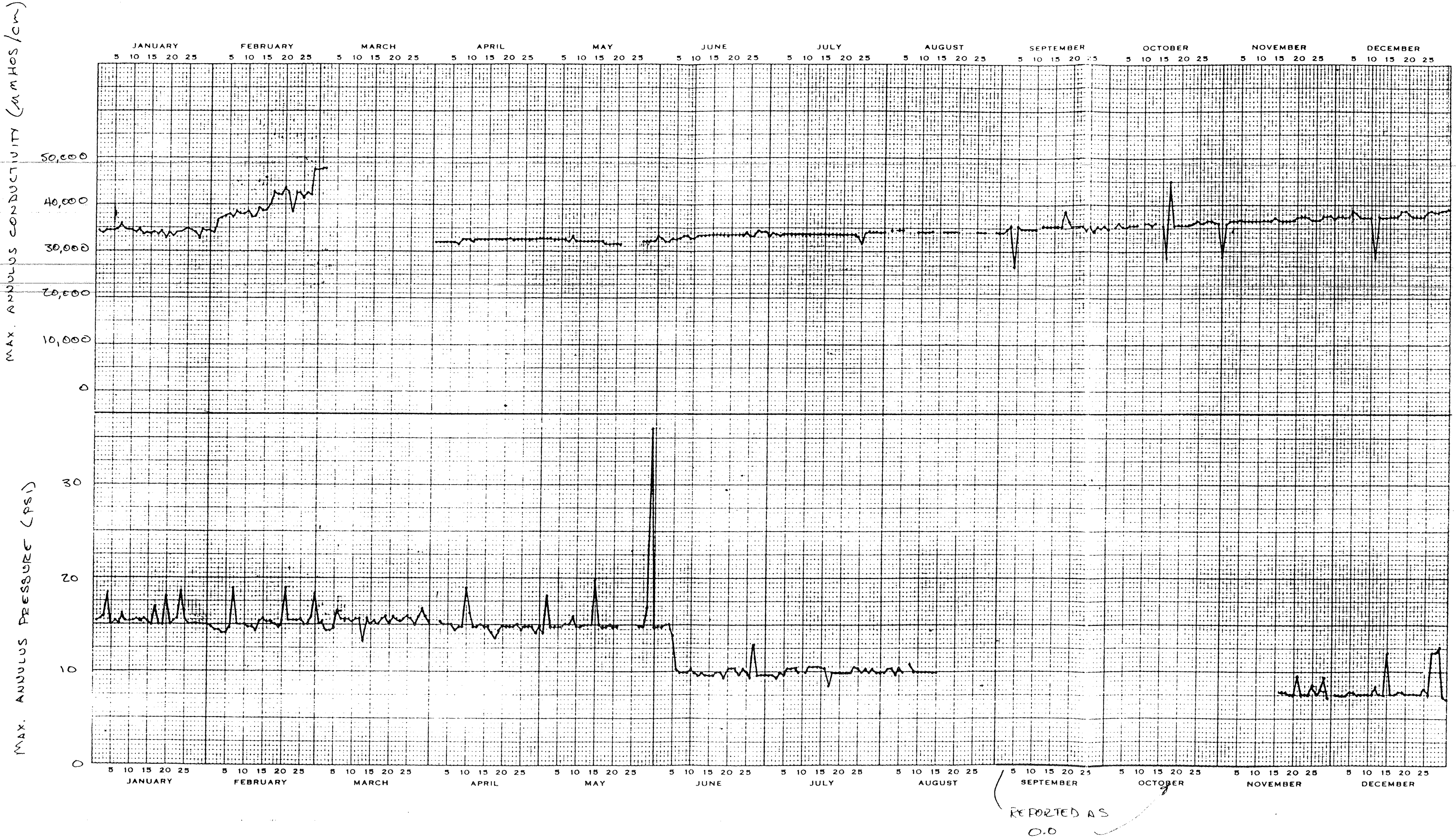
APPENDIX 2

Page 1/3 Annulus Pressure and Conductivity Data from the Plant Recording Instrumentation--1980

Page 2/3 Annulus Pressure and Conductivity Data from the Plant Recording Instrumentation--1981

Page 3/3 Annulus Pressure and Conductivity Data from the Plant Recording Instrumentation--1982

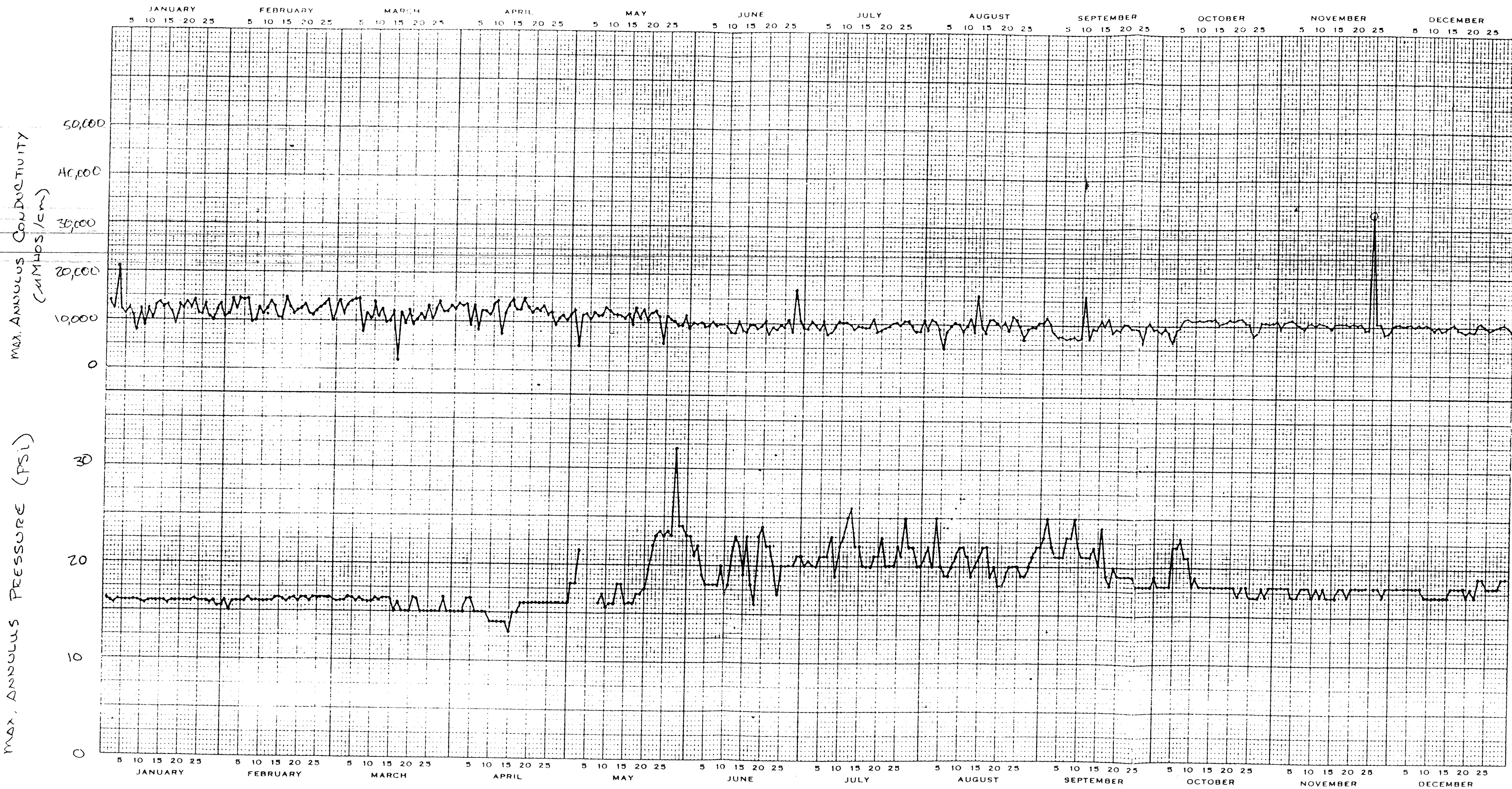
February 4, 1983



MARGATE 1980

RECORDED AS
0.0 PSI

MARGATE 1981



MARGATE 1982

INVESTIGATIONS FOR MODIFICATIONS
TO THE
DEEP-INJECTION WELL
CITY OF MARGATE, FLORIDA

APPENDIX 3

Page 1/2	Monthly Average Annulus Conductivity Measured at the Wastewater Plant Laboratory
Page 2/2	Monthly Average Monitoring Well Conductivity Measured at the Wastewater Plant Laboratory--Samples from 2,110 to 2,120 feet in depth

February 4, 1983

Appendix 3
MONTHLY AVERAGE ANNULUS CONDUCTIVITY
MEASURED AT THE WASTEWATER PLANT LABORATORY

1977	
May	23,000
June	22,300
July	22,500
August	22,300
September	21,000
October	21,000
November	20,000
December	21,000

1978	
January	20,000
February	19,300
March	17,500
April	19,000
May	18,000
June	18,000
July	17,000
August	16,200
September	17,500
October	19,000
November	18,000
December	14,000

1979	
January	15,500
February	12,600
March	18,000
April	14,000
May	15,000
June	12,000
July	15,000
August	15,000
September	15,500
October	14,000
November	14,000
December	13,500

1980	
January	15,000
February	13,000
March	15,000
April	12,600
May	15,500
June	19,000
July	16,300
August	12,800
September	16,000
October	16,000
November	16,000
December	13,000

1981	
January	15,000
February	15,500
March	16,500
April	16,000
May	12,500
June	15,500
July	15,000
August	14,500
September	18,500
October	13,200
November	13,300
December	11,900

1982	
January	12,300
February	12,400
March	11,700
April	12,000
May	11,300
June	9,500
July	9,500
August	9,800
September	9,100
October	10,300
November	10,200
December	9,800

Appendix 3--Continued
MONTHLY AVERAGE MONITORING WELL CONDUCTIVITY
MEASURED AT THE WASTEWATER PLANT LABORATORY--
SAMPLES FROM 2,110 TO 2,120 FEET IN DEPTH

1977	
May	6,950
June	7,200
July	11,450
August	12,100
September	8,750
October	10,200
November	9,600
December	11,000

1978	
January	10,800
February	12,800
March	13,000
April (11)	16,750
April (21)	3,100
May	4,400
June	(leak
July	repaired)
August (28)	41,000
September	40,000
October	44,000
November	39,000
December	36,000

1979	
January	36,000
February	37,000
March	33,000
April	35,000
May	33,500
June	32,000
July	29,500
August	39,000
September	38,000
October	36,000
November	36,000
December	35,000

1980	
January	36,500
February	28,000
March	29,000
April	34,000
May	37,000
June	45,000
July	27,000
August	29,900
September	32,000
October	32,000
November	29,000
December	33,000

1981	
January	36,000
February	32,000
March	32,000
April	28,500
May	33,000
June	33,000
July	26,000
August	27,500
September	35,000
October	23,000
November	33,000
December	22,500

1982	
January	22,000
February	30,000
March	26,000
April	21,000
May	24,500
June	27,000
July	21,000
August	12,500
September	9,800
October	35,000
November	30,000
December	33,000

1983	
January	32,500

INVESTIGATIONS FOR MODIFICATIONS
TO THE
DEEP-INJECTION WELL
CITY OF MARGATE, FLORIDA

APPENDIX 4

Daily Annulus Conductivity Measured at the Wastewater Plant Laboratory--January 1983

February 4, 1983

Appendix 4
DAILY ANNULUS CONDUCTIVITY MEASURED AT THE WASTEWATER PLANT LABORATORY--JANUARY 1983

January 1983	
1	10,200
2	9,600
3	4,300
4	3,800
5	3,600
6	3,500
7	3,400
8	3,600
9	2,800
10	3,350
11	3,400
12	3,300
13	2,700
14	3,000
15	3,000
16	2,850
17	2,950
18	2,950
19	3,000
20	3,200
21	3,200
22	3,300
23	3,250
24	2,600
25	3,300
26	3,000
27[a]	330[a]
28[a]	400[a]
29	3,500
30	3,500
31	3,000
February 1983	
1	4,000
2	3,900
3	3,700

[a]Pumped freshwater into annulus between 2:45 a.m. and 4:30 a.m. of January 27, 1983 for underwater TV survey.

INVESTIGATIONS FOR MODIFICATIONS
TO THE
DEEP-INJECTION WELL
CITY OF MARGATE, FLORIDA

APPENDIX 5

Daily E. Coli Results--Samples from Monitoring Annulus Determined by Plant Laboratory

February 4, 1983

Appendix 5

DAILY E. COLI RESULTS--SAMPLES FROM MONITORING ANNULUS DETERMINED BY PLANT LABORATORY

1-14	228
1-15	335
1-16	70
1-17	5,038
1-18	470
1-19	100
1-20	400
1-21	100
1-22	<10
1-23	<10
1-24	20
1-25	130
1-26	50
1-27	<10
1-28	No Sample
1-29	70
1-30	100
1-31	100
2-1	40
2-2	40

INVESTIGATIONS FOR MODIFICATIONS
TO THE
DEEP-INJECTION WELL
CITY OF MARGATE, FLORIDA

APPENDIX 6

Summaries of Meetings with TAC

February 4, 1983

SUMMARY OF MEETING

CH2M HILL

DATE: January 20, 1983

SUBJECT: City of Margate Injection Well

PROJECT: FC242.B2

LOCATION: DER Offices, West Palm Beach

ATTENDING:
Bruce Kester, BCEQCB, Broward County
John Guidry, DER, West Palm Beach
Gardner Strasser, DER, West Palm Beach
Jerry A. David, City of Margate
Richard J. Deuerling, DER, Tallahassee
Craig Brown, EPA, Atlanta
Fred Meyer, USGS, Miami
Abe Kreitman, SFWMD, West Palm Beach
Leslie Wedderburn, SFWMD, West Palm Beach
Phil Waller, CH2M HILL, Gainesville
J. I. Garcia-Bengochea, CH2M HILL, Gainesville
J. M. Dumeyer, CH2M HILL, Boca Raton
Jeff Lehnen, CH2M HILL, Gainesville

Summary prepared by Jeff Lehnen, January 25, 1983.

1. Garcia-Bengochea gave a summary of the construction details of the injecton well and operating data. The annulus water quality has freshened to about 3,000 μmhos/cm of specific conductivity. However, the pressure has not risen above approximately 20 to 21 psi. Injection pressure is approximately 35 psi with one pump injecting and 44 psi with two pumps.

   He also pointed out that the bottom (14 feet) of the 24-inch casing was milled during construction (1973) because it had been flattened while being installed.

2. It may be possible to cement the annulus either by tremie pipes or by "bull-head" using Halliburton spherelight cement. The first method would be much better if possible.

3. TAC concern is the integrity of the well. They suggest a TV survey first, a cement bond log after cementing, and a pressure test of the 24-inch casing. Garcia-Bengochea expressed that it would be very difficult and expensive to run the pressure test.

4. TAC also suggested that planning for emergency disposal and for the future increased flow rates be addressed as part of this work. They raised the possibility of a second well to satisfy the above.

5. The next tentative TAC meeting was set for February 1, 1983, or before if at all possible.

ja/GNCR5

SUMMARY OF MEETING

CH2M HILL

ATTENDEES: Thomas Hissom/City of Margate
Jerry David/City of Margate
Bruce Kester/BCEQCB, Ft. Lauderdale
Leslie Wedderburn/SFWMD, West Palm Beach
Gene Coker/EPA, Atlanta
John Guidry/DER, West Palm Beach
Roy Duke/DER, West Palm Beach
Fred Meyer/USGS, Miami
Leslie Bell/DER, Tallahassee
Gardner Strasser/DER, West Palm Beach
Larry Hayden/Deep Venture, Perry
Jim Hayden/Deep Venture, Perry
Ross Sproul/CH2M HILL
J. I. Garcia-Bengochea/CH2M HILL

DATE: January 27, 1983

LOCATION: Howard Johnson Motor Lodge, SR 84 & I-95, Ft. Lauderdale, Florida

SUBJECT: Margate Deep Injection Well

PROJECT: FC16718.A0

Summary prepared by C. R. Sproul, February 3, 1983.

1. CH2M HILL provided handouts showing:

   a. Tabulation of 1977-1982 monthly laboratory determinations of conductivity in the 2,000-foot monitor zone

   b. Tabulation of 1977-1982 monthly laboratory determinations of annulus conductivity

   c. Tabulation of January, 1983 E. Coli data for annulus samples

   There are some indications that conductivity in the injection well annulus began to drop in late 1981. However, the first clear indications of freshwater in the annulus occurred late in May 1982.

2. CH2M HILL reviewed the results of the color television inspection of the injection well 24-inch casing. The survey reached a depth of 2,380 feet, which is 71 feet below the top of the cement outside the casing. Surveys were run both with the well static and when water was being pumped into the annulus.

The interior of the 24-inch casing has a light to moderate coating of a light-colored substance (probably $CaCO_3$) with darker blotches. Most of the welded joints could be seen clearly. No indications were seen of a break of leak in the 24-inch casing.

3. Alternatives for repair of the well were presented and discussed. These include:

   a. Take well out of service (discharge to canal) and place cement in the annulus through tremie pipe

   b. Modify well head to allow tremie cementing of the annulus without taking well out of service

   c. "Bullhead" squeeze cement from surface, without taking well out of service

   Bruce Kester (BCEQCB) stated that the Broward County would not be in favor of any alternative that required discharge to the canal system.

4. Roy Duke (DER) summed up the committee's present position as follows:

   a. A backup injection well is needed to accommodate flow from proposed expansion of Marge WWTP.

   b. Additional monitoring is needed, at 2,000-zone and 1,600-zone.

   c. The committee would consider continued operation of the well in its present condition for some reasonable length of time until a backup well could be constructed.

   d. No grant money is available for 1983. A grant in 1984 may be possible; an application to establish priority should be pursued now.

5. CH2M HILL will review data, discuss well repair methods with well cementing experts, and present recommendations to the City of Margate by February 7, 1983.

INVESTIGATIONS FOR MODIFICATIONS
TO THE
DEEP-INJECTION WELL
CITY OF MARGATE, FLORIDA

APPENDIX 7

Technical Information on Ultra-light Slurries

February 4, 1983

OIL&GAS JOURNAL

TECHNOLOGY

Reprinted from the February 2, 1981 edition

Microspheres cut density of cement slurry

W. M. Harms
Halliburton Services
Duncan, Okla.

J. T. Lingenfelter
Halliburton Services
El Centro, Calif.

Past attempts to fulfill the long recognized need for pressure stable, extra-low density (8-12 lb/gal) cementing slurries which would develop adequate compressive strength have enjoyed limited success. Under these demanding conditions the commonly available light weight slurries typically result in low strength development over a long period of time.

Recently, a light weight additive has been developed which can be used to formulate cementing compositions that have densities as low as 8.5 lb/gal. These type slurries can develop good compressive strength at temperatures as low as 28°F.

The additive will withstand temperature conditions ranging from permafrost to high-temperature thermal wells.

The new admixture consists of small (10-100μm) diameter inorganic high-strength microspheres (HSMS) which remain useful at pressures up to 6,000 psi.

Four major areas have already been identified as practical candidates for low-density slurries prepared with the additive.

These are:

- Thermal wells that require minimum density cement compositions with effective insulation properties.
- Incompetent formations on and offshore requiring cement densities less than 11 lb/gal.

Paper presented at the API Pacific Coast joint chapter meeting, Bakersfield, October 1980.

- Cold formations (28-80° F.) that need minimum cementing densities.
- Offshore platform grouting.

Descriptions of these compositions, their compressive strength development, pressure resistance, thickening times, and other properties are presented here along with data pertaining to the numerous applications that have been completed to date.

Cement applications. Controlling water flow in mine shafts by grouting with cement slurries[1] dates back to the 1880s while cementing casing to the formation in oil and gas wells[2] was a recommended procedure as early as 1911. However, the advantages of using low-density cementing slurries to achieve successful, competent cement jobs was not generally recognized until the 1940s.

Since that time, light weight slurries have been recommended for use in wells that extend through weak subterranean formations that are sensitive to hydrostatic pressure exerted by the column of cement.

Weak or unconsolidated formations are found worldwide, and due to increased exploration activities, more and more incompetent formations are being encountered which will break down when fluids slightly heavier than water fill the annular space. Thus, an increasing need for ultra-low density cements has arisen.

Numerous ingredients have been used to prepare light weight cementing slurries. Bentonite,[3,4] diatomaceous earth,[4] gilsonite,[4] ground plastics,[4] asphalt emulsions,[4] walnut shells,[4] and silicate extenders[5] have all found acceptance.

Fig. 1

Microspheres for lightening cement

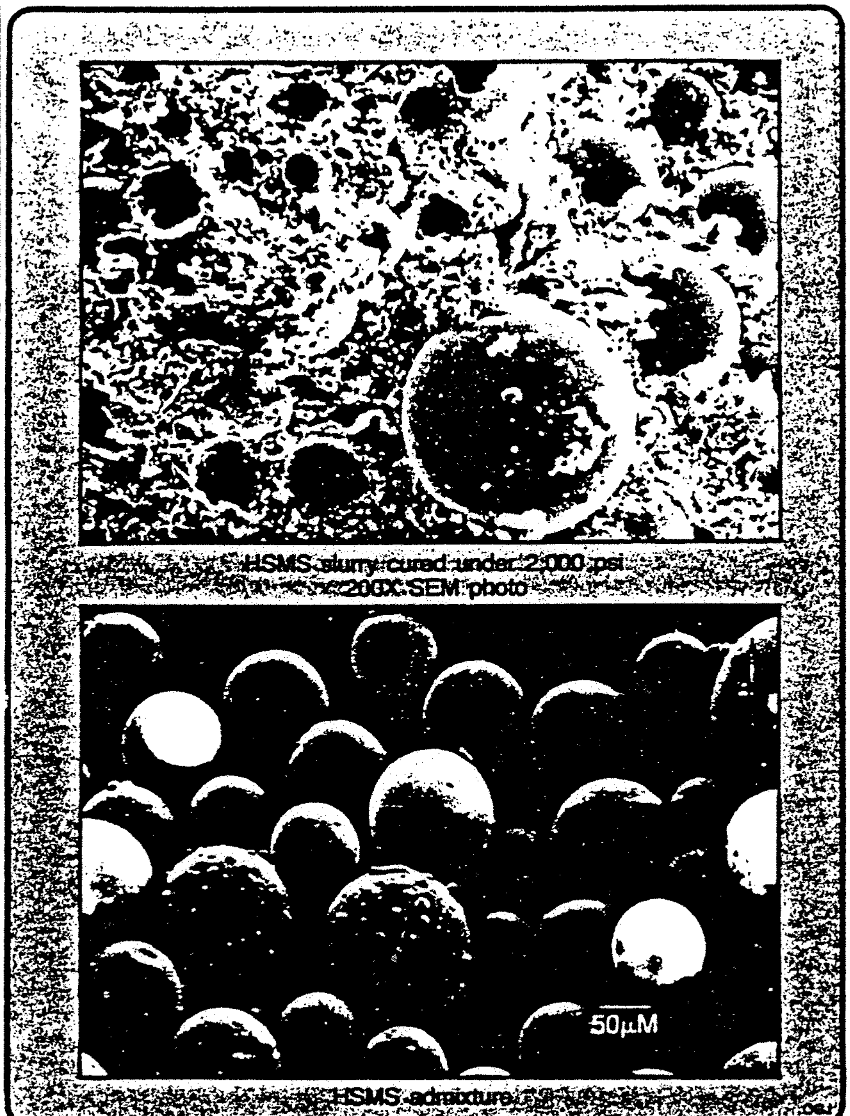


Table 1

Sieve analysis

Sieve size (Mesh)	Weight %
On 40	0
Through 40 on 60	4.5
Through 60 on 100	52.4
Through 100 on 140	25.9
Through 140 on 170	4.0
Through 170 on 200	5.9
Through 200 on 230	1.3
Through 230 on 325	2.3
Through 325	1.2

Yet even though many of these materials remain in use today, the lower slurry density limit for useful strength development in 24 hours at moderate temperatures has been approximately 11 lb/gal.

This limit is the result of a high water content in the common types of light weight cementing slurries. The development of compressive strength by hydraulic cement mixtures is a direct function of the water to cement ratio (w/c).

To prepare commonly available 11 lb/gal slurries, a w/c approximately equal to 1.8 (20 gal/sk) is required; an upper water limit beyond which it is difficult to achieve useful strength development.

To prepare 10 lb/gal cementing slurries with the available additives would require an approximate w/c of 3.0 (30+ gal/sk) which is not feasible.

The incorporation of hollow microspheres (Table 1) in a cementing slurry essentially allows one to use encapsulated air as a light weight additive.

Selection of a proper microsphere that will withstand the mechanical shear, frictional forces, and hydrostatic pressures encountered during blending and placement of a hydraulic cement slurry in oil wells has resulted in the introduction of high strength microspheres (HSMS) as a light weight cementing additive. This admixture has reduced the density limitation for pressurized cementing slurries from 11 lb/gal to densities less than the mixing water alone.

The strength achievement possible with these slurries is such that low-density slurries can now be used over a wide range of pressure and temperature conditions.

The ability of this material to reduce the density of a cement slurry is due to a low particle density and relatively low water absorbency. The effective particle density of HSMS ranges from 5.25 lb/gal (0.63 g/cc) at atmospheric pressure to about 8.33 lb/gal (1 g/cc) at 6,000 psi. (Table 2). This gradual, but limited density increase with increasing pressure is the characteristic which makes the material suitable for use in high pressure applications.

The low water absorbency together with the low particle density results in greatly reduced w/c ratios as compared to other types of low density admixtures. The result is that one can expect strength development of 10 lb/gal HSMS slurries to approach those of 13 lb/gal prepared from other types of additives. Slurry C with HSMS (Table 3) uses only 0.78 w/c compared to 2.78 w/c for an equivalent density slurry prepared with silicate extender (Table 4). The direct result of this lower w/c ratio is a vast improvement in the strength achieved and a much shorter waiting on cement (WOC) set time.

Higher strength development, shorter WOC times, and lower w/c ratios allow one to prepare and place light weight cementing slurries in cooler formations at lower densities than ever before possible.

This performance translates to shorter rig times, fewer remedial cementing jobs, and more competent cement bonding properties than possible with conventional light weight additives.

Even though HSMS was primarily introduced to allow the use of cement slurries with densities less than 11 lb/gal, it can also be used to obtain significant strength increases from slurries with densities as high as 15 lb/gal.

Prospective applications. A number of applications have been considered for slurries containing HSMS light weight aggregate.

Platform grouting in marine environments to secure pile-structure connections with weak bottom seals is one possibility and "drilled" piles can be grouted into the bore hole and tied

Fig. 2

Slurry density

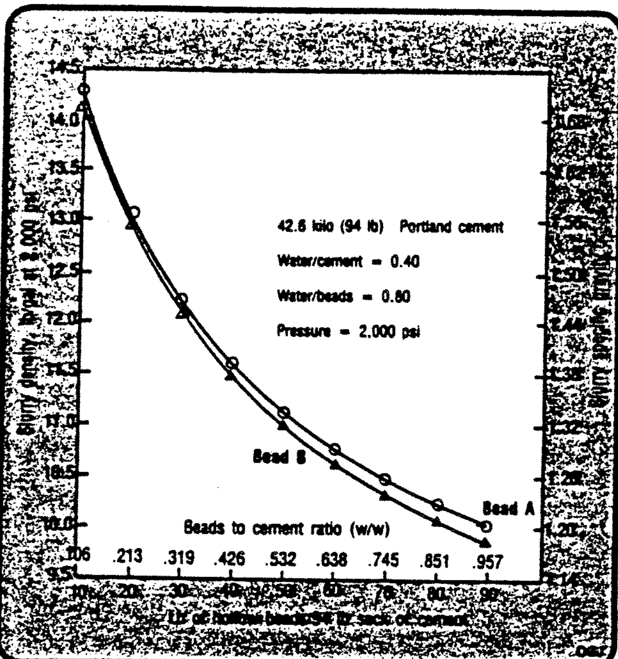
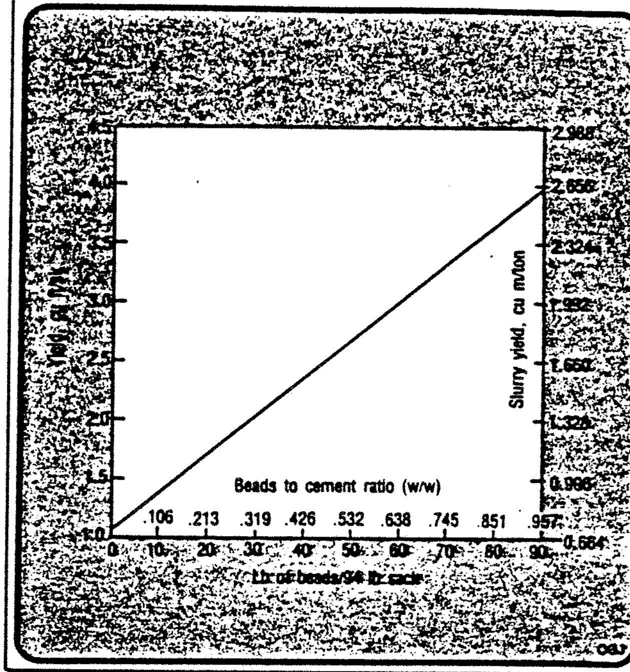


Fig. 3

Yield of slurries



into the structure in one continuous operation to eliminate two stage lines and tools.

Offshore conductor pipe and casing can be competently cemented into weak, unconsolidated mudstone and silt at very cool temperatures with operations being resumed after 12-24 hours WOC.

Fragile permafrost formations can be cemented with 6-12 hour WOC times.

Floating bridge plugs can be cemented in brine wells and salt domes to allow eventual placement of permanent cap plugs prepared with densified, salt-saturated cement slurries.

Lightweight salt-saturated cement slurries resulting in much improved bond logs can be prepared for use in salt sections with lost circulation zones.

Cements with highly effective thermal insulation properties can be placed to cement steam injection wells, while geothermal formations with notorious lost-circulation problems can be routinely cemented with a minimum of stages and tools to provide high-percentage completion rates and improved bond logs.

Physical properties and performance. A typical particle size distribution for HSMS admixture is presented in Table 1, while Fig. 1 shows a scanning electron microscope picture of a set cement containing HSMS.

The admixture consists of hollow inorganic fused spheres with an elemental composition high in silicon and aluminum.

The relationship between effective HSMS density and hydraulic pressure

Table 2

Bead density

Pressure psi	Pressure kPa	Bead A gal/lb	Bead A g/cc	Bead B gal/lb	Bead B g/cc
0	0	0.1824	0.658	0.1753	0.685
200	1379	0.1590	0.755	0.1620	0.741
500	3448	0.1550	0.775	0.1578	0.761
1000	6895	0.1493	0.804	0.1527	0.786
2000	13790	0.1400	0.857	0.1447	0.830
3000	20685	0.1314*	0.914*	0.1386	0.866
4000	27580	0.1239*	0.969*	0.1325	0.906
5000	34475	0.1175*	1.022*	0.1268	0.947
6000	41370	0.1122*	1.070*	0.1217	0.986

*Extrapolated value

Table 3

Expansive low-density HSMS slurries

All mixes contain: 100 parts API Class A cement, plus ≤ 10 parts expansive admix plus other minor components. Listed by weight.

Mix No.	Other components HSMS	Other components Sea water	Density, lb/gal atm.	Density, lb/gal 200 psi	Yield ft³/sk	Consty Bc	Compressive strength, psi 24 hr	75°F 3 day	75°F 7 day	120°F 3 day	120°F 7 day
A	85	101.4	9.18	9.52	3.98	14	246	435	609	1363	2625
B	69	90.6	9.52	9.77	3.46	12	304	580	768	1870	2639
C	48	73.6	10.18	10.68	2.73	14	638	1116	1479	2581	3147
D	34	63.1	11.18	11.52	2.25	17	1000	1812	2378	3843	4437
E	24	55.8	12.19	12.44	1.92	22	1837	2320	2697	4481	4263
F	17	50.3	13.11	13.44	1.67	26	1856	2784	3292	4887	4597
G	8.7	44.2	14.44	14.69	1.40	32	2794	3524	3973	6134	5844
H	3.6	43.4	15.44	15.69	1.27	32	3016	4263	4640	6685	5569

for two types of HSMS beads is shown in Table 2.

The general effect of HSMS concentration on cement slurry density and on slurry yield are illustrated in Figs. 2 and 3, respectively. The gradual variation of density with pressure for a cementing slurry containing 64% HSMS is shown in Fig. 4.

Compressive strength data obtained with expansive cementing slurries formulated with HSMS compared to conventional slurries prepared with silicate extender are tabulated in Tables 3 and 4 and presented graphically in Figs. 5 and 6.

In Fig. 7, compressive strength data for portland cement compositions containing HSMS is compared to that of slurries prepared with silicate extender and bentonite extenders. Table 5 presents strength and permeability data used for a slurry containing HSMS compared to a commonly used geothermal well cement.

Table 6 shows the properties of a HSMS blend that, to date, has been used to successfully cement over 60 geothermal wells.

Discussion of results. Field use of HSMS presents no unusual difficulties. The particle size of HSMS, as shown in Table 1, is similar to that of coarse silica flour which has been in common use for years.

This size distribution allows efficient bulk blending with hydraulic cements and also minimizes the amount of extra mixing water required for additive wetting. This reduced water requirement (as low as 55%) is used to advantage to maintain low w/c ratios for HSMS slurries, the result being improved strengths from low density cements.

The density versus HSMS concentration data and slurry yield versus HSMS concentration data (Fig. 2 and 3) indicate that useful, high yield cement slurry compositions can be formulated at densities approaching 9.5 lb/gal even at hydraulic pressures of 2,000 psi.

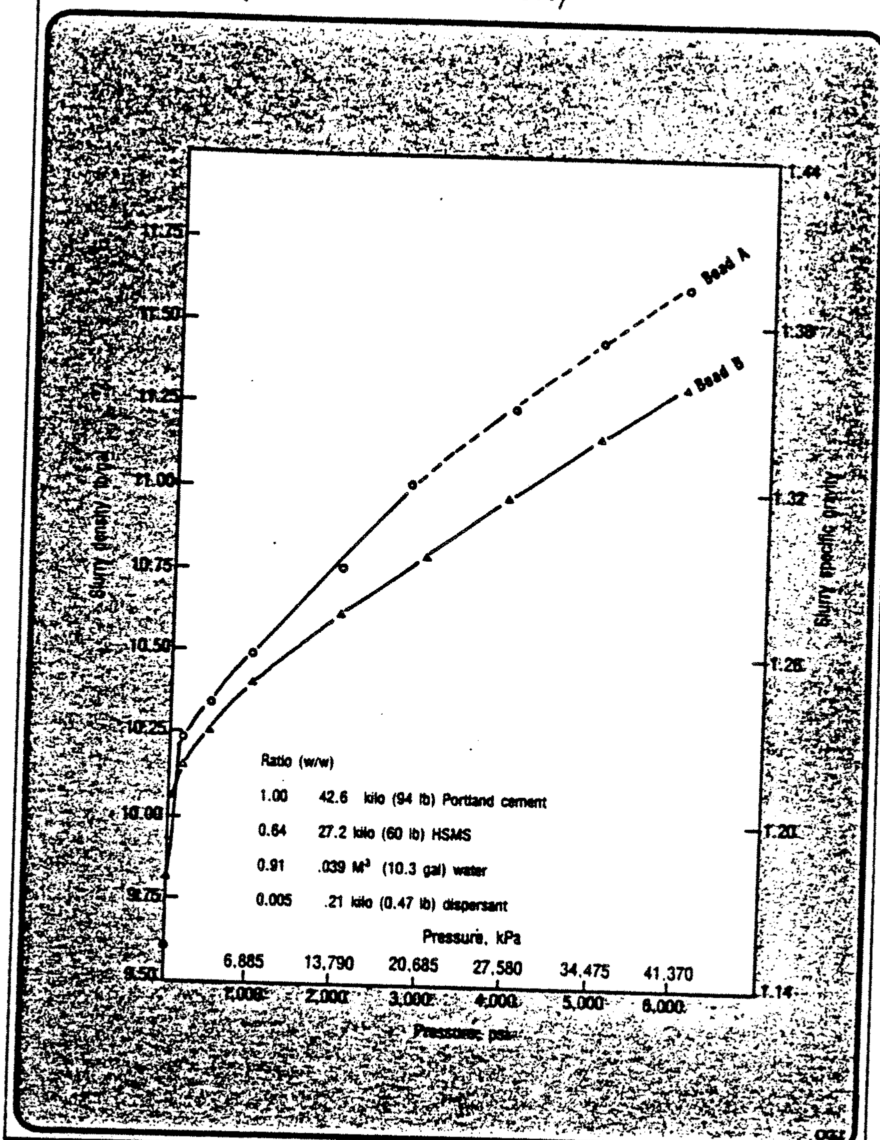
The pressure-density response of a typical HSMS slurry (Fig. 4) indicates that the effective density response of HSMS additive is nearly linear with increasing pressure and that the additive has an applicable use range from atmospheric pressure to 6,000 psi.

Table 2 expresses the effective density of HSMS additive as a function of hydraulic pressure over this usage range. The fact that the effective density of HSMS varies from 0.7 to 1.00 minimizes the tendency of the HSMS additive to separate out from cement slurries upon standing, even if the slurry becomes overwatered.

A comparison of compressive strength developments of expansive grouts containing HSMS to low density grouts containing silicate extender (Tables 3 and 4 and Figs. 5 and 6), indicates that the use of HSMS results in grouts which have much higher compressive strength at the conditions encountered in grouting platform legs

Effect of pressure on density

Fig. 4



Slurries with sillicate extender

Table 4

Mix No.	Other components: Silicate extender	Other components: Sea water	Density, lb/gal: atm.	Density, lb/gal: 200 psi	Yield ft³/sk	Consty Bc	24 hr	75°F: 3 day	75°F: 7 day	120°F: 3 day	120°F: 7 day
I	6.20	231	10.9	10.9	3.9	2	15	15	44	29	73
J	3.78	157	11.7	11.7	2.8	2	102	334	305	15	334
K	2.40	116	12.4	12.5	2.2	2	232	595	624	421	667
L	1.18	79.5	13.7	13.9	1.7	3	856	1146	1537	1262	1842
M	0.27	52.1	15.4	15.44	1.24	5	1885	3408	3669	3394	4090

A high water ratio "low density" admixture.

Fig. 5

Compressive strength after 72 hr

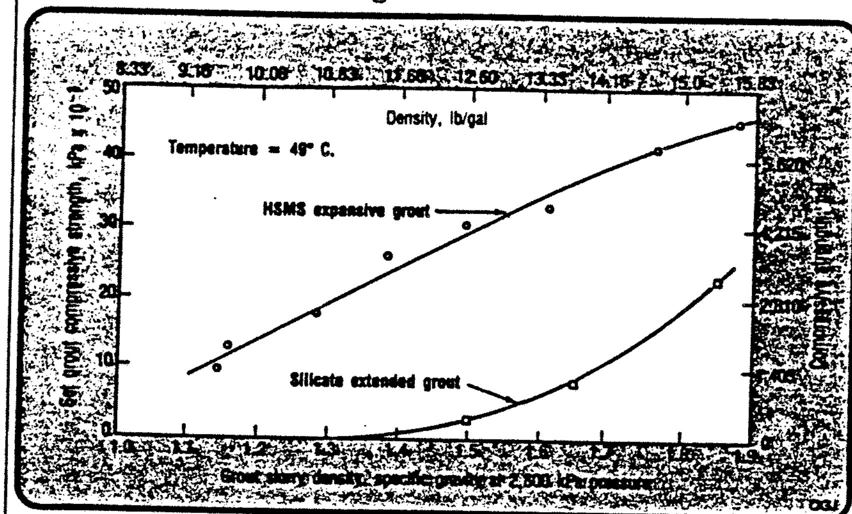


Table 5

High temperature strength

Composition A parts by weight	Composition B parts by weight
100 API Class G cement	100 API Class G cement
40 Silica flour	40 Silica flour
5 Lime	3 Silicate extender
0.75 Dispersant	164 Water
0.30 Retarder	
73.1 HSMS	
104 Water	

Composition	Density, lb/gal	Yield, ft³/sk	Compressive strength psi at 450+°F. 3 day	1 month	3 month	Permeability air, md. 3 month
A	12.0	3.56	2190	2016	1856	0.47
B	12.0	3.18	508	ND	580	4.82

Table 6

Thermal conductivity of HSMS cement slurries

All slurries contained 0.5 parts dispersant, samples cured at 500 psi for 7 days at 120°F. or 1 day at 450+°F.

Light weight additive	Test slurry* Cement	Water	Silica flour	Other	Density, lb/gal	Curing Temperature, °F.	K value BTU/hr-ft-°F.
Perlite	Class G	96.1	40	2(Gel)	13.6	120°F 450°+	1.76 0.43
51.5 HSMS B	Ciment Fondu	105.5	65	......	11.6	120°F 450°F	0.334 0.197

*Additive per 100 parts cement by weight.

Table 7

Floating cement plug

Composition A, parts by weight	Composition B parts by weight
100 API Class A cement	100 API Class A cement
133 HSMS	100 HSMS
1.5 Fibers	3 Calcium chloride
180 saturated salt water	114 Fresh water
≤ 1 Other ingredients	≤ 2 Other ingredients

Composition	Density, lb/gal	Yield, ft³/sk	Compressive strength, psi @80°F. 24 hr	3 day	7 day	28 day
A	9.8	5.63	44	131	232	624
B	9.4	4.29	203	305	ND	740

and piles.

The expansive feature of these grouts is a highly desirable property.

The superiority of low-density oil well cements prepared with HSMS light weight admixture is illustrated in Fig. 7. The data indicate that competent hydraulic cement mixtures much less dense than 11 lb/gal are now achievable with HSMS additive.

This increased strength of light weight cements, compared to those prepared with bentonite or silicate extender, is again mainly attributed to the reduction of the w/c ratio.

Over 100 successful cementing jobs which contained HSMS admixture have been completed to date.

One of the more unusual applications of HSMS has been the capping of leached out salt caverns filled with saturated brine water. Cementing compositions that contained enough HSMS to be lighter than the brine water, and thus would float, were placed into the wells.

Solid floating bridge plugs resulted, after which a dense, saturated salt cement slurry was placed to completely seal the wells.

Table 7 describes a typical floating composition and its properties.

Extremely good compressive strengths for a slurry of this density were achieved.

Similar type slurries have been used to advantage in cementing brine wells used for production of brine water. In these cases, lost circulation problems have been avoided by cementing these formations with HSMS slurries. Very good sonic bond logs were obtained after cementing with 10.9 lb/gal, saturated salt HSMS slurries.

The extremely incompetent formations and high temperatures encountered in drilling geothermal wells require a cementing composition with low density and adequate thermal stability.

Test results (Table 5) indicate that a thermal cement containing HSMS developed higher strength and lower permeability than cement containing silicate extender.

The insulating properties of a similar HSMS cement (Table 6) are far superior to conventional cements such that the thermal conductivity of the wet-cured HSMS slurry was lower than that of a dry-cured conventional cement.

The temperature stability and insulating properties of HSMS cements make them ideal candidates for geothermal or steam-injection wells.

In at least one area a geothermal HSMS formulation has become the standard cementing slurry. The properties of this formulation are listed in Table 8. Over 60 cementing jobs using this formulation have been completed to date.

Case histories. Thus far all of the grouting and cementing jobs performed using HSMS admixture have been in subterranean applications involving oil, gas, steam production, steam injection, brine production, and brine disposal wells.

Some of these jobs were performed offshore in deep water.

The first use of a HSMS slurry was to cement 749-ft strings of 7-in. casing into 13⅞-in. holes for use as steam injection wells in a shale-oil recovery project near Rangely, Colo. In this case, the objective was to formulate a cement with the greatest heat insulation properties for a specified minimum compressive strength at 500°F.

The formulation selected was 0.5 dispersant in Slurry 1, Table 9. From laboratory tests, this cement had a density of 11.8 lb/gal at 1,200 psi hydraulic pressure, and had a thermal conductivity value of 0.196 BTU/hr-ft-°F. after curing at 500°F.

A series of these wells was cemented with no reports of slurry loss to the weak formations during placement and no reports of any operational problems after steam injection at 800°F.+ was commenced.

The next application was a job run to evaluate continuous mixing and density control problems with a slurry designed for casing jobs in permafrost areas. A 7-in. casing was cemented in a 9⅞-in. hole to a depth of 615 ft. The cement formulation was Slurry 2, Table 9 with 0.5 parts dispersant.

Although the temperature in this hole was 45 to 65°F., the cement used was designed to develop 500 psi compressive strength in 24 hr at 28°F.

This job confirmed that a low density HSMS blend could be transported and mixed with conventional oil field equipment. A jet mixer was used to mix the slurry while the water-cement ratio was controlled via density measurements from an accurately calibrated densometer in the slurry injection line for a slurry density of 11 lb/gal.

However, this density later proved to be near the minimum for which density measurements can be reliably used for water-cement ratio control.

HSMS slurry was used for two jobs in deep water, offshore Newfoundland.[6]

The first was a 30-in. conductor pipe set in a 36-in. hole to 328 ft below sea bottom with formation temperature from 35°F. to 50°F. The second was a 20-in. surface casing set to 1,650 ft below sea bottom with temperature from 35°F. to 60°F.

The problem in this case was a low density requirement to prevent loss to weak formations and the development of 250 psi compressive strength within 24 hr so drilling operations could be resumed. Cement was circulated to the proposed level on both jobs and drilling operations were resumed on schedule.

The slurry used for both jobs was 0.5 parts by weight dispersant in Slurry 3, Table 9. Laboratory tests showed this mix to have a slurry density of 11.7 lb/gal at 1,000 psi hydraulic pressure and 12.5 lb/gal at 4,000 psi hydraulic pressure. The mixture developed a compressive strength (at 40°F.) of 242 psi in 24 hr, 516 psi in 72 hr.

A number of casing and liner jobs have also been run. In all these cases,

Fig. 6

Strength after 24 hr at 24° C.

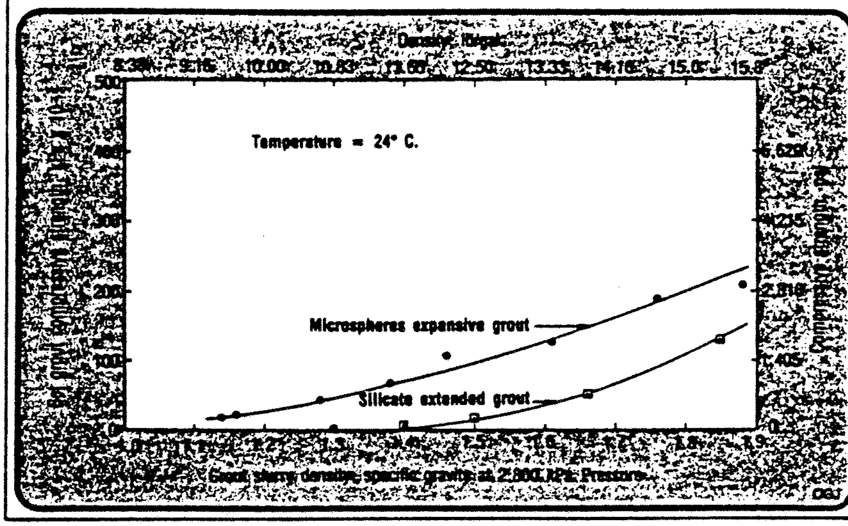


Table 8

HSMS geothermal slurry

Density = 11.5 lb/gal (at 6,000 psi)
10.9 lb/gal (atmospheric)

Composition (W/W)***	Thermal Conductivity	1 Day Compressive strength, psi at 475°F.	7 Day
100 API Class G cement	BTU/hr-ft-°F	2475	3757
53 HSMS	K = 0.367*		
40 Silica flour	K = 0.172**		
		Air permeability, md	
5 Lime		0.051	0.011
4 Bentonite			
		Porosity, %	
1 Dispersant	*Sample Cured at 80°F		
0.5 Polymer	**Sample Cured at 550°F	55.6	41.2
	***Weight/Weight		
0.3 Retarder			
93 Water			

Table 9

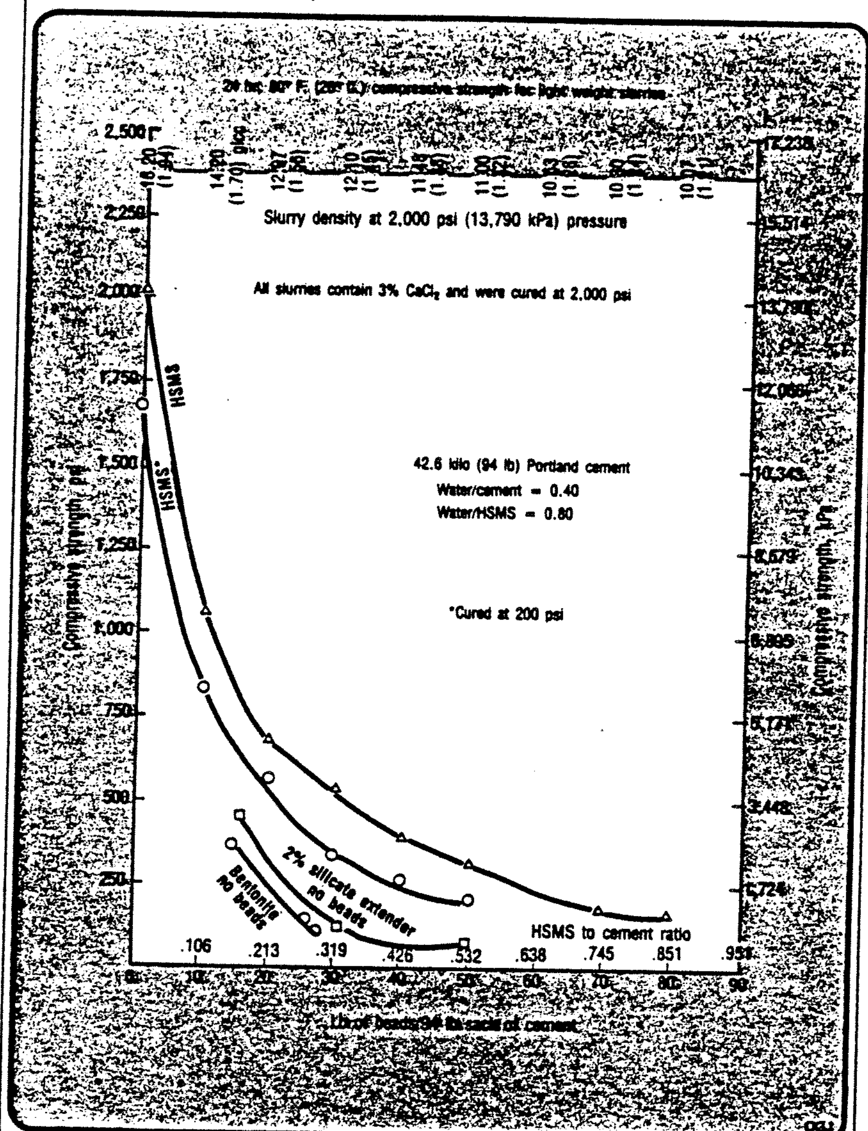
HSMS low density cements

Slurry	Slurry (Parts by weight): Cement (100)	HSMS (b)	Water	Other	Density, lb/gal	Curing Temperature °F.	Compressive Strength, psi (hr)
1	Ciment Fondu	50	110	65-Silica flour	11.6	500	508(168)
2	Ciment Fondu	49	85.2	1-NaCl	11.0	28	508(24)
3	Class G	29.4	70	2.4 $CaCl_2$	11.8	40	798(24) 1494(48)
4	Class G	37	79	—	11.6		
5	Ciment Fondu	40	88	40-Silica flour	12.1	50	1943(24) 2335(48)
6	Class A	100	114	3-$CaCl_2$	9.3	28	203(24) 725(672)

All blends contained approx. 0.5 parts dispersant.
Density at bottom hole hydraulic pressure.

Additives compared

Fig. 7



the objective was to provide the highest compressive strength for the low density needed to prevent slurry loss into weak formations. The deepest was a 7-in. liner set to 6,000 ft with a bottom hole placement pressure of 3,625 psi. The slurry used was 0.4 dispersant in Slurry 4, Table 9.

Measured surface density for this slurry was 10.8 lb/gal which corresponds to a density at 3,625 psi of 11.6 lb/gal. On all jobs to date, the cement top was found at or near the calculated fill level and no reports have been received of fluid migration in the cemented annulus.

Thermal stability, thermal insulation, and minimum density were properties required to cement fibercast casing into two experimental wells that had been drilled into the Athabasca Tar Sands.

A cement blend consisting of (parts by weight) 100 Ciment Fondu, 40 silica flour for thermal stability, 40 HSMS for thermal insulation and density reduction, 0.5 dispersant for improved slurry rheology, and 88 fresh water met all requirements including high early compressive strength when cured at 50°F. Slurry 5, Table 9.

One unusual application for an HSMS grout was to place a floating plug on the surface of saturated brine water under nitrogen cap at 1,000 psi pressure. The object was to form a base plug in the 5-ft diameter neck of a solution cavern in a salt dome so the neck could be subsequently plugged using a saturated salt water cement.

The grout selected was (parts by weight) 100 API Class A cement, 100 HSMS, 3 calcium chloride, 1 dispersant, and 114 water, Slurry 6, Table 9. Laboratory tests showed a density of 9.8 lb/gal at 1,000 psi and compressive strength development at 80°F. of 150 psi in 24 hr and 725 psi in 28 days.

A volume of slurry sufficient to fill 33 ft of neck was successfully mixed and pumped into place. Three days later the plugged neck was tagged and the plug was found to be near the calculated position. The seal job was then completed with saturated salt water cement.

A second job similar to this one has also been successfully completed.

A major application for HSMS slurries has been the cementing of casing in geothermal steam production wells. Typical are the wells in the Cerro Prieto geothermal field near Mexicali, Mexico.

This area has long been plagued with weak subterranean intervals that break down if the mud weight exceeds 10.5 lb/gal. Most well completion programs there involve setting 13⅜-in. casing at 3,300 ft followed by 9⅝-in. casing to 6,600 ft.

The lower 3,000 ft interval usually crosses several lost circulation zones. Successful cementing of the first stage previously occurred only 50% of the time which necessitated having on location a 200-300% excess of Perlite geothermal cement blend in anticipation of losing large quantities of cement slurry.

Bond logs often indicated mediocre to no-bond results in the lost circulation zones.

Providing sufficient bulk storage and bulk transport equipment to complete these type jobs became a definite concern. Since the HSMS admixture described in Table 8 has been introduced to cement these wells, the success rate on first stage jobs has surpassed 95%, the amount of bulk equipment on location has been significantly lowered, and the bond logs indicate improved bonding over the interval, with most of the bonding being perfect or nearly perfect in quality.

These results support the laboratory observation that HSMS type slurries possess an inherent ability to combat lost circulation problems by forming an efficient, immobile filter cake that is resistant to flow when placed across a permeable matrix.

This ability coupled with high compressive strength development from a low-density slurry having excellent thermal insulation properties (k = 0.172 BTU/hr-ft-°F.) has proven HSMS slurries to be the geothermal cement of choice in the Cerro Prieto region.

Cement formulations very similar to this have also been used to successfully complete long interval (2,000-4,000 ft) 9⅝-in. casing jobs in other areas of California and Arizona plagued with washouts and weak formations.

The deepest conditions where an HSMS slurry has been placed involve two 11,000-ft wells, one in California and another in Arizona with casing set to approximately 10,300 ft and a stage collar placed at 6,000 ft.

Slurry composition was (parts by weight) 100 API class G cement, 53 HSMS, 40 silica flour, 4 bentonite, 1 dispersant, 1 fluid loss polymer, 5 hydrated lime, 1 high temperature retarder, and 93 water. This slurry was sufficiently retarded for 8 hours pumping time at 400°F.

Both jobs were completed, but the experience from the first job again emphasized the importance of proper conditioning of the well before cementing operations are commenced.

Viscosity problems occurred because the mud had not been sufficiently lowered in solids and no spacer fluid was introduced prior to cementing which caused a lost circulation situation until it was remedied by addition of cotton seed hulls. Returns were then regained and the HSMS cement was placed.

Due to high mud solids, additional problems were encountered during displacement. These were overcome by displacing with water.

The second job was completed without difficulty because care was taken to condition the mud, introduce a spacer, and limit mud solids. The use of the HSMS cement slurries did successfully prevent any problems which would likely have occurred due to an overweight cement slurry.

Conclusions. The high strength microspheres described here are useful in formulation of low density slurries which develop compressive strength substantially higher than those formulated with other low density additives. The lower density limit for useful compressive strength is substantially lower for slurries using HSMS. The increased compressive strength-slurry density ratios associated with cements utilizing this material result from lower water/solids ratios. The HSMS is unique as a low density additive for high temperature applications in that it actually possesses a low density and does not merely absorb water while it disperses the cement solids. The HSMS has been successfully used in cementing compositions covering a wide range of applications from Arctic conditions to geothermal wells. The presence of HSMS in cementing formulations drastically improves the heat insulation properties of the set cement. All laboratory and field results indicate that the HSMS admixture imparts special lost circulation treatment properties to the cement slurry by forming a thick, immobile filter cake across permeable zones. Improved bond logs have been a consistent feature of cementing jobs completed with HSMS formulations.

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John Lingenfelter is a field engineer, Halliburton Services, El Centro, Calif. He ran one of the prototype cement jobs with the technique described here and participated in many of the subsequent applications during product development. Lingenfelter's special interest is the geothermal work near El Centro but he has cemented conventional oil wells by the same method. He prepared the case histories presented here. Lingenfelter earned a BS in mechanical engineering from California State Polytechnic University, Pomona, and joined Halliburton in 1978.

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Low density foam cements solve many oil field problems

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10-second summary

Recent experience obtained from numerous applications of very lightweight portland cement has proven that the technology has been developed that will allow this unique service to become a common practice. The following article discusses the need for foam cement, its development and several actual case histories.

The routine use of minimum density cement slurries (4 to 11 ppg) in oil field applications has been limited primarily because no convenient, cost-effective process existed that could provide useful compressive strength development. But lately, the careful selection and use of surfactants and foam stabilizers in addition to use of properly designed field equipment has enabled the mixing and placement of stable foam cement slurries with instantly variable and controllable downhole slurry densities from 3.5 to 14 ppg over a wide range of conditions. Typical physical properties such as compressive strength, porosity and permeability for foam cements of various densities are presented.

Foamed cement slurries have been successfully applied in the field on squeeze jobs, leaking LPG underground reservoirs, salt-zone washouts, as well as primary cementing jobs. Case histories covering 31 field jobs will be discussed.

WHY FOAM CEMENT IS NEEDED

There have always been areas in which weak zones would support only a limited height of normal-density (11 to 18 ppg) cement column without breaking down. In the past, multiple stage jobs were often attempted to obtain the needed annular fillup, or the problem was simply neglected at the risk of later corrosion and interzonal communication.

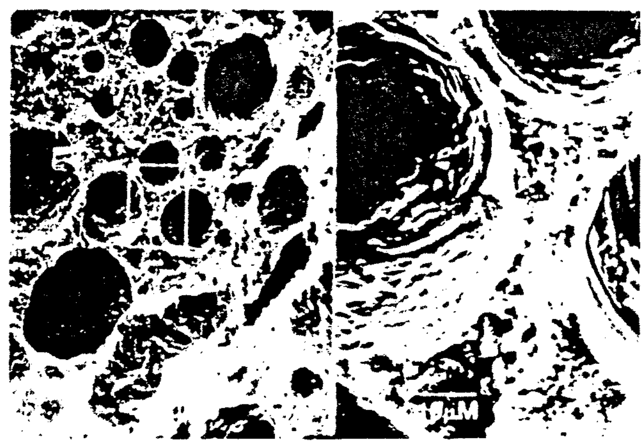


Fig. 1—Magnified views of a stable, 10 ppg foam cement shows the discrete cells necessary for high compressive strength and low permeability.

Past attempts to formulate competent lightweight cements below 10.5 ppg using traditional water extending additives have been mostly unsuccessful. But since 1978, two new types of ultra-lightweight cement slurries have been available. Both incorporate a gas as the lightweight additive. In one, gas is encapsulated within hard, pressure-resistant hollow microspheres.[1,2] The use of microspheres can provide competent cement slurries with densities lower than that of water.

The second concept, the subject of this article, is high-pressure foam cement. The application of pressurized gas to improve cement slurry displacement was first introduced as aerated mud or cement.[3,4] While this approach has been applied successfully it never achieved wide acceptance. No attempts were made to stabilize the commingled gas and prevent coalescing and percolation of the gas through the cement column. However, if a pressurized gas was dispersed uniformly throughout a cement slurry and constrained until the cement sets, then a true lightweight foam cement would result. This concept is not new. Cellular foam concrete has long been available for surface applications,[5] and as

TABLE 1 — Effect of foaming surfactants on foam cement properties

Surfactant	Surfactant chemical class	Comments about foam cement visible properties	Relative maximum foam quality achievable	24-hour, 100°F compressive strength (psi) of 8 ppg foam cement cured at 100°F
Alkylamidosulfo betaine	Amphoteric	Thin, large air cells	285	317
Amidoalkyldimethyl betaine	Amphoteric	Thin, noticeable air cells	300	202
Alpha-olefin sulfonate	Anionic	Very thick, not uniform	250	252*
Alkylphenol polyglycolether sulfate	Anionic	Very thin, noticeable air cells	175	220**
Alkylethoxylated sulfate	Anionic	Uniform texture	450	292
Alkylethoxylated sulfate + stabilizer		Smooth, fine uniform texture	550	227

* Because sufficient foam volume could not be achieved, this slurry actually had a density of 9.4 ppg.
** Because sufficient foam volume could not be achieved, this slurry actually had a density of 10.8 ppg.

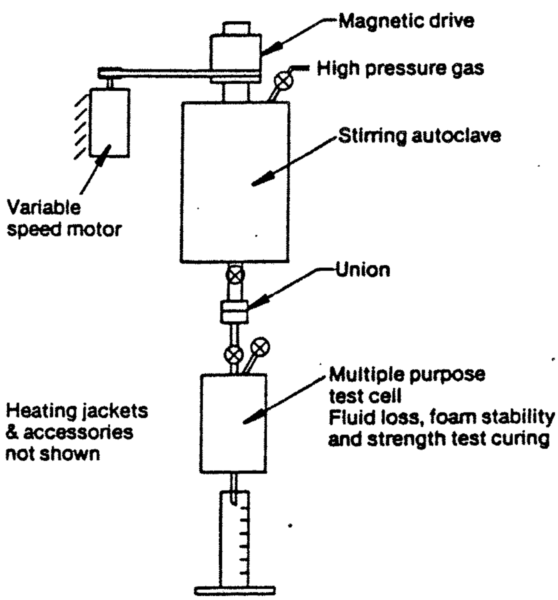


Fig. 2—Althought most testing has been done under atmospheric preparation conditions, this high pressure foam slurry generation and testing apparatus has been used to confirm results. Few major differences have been noted between the two testing conditions.

early as 1975 Aldrich and Mitchell[6] proposed that foam cement be applied in the oil field. In 1981, Davies and Hartog[7] presented experiences with foamed cement compared to the properties recorded in an extensive literature study. They described the results of one field application but the conditions on this particular well were not too demanding.

LAB DEVELOPMENT

Foam cement for field application requires that a stable foam be created wherein the entrained gas is trapped in discrete bubbles that are uniformly dispersed throughout the slurry. If gas bubbles are not discrete and within a certain size range, then the foam can be unstable and the set cement will have high permeability and low compressive strength.[6] For these reasons, unstable foam cement is not suited to oil well cementing.

Selection of suitable foaming surfactants is critical in the preparation of stable foams. Table 1 illustrates how the chemical composition of the foaming surfactant can affect the volume of gas entrained and the physical nature and compressive strength of the set cement. Fig. 1 shows the type of discrete cells required for good foam stability, high compressive strength and low permeability.

Retained stability at high foam quality is important for foam cements with densities less than 9 ppg. Small, fine foam bubbles are believed to promote stronger cement walls around the bubbles and provide a set cement of increased integrity.[8] For these reasons, the alkylethoxylated sulfate with stabilizer was selected. In the lab, stable foam cements are conveniently prepared with stirring devices that provide high shear rates. For routine testing, this atmospheric method of preparation is quick and convenient. For job simulation testing, however, foam cement slurries must be generated, transferred, tested and cured under high pressure. Fig. 2 presents a schematic of a stirring autoclave setup that has proven invaluable in accomplishing this task.

Except for thickening time tests, most lab testing has been conducted under atmospheric preparation conditions because of the convenience factor. Few major differences have been noted in physical results when atmospheric samples are compared to high pressure samples.

As with ordinary slurries, the water ratio of a foam cement slurry has a major effect on the strength of the set solid. This is illustrated by the results in Table 2. The chemical and physical properties of the cement also can have a major effect on strength development as shown in Fig. 3. Permeability of set foam cement varies as a function of both entrained gas volume and curing temperature. Table 3 lists typical permeability data.

To those familiar with the lack of strength development of ordinary low density oil well cements (10 to 11.5 ppg) the ability of foam cement to achieve strengths in excess of 500 psi with air permeabilities less than 20 md at cool temperature conditions seems remarkable. Foam cement achieves higher strengths than water-extended cements primarily because of the very low density of gas versus that of water. As a result, it takes fewer volumes of gas per volume of cement to achieve the same density reduction. Absence of these additional

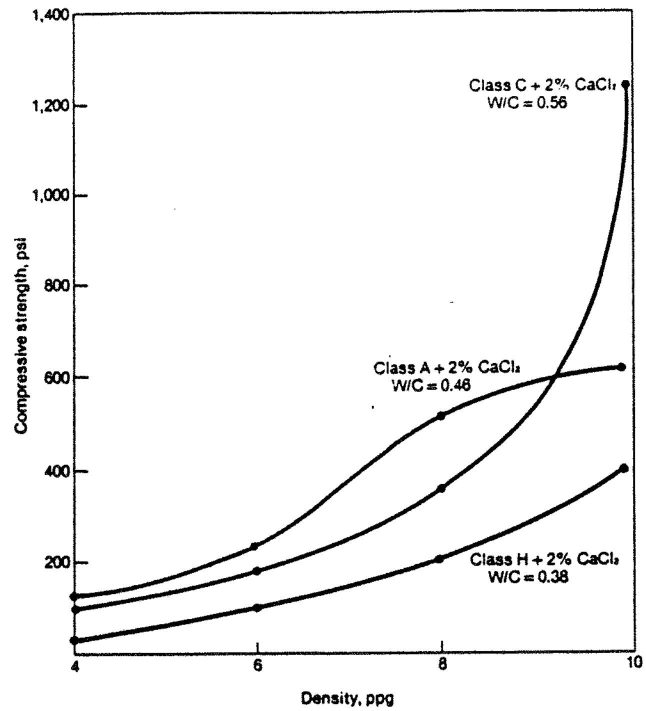


Fig. 3—This graph of results from a 24-hour compressive strength development test run at 100° F illustrates how physical and chemical properties can affect foam cement strength development.

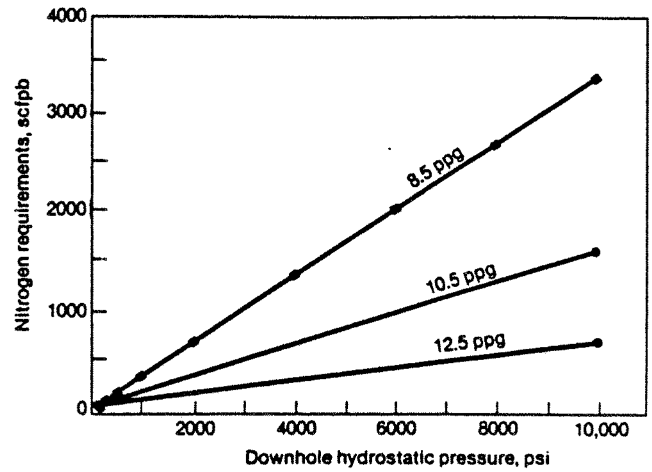


Fig. 4.—Nitrogen requirements for preparing an 8.5 ppg foam cement. Values are in standard cubic feet of N_2 per barrel of 14.8 ppg cement.

Table 2—Effect of water ratio on foam cement strengths

Water ratio		0.72		0.60		0.46		0.38	
Surface density of cement slurry, ppg		13.6[a]		14.5[b]		15.6[c]		16.4[d]	
		Compressive strength (psi)							
		24 hr	72 hr	24 hr	72 hr	24 hr	72 hr	24 hr	72 hr
Density of foam, ppg	8	224	230	260	518	395	665	825	1070
	6	84	128	131	168	163	288	235	208
	4	43	57	38	82	18	56	20	60

Samples cured at atmospheric pressure and 100°F. All samples contained 1.5% surfactant + 0.75% stabilizer by volume of water.

[a] Lone Star H, w/c = 0.75 + 2% solids stabilizer + 2% $CaCl_2$
[b] Lone Star H, w/c = 0.60 + 3% $CaCl_2$
[c] Lone Star H, w/c = 0.46 + 3% $CaCl_2$
[d] Lone Star H, w/c = 0.38 + 3% $CaCl_2$

dilution volumes in foam cement results in much stronger, competent cement.

FIELD SCALE ADAPTATION

Although stable foam cement could be prepared in the lab, early full scale model tests, conducted with a foam generator equipped with large bore jets, were not entirely successful. Foams generated in these tests were stable for only short periods of time. Modifications were clearly indicated.

Subsequent tests with modified foam generators eliminated the foam stability problems, and the foam cement was ready for field application. Current nitrogen servicing equipment is more than capable of providing sufficient quantities of gas at suitable rates for cementing purposes. Fig. 4 illustrates the quantity of

TABLE 3—Permeability of set foam cement, K (air), milliDarcy

Surface slurry = API class H cement + 2% $CaCl_2$, w/c = 0.38

	Density, ppg			
	4	6	8	10
65°F	129	28	1.3	1.5
100°F	159	111	6.7	2.3

Surface slurry = API Class C Cement + 2% $CaCl_2$, w/c = 0.56

	Density, ppg			
	4	6	8	10
65°F	—	15.2	1.32	1.12
100°F	—	846*	0.42	0.11

* Sample most likely had a microcrack present

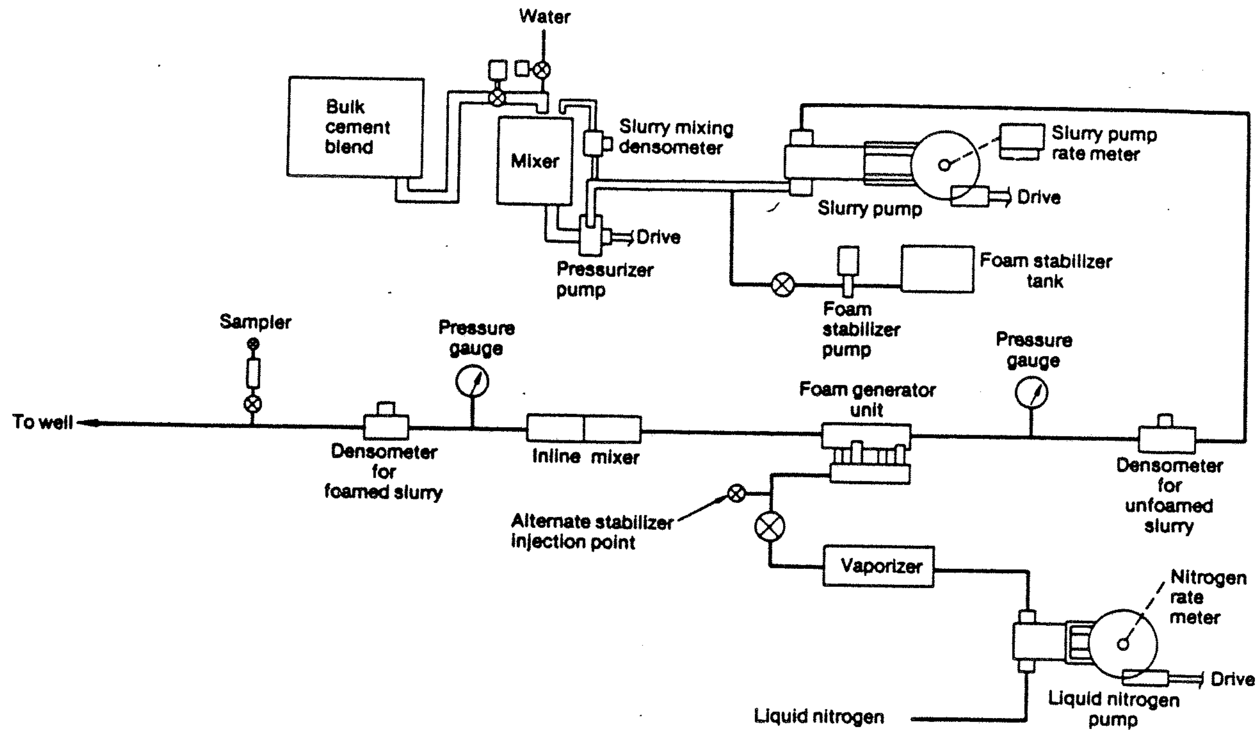
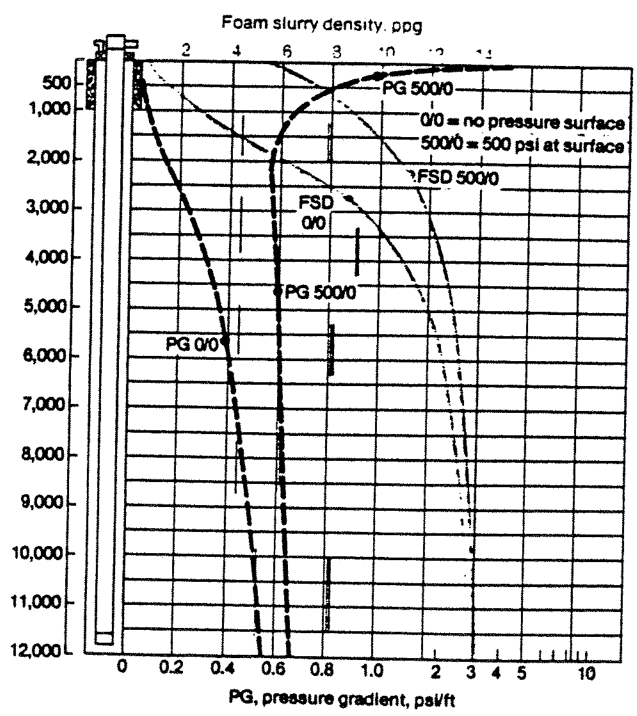


Fig. 5—Equipment needed in the field to mix and monitor foam cements is very similar to that used in conventional jobs. The major exceptions are the foam generator inserted into the slurry discharge line and the nitrogen unit.



—— PG to prevent fluid or gas entry ▬▬ Upper limit PG for pressure parting

Fig. 6—Graph illustrates problems involved with using a constant gas rate foam cement to remedy lost circulation problems. Two options are shown—one using no back pressure on the annulus during circulation, another in which 500 psi are held at the surface. In this situation, a higher density *cap* would be more effective (see Fig. 7).

nitrogen per barrel of cement slurry required to prepare low density foam cements. Even for 8.5 ppg foam cement at 10,000 psi downhole pressure, only 3,500 standard cubic feet per barrel (scfpb) are necessary. Existing trucks can deliver from 350 to 9000 scfm. If more capacity or higher rates ever become necessary, additional nitrogen units can be brought to well site.

On location, equipment and monitoring devices are connected as illustrated in Fig. 5. In nearly all respects, it resembles an ordinary job with regular equipment. The foam generator is inserted into the cement slurry discharge line that is connected to the wellhead, and the nitrogen unit is connected to the foam generator. Cement slurry is mixed in a normal fashion and foam surfactants and stabilizers are injected into the slurry as it is picked up by the displacement pump truck. Coordination of slurry pump, surfactant injection, and nitrogen delivery rates are the crucial parameters that must be planned and executed to properly deliver foam cement having the desired properties downhole.

In foam cement applications instantaneous downhole density control is possible. This density flexibility allows a wide latitude in designing the overall job before it is actually run in the field. Jobs can be planned with the option of changing the density as pressure and circulation events vary during the job.

DOWNHOLE BEHAVIOR OF FOAM CEMENT

Previous publications have suggested that foam cement applications can be divided into two types:[9] Constant gas rate and constant slurry density.

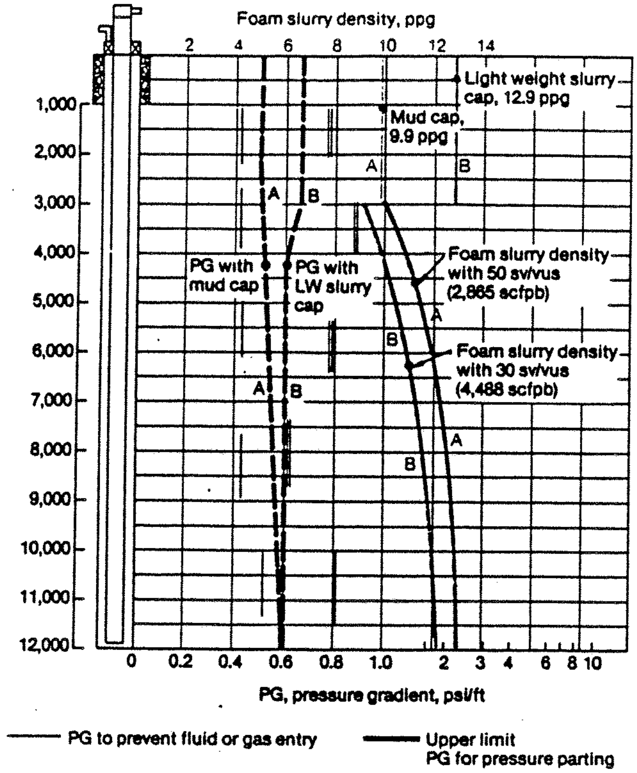


Fig. 7—To overcome problems illustrated by Fig. 6, a *cap* of mud or heavier cement can be used with constant gas rate foam cements.

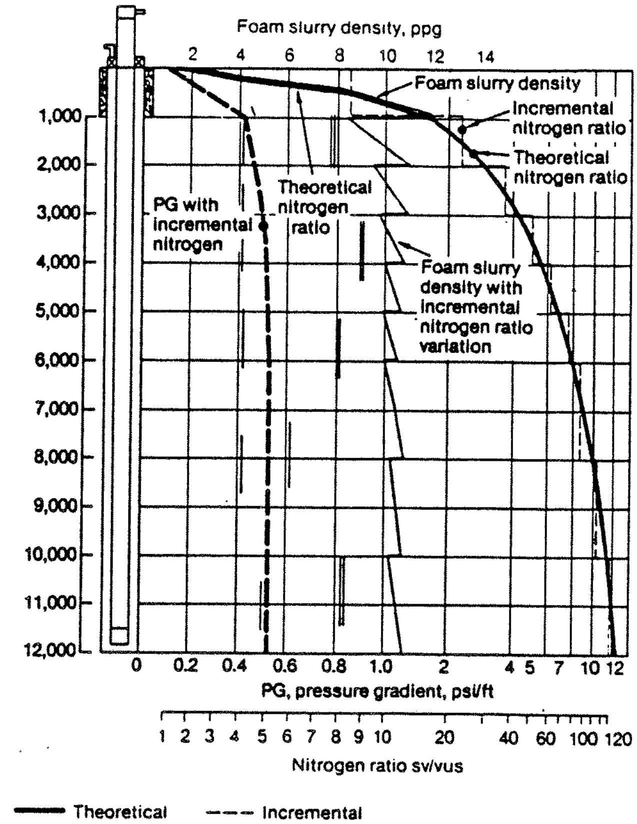


Fig. 8—To obtain a constant density foam cement, the nitrogen ratio must be adjusted with depth. In this example, the ratio is changed every 1,000 ft at shallower depths and at every 2,000 ft at greater depths to obtain an average slurry density of 10.5 ppg.

These two designations represent the two extremes and are normally greatly modified to arrive at a practical job design.

Constant gas rate foam cement. This technique can be used to remedy lost circulation problems, with certain limitations. Fig. 6 shows the difficulties in attempting to use a constant gas rate foam cement and to circulate it back to surface. This example shows a foam cement with 30 standard volumes of nitrogen per unit volume of unfoamed slurry (sv/vus) (168 scfpb). With no back pressure on the annulus at the surface (curves labeled 0/0) the pressure gradient (PG) is below the fluid entry gradient to about 7,000 ft and cement above 2,000 ft would not be dense enough to provide low enough permeability for casing protection. If nitrogen content is reduced, density at the shallow depths can be corrected, but the maximum pressure gradient easily can be exceeded at the greater depths.

This profile can be partly corrected by holding back pressure at the surface. The 500/0 curves in Fig. 6 show the effect of holding 500 psi back pressure. However, application of this method runs the risk of breaking down weak, shallow formations unless intermediate or deep surface casing has been set to about 1,000 ft. A better approach to using a constant rate foam cement is to use a nonfoamed "cap" of either mud or regular lightweight cement ahead of the foam cement. Fig. 7 shows the results of using a 3,000 ft cap of 9.9 ppg mud (curves *A*) and a 12.9 ppg regular lightweight cement (curves *B*). Even with the lighter 9.9 ppg mud cap, the foam slurry density is never less than 9.2 ppg, which provides low permeability and sufficient compressive strength. And the pressure gradient profile falls well within the maximum and minimum limits.

Constant density foam cement. Theoretically, constant density can be maintained throughout a foam cement column by continuously adjusting the gas ratio. In practice, incremental adjustments are used but the increments are designed to cause only minor, acceptable density variation throughout the column.

The results of changing the nitrogen ratio for every 1,000 ft of slurry at shallow depths and every 2,000 ft at the greater depths is shown in Fig. 8. The initial ratio was 8.5 sv/vus (47.7 scfpb) for the slurry to be placed near the surface, and this increased to 123 sv/vus (690 scfpb) for the slurry at 12,000 ft. The 8.5 sv/vus requires only 191 scfm nitrogen if the unfoamed slurry is pumped at 4 bpm. This rate is too low to make accurate delivery with most nitrogen pumps now in use in oil well servicing. The properties of foam cement with only 8.5 sv/vus in the top 500 ft (3 to 8 ppg) are marginal for competent cement. Unless intermediate casing has been set or unless poor quality cement in the upper 500 to 1,000 ft can be tolerated, placement of a non-foamed slurry cap is recommended followed by foam cement prepared by incrementally adjusting the nitrogen ratio.

Results of using only 200 ft of a neat class C slurry cap or lead slurry are shown in Fig. 9. The minimum foam slurry density is 9.8 ppg and the pressure gradient still does not exceed the breakdown pressure at 8,000 ft.

Actual applications of foam cement have shown that a

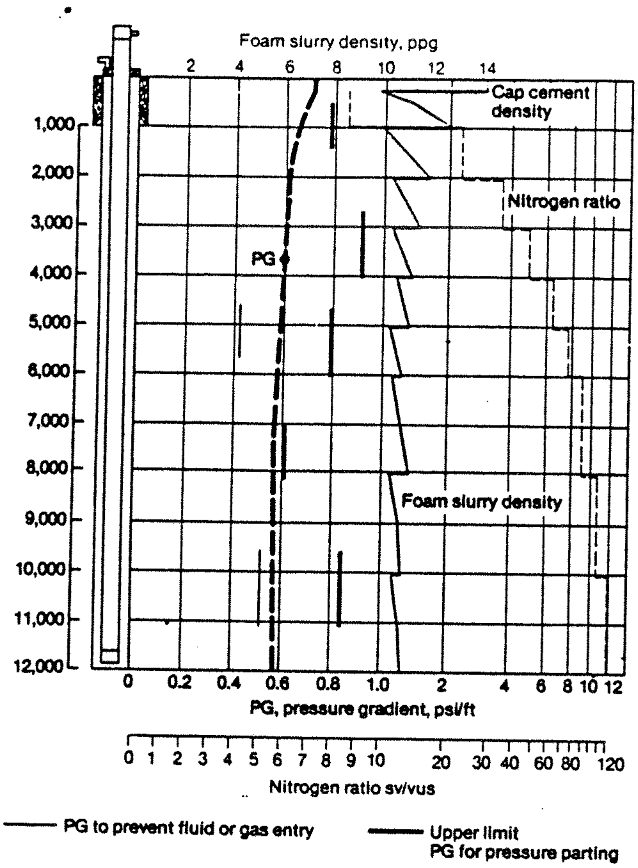


Fig. 9—In this example, the nitrogen ratio was adjusted with depth, but a 200-ft, 14.1 ppg cement *cap* was also used.

blending of fixed gas rate and constant foam slurry density procedures will provide the most practical method in field operations. The following suggestions are offered:

- Use constant nitrogen ratios only for jobs in which a non-foamed cap equal to 10 to 30% of the total depth can be used or when poor cement and low hydrostatic pressure can be tolerated in top 25% of the column

- Use incremental nitrogen ratio adjustment if a constant nitrogen ratio results in unacceptable strength and permeability in the upper part of the foam slurry.

- Limit incremental adjustments to a maximum interval of 1,000 ft for depths less than 6,000, and to 2,000 ft for depths greater than 6,000 ft.

FOAM SLURRY DESIGN PROCEDURE

The in-place hydrostatic pressures and unfoamed slurry density on the surface are major factors that determine the amount of nitrogen (or other gas) needed to achieve a desired in-place foam slurry density. Temperature has less influence but cannot be excluded. The hydrostatic pressure, estimated downhole temperature and Z values are used with the general gas law equation to calculate gas density and volume of gas per unit volume of unfoamed slurry. Results then are used with the unfoamed slurry density to calculate downhole slurry density. Expeditious solutions require a computer or at least a programable calculator with a printer, because two or more of the variables are interdependent. Data shown in Figs. 6, 7, 8 and 9 were calculated using a programable calculator to determine an approximate equation for the temperature and Z values based on hydrostatic pressure and temperatures typical for an oil well.

The general procedure for a foam slurry design is as follows:

- Determine maximum and minimum pressure gradients and plot as shown in Figs. 6, 7, 8 and 9.

- Select depth and density of cap fluid or unfoamed lead slurry based on general guidelines, well conditions and experience.

- Calculate average foam slurry density needed for intervals as indicated by general guidelines.

- Determine nitrogen ratio, foamed slurry density at the top and bottom of the interval, and volume of unfoamed slurry in the interval.

If a constant nitrogen ratio is used over a very large interval, additional calculation programs should be run to check the pressure gradient at 500-ft increments across the entire foam cement interval.

USES FOR FOAM CEMENT

A number of problems encountered in the oil field can potentially be remedied by the placement of a gas containing ultra-low-density fluid that will harden. Therefore, foam cement becomes a feasible option for the following uses:

1. Placement of extra-low-density floating cement plugs on top of liquids contained in underground storage caverns, followed by placement of normal cement on top of the plug to seal the cavern.

2. To avoid losses into zones that pressure part so that a longer column of competent cement can be placed in one stage to help eliminate problems and costs of multistage jobs that are necessary when using regular lightweight slurries.

3. Filling or sealing off cavernous or irregular *megaDarcy* lost circulation zones, thus allowing the annulus above the zone to be cemented (present cementing procedures with regular lightweight slurries place no cement above, and rarely even place cement completely across, a *megaDarcy* zone).

4. To provide thermal protection, foam cement is an excellent insulator (K = 0.15 to 0.4 Btu/hr-ft-°F) and provides insulation from cold water formations that cause paraffin deposits, insulates steam injection pipe, or protects geothermal steam production pipe.

5. To allow control of lost circulation in dry drilled (gas or air) or ordinary fluid drilled holes so that circula-

TABLE 4 — Summary of Foam Cement Jobs

Job Number	Date	Type of job	Total Depth ft	Geographical area	Field	Depth of foam cement, ft	Quantity of foam cement, sacks	Quantity of nitrogen, scf	Surface density, ppg	Foam density, ppg	Reasons for running foam	Past types of unsuccessful jobs
1)	11/79	Propane Storage	600			125	1,575	90,000	13.8	3.5-4.2	To seal off LPG storage caverns	Rapid gelling, quick setting cements
2)	01/80	Propane Storage	600			125	2,030	133,500	13.8	3.5-4.2	Same as #1	Same as #1
3)	02/80	Propane Storage	600			125	2,020	107,250	13.8	3.5-4.8	Same as #1	Same as #1
4)	10/80	Squeeze	3,200	Crane Co., Texas	McElroy	1,600	500	113,000	14.2	6-8	Large cavern with very low frac gradient	Gypsum cement, sodium silicate, lost circ. plugs
5)	11/80	4 1/2-in. Long String	6,982	Reagan Co., Texas	Spraberry	3,000–5,000	300	36,000	14.1	9.5	Low frac gradient, multiple stage tools not practical	N_2 aerated mud, silicate extender cement
6)	01/81	5 1/2-in. Long String	8,600	Howard Co., Texas		2,000–6,000	750	80,000	14.1	8.5	Same as #5	Same as #5
7)	02/81	4 1/2-in. Long String	6,915	Reagan Co., Texas	Spraberry	3,000–4,500	200	30,000	14.1	9.3	Same as #5	Same as #5
8)	02/81	Squeeze	3,200	Crane Co., Texas	McElroy	1,540	400	100,000	14.2	8.0	Same as #4	Same as #4
9)	02/81	4 1/2-in. Long String	9,500	Martin Co., Texas		2,000–5,500	450	89,000	14.8	8.5	Same as #5	Same as #5
10)	02/81	5 1/2-in. Liner	2,785	Crane Co., Texas	McElroy	Surface–1,600	150	14,000	14.8	9.0	Large cavern, low frac gradient	Large volumes of lost circ. material
11)	02/81	5-1/2-in. Long String	8,600	Carter Co., Oklahoma		6,200–8,400	490	102,000	14.6	7.5-12	Severe lost circulation	Cotton seed hulls, cement plugs
12)	03/81	2-3/8-in. Liner	8,770	Ector Co., Texas	Spraberry	4,000–7,000	650	100,000	14.8	8.5-9.0	Severe lost circulation parted pipe	
13)	03/81	5 1/2-in. Long String	8,450	Upton Co., Texas	Spraberry	2,500–6,000	450	60,000	14.1	9.0-8.5	Same as #5	Same as #5
14)	03/81	5-1/2-in. Liner	2,778	Crane Co., Texas	McElroy	Surface–1,600	125	11,000	14.8	8.5	Same as #10	Same as #10
15)	04/81	8-5/8-in. Intermediate	5,212	Ector Co., Texas	Spraberry	Surface–4,800	2,250	212,000	14.8	9.0	Needed pipe protection, low fracture gradient	
16)	05/81	5 1/2-in. Production String	9,520	Ector Co., Texas	Spraberry	500–7,500	500	90,000	15.6	9.5	Desire to tie back into intermediate string	
17)	05/81	5-1/2-in. Liner	2,805	Crane Co., Texas	McElroy	Surface–1,600	100	10,000	14.8	8.4	Same as #10	Same as #10
18)	05/81	4-1/2-in. Long String	6,400	Irian Co., Texas	Spraberry	Surface–3,600	600	35,000	14.8	9.5	Circulate cement without intermediate casing	
19)	06/81	4 1/2-in. Long String	6,400	Irian Co., Texas	Spraberry	Surface–3,600	600	35,000	14.8	9.5	Same as #18	Same as #18
20)	07/81	5 1/2-in. Long String	2,300	Freemont Wyoming		1,800	100	7,500	15.6	9.0	Insulate cold zone @ 1,800 ft paraffin problem	Continued use of solvents and scrapers
21)	06/81	7 5/8-in. Intermediate	9,491	Crane Co., Texas	Devonian	6,000–1,000	750	80,000	14.1	10.2	Low frac gradient	Not attempted
22)	07/81	4 1/2-in. Long String	6,420	Irian Co., Texas	Spraberry	Surface–3,200	600	35,000	14.8	9.5	Same as #18	Same as #18
23)	07/81	4-1/2-in. Long String	8,400	Upton Co., Texas	Spraberry	3,750–5,500	330	45,000	14.1	9.0	Low frac gradient	Silicate extended cement
24)	07/81	4 1/2-in. Long String	6,400	Irian Co., Texas	Spraberry	Surface–4,000	600	35,000	14.8	9.1	Same as #18	Same as #18
25)	07/81	4 1/2-in. Long String	7,000	Reagan Co., Texas	Spraberry	4,000–1,500	360	43,000	14.1	9.0	Same as #5	Same as #5
26)	08/81	4 1/2-in. Long String	8,350	Upton Co., Texas	Spraberry	4,000–2,500	320	42,000	14.1	8.5	Same as #23	Same as #23
27)	09/81	5-1/2-in. Liner	10,500	Lea Co., New Mex.		9,000–4,000	650	175,000	14.2	8.5	Tie back into intermediate, low frac gradient	Stage cementing
28)	10/81	4 1/2-in. Long String	8,700	Upton Co., Texas	Devonian	4,000–7,000	350	76,000	14.1	8.0	Low frac gradient	N_2 aerated mud
29)	10/81	4 1/2-in. Long String	7,150	Reagan Co., Texas	Spraberry	1,000–5,000	710	80,000	14.1	8.0	Same as #28	Same as #28
30)	11/81	4 1/2-in. Long String	6,850	Reagan Co., Texas	Spraberry	1,500–4,000	360	40,000	14.1	8.5	Same as #5	Same as #5
31)	11/81	5 1/2-in. Long String	8,350	Upton Co., Texas	Spraberry	2,500–6,000	570	80,000	14.1	9.0	Same as #28	Same as #28

tion can be re-established and drilling continued without the entry of unwanted fluid or gas into the wellbore.

FIELD APPLICATIONS

Many of the applications just cited have been attempted, and most have been successful. Following are some examples.

Use 1. Although foam cement was available as an oil well service in 1978, to the authors' knowledge it was first used in 1979. An underground LPG storage cavern leached from a salt zone was in communication with an old large-diameter 800 ft TD mine shaft that had been back-filled with rubble and abandoned. Injection wells had been placed into this shaft, and numerous normal density cement squeeze jobs had been performed, but all had been unsuccessful in relieving gas pressure on the injection wells. Apparently these slurries channeled through the LPG-saturated matrix of the shaft all the way to bottom. It was decided to apply foam cement with a density of 3.5 to 4.2 ppg in the belief that it would spread out on the top of any LPG zones and seal the matrix. After the first foam cement job, which provided about 8,000 ft^3 of foam slurry, the vapor pressure was relieved by nearly 80%, indicating the rubble had been partially sealed. Communication between the injection wells also had been modified. After two subsequent jobs, remaining escaping gas was easily controlled and removed by surface compressor units (Table 4, jobs 1, 2, and 3).

Use 2. Primary field application of foam cement to date has been in the multi-pay Spraberry field of the Permian basin in West Texas. Wells in this area are typically drilled with 8 to 10 ppg muds to TD of 6,500 to 9,500 ft with several lost circulation zones intermixed with corrosive water zones above the hydrocarbon-bearing zones. Ideally, maximum corrosion protection is accomplished when the casing-borehole annulus is filled from surface to TD with competent cement.

Surface casing generally is set and cemented back to surface from 600 to 1000 ft with few problems. Some operators elect to run an intermediate string of casing, but increased drilling times and high casing costs have made this unattractive. Also in certain areas, a severe lost circulation zone, normally not covered by intermediate pipe, lies just above the pay intervals located at 6,000 ft.

Commingled nitrogen followed by normal light density cements have allowed cement to be placed higher, but not high enough to successfully seal back to the surface pipe nor even cover all of the corrosive water intervals. Cement slurries containing large amounts of lost circulation materials also have been tried, but they so greatly exceeded parting pressure that circulation was lost. Other operators have used strategically placed, multiple-stage cementers, but this is usually not satisfactory due to the desire to avoid the expense of bringing a workover rig to location to drill out the stage tools. Instead, operators prefer to run casing down past the pay intervals with baffle rings in place in the casing string to separate the 3 to 4 zones of interest. These wells are then perforated, acidized and fracture-treated through the casing with the benefit of wireline equipment.

An operator new to the Spraberry trend was concerned about casing failures and wanted to protect the pipe with cement from a TD of 6,982 ft back to 2,500 ft. This interval contained all the problem zones in that area. In normal density jobs, cement had been brought back to only 3,500 ft primarily due to losses into a severe lost circulation zone at 4,200 ft.

The foam cement job performed on this well was based on pressure-volume calculations and knowledge of the area. The design called for a 500-ft unfoamed cement cap from 2,500 to 3,000 ft, foam cement from 3,000 to 5,000 ft and dense perforating cement from 5,000 to TD of 6,982 ft. Cement volumes were calculated and normal excesses were included. The following field procedure was followed.

- Pump 10 barrels mud flush
- Pump five barrels fresh water
- Mix 33 barrels class C 50/50 pozzolan with 2% bentonite, 6 lb salt, 1/4 lb per sack cellophane flakes and 0.5% friction reducer
- Mix 20 barrels class C with 1/4 lb per sack cellophane flakes, foam with 380 scfpb nitrogen and foaming agent
- Mix 20 barrels cement mixture, foam with 430 scfpb nitrogen
- Mix 20 barrels cement mixture, foam with 480 scfpb nitrogen
- Mix 20 barrels cement mixture, foam with 529 scfpb nitrogen
- Mix 112 barrels cement mixture as in the third step
- Displace plug to shoe.

The specified nitrogen ratios resulted in a downhole slurry density of 9.5 ppg which was 0.3 ppg lower than the fluid used to drill the well. During the cement job, circulation remained excellent. Most of the mud was displaced from the annulus.

Results were considered excellent with top of cement at 1,500 ft with good apparent bonding. The higher-than-designed top of cement achieved was believed to be due to better-than-anticipated hole conditions through the foam protected interval. This operator has since completed three additional foam cement jobs in which the amount and density of the foam slurry was varied to suit individual well conditions (Table 4, jobs 5, 7, 25 and 30).

Uses 2,3. In the McElroy field of West Texas, foam cement has been used to fill and seal off large caverns caused by leached out salt sections that also had mega-Darcy lost circulation (see Table 4, jobs 4, 8, 10, 14 and 17). Foamed cement slurries and foamed, fast-setting gypsum/portland cement slurries containing various solid lost-circulation additives have been used to successfully place cement in these cavernous zones. These jobs were primarily conducted to repair damaged pipe or condition an old hole so that a new string of pipe could be run followed by placement of a solid sheath of foam cement around the new liner to provide protection.

Past efforts in this area included salt-saturated slurries, extremely fast-setting slurries and lost-circulation plugs consisting of many different types of material. These methods were seldom successful due primarily to the excessive hydrostatic pressure exerted on the formation. Thus foam cement provided a useful solution, putting 8.5 to 9.0 ppg cement in place while staying under the zone-parting pressure.

Use 4. Operators in one area of Wyoming have experienced excessive paraffin buildup in newly completed wells. Solvents, scrapers and hot oil treatments provided only temporary relief. It was found that the cause of the problem was an abnormally cool water-bearing formation between the oil zone and surface that cooled production fluids enough that paraffin was deposited.

It was suggested that the casing be insulated from the cool zone by placement of foam cement (Table 4, job 20). The interval around 1,800 ft was successfully covered using 9 ppg foam cement and the operator has had essentially no paraffin problems in this well.

EVALUATION OF RESULTS

Success of foam cement jobs can be measured in two ways — factors noticed during the job and post-job

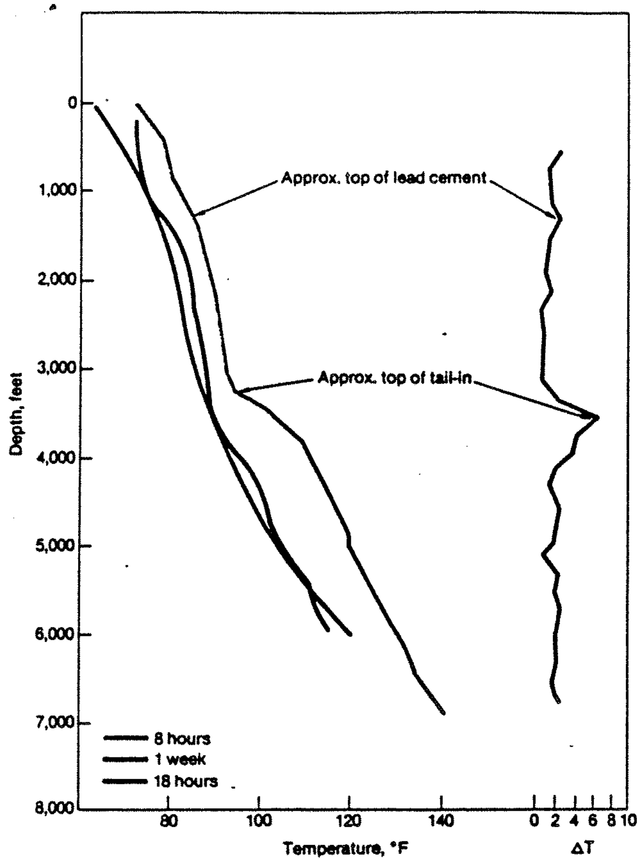


Fig. 10—Typical temperature survey of a West Texas Spraberry well shows how various cement interfaces are located behind casing.

evaluation. During the job, such things as interrupted circulation, sudden or unexpected increases or decreases in surface pressure and data about mixing and measuring procedures should be carefully recorded. Experience indicates that certain guidelines should be followed to help assure the best possible results from a foam job. These basic items are important for a successful foam cement job.

- A means of mixing a unfoamed surface cement slurry at a specified air free density with a reasonable accuracy (e.g., ± 0.1 ppg)
- Method of measuring the unfoamed slurry pump rate and total volume with an accuracy of ± 5% or better
- Techniques for introducing foam stabilizing chemicals into the unfoamed slurry or nitrogen stream with an accuracy of ± 10%
- Facilities for measuring and controlling gas injection rate based on mass or standard volume
- Injection of the gas into the unfoamed slurry stream with sufficient energy to obtain maximum stabilization
- An inline mixing device to add stability and uniformity to the foam slurry. Up to a point, higher energy provides greater stability. Inappropriate field sampling methods can easily lead to false conclusions regarding the stability of field-mixed foam cement.

Post treatment measurements using bond logs and temperature surveys have been used for evaluation of foam cement jobs. Bond logs indicate the presence of foam cement primarily through attenuation of the amplitude curve and the micro-seismogram. The amplitude curve responds to differing densities of both the conventional cements present and to the foam cements, and is helpful in location the interfaces of the two. To get the most information possible, it is recommended that the amplitude be set as high as possible to provide a greater range and therefore better resolution on the curve, which will better show changes in density.

The micro-seismogram may not show as good apparent bond through the foam as through normal density slurries, but arrival of formation signals along with each free pipe signal indicates that bonding has occurred. Correlation of the micro-seismogram with gamma ray or density logs for verification of formation signals has been found to be a helpful tool in evaluating bond quality.

Temperature surveys, run 8 to 24 hours after completion of the job, have proven valuable in locating the top of the different intervals of cement. Cap and tail-in cements will show a temperature gradient greater than normal background, while the foamed interval will be about the same as background profiles and has even shown a less than normal temperature gradient. Fig. 10 shows a typical temperature survey that located the various cement interfaces behind casing.

Evaluation of results should not be left to one graph, one chart, or one log, but rather as much information as possible should be gathered and correlated.

CONCLUSIONS

Several important conclusions have been drawn from past experiences. One is that foam cement offers many attractive properties wherever there is a need for ultra-low-density cements in the oil field. Among these are high strengths and reasonably low permeabilities.

Certain guidelines must be followed to provide good results from foam cement jobs, and these have been identified and are achievable.

Foam cement has proven to be very effective in remedying lost circulation. However, one must recognize that large volumes of foam slurry can easily be lost into a fractured formation because most foam slurries have low API fluid loss values and a very low solid volume to slurry volume ratios — the exact properties desired for an effective fracturing fluid. Therefore, successful lost circulation control with foam cement depends mainly on its low density thixotropic properties. By contrast, lightweight slurries that contain microspheres, gilsonite or walnut hulls owe much of their lost circulation control to their fracture plugging ability. For this reason, it is advantageous to incorporate solid lost-circulation materials into foam cement slurries. Cellophane flakes have been routinely used.

In addition to overcoming density limitations mandated by breakdown gradients, the successful foam cement job should always meet two general objectives. It should provide sufficient hydrostatic pressure to prevent entry of fluids or gas into the annulus. It should also provide good cement soundness and sufficiently low permeability to prevent corrosive water and/or gas from penetrating the cement sheath and affecting the casing.

Foam cement promises to be a versatile cementing service by virtue of its instantaneous density control capabilities that can be applied both to routine problems and to the most difficult of jobs.

Foam cement jobs can be evaluated using standard post-job procedures, but special precautions should be exercised when running or interpreting cement bond logs. Temperature surveys have proven to be valuable evaluation tools.

ACKNOWLEDGEMENTS

The authors extend their appreciation to Halliburton Services for permission to prepare and present this article and to the many co-workers in the lab and field who contributed their time and advice. Mr. David Lord was instrumental in adapting the calculation processes for field use, and his support is appreciated.

This article was adapted from the paper, "Oil field application of low density foamed portland cements," the authors presented to the Southwestern Petroleum Short Course held in Lubbock, Texas, April 1982.

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About the authors

RICHARD C. MONTMAN *earned a B.S. degree in geological engineering in 1978 from New Mexico State University. He joined Halliburton Services at Brownfield, Texas in 1979 and was later transferred to Rankin, Texas, where he now serves as district engineer.*

DAVID L. SUTTON *obtained a B.S. degree in chemical engineering in 1950 from Iowa State College. He worked at various positions in geophysical exploration until joining Halliburton in 1953. He worked as an engineer trainee, acidizer cementer, field chemist and division chemist in Lovington, New Mexico, then transfered to Halliburton International Operations in 1965 and established a regional field service laboratory at Wiesbaden, West Germany for European and Mid-East operations. Mr. Sutton joined Halliburton Services' CRD in Duncan, Oklahoma in 1969 as a Senior Chemist. His present position is research chemist in the Cement Section.*

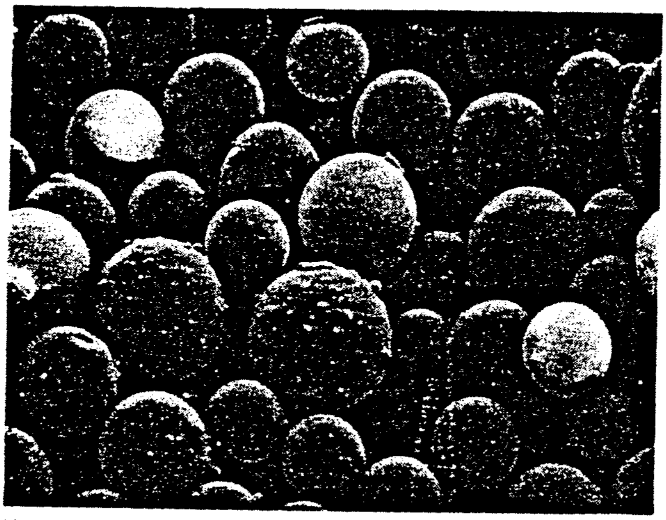
WELDON M. HARMS *is a research chemist with Halliburton Services in Duncan, Okla. He was graduated from Northwest Oklahoma State University with a B.S. in chemistry and earned a Ph.D. in chemistry from Oklahoma State University. After postdoctoral work at the University of Texas, Mr. Harms joined Halliburton in 1974. His research work has focused on light weight cements, polymeric fluid loss control agents and cement set retarders.*

BHARAT G. MODY *is a technical advisor with Halliburton Services in the Midland Division. His experience involved working in cementing research concerning various aspects of oil well cementing, combating loss circulation and subsurface water flow. Presently he is involved in enhanced oil recovery operations in the EOR Department.*

CEMENTING TECHNICAL DATA

HALLIBURTON SERVICES

SPHERELITE™ LOW DENSITY CEMENT



Halliburton's Spherelite additive, shown above at 200X, can be used to mix ultra light weight slurries that will provide relatively high compressive strengths even under low curing temperatures.

Spherelite™ cement additive provides a means of preparing 9 to 12 lb/gal light weight cementing slurries that will produce adequate compressive strength in a minimum period of time, even when the slurries are cured under relatively low temperatures. Compared to the properties of traditional light weight cement slurries, prepared principally by adding extra mixing water, the incorporation of Spherelite additive into cement slurries presents an attractive alternative method of providing light weight cement slurries that have several inherent advantages.

Proven Applications of Spherelite Cements

1. Low-density grouting mixtures.
2. Low-density cements for cementing offshore conductor and casing pipe in weak, unconsolidated formations.
3. Cementing composition for fragile permafrost formations.
4. Low-density slurry for geothermal well cement having low thermal conductivity values.
5. Low-density, thermal cement for steam-injection wells.
6. Ultra-low density cement for a floating bridge plug.

Advantages

1. Compatible with all API classes of cements.
2. Improved early compressive strength development.
3. Allows preparation of slurries having densities from 9 to 12 lb/gal.
4. Effective up to exposure pressure of 6000 psi.
5. Set cement has improved heat insulation properties.
6. Functions as a lost circulation aid.
7. Compatible with all other cement additives, retarders, dispersants, accelerators, fluid loss control chemicals, Thix-Set cement, etc.
8. Increased slurry volume yields due to the bulk density of Spherelite additive (25 lb/cu ft).

Spherelite additive consists of hollow, inorganic spheres which are competent up to 6000 psi total exposure pressure. Light weight slurries prepared with Spherelite additive will generally develop higher 24-hour compressive strength than equivalent density slurries prepared with bentonite, gilsonite, or silicate extenders. This property is illustrated in Figure 1. Figure 2 shows yield of slurry per pound of Spherelite additive used. One can use Figure 3 to estimate the quantity of Spherelite required per sack of cement to achieve any desired density under different working pressures. Ultra-low density grouting mixtures (7.8 to 8.8 lb/gal) that will yield approximately 200 psi compressive strength development in 24 hours at 65°F can be prepared with high alumina cement as indicated in Table I. Properties of Spherelite cement slurries prepared at different densities are listed in Table II. Table III presents data for slurries useful for geothermal well cementing. Thermal conductivity values for two common cementing compositions are in Table IV.

These data reflect the ability of Spherelite additive to provide low density cementing compositions having improved early compressive strength, low thermal conductivity, and improved lost circulation properties.

Table I

Slurry Properties for Grouting Mixtures having Ultra-Low Densities

Slurry Weight = 8.78 lb/gal at 1500 psi

90 lb of Fondu™[(a)] + 168 lb of Spherelite + 22.7 gal/sk water

Retarder[(c)] Percent	Thickening Time (Hours:Minutes)		Compressive Strength[(b)] psi at 65°F		
	65°F	85°F	8 hr	24 hr	72 hr
None	3:30	1:15	130	235	295
0.125%	5:00+	1:00	50	180	250
0.250%	5:00+	3:00	20	155	230
None[(d)]	5:00+	5:00+	N.S.	60	165

[(a)] Fondu is a calcium aluminate cement sold by Lone Star Lafarge, Inc.

[(b)] Atmospheric curing conditions. Strengths at 1500 psi pressure would be expected to be 5 to 15% higher.

[(c)] Halliburton CW-1, used as a retarder for Fondu cement.

[(d)] 94 lb of Class H + 2% Econolite additive + 16.6 gal/sk water, slurry density = 11.5 lb/gal at 1500 psi.

N.S. = Not Set

Table II

Slurry Properties of Cementing Composition for Normal Well Applications

80°F Compressive Strengths of Light Weight Slurries Prepared with Spherelite Cement

All slurries mixed at $w/c = \frac{0.40 \times \text{Cement} + 0.80 \times \text{Spherelite}}{94}$. All samples cured at 80°F at 2000 psi. All slurries contained 0.4% CFR-2 friction reducer based on the weight of cement.

Test Slurry				Calculated Slurry Density (lb/gal) 2000 psi	80°F - 24 Hr Compressive Strength - psi
Spherelite	Cement	Water (gal)	Other		
80 lb	94 lb Class H	25.5*	4% $CaCl_2$	9.5	50
50 lb	94 lb Class H	21.3**	3.5% $CaCl_2$	10.00	75
80 lb	95 lb Class H	12.2	3% $CaCl_2$	10.00	151
60 lb	95 lb Class H	10.3	3% $CaCl_2$	10.63	172
45 lb	94 lb Class H	8.8	3% $CaCl_2$	11.23	254
35 lb	94 lb Class H	7.9	3% $CaCl_2$	11.61	390
60 lb	90 lb Fondu™	10.3	- - -	10.45	631
45 lb	90 lb Fondu	8.8	- - -	11.03	727
35 lb	90 lb Fondu	7.9	- - -	11.40	800

*Plus 6% Econolite additive, $w/c = \frac{0.40 \times \text{Cement} + 2.18 \times \text{Spherelite}}{94}$, no CFR-2 additive.

**Plus 4% Econolite, $w/c = \frac{0.40 \times \text{Cement} + 2.80 \times \text{Spherelite}}{94}$, no CFR-2 additive.

Table III

Properties of Spherelite and Cement for Ultra-High Temperature Applications

505°F Compressive Strength Data for 11.6 lb/gal Cementing Slurries at 5600 psi Pressure

	Test Slurry				Compressive Strength (psi) 505°F - 3000 psi		
	Spherelite	Cement	Water (gal)	Other	3 Day	1 Month	3 Month
1	70.4 lb	Class G	11.39	40% SSA-1 + 0.75% CFR-2 + 0.3% HR-12	2535	1650	1195
2	68.7 lb	Class G	12.00	40% SSA-1 + 0.75% CFR-2	2115	1990	1820*
3	48.3 lb	Class J	8.91	0.4% CFR-2	1595	1455	1860
4	None	Class G	18.5**	40% SSA-1 + 3% Econolite*	490	- - -	550***

* Permeability at 3 months 0.47 md.
** This represents a 12 lb/gal slurry prepared with Econolite additive.
*** Permeability at 3 months 4.82 md.

Table IV

Thermal Conductivity of Spherelite Cement Slurries

All slurries contained 0.5% CFR-2, ΔP or drag reducer, samples cured at 500 psi for 7 days at 120°F or 1 day at 450+°F.

	Test Slurry							
	Spheres	Cement	Water (gal)	SSA-1	Other	Density (lb/gal)	Curing Temp. °F	K Value (BTU/hr - ft - °F)
1	1 cu ft Perlite	Class G	10.95	40%	2% Gel	13.6	120°F 450+°F	1.26 (average) 0.43
2	50 lb Spherelite	Fondu	11.9	65%	- - -	11.42	120°F 450+°F	0.334 0.197 (average)

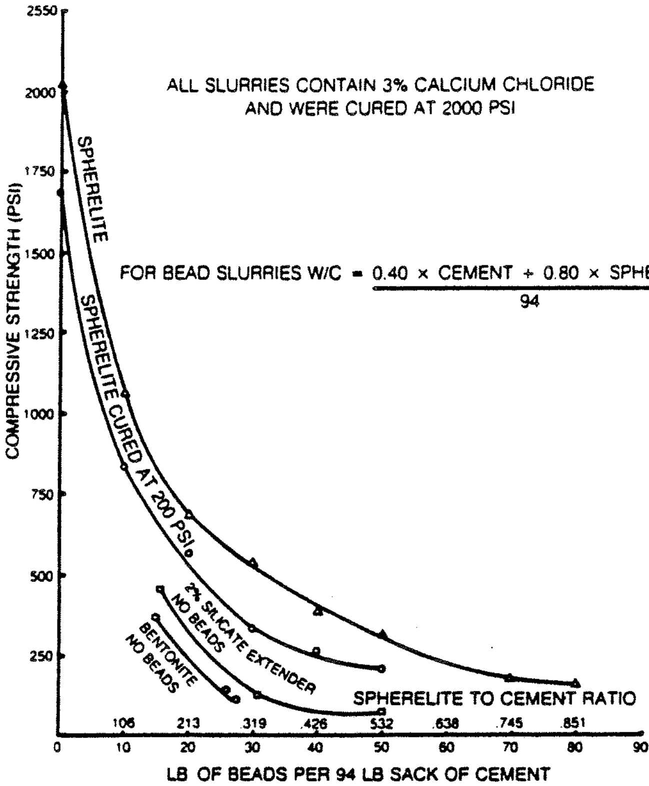


Fig. 1 - 24 hr 80°F (26°C) compressive strength for light weight slurries.

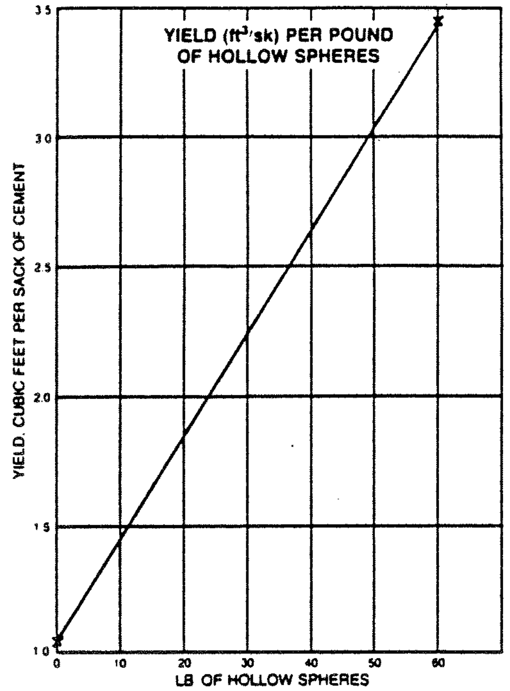


Fig. 2 - Yield (ft^3/sk) per pound of Spherelite additive.

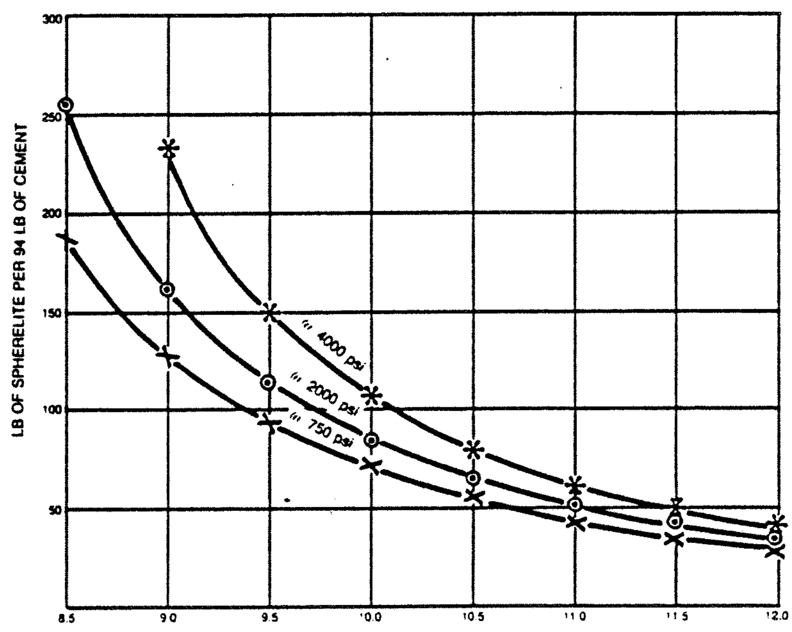


Fig. 3 - Pounds of Spherelite required per sack of cement to prepare lightweight cement slurries under varying pressures.

$$w/c = \frac{0.40 \times \text{Cement} + 0.75 \times \text{Spherelite}}{94}$$

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CEMENTING
TECHNICAL DATA

HALLIBURTON
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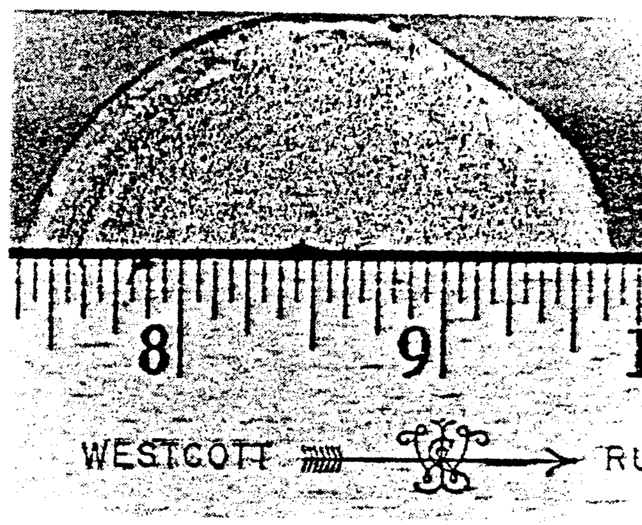
Halliburton's Foam Cement



Shown above is a sample of Halliburton's Foam Cement light enough (6.2 lb/gal) to float on water yet strong enough to exhibit over 180 psi compressive strength after 72 hr at 100°F.

Halliburton's Foam Cement makes lightweight slurries (6 to 11 lb/gal) for well cementing relatively easy to produce. Also, Foam Cement makes ultralightweight slurries (3 to 4 lb/gal) for specialty applications readily available.

Lightweight Foam Cement slurries are especially useful for cementing wells that pass through zones having very sensitive fracture gradients that have consistently failed to support the hydrostatic pressure of conventional lightweight slurries. Also, Foam Cement has potential for low density grouting mixtures and for lightweight slurries used for cementing offshore conductor and casing pipe in weak unconsolidated formations. It can also be used to form floating cement plugs on hydrocarbon or aqueous fluids.

The nature of Halliburton's Foam Cement helps make it economically attractive. It increases the yield of a sack of cement from 1 cu ft to as much as 4 cu ft depending on weight of the foamed slurry. Also, Foam Cement acts as a lost circulation aid thereby reducing the amount of other additives required. It is useful to depths of 10,000 ft and temperatures up to approximately 150°F.

Foam Cement may be formed by using readily available, standard equipment and a gas such as nitrogen. Halliburton's FMCEM computer program can provide the proper mixing rates and volumes for the desired final slurry weight.

The following case histories illustrate the effectiveness of Halliburton's Foam Cement.

- West Texas operator wanted to cement a long interval that included a lost circulation zone but did not want to perform a multiple stage job. Well data included 4-½-in. casing in a 7-⅞-in. hole with desired fill from below 9,000 ft to 3,000 ft. Lost circulation zone was from 5,500 ft to 6,000 ft. After a fluid caliper was run, Halliburton recommended 150 sacks Class C cement with 4% gel as cap cement, 450 sacks Class C cement with 0.2% HALAD®-

22 and an average of 730 scf nitrogen per barrel as lightweight cement, and 750 sacks of equal parts Class H and POZMIX® A with 6 lb salt and ¼ lb Flocele as good perforating and productive interval cement. FLO-CHEK™ 21 was recommended ahead of cement for mud removal and controlling lost circulation. Job was successfully run in one stage with top of cement within 50 ft of desired placement. Customer was pleased and plans to continue using Foam Cement.

- Operator was having problems with extreme casing leaks because of a salt section of corrosive brine water. Leaks were taking 3 to 5 bbl/min at 0 pressure. Casing was 7 in. set to 2,655 ft with leaks between 1,727 and 1,851 ft. Halliburton pumped our Foam Cement composed of 50/50 Cal-Seal foamed to 8 lb/gal followed by 200 sacks of Class C cement foamed to 8 lb/gal. When cement was displaced with fresh water, well showed 100 psi squeeze pressure indicating the leaks had been stopped.
- Mid Continent operator was having little success in cementing around the shaft of an abandoned salt mine that had been converted into a storage area for liquid propane. Gaseous propane was leaking from the shaft. Conventional and exotic methods of cementing had not been successful, in providing the desired seal. Operator contacted Halliburton. We recommended a foamed slurry of 3.9 lb/gal at 125 psi. This slurry would float on the propane and provide a bridge or anchor that would support a subsequent heavier weight slurry to permanently isolate the shaft from the liquid propane. Halliburton's Foam Cement started as a 13.8 lb/gal slurry made with Class A cement, Econolite, and calcium chloride. This job and subsequent jobs have succeeded in essentially stopping the flow of gaseous propane from the shaft.

Whether you need a lightweight slurry for cementing through problem zones, an ultralightweight slurry for specialty applications, or a slurry to provide inexpensive fillup, Halliburton's Foam Cement may meet your needs. To find out more, contact your local Halliburton representative.

COMPRESSIVE STRENGTHS OF FOAM CEMENT

Cured at Atmospheric Pressure

Class A Cement

Surface Slurry: 15.6 lb/gal (Class A, 2.0% $CaCl_2$)

Curing Temperature	65°F			100°F			140°F		
	Compressive Strength (psi)								
Density of Foam Cement (lb/gal)	12 Hr	24 Hr	72 Hr	12 Hr	24 Hr	72 Hr	12 Hr	24 Hr	72 Hr
10	130	220	490	370	630	1040	510	870	1100
8	70	190	210	230	530	720	250	430	680
6	40	100	210	150	230	300	160	340	200
4	10	50	60	60	110	140	70	110	60

Class H Cement

Surface Slurry: 16.4 lb/gal (Class H, 2.0% $CaCl_2$)

Curing Temperature	65°F			100°F			140°F		
	Compressive Strength (psi)								
Density of Foam Cement (lb/gal)	12 Hr	24 Hr	72 Hr	12 Hr	24 Hr	72 Hr	12 Hr	24 Hr	72 Hr
10	60	160	290	130	400	440	150	570	500
8	40	80	160	110	200	350	120	200	190
6	20	50	100	90	90	180	50	90	90
4	10	20	30	10	30	50	10	30	30

Class C Cement

Surface Slurry: 14.8 lb/gal (Class C, 2.0% $CaCl_2$)

Curing Temperature	65°F			100°F			140°F		
	Compressive Strength (psi)								
Density of Foam Cement (lb/gal)	12 Hr	24 Hr	72 Hr	12 Hr	24 Hr	72 Hr	12 Hr	24 Hr	72 Hr
10	50	410	1130	260	1280	1280	650	1250	1390
8	70	240	320	270	350	780	260	650	530
6	50	120	200	150	180	310	120	150	140
4	10	30	110	60	80	150	50	70	80

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Appendix B

MEETING SUMMARIES

SUMMARY OF MEETING

DATE:	November 19, 1984
SUBJECT:	Margate DIW IW-2 Project Status Meeting
LOCATION:	Department of Environmental Regulation 3301 Gun Club Road West Palm Beach, Florida
ATTENDING:	John Guidry/DER West Palm Beach Richard Deuerling/DER Tallahassee Paul Feldman/DER West Palm Beach David Butler/SFWMD Kipton Lockuff/Margate J.I. Garcia-Bengochea/CH2M HILL Gainesville Thomas McCormick/CH2M HILL Boca Raton Phil Waller/CH2M HILL Tampa Jerry Foess/CH2M HILL Boca Raton
PROJECT NO.:	FC16718.A2
PREPARED BY:	Thomas M. McCormick/CH2M HILL Boca Raton

The meeting was opened by Tom McCormick with a report on the status of construction on the new injection well. Alsay-Pippin has completed construction and testing of the injection well and the monitor well. Installation of monitoring instrumentation is complete, the monitor well has been developed to background, and the repeat TV survey of the injection well has been completed and copies of the videotape are now being made.

Jerry David is having his City Engineer prepare a drawing of his piping interconnection for review by DER.

Data collected during the initial test of the repair technique was reviewed along with the report on the tracer test dated November 6, 1984.

tmTMC/021

A question was raised concerning the 79-foot difference between the recorded cement top of 2309 feet and the depth (2230 feet) at which downward movement of the tracer was halted.

In answer to the question, Tom McCormick noted the following:

1. The recorded cement top at 2309 feet is believed to be based on an analysis of a Cement Bond Log, and may actually be the last point of solid bond to the casing. During cementing of the 24-inch casing on Margate IW-2, the first stage cement top was tagged at 2220 feet.

2. The tracer was mixed in a frac-gel with a weight of approximately 9 lbs/gallon, slightly higher than the fluid in the annulus. Should the downward movement of the tracer slug be halted by a zone of increased transmissivity, with the lighter water being injected behind the tracer moving out into the formation, then the weight of the gel should have carried the tracer downhole and there would have been a less sharp peak of gamma activity than that shown by the gamma tool.

3. The manner in which the gamma count went to a peak, maintained that peak for 55 minutes, and then sharply dropped towards background, indicated that the slug of tracer was pushed out of the range of the recording probe.

To address TAC concerns, Dr. Garcia-Bengochea recommended that a slug of neat cement be injected before starting the Nitrogen foam cement. This heavier cement would help to ensure a good seal against the existing cement top.

The repair of the well is tentatively scheduled for mid-January. This date will be accelerated, if possible.

MEMORANDUM

CH2M HILL

TO: John Guidry/DER
Leslie Bell/DER
Gardner Strasser/DER
Leslie Wedderburn/SFWMD
Bruce Kester/BCEQCB
Jack Hickey/USGS Tampa
Stallings Howell/EPA Atlanta
Jerry David/City of Margate
Tom Hissom/City of Margate
Kipton Lockcuff/City of Margate
Richard Leonardi/Haliburton Services, Texas
Darrell McFatridge/Haliburton Services, Louisiana
J. I. Garcia-Bengochea/CH2M HILL

FROM: Thomas M. McCormick/CH2M HILL

SUBJECT: Radioactive Tracer Survey Performed on Margate IW-1

DATE: November 6, 1984

PROJECT NO: FC16718.A2

On 10-23-84 a radioactive tracer survey was run in the annulus on the City of Margate old injection well, IW-1. This was a preliminary test of the proposed repair technique.

Two micro-curies of Lanthium Nitrate were mixed in 20 barrels of frac-gel and injected into the annulus of the 24" casing. Following injection of the tracer, water was pumped into the annulus to force the tracer down the annulus. The rate of pumping was varied from 1 barrel per minute to 4 barrels per minute to observe the pressures created in the annulus at the different pumping rates. A total of 879 barrels of fluid were pumped into the annulus. A gamma probe was run inside the 24" casing to track the movement of the tracer. The well stayed in service throughout the test.

The results of the test are positive, an increase in gamma ray activity was recorded all the way down to a depth of 2230 feet below pad.

The tracer remained bound in the frac-gel which appeared to move as a slug to a depth of 2220' to 2230' where downward motion was halted. Injection of water was continued while the slug of tracer and gel appeared to dissipate into the formation. The gamma count stayed elevated for 43 minutes and then rapidly dropped off to near background level.

The lack of increase in the gamma count below 2230 feet in depth could be attributed to either filling of the annular space with accumulated rock debris, an error on the recorded cement top (2309'), or the presence of a zone of such transmissivity that the gel and the tracer contaminated water pumped behind it moved into the formation rather than down the annular space.

The recorded cement top of 2309' was based on the interpretation of the cement bond log, and probably does not represent the actual top of fill in the annulus. During the cementing of the 24" casing on IW-2, first stage cement was tagged at a depth of 2220'.

In the event that the downward motion was halted by a zone of high transmissivity, the nitrogen foam cement should overcome the transmissivity of the formation and continue to migrate downhole to fill the remainder of the annulus.

Geophysical logging performed during the drilling of IW-2 does show a zone of increased transmissivity between 2180' and 2240' in depth. (Reference is made to the geophysical logging performed on Margate IW-2 on 5/8/84 and mailed with the Summary of Work dated 5/3/84 through 5/10/84.)

Haliburton's Radiation Safety Officer, Mr. Richard Leonardi, performed a physical radiation survey of the site before and after the pumping of the tracer and reported no increase in the background radiation levels at the site.

A copy of Mr. Leonardi's report is included with this mailing along with the geophysical logs performed before and after the injection of the tracer.

Data gathered during the test is summarized in tabular form attached.

TMC:015

Table 1

Time	Depth	Gamma*	Background*	Pumping Rate**	Remarks
01:00	100	05	05	1	commence injection of tracer
04:46	100	156	05	1	leading edge of tracer slug
28:42	278	200		1	travel time = 1.8 ft/min
1:12:47	390	710		2	
1:25:54	590	610		2	
1:34:30				3	pumping rate increased to 3 bpm
1:47:30	876	350		3	
1:59:00				4	pumping rate increased to 4 bpm
2:07:56	1103	680		4	trailing edge of slug
2:05:20	1165	660		4	leading edge of sludge
2:19:20	1197	750		4	leading edge of slug
2:36:30	1304	340		4	
3:17:54	1880	260		4	
3:38:04	2162	240		4	
3:43:00	2260	05		4	no sign of tracer
3:48:00	2220	200		4	downward movement of slug halted
4:40:00	2300	6		4	
4:43:00	2226	25		4	slug dissipated into formation
4:50:00	2300	5		4	gamma count remains at background

*Counts per second.
**Barrels per minute.

TMC:015a

RADIOACTIVE TREATMENT REPORT (RTR)

Well Owner *Margate City* Well Name *Sewage Disposal Well #1.*
State *Florida* County *Broward* Field *Sewer Plant*
Service Ticket No. *57,[illegible] 574366* Ticket Date *10-23-84*

MATERIAL RECORD

(Circle One)

2 - RAC-2 - I-131
3 - RAC-3 - Sc-46
4 - RAC-4 - Ir-192
5 - Tracing Sand - Ir-192
6 - Super Props
8 - Tracing Sand - I-131
9 - Tracing Sand - Ag-110m
10. La-140 (LaNO3)

P.O. Number *—* mCi *—*

R/A Material Sent to Jobsite: *2* mCi

R/A Material Used: *2* mCi

Disposition of Unused R/A Material: *Returned empty containers and dry disposables to Duncan, Ok, for*

Type of Service: *waste processing.*

Survey Meter Used:

Make *Ludlum Model 14-C*
Serial Number *21154*
Last Calibrated *10/15/84*

Exposure Data:

Dosimeter
Make
Serial Number
Reading Before
Reading After

PHYSICAL RADIATION SURVEYS

Vehicle Survey *Bkg. = 0.02 mR/hr.* *Bkg. = 0.02 mR/hr.*

After Vehicle loaded:

Side *0.02 mR/hr.*
Front *0.02 mR/hr.* Rear *0.5 mR/hr.*
Side *0.02 mR/hr.*

Prior To Return To Camp:

Side *0.02 mR/hr.*
Front *0.02 mR/hr.* Rear
Side *0.02 mR/hr.*

	Before	After
Delivery Vehicle	*Bkg.*	*Bkg.*
~~Blender Tub~~ *(2) 10 BBL Cement Pump Tanks*	*Bkg.*	*[illegible]*
Job Area	*Bkg.*	*Bkg.*
Waste Pit ** No Pit*	*—*	*—* *No pit*
Personnel Clothing	*—*	*—*

1. Indicate position of source in vehicle with X
2. Measure and record radiation at each extremity of the vehicle
3. Place copy of vehicle when transporting radioactive sources

* All meter readings expressed in mR/hr unless otherwise stated, and taken as near the surface as is reasonable.

Job Area During Tracer Injection *0.5 mR/hr.*

Signature of Qualifying Operator Emp. No. Badge No

Signature of Raytrac Operator *R.A. Leonardi Jr.* Emp No *C5837* Badge No *044819*

Halliburton Camp *Felda, Florida* Date *10-23-84*

Immediately upon completion of job, complete this form and mail to Halliburton Services, Attention: Dan G. Kelly, Drawer 1431, Duncan, OK 73536. You must keep a copy of this report for your R/A files for inventory purposes.

CH2M HILL

SUMMARY OF MEETING

Date: August 22, 1984

Subject: Part I - Repair of Margate IW-1

Location: Office of the City Manager
Margate City Hall

Attending: Tom Hissom/City of Margate
Jerry David/City of Margate
Kipton Lockcuff/City of Margate
Mayor Wiesinger/City of Margate
Thomas McCormick/CH2M HILL

Project: FC16718.A2

Prepared by: Thomas M. McCormick

Mr. Hissom and Jerry David reviewed the reasons for performing the repair work. Mr. Hissom questioned the need to perform the repair. Tom McCormick pointed out that if the well was not repaired, DER would require that it be abandoned, and part of the abandonment procedure would involve plugging the annulus. Total cost for abandonment would be within the range of $225,000.00. Obviously not in Margate's best interest.

Tom McCormick outlined the reasons for separating the repair work into two distinct steps: Part I, Test of the Technique, and Part II, Repair of the Well. The primary reason for separating the two is to allow a more careful analysis of the performance of the technique before committing funds and resources to the repair.

Tom McCormick reviewed for Mr. Hissom and Mayor Wiesinger the expected sequence of work and its associated costs. No dollar figure was presented for the Well Driller or for CH2M HILL.

Mayor Wiesinger requested clarification of a statement in Jerry David's memo to the Commissioners concerning possible collapse of the casing. Jerry David stated that the possibility was remote but it did need to be recognized.

Tom McCormick supported Jerry David and referred to the paragraph in his proposal concerning "Hold Harmless" clauses that might be expected from Haliburton. The possibility is remote but must be recognized.

Mr. Hissom and Jerry David discussed the possibility of negotiating a price with a local driller. The amount of actual work required of the driller would be small, and the major risk is born by the City in any event. The primary reason for having a driller onsite is to allow Haliburton to function as a service company and not contract directly with the City. In addition, DER does require the work be performed by a licensed driller. If the work was placed for bid, prices are expected to fall between $125,000 and $330,000, the range on the original contract. The cost of the work, exclusive of negotiated payments to the driller and CH2M HILL's expenses is anticipated to be between $80,000 to $85,000.

In view of the potential savings to the City, Mr. Hissom decided to ask the City Commissioners for permission to negotiate the work with a driller.

Tom McCormick presented a copy of the attached proposal.

TMC:33

MEMORANDUM

CH2M HILL

TO: The File

FROM Tom McCormick

DATE: August 6, 1984

SUBJECT: Proposed Repair of Margate IW-1

LOCATION: CH2M HILL offices, Deerfield Beach

ATTENDING: Jerry David/City of Margate
Kipton Lockuff/City of Margate
J. I. Garcia-Bengochea/CH2M HILL
Dick Bedard/CH2M HILL
Tom McCormick/CH2M HILL
Omur Akai/CH2M HILL

PROJECT NO. FC16718.A2

J. I. Garcia-Bengochea briefly summarized the past history of the repair project and the events that brought it to its current status.

CH2M HILL's discussions with Haliburton and Alsay-Pippin were reviewed. Haliburton can only perform as a service company and will not contract directly with the City of Margate. Alsay-Pippin, initially not interested in the additional work, would perform the work on a time and material basis but this was unacceptable to the City.

Dick Bedard raised the question of liability for the risk of damage to the well during the repair effort. The probability of damage to the well is very low, but the cost of such damage could be very great. Given the number of unknowns involved in the repair process Dick suggested that Margate consider the use of a "Hold Harmless" clause in their agreement with CH2M HILL.

Tom McCormick outlined in detail three basic sequence of events that could occur during the repair attempt and the costs associated with each.

A. Nitrogen foam cement is placed to the existing cement top at 2309'.

B. Nitrogen foam cement is placed to a flow zone and then displaces into the formation leaving a portion of the annulus uncemented. This would necessitate perforation of the casing and placing of additional cement via the squeeze packer method.

C. Cementing operations in some manner damage the existing casing, necessitating further work to repair the well.

Following the discussion of potential difficulties, Tom McCormick asked if it would be possible to break the repair program into two parts. Part I would consist of a test of the repair technique, involving only Haliburton and CH2M HILL. Part II would consist of the actual repair involving CH2M HILL, Schlumberger, Haliburton and the Drilling Contractor. Separating Part I from Part II would allow the the engineer and the owner time to modify the repair technique if necessary.

All parties judged this to be a prudent way to proceed.

CH2M HILL will prepare an estimate of costs for Part I, along with a chart outlining the potential event sequences for Part II and their associated costs.

TMC:27

MT6 - 8-6-85

REPAIR OF MARGATE INJECTION WELL IW-1

1. Delivery of the 24" gate valve for IW-2 is scheduled for August 20, installation of both wellheads should be complete by August 31.

   Delivery of the Curry Control Package is scheduled for September 14, with installation complete by September 28.

Original Contract Sum				$2,525,500.00
Amount paid out as of estimate #4			$2,072,675.54	
Item	Item	Amount		
	Inj. well			
33	Wellhead	$ 15,000.00		
33	Demob	14,980.00		
	Monitor well			
17	Wellhead	6,500.00		
18	Site Clean-up	2,000.00		
		38,480.00		
Change Order - Curry Controls		800.00±		
Release of Retainage		109,086.91		
			$148,366.91	
Amount remaining on Contract				303,687.85 $±304,487.55

3. Proposed Schedule of Events

I. Preparation of site and collection of baseline data

1. Install potable water connection to injection well for flushing of well prior to running T.V. survey.

2. CH2M HILL logs well, caliper and gamma for basline data (using Deep Venture Riser and Pack-off).

3. Margate injects potable water for 1 day ± (Twice casing volume = approximately 110,000 gallons)

4. Deep Venture performs preliminary survey.

II. Test Injection of $I2_2^{131}$ tracer

5. Haliburton injects I_2^{131} tracer into existing annulus tap.

6. CH2M HILL tracks tracer front with gamma tool.

III. Decision to proceed is made based on results of gamma logs from step f. If results are negative see V.

7. If results are positive, Haliburton kills the well and the annulus.

8. City forces modify the wellhead by placing two additional 2" taps into the annulus at 120° from the existing tap.

9. Schlumberger runs a baseline CBL.

10. CH2M HILL runs a baseline T° log.

11. Haliburton sets-up and pumps N_2 foam cement with I_2^{131} tracer using the bullhead method.

12. CH2M HILL runs gamma during cementing, caliper and T° after 12 hours of setting time.

13. Schlumberger runs confirmation CBL.

MTG NOTES 8-6-85

IV. Decision is made concerning the results of the N_2 foam injection.

14. If IV is positive City commences injection of potable water to flush casing for T.V. inspection.

15. Deep Venture runs a color T.V. survey.

16. IW-1 goes back into service.

17. CH2M HILL prepared engineering report.

18. A presentation concerning the repair is made to TAC.

VI. Several events could substantially alter the manner in which we approach the repair of the well - if:

A. During the initial test of the procedure we are unable to track the I_2^{131} Tracer below a given depth: we will have to determine whether a transmissive zone or a formation squeeze against the casing is blocking the downward movements of the Tracer.

B. During the cementing operation we have an equipment failure: we should have 15 to 30 minutes of slack time before the cement begins to act up. It will be our option to either effect a repair, continue pumping, or attempt to reverse out the cement already placed.

C. Following cementing of the well we find cement has not moved below a certain depth: We then perforate and continue cementing using the Packer Method of squeeze cementing.

D. Follow cementing of the well we find that the casing has collapsed: At this point we would investigate the possibility of performing a pressure test to determine the integrity of the casing.

4. Contractors/Subcontractors

1.	CH2M HILL Engineers		$30,000
2.	CH2M HILL Geophysical		2,000
3.	Haliburton	- Killing of Well & Annulus Injection of I_2^{131} Tracer	1,190

MTG NOTES
8-6-85

		- N_2 Foam Cement	51,703
		- Squeeze Packer	40,000
4.	Schlumberger	- Cement Bond Log	8,400
		- Casing Punch	4,000 (per 4 holes)
5.	Deep Venture	- Color T.V.	7,000
6.	Morton Well Driller		?

TMC:26

SUMMARY OF MEETING

CH2M HILL

SUBJECT: City of Margate Deep-Injection Well System

DATE: March 8, 1983 (11:30 a.m.)

LOCATION: DER Offices, West Palm Beach, Florida

ATTENDEES:
Leslie Bell/DER, Tallahassee
Roy Duke/DER
John Guidry/DER, West Palm Beach
Gardner Strasser/DER, West Palm Beach
Abe Kreitman/SFWMD, West Palm Beach
Leslie Wedderburn/SFWMD, West Palm Beach
Bruce Kester/BCEQCB, Broward County
Fred Meyer/USGS, Miami
Craig Brown/EPA-IV
Gene Coker/EPA
Jerry David/City of Margate
Tom Hissom/City Manager, City of Margate
C. L. Chandler/Halliburton Service
John Dumeyer/CH2M HILL, Boca Raton
J. I. Garcia-Bengochea/CH2M HILL, Gainesville

Summary prepared by J. I. Garcia-Bengochea March 11, 1983.

1. Fred Meyer asked for the outline of the program to cement the injection well annulus using the foam cement proposed by Halliburton. Garcia-Bengochea described the outline of the proposed program which is attached. Clarence Chandler (Halliburton) went into details of program, showed samples of 2" x 2" briquets prepared with Margate water and different cements. Results of compressive strength of briquets cured at 80°F and 500 psi is as follows:

   - Foam cement, slurry weight 8.5 lb/gal after 24 hours = 270 psi
   - Foam cement, slurry weight 8.5 lb/gal after 72 hours = 525 psi
   - Standard Gilsonite cement (as presently used) after 24 hours = 170 psi
   - Standard Gilsonite cement (as presently used) after 72 hours = 385 psi

   Chandler explained that slurry weight is controlled by how fast cement is mixed and how fast N_2 is supplied. He also stated that Halliburton has been using foam cement now for 4 to 5 years, mainly in the high-cement-loss areas of western Texas.

2. Bruce Kester asked if the foam cementing program, as explained, could be done without discharging effluent to the canal. Garcia-Bengochea answered yes.

3. The question of how to show that the cement has been properly placed was raised. Garcia-Bengochea explained that the comparison of CBL before and after cementing would show where the cement was placed. Chandler explained that CBL in a 24-inch casing with foam cement would show low strength cement or poor cement bond because of the size of the casing but that it would definitely show the presence of the cement.

4. Another question raised was the protection of the casing against collapsing during the cementing operation. Chandler responded that Halliburton planned to never exceed 60 psi as the injection pressure into annulus.

5. The question of the permeability of foam cement was also brought up. Chandler explained that properly mixed and placed foam cement would have air permeability less than 1 millidarcy after setting and much less water permeability.

6. Fred Meyer asked the difference in cost between Spherelite and foam cements. Garcia-Bengochea answered approximately 2 to 1. Chandler emphasized that in his opinion foam cement would do a better job.

7. Fred Meyer asked what had to be done if cement does not go beyond 1,600 feet. Garcia-Bengochea answered that the purpose of the radioactive tracer test before cementing would indicate if cement would or would not go below 1,600 feet. All indications are that it would. If it does not another repair method would have to be selected.

8. Bruce Kester brought the point that his agency, BCEQCB, considers the drilling and placing into operation of another injection well is of first priority. Kreitman asked time of completion for second well. Garcia-Bengochea estimated 12 months.

9. Leslie Wedderburn explained that the proposed plan to cement annulus would compromise the effective monitoring of the upper saltwater and brackish aquifers and that a new shallow monitoring well (±1,600 feet) would have to be considered.

10. It was agreed to request CH2M HILL to submit the proposed outline of the program in writing and for the City of Margate to submit an application for a permit to re-establish the integrity of the system by next week and then to have another TAC meeting the following week.

Meeting adjourned at 1:20 p.m.

gnCR7

FC16718.AO

CITY OF MARGATE

OUTLINE OF PROGRAM TO CEMENT INJECTION WELL ANNULUS
USING HALLIBURTON FOAM CEMENT
Prepared by J. I. Garcia-Bengochea
(February 14, 1983)

ASSUMPTIONS:

1. Use "Foam Cement" as recommended by Halliburton.

2. WWTP effluent will not be discharged to Margate Canal during cementing operations.

3. Any work inside the 24-inch casing will be done between 11:00 p.m. and 6:00 a.m. (low flow period) when injection pumping can be temporarily stopped letting the wastewater accumulate in the chlorine contact chamber and pumping station wet wells.

GENERAL PROCEDURE:

1. First Night:

   - Run CBL of 24-inch casing for background information.

   - Run gamma log inside 24-inch casing for background information.

RATE

2. Second Night:

   - Insert gamma probe inside 24-inch casing.

     microcurie

   - Inject 10 cc of Iodine 131 (half life 8 days).

   - Inject freshwater after Iodine 131 at highest rate possible (± 200 gpm) to displace Iodine 131 down into annulus.

   - Follow Iodine 131 with gamma probe and determine if Iodine 131 reaches 2,300 feet in depth.

   - If it does, remove gamma probe and continue with step 3.

3. Third Night:

   - Pump into annulus without interruptions:

     (1) 100 barrels of Bentonite-Water Spacer.

5 microcurie foam cement

(2) 400 sacks of Florida "H" cement + 25% Gel + 4% $CaCl_2$ + 10 lb/sac (4,000 ponds) of Cal Seal. Slurry weight 11.7 lb/gal.

(3) Pump 1,927 sacks of Florida "H" cement + 3% $CaCl_2$ + 2.25% foamer + 40.18 SCF of N_2 per sack. Slurry weight 8.5 lb/gal.

(4) Shut annulus. Hold pumping into well as much as possible in order to give cement time to set before any disturbance.

4. Eighth Night:

- o Run CBL of 24-inch casing to check coverage of cement.

Alternate During Third Night:

- o Pump radioactive tracer with (1), (2), and (3) above.

- o (5) Insert Gamma probe inside 24-inch casing after shutting annulus off and determine distribution of radioactive tracer behind casing.

gnCR7

Appendix C

GEOPHYSICAL LOGGING PERFORMED DURING THE INITIAL TRACER TEST OF THE REPAIR TECHNIQUE
OCTOBER 1983

Appendix D

GEOPHYSICAL LOGGING

Runs Prior to Placement of the
Spherelite Cement

CH2M
HILL

RECORD OF UNDERWATER TV SURVEY

Project: Repair of City of Margate Deep Injection Well IW-1

FC16718.A8

Well: City of Margate Deep Injection Well IW-1

Survey By: Deep Venture, Route 2, Box 329-B, Perry, Florida 32347

Survey Date: April 6, 1985 Total Depth of Survey: 2459'

Total Depth of Well: 3200'

Witnessed By: L. Hayden, Deep Venture

T. McCormick, CH2M HILL

Reviewed By: T. McCormick Date: April 19, 1985

Remarks: This survey preceded the repair of the well. The purpose of the survey was to inspect the condition of the casing prior to the pressure injection of spherelite cement into the annular monitoring system and to provide a basis for comparison for inspection of the casing following placement of cement. No evidence of the cause of the contamination of the annular space was detected during the TV survey. Casing welds were noted at the depths recorded below. Many joints were not evident, probably due to the build-up of calcium carbonate/grease sludge. This material appears to become thicker towards the base of the casing. Estimates of the thickness of the coating vary from 1/4 inch to 1 inch. At 2447 feet in depth there is unidentified debris in the well bore and since the cement bond log indicated a cement top at 2300 feet, the decision was made to not risk loss of the camera in an attempt to survey the final 10 feet of the casing. Casing joints recorded at:

Depth in Feet		OBSERVATIONS
From	To	
213		Casing joint
240	370	Silt or salt reduces clarity of picture
548		Casing joint
590		Casing joint

CH2M
HILL

RECORD OF UNDERWATER TV SURVEY

Project: Repair of City of Margate Deep Injection Well IW-1

FC16718.A8

Well: IW-1 Date: 4/6/85 Total Depth: 2459

Depth in Feet From	To	OBSERVATIONS
631		Casing joint
711		Casing joint
796		Casing joint
910		Casing joint
1079		Casing joint
1208		Casing joint
1250		Casing joint
1290		Casing joint
1455		Casing joint
1579		Casing joint
1623		Casing joint
1745		Casing joint
1787		Casing joint
1828		Casing joint
1904		Casing joint
1938		Casing joint
1979		Casing joint
2096		Large patch of coating material dislodged
		from wall, no evidence of damage to casing.
2146		Coating material appears to be "built up".
		No evidence of damage to casing or sign of

CH2M
HILL

RECORD OF UNDERWATER TV SURVEY

Project: Repair of City of Margate Deep Injection Well IW-1

FC16718.A8

Well: IW-1 Date: 4/6/85 Total Depth: 2459

Depth in Feet From	To	OBSERVATIONS
2146 (continued)		flow exiting well bore.
2152		Casing joint
2227		Casing joint
2265		Casing joint
2303		Casing joint
2373		Casing joint
2411		Casing joing
2443		Disturbed area on casing wall appears to be the result of the CBL tool passage.
2446	2459	Unidentified debris in the well bore, might be airline or drill pipe.

TMC2/1002

Runs During Placement of the Spherelite Cement

Runs Following Placement of the
Spherelite Cement

CH2M
HILL

RECORD OF UNDERWATER TV SURVEY

Project: Repair of City of Margate Deep Injection Well IW-1

FC16718.A8

Well: City of Margate Deep Injection Well IW-1

Survey By: Deep Venture

Route 2, Box 329-B, Perry, Florida 32347

Survey Date: April 9, 1985 Total Depth of Survey: 2447

Witnessed By: L. Hayden, Deep Venture

T. McCormick, CH2M HILL

Reviewed By: T. McCormick Date: April 19, 1985

Remarks: This survey was completed following the repair of the well by bullhead injection of spherelite cement into the annular monitoring system. The purpose of the survey was to inspect the condition of the casing to determine if any harm had resulted from the pressurizing of the annulus. The survey confirmed that no physical damage had occurred to the casing during the repair. After considerable examination of the unidentified debris between 2447 and 2459 feet in depth, the item appears to be a portion of cement line, twisted and pushed to one side by passage of a drilling tool. Since this item represents a considerable hazard to the recovery of the video camera it was decided to not attempt a survey to the complete depth of the well.

Depth in Feet		OBSERVATIONS
From	To	
213		Casing joint
241		Casing joint
290		Casing joint
375		Casing joint
630		Casing joint
710		Casing joint
796		Casing joint

CH2M
HILL

RECORD OF UNDERWATER TV SURVEY

Project: Repair of City of Margate Deep Inejction Well IW-1

FC16718.A8

Well: IW-1 Date: 4/19/85 Total Depth: 2447

Depth in Feet		OBSERVATIONS
From	To	
1207		Casing joint
1249		Casing joint
1289		Casing joint
1455		Casing joint
1490		Casing joint
1785		Casing joint
1828		Casing joint
1904		Casing joint
1936		Casing joint
1781		Casing joint
2061		Casing joint
2094		Casing joint
2104		Casing joint
2144		Casing joint
2227		Casing joint
2264		Casing joint
2302		Casing joint
2335		Casing joint
2372		Casing joint
2411		Casing joint

CH2M
HILL

RECORD OF UNDERWATER TV SURVEY

Project: Repair of City of Margate Deep Inejction Well IW-1

FC16718.A8

Well: IW-1 Date: 4/19/85 Total Depth: 2447

Depth in Feet From	To	OBSERVATIONS
2435		Disturbed area on casing well appears to be the result of the passage of the CBL tool.
2447	2459	After extensive viewing the debris appears to be a portion of a cement line, twisted off and pushed to one side.

Appendix E

RELEVANT CORRESPONDENCE

CH2M HILL
Engineers
Planners
Economists
Scientists

RECOMMENDATION TO UTILIZE SPHERELITE CEMENT IN LIEU OF NITROGEN FOAM CEMENT

SUMMARY

During calculations of gas volumes required for injection of the nitrogen foam cement, Halliburton has determined that they will not be able to comply with the 60 psi pressure constraint imposed by CH2M HILL to protect the casing from damage.

RECOMMENDATION

During investigations of the feasibility of the bullhead injection technique for repair of the injection well, Spherelite Cement was initially recommended as the appropriate material for filling the annular space. While costing out the material required, the Cementing Contractor, Halliburton Services, recommended that a relatively new service, Nitrogen Foam Cementing, be considered because of economy, reduced cement loss, and the ability to produce a foamed cement of very low density and very low transmissivity.

The performance of this cement was analyzed based on a static density of 8.5 lbs/gallon and in 1983 CH2M HILL recommended that the City utilize the Nitrogen Foam Cement as the material for filling the open annular space during repair of the well.

Because of the high cost of the bids received for repair of the well, the City chose to not award the repair portion of the contract and in 1984 requested that CH2M HILL investigate the possibility of the City performing a major portion of the work with City forces.

As part of that investigation, CH2M HILL performed a Radioactive Tracer Test on the annulus of the well.

This test yielded two important items of data, the annulus is open to fluid flow to the existing cement top at 2030 feet, and the 60 psi pressure constraint placed by CH2M HILL is approached at very low pumping rates. Halliburton expressed some concern over these low pumping rates because their cement foaming equipment was not designed to perform at such low rates.

In light of this concern, CH2M HILL asked that Halliburton carefully review their calculations and procedures to ensure that the cement foam would not degenerate at low injection rates.

It was during this review process that Halliburton noted an aspect of bullhead injection of foamed cement that was not recognized at the time that the first recommendation was made.

Because of the compressibility of the gas, Nitrogen Foam Cement behaves as a dynamic density fluid until it ceases to move within the hydrostatic column. The density of fluid injected at the surface varies considerably from that of the fluid once it reaches its intended point in the annulus. Increasing hydrostatic pressure as the cement moves down the annulus compresses the gas and increases the density of the gas entrained cement mixture. To achieve the design density of the cement (8.5 lbs/gallon) at a given depth, one must initially injection a cement mixture that is much less dense. Calculations are performed as noted in the attached letter from Mr. Bruce Thomas, Division Engineer with Halliburton Services. These calculations are performed by computer because they become quite complex as the hydrostatic pressure of the foam cement column varies continuously with depth and amount of nitrogen entrained in the cement foam.

In a direct injection cement job, these calculations are important for cement quality control but they do not materially effect the apparent surface pressure because one is continually relieving the the hydrostatic pressure at the surface as fluid is displaced from the well.

With bullhead injection, the fluids are displaced from the bottom of the column into the formation and the energy necessary to perform this work is reflected at the surface as increasing pressure. As the fluid being pumped into the annular space decreases in density, there is a corresponding increase in pressure.

When Halliburton commenced their gas volumetric calculations, it became apparent that if the bullhead injection technique is to be utilized in repair of the well, the apparent surface pressure will quickly exceed the 60 psi pressure constraint placed by CH2M HILL.

The 60 psi pressure constraint is conservative. However, since any damage to the well could result in tremendous expense to the City, CH2M HILL cannot recommend relaxation of that constraint.

On January 30, 1985, Mr. Bruce Thomas, Division Engineer for Halliburton Services, Mr. David Onan, Senior Chemist of Halliburton Services Research Center, Dr. Ignacio Garcia of CH2M HILL, and Mr. Tom McCormick of CH2M HILL, met to discuss the remaining options available for repair of the well.

Any attempt at placing the cement via a tremie method was eliminated because of the almost certain risk that the tremie would either not make it to an appropriate depth or would be come hung in the hole during removal, thus jeopardizing the utility of the well.

Direct injection was eliminated because of the expense of casing perforation and placement of packers.

Pressuring of the casing with a retrievable downhole packer was eliminated because of the expense of the unit and the need for a large rig capable of setting the packer at the required depth.

After review of these options, the recommendations of CH2M HILL is that the City continue with the bullhead injection technique and utilize the spherelite cement originally recommended as a plugging material.

At the request of CH2M HILL, Halliburton has prepared a Service Analysis of the cost for Spherelite Cement (copy attached). The advantages of this material are that it can be placed as a static density material, it is very stable with regards to degeneration of the cement fluid, and can be plumped at the very low rates necessary to remain within the 60 psi pressure constraint.

HALLIBURTON DIVISION LABORATORY

HALLIBURTON SERVICES, A DIVISION OF HALLIBURTON COMPANY
LAUREL, MISSISSIPPI

LABORATORY REPORT

No. L. C. 1327A-84

To Mr. B. D. Thomas
HALLIBURTON SERVICES
Shreveport, LA 71101

Date 12-28-84

We give below results of our examination of cement and cement additives from Ft. Myers, FL. Mixing water from location and Laurel Tap.

Submitted by Mr. Thomas

Marked CH2-Hill, City of Margate Injection Well #1, Broward Co., FL; BHST 80°F, 1500', Csg. Conds.

	CEMENT	ADDITIVES	WATER RATIO Gal/Sk	SLURRY WT. Lbs/Gal	SLURRY VOL. Cu Ft/Sk	T. T. T. Hrs/Min
(1)	H.Y.B.C.	1.5% Howco Suds 0.75% HLX-C267	5.2	15.6	1.18	9:20
(2)	H.Y.B.C.	1.5% Howco Suds 0.75% HLX-C267 0.15% HR-4	5.2	15.6	1.18	9:00+
(3)	H.Y.B.C.	25% Gel 10 lbs./sk.CalSeal 2.5% $CaCl_2$	19.0	11.86	3.22	4:40
(4)	H.Y.B.C.	25% Gel 10 lbs./sk.Cal-Seal	19.0	11.86	3.22	10:00+
(5)	H.Y.B.C.	25% Gel 10 lbs./sk.Cal-Seal 5.0% $CaCl_2$	19.0	11.86	3.22	3:20
(6)	H.Y.B.C.	1.5% Howco Suds 0.75% HLX-C267	5.2	15.6	1.18	8:00
(7)	H.Y.B.C.	25% Gel 10 lbs./sk. Cal-Seal 1.0% $CaCl_2$	19.0	11.86	3.22	7:45

TIME TO TEMP	FINAL TEMP	FINAL PRESSURE
0 Minutes	80°F	500 psi

RHEOLOGY @ 80°F

RPM		CENTIPOISES			
			(*)	(**)	(***)
600	(3)	62	3	4	10
300		52	2	3	6
200		48	1.5	2.5	5
100		43	1	1.5	3.5

(3) K' .1582

N' .2039

COMPRESSIVE STRENGTHS: Cured @ 80°F, atmospheric pressure & 100% Humidity.

	12 Hours	24 Hours	48 Hours	72 Hours
(1)		165 psi		290 psi
(6)	90 psi	190 psi	400 psi	650 psi
(7)	190 psi	200 psi	220 psi	265 psi

*3 lbs./bbl. Bentonite flush
5 lbs./bbl. Bentonite flush
*10 lbs./bbl. Bentonite flush

Slurries (1), (2), and (3) were mixed with Laurel Tap Water.

Slurries (4), (5), (6) and (7) were mixed with water from location.

Respectfully submitted,

.aboratory Analyst

RS-KL-LW-GG-SF/mfa

cc: A. F. Strange, E. L. McElrath

HALLIBURTON SERVICES

By Randy Sullivan

CHEMICAL RESEARCH AND DEVELOPMENT DEPARTMENT

HALLIBURTON SERVICES
DUNCAN, OKLAHOMA

LABORATORY REPORT

No. C14-H005-85

To Mr. B. D. Thomas
Halliburton Services
Shreveport, LA

Date February 20, 1985

We give below results of our examination of an 8.5 lb/gal slurry design for disposal well application.

Submitted by Bruce Thomas - Division Engineer

Marked City of Margate IW-1 disposal well; Margate, Florida

PURPOSE

The purpose of this project was to determine the feasibility of using an 8.5 lb/gal foamed cementing composition for annular cementing (bullhead) of a waste water disposal well.

Submitted (by CH_2M Hill) design criteria consisted of a 1,000 psi maximum bottom hole pressure and a 60 psi maximum wellhead pressure. The latter was established on the basis of casing collapse pressure using a pipe corrosion factor.

CONCLUSIONS AND DISCUSSION

A preliminary investigation into the maximum wellhead pressure to be expected during this operation (using a current foam cement SLURRY-FLO computer program) indicated that excessive pressure would result during the initial stages of nitrogen injection. This became evident using both 15.6 lb/gal and 11.9 lb/gal starting surface slurry densities. Refer to Figures 1 and 2. These figures illustrate hydrostatic pressure with and without friction pressure based on a pump rate of 4 bbl/minute.

Because of the submitted constraint on wellhead pressure, it became necessary to secure an alternative slurry design. The slurry selected for final slurry design consisted of the following:

HYBC + 217 lb SPHERELITE/sk + 9.4 lb Cal-Seal/sk + 12.5 lb gilsonite/sk + 6% $CaCl_2$, 33.85 gal water/sk; Slurry weight (@ 1,000 psi) - 8.5 lb/gal, Slurry volume (@ 1,000 psi) - 9.68 cu ft/sk.

Test results indicated that this composition would provide a pumping time of 10 hours, 40 minutes, a transition time (time to reach 500 lb/100 ft^2) of 1 hour, 28 minutes, and 2 and 7 day compressive strengths of 25 psi and 65 psi, respectively. This composition was determined to have, after curing 7 days at 80°F, a porosity and permeability (to water) of 44.2 percent and 48.0 millidarcies, respectively.

Friction pressure calculations were performed using "EQFRC" based on 2 sectors, 24 in. casing in 30 in. casing and 24 in. casing in 34 in. hole (radioactive caliper). Maximum friction pressure was determined to be approximately 45 psi based on an average 8.25 lb/gal downhole density. The EQFRC outputs are provided in the Data Section of this report. The tail cement shown in these outputs represents the aforementioned SPHERELITE composition.

SCOPE AND PROCEDURE

Wellhead pressures using foam cement were determined utilizing a current foam cement SLURRY-FLO computer program (Hewlett-Packard) being modified for TSO.

Where applicable, tests were conducted according to API Spec 10, "Specification for Materials and Testing for Well Cements."

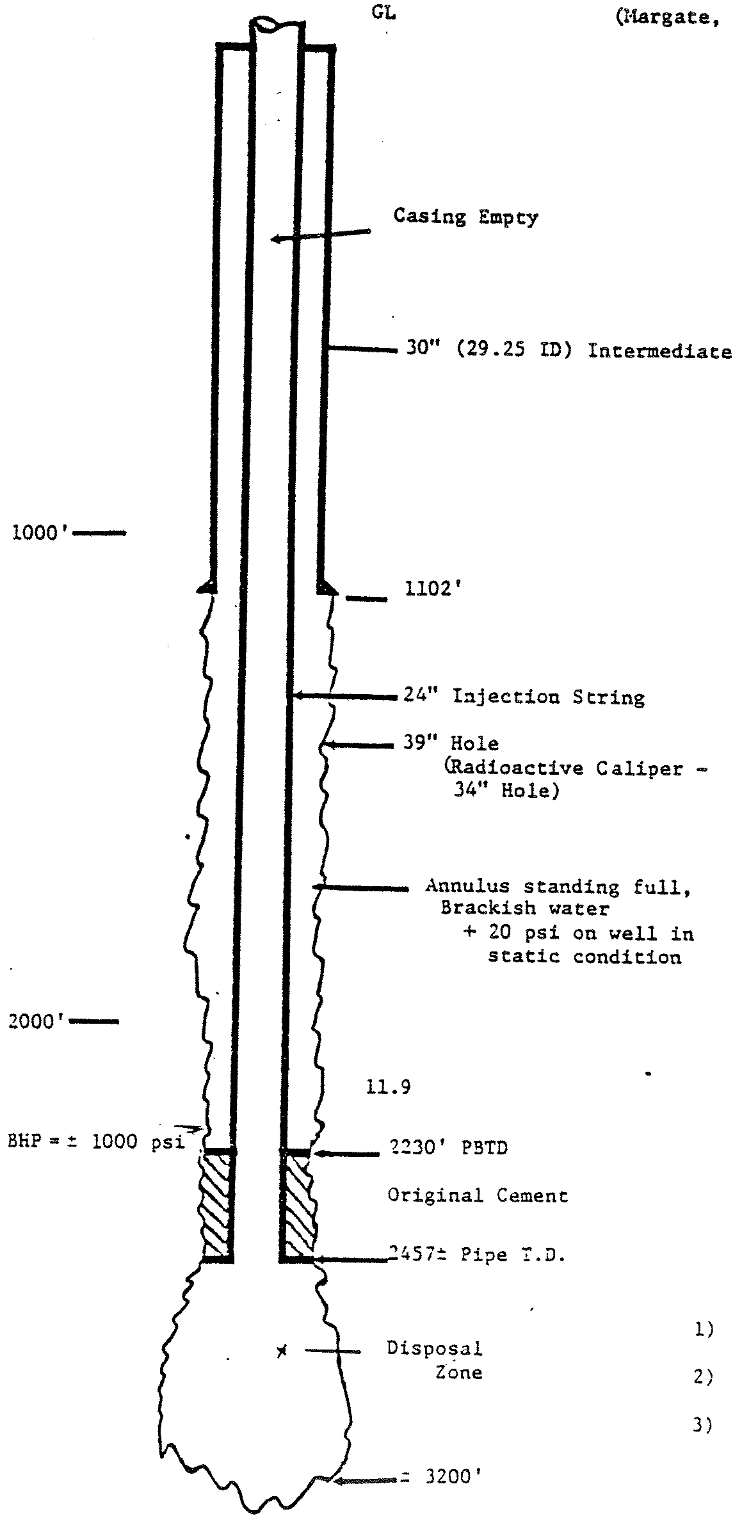
The transition time was determined using a magnetic stirring consistometer The transition time was measured after simulating placement of cement slurry (6 hours) and allowing slurry to set static. During the static period, the gel strength development was continuously monitored until the end of transition time (500 lb/100 ft^2 gel strength development). Testing was conducted at 80°F BHCT and 1,000 psi BHP.

The SPHERELITE compositions were mixed using a Hobart Model N-50 mixer for mixing the SPHERELITE additive into the premixed cement slurry containing the proper amount of mixing water. Afterwards, the densities were checked (for comparison to the calculated densities), before and after pressurizing, using a Beckman Air Comparison Pycnometer.

DATA

Well Configuration

MARGATE IW-1
(Margate, FL)



Hole Volumes

24 in 30" (Lead) 0-50 - 76.3 cf

24 in 30" (Foam) 50-1102 - 1604.3 cf

24 in 39" (Foam) 1102-2130 = 5298.3 cf

24 in 39" (Lead) 2130-2230 - 515.4 cf

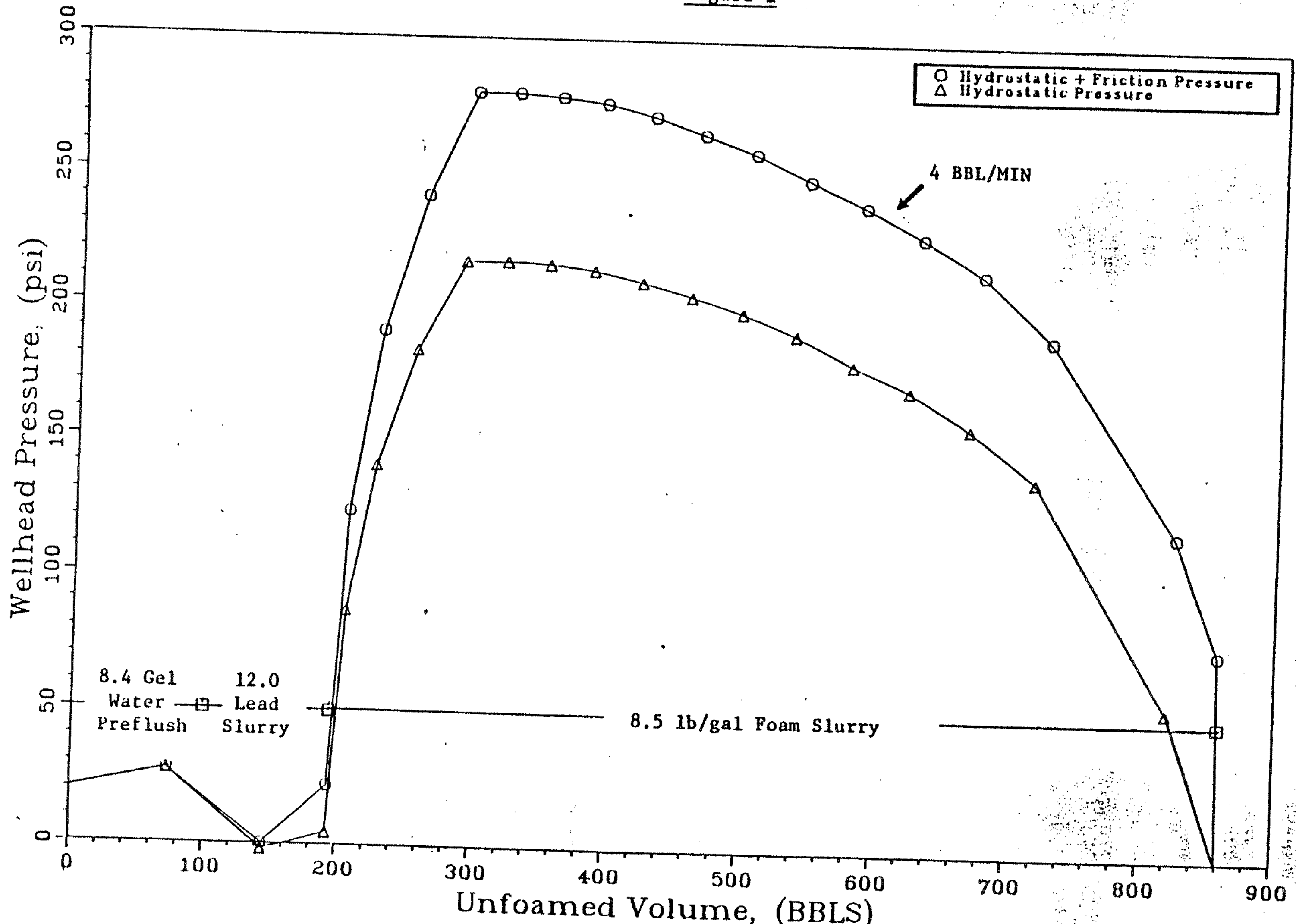
Lightweight slurry vol.
cu ft to fill - 6902.6 cu ft

Submitted Design Criteria

1) Maximum wellhead pressure - 60 psi
2) Bottom hole pressure - ≈1000 psi.
3) Maximum Slurry Density - 8.5 lb/ga

DATA (Cont'd)

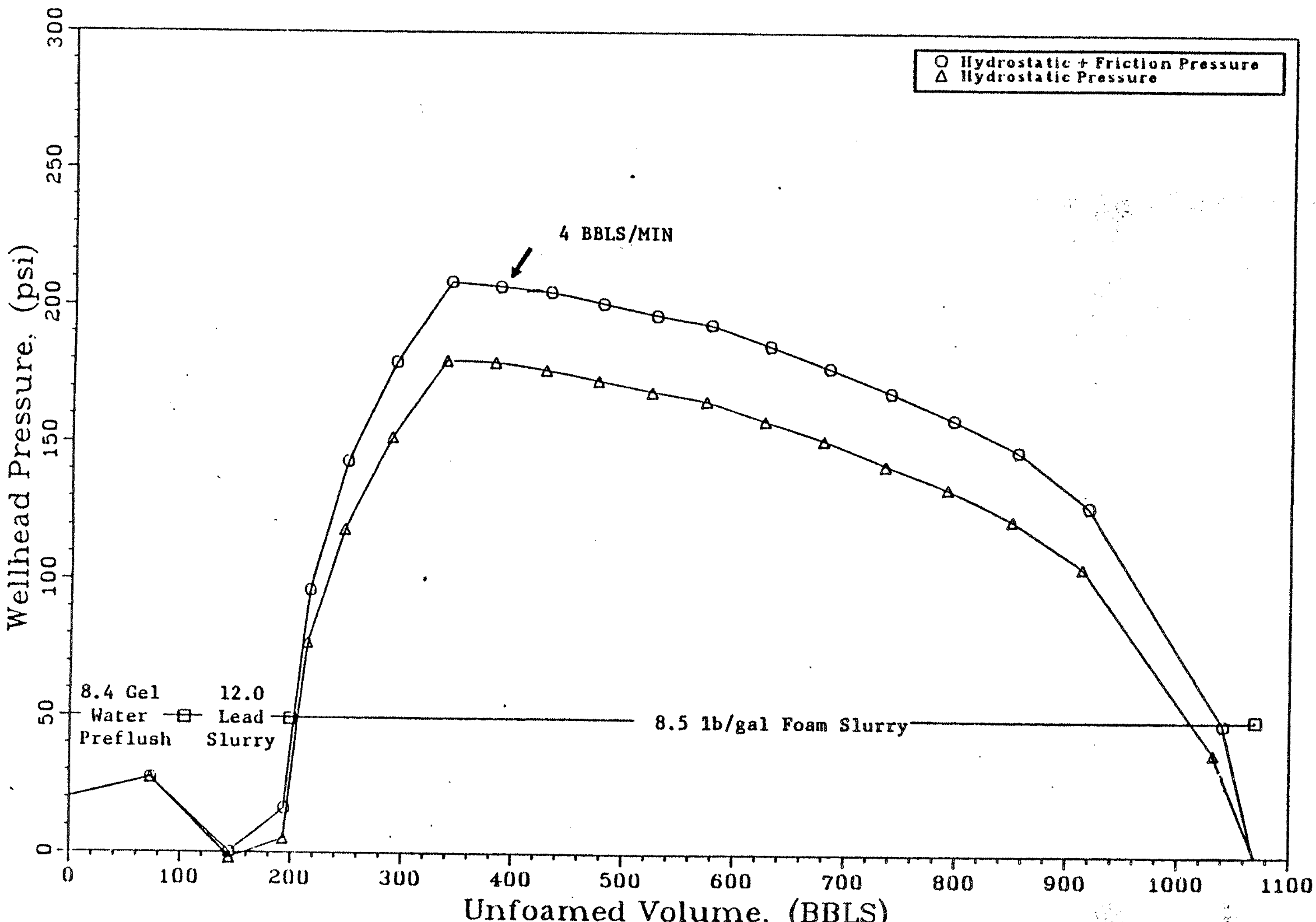
Figure 1



Surface Density - 15.6 lb/gal

DATA (Cont'd)

Figure 2



Surface Density - 11.9 lb/gal

DATA (Cont'd)

FMCEM Outputs

ENG104 CH2M HILL MARGATE PROJECT

INTERVAL NO.	LENGTH FT	FLUID DENSITY - LB/GAL SURFACE UN-FOAMED	DOWN-HOLE AVG.	DOWN-HOLE TOP	DOWN-HOLE BOTTOM	PRESSURE PSI TOP	PRESSURE PSI BOTTOM	AVG. TEMP DEG F	GAS SCF PER BBL	AVG. EXP. FACTOR BBLS FOAM PER BBL SLURRY
1	50.	11.9	11.9	11.9	11.9	0.	31.	80.	0.	0.0
2	100.	15.6	8.4	7.1	9.7	31.	75.	80.	21.	1.905
3	100.	15.6	8.5	7.7	9.2	75.	119.	80.	35.	1.865
4	100.	15.6	8.5	7.9	9.0	119.	163.	80.	49.	1.857
5	100.	15.6	8.5	8.1	8.9	163.	208.	80.	64.	1.855
6	100.	15.6	8.5	8.1	8.8	208.	252.	80.	78.	1.856
7	100.	15.6	8.5	8.2	8.8	252.	296.	80.	92.	1.857
8	100.	15.6	8.5	8.2	8.8	296.	340.	80.	107.	1.860
9	100.	15.6	8.5	8.3	8.7	340.	384.	80.	122.	1.862
10	100.	15.6	8.5	8.3	8.7	384.	428.	80.	137.	1.865
11	100.	15.6	8.5	8.3	8.7	428.	472.	80.	151.	1.867
12	100.	15.6	8.5	8.3	8.7	472.	517.	80.	166.	1.870
13	100.	15.6	8.5	8.3	8.7	517.	561.	80.	182.	1.873
14	100.	15.6	8.5	8.4	8.6	561.	605.	80.	197.	1.876
15	100.	15.6	8.5	8.4	8.6	605.	649.	80.	212.	1.879
16	100.	15.6	8.5	8.4	8.6	649.	693.	80.	228.	1.882
17	100.	15.6	8.5	8.4	8.6	693.	737.	80.	243.	1.885
18	100.	15.6	8.5	8.4	8.6	737.	782.	80.	259.	1.888
19	100.	15.6	8.5	8.4	8.6	782.	826.	80.	274.	1.891
20	100.	15.6	8.5	8.4	8.6	826.	870.	80.	290.	1.895
21	100.	15.6	8.5	8.4	8.6	870.	914.	80.	306.	1.898
22	80.	15.6	8.5	8.4	8.6	914.	949.	80.	320.	1.900
23	100.	11.9	11.9	11.9	11.9	949.	1011.	80.	0.	0.0

ENG104 CH2M HILL MARGATE PROJECT

INTERVAL NO.	LENGTH FT	FLUID DENSITY - LB/GAL SURFACE UN-FOAMED	DOWN-HOLE AVG.	DOWN-HOLE TOP	DOWN-HOLE BOTTOM	PRESSURE PSI TOP	PRESSURE PSI BOTTOM	AVG. TEMP DEG F	GAS SCF PER BBL	AVG. EXP. FACTOR BBLS FOAM PER BBL SLURRY
1	50.	11.9	11.9	11.9	11.9	0.	31.	80.	0.	0.0
2	100.	11.9	8.4	7.6	9.2	31.	75.	80.	10.	1.433
3	100.	11.9	8.5	8.0	9.0	75.	119.	80.	17.	1.414
4	100.	11.9	8.5	8.1	8.8	119.	163.	80.	24.	1.410
5	100.	11.9	8.5	8.2	8.8	163.	208.	80.	30.	1.410
6	100.	11.9	8.5	8.3	8.7	208.	252.	80.	37.	1.410
7	100.	11.9	8.5	8.3	8.7	252.	296.	80.	44.	1.411
8	100.	11.9	8.5	8.3	8.7	296.	340.	80.	51.	1.412
9	100.	11.9	8.5	8.4	8.6	340.	384.	80.	58.	1.413
10	100.	11.9	8.5	8.4	8.6	384.	428.	80.	65.	1.414
11	100.	11.9	8.5	8.4	8.6	428.	472.	80.	73.	1.415
12	100.	11.9	8.5	8.4	8.6	472.	517.	80.	80.	1.417
13	100.	11.9	8.5	8.4	8.6	517.	561.	80.	87.	1.418
14	100.	11.9	8.5	8.4	8.6	561.	605.	80.	94.	1.420
15	100.	11.9	8.5	8.4	8.6	605.	649.	80.	102.	1.421
16	100.	11.9	8.5	8.4	8.6	649.	693.	80.	109.	1.422
17	100.	11.9	8.5	8.4	8.6	693.	737.	80.	116.	1.424
18	100.	11.9	8.5	8.4	8.6	737.	782.	80.	124.	1.425
19	100.	11.9	8.5	8.4	8.6	782.	826.	80.	131.	1.427
20	100.	11.9	8.5	8.4	8.6	826.	870.	80.	139.	1.428
21	100.	11.9	8.5	8.4	8.6	870.	914.	80.	147.	1.430
22	80.	11.9	8.5	8.5	8.5	914.	949.	80.	153.	1.431
23	100.	11.9	11.9	11.9	11.9	949.	1011.	80.	0.	0.0

DATA (Cont'd)

Recommended Base Slurry Properties

1) HYBC + 217 lb SPHERELITE/sk + 9.4 lb Cal-Seal/sk + 12.5 lb gilsonite/sk, 33.85 gal water/sk; Slurry weight (@ 0 psi) - 8.0 lb/gal, Slurry weight (@ 1,000 psi) - 8.5 lb/gal, Slurry volume (@ 0 psi) - 10.33 cu ft/sk, Slurry volume (@ 1,000 psi) - 9.68 cu ft/sk.

Alternative Slurry Properties

2) HYBC + 235 lb SPHERELITE/sk + 9.4 lb Cal-Seal/sk + 12.5 lb gilsonite/sk + 9.4 lb Silica Fume/sk, 32.2 gal water/sk; Slurry weight (@ 0 psi) - 8.0 lb/gal, Slurry weight (@ 1,000 psi) - 8.5 lb/gal, Slurry volume (@ 1,000 psi) - 9.89 cu ft/sk.

3) HYBC + 243 lb SPHERELITE/sk + 9.4 lb Cal-Seal/sk + 12.5 lb gilsonite/sk + 14.1 lb Silica Fume/sk, 32.2 gal water/sk; Slurry weight (@ 0 psi) - 8.0 lb/gal, Slurry weight (@ 1,000 psi) - 8.5 lb/gal, Slurry volume (@ 1,000 psi) - 10.10 cu ft/sk.

4) HYBC + 266 lb SPHERELITE/sk + 9.4 lb Cal-Seal/sk + 12.5 lb gilsonite/sk + 32.9 lb Diacel D/sk, 51.2 gal water/sk; Slurry weight (@ 0 psi) - 8.0 lb/gal, Slurry weight (@ 1,000 psi) - 8.5 lb/gal, Slurry volume (@ 1,000 psi) - 13.25 cu ft/sk.

Thickening Time Tests[1]

(Recommended Base Slurry - 80°F BHCT)

$CaCl_2$ (%)	Thickening Time (Hours:Minutes)
1	16:30
3	13:30
6	10:40
8	10:66[2]
10	9:50
12	18:00+
15	18:30+

[1] All slurries prepressurized to 1,000 psi.

[2] This test was showing 42 Bearden units of consistency (Bc) at 10:66; starting consistency was 18 Bc.

DATA (Cont'd)

Compressive Strength Tests[1]

80°F BHST - Atmospheric

Slurry No.	$CaCl_2$ (%)	Compressive Strength - PSI 2 Day	3 Day	5 Day	7 Day
1	2	--	22	--	--
1	3	--	26	--	--
1	6	25	--	--	65
1	8	--	20	--	50
1	10	30	--	--	50
1	15	--	--	36	65
2	6	--	39	50	--
3	6	--	43	80	--
4	6	--	51	91[2]	--

[1] All slurries prepressurized to 1,000 psi.

[2] Specimen was determined to have a permeability (to water) of 9.2 md.

Permeability Test

(Recommended Slurry)

Water (md)

48.0

Porosity Test

(Recommended Slurry)

Porosity (Percent)

44.2

Gel Strength Test

(Recommended Slurry)
80°F BHCT @ 1,000 psi N_2

Transition Time
(Hours:Minutes)

1:28

DATA (Cont'd)

EQFRC Outputs*

24 IN. CSG. IN 30 IN. CSG.

SLURRY NO.	N PRIME	K PRIME	WEIGHT LBS/GAL	VOLUME CU FT/SK	FL RT BPM	V-ANN FT/SEC	REY. NUMBER	FR P-PSI /1000 FT
GEL WATER								
1	0.58	0.00200	8.400	0.0	4.00	0.21	173.	0.2
LEAD CEMENT								
2	0.24	0.15820	12.000	3.320	4.00	0.21	5.	11.8
TAIL CEMENT								
3	0.91	0.00400	8.000	11.390	4.00	0.21	55.	0.7

24 IN. CSG. IN 34 IN. HOLE

SLURRY NO.	N PRIME	K PRIME	WEIGHT LBS/GAL	VOLUME CU FT/SK	FL RT BPM	V-ANN FT/SEC	REY. NUMBER	FR P-PSI /1000 FT
GEL WATER								
1	0.58	0.00200	8.400	0.0	4.00	0.12	102.	0.1
LEAD CEMENT								
2	0.24	0.15820	12.000	3.320	4.00	0.12	2.	5.5
TAIL CEMENT								
3	0.91	0.00400	8.000	11.390	4.00	0.12	46.	0.2

* Wellhead pressure calculated = maximum friction pressure output (24 in. Csg. in 30 in. Csg.) + differential hydrostatic pressure based on 8.25 lb/gal slurry density (957 psi); i.e., (0.7 × 2.23) + 43 ≃ 45 psi.

cc: P. J. Broussard, Jr.
A. F. Strange
R. M. Lasater
D. K. Smith
L. T. Watters

Respectfully submitted,

Laboratory Analyst

Terry, Couch
Book nos. 720, 782, 750, 722, 721, 719, 5380/cm

HALLIBURTON SERVICES

By David D. Onan
David D. Onan R.L.

HALLIBURTON SERVICES
PAT J. BROUSSARD, Manager
Shreveport Division
330 MARSHALL STREET, SUITE 600
TRANSCONTINENTAL TOWER
SHREVEPORT, LOUISIANA 71101-3037

March 15, 1985

Morton Well Drilling
201 N.W. 20th Avenue
Ft. Lauderdale, FLA 33311

ATTENTION: Mr. Morton Tilley

RE: Final proposal, city of Margate IW-1 Disposal Well, Margate, FLA.

WELL DATA:

Injection String:	24" O.D. Set @ 2,457'
Intermediate String:	30" O.D. 29.25" I.D. set @ 1,102'
Hole Size:	34" average
Top Original Cement:	2,230'
Fill-up Required:	Lead Slurry - 100' from 2,230' - 2,130' Light Weight Slurry - 2,130' to surface
BHST:	80°F.

REVIEW OF JOB CRITERIA

As we have discussed on many occasions, there are a number of factors which may effect the successful outcome of this cementing job. The variables listed below are a matter of great concern to us, in addition to other factors which may exist and of which we have no knowledge. We are dealing with a very unusual and critical situation with variables that are beyond our control and therefore take no responsibility for the eventual outcome of this job. This is reviewed in our Work Order Contract and Hold Harmless Agreement which must be executed before we can procede with the job. The following are some of the variable factors which are of concern:

(1) Casing integrity - The 24" injection string has been in place for 10-12 years exposed to the disposal effulent. Condition of this casing is unknown and collapse resistance is very questionable. We have been given a maximum annular pressure of 60 psi (surface) under which we will stay during the job. If the casing were to fail, the cement or fluid being pumped would communicate and fall to the disposal zone in addition to exposing the open hole annulus to the disposal zone. The well will be on injection during the cementing procedure, which should aid in reducing the differential pressure across the casing string.

(2) Downhole conditions - The cementing job will be pumped in a "bullhead" manner, ie, pumped down the annulus into the formation. A radioactive tracer survey run in 1984 indicated that pumped fluid entered a zone at ±2,200' - 2,230', but we have no true data to indicate how much fluid this zone will take; whether fluid can be pumped in freely at low pressure or will accept fluid in a restricted manner and higher pressure. This could greatly alter surface pump in pressures and rates. Another downhole consideration is the proximity of the disposal zone. The pumping annulus and disposal zone are seperated in the wellbore area by a cement sheath placed during initial completion of the well. If the cement sheath or bond were to fail, any fluids or cements in the annulus could fall into the disposal interval. The possibility also exists that the injection zone rock could fail at some point inside the zone away from the wellbore and set up communication between the annulus and disposal zone. Job plans call for placing the lead cement slurry to 2,230' and stopping pumping before cement enters the formation. Note, however, that we will be displacing the total current annulus volume (±900 bbls.) plus pre-flush (±100 bbls.) into the zone. We have no idea of the effect these fluids will have on the injection zone, and under worst case situations could cause the problems described above.

(3) Stability of annular column - The densities of the pumped cements are designed to be equal to or less than the density of the fluids currently in the annulus. It is possible that due to injection point or other conditions, that once a full cement column is in place, the column may fall to some point away from surface. Should this happen, the cement top would have to be determined and other plans made to "top out" or place additional cement in the annulus at a later date to fully fill to surface.

Hole conditions may be such, or change, so that the entire volume of cement can not be placed due to pressure or time restraints. We plan to pump at ±4 BPM if wellhead pressure allows, which would place the cement volume in less than four hours. With cement thickening times noted in attached lab reports, we should be able to pump for over seven hours at roughly 2 BPM if pressures are high. If pump pressures approach maximum 60 psi wellhead exist, we will slow injection rates to as low as practical and pump cement for as long as possible if so directed by the contractors.

(4) Open hole volumes/conditions - Volume of the open hole from 1,102' - 2,230' were estimated with best available data since no caliper survey of this interval was available to accurately determine hole configuration. We have calculated this volume and added 25% excess to attempt to provide adequate cement volume. If actual open hole volume is greater than calculated, the cement may not fill to surface at the conclusion of the job. Should hole volume be less than calculated, we will have cement leftover at the conclusion of the job.

The 1984 radioactive tracer survey indicated fluid injection at ±2,230'. This does not insure that any pumped fluids will follow the same course. It is always possible that another zone up the hole may take all or part of the fluid leaving a gap in the cement column or possibly a pressure problem.

These are a few of the major factors which could effect the eventual outcome of the cementing job. Any number of these or other factors may become critical factors and since they are of concern we thought that they should be reviewed and again considered prior to the job.

(5) Other considerations:

(1) The well will be on injection during the cementing procedure to keep the injection string full while we pump on the annulus.
(2) The lead slurry will be tagged with 10 millicuries of radioactive material. It's progress and stopping point will be monitored by a gamma tool in the injection string. This will be valuable in following our placement progress.
(3) Should any cement be left over on the surface at the conclusion of the job, it is the property of the contractor and must be removed from our storage bins and disposed of in a timely and proper manner.
(4) A small disposal pit must be dug on location for containment of prime-up, wash-up and any potential vented fluids. Mr. Rod McElrath of our Felda, FLA service center can discuss size and placement of this pit.

CEMENT CALCULATIONS

IN CUBIC FEET:

Lead slurry - Fill 100' (24" casing) in 34" hole
2,230' - 2,130')
100 lin. ft. x 3.1634 cu. ft./lin. ft. =
316 cu. ft.

Light weight slurry - Fill 1,028' (24" casing in 34" hole
2,130' - 1,102')
1,028 lin. ft. x 3.1634 cu. ft./lin. ft. =
3,252 cu. ft.
Plus 25% excess = 4,065 cu. ft.

Light weight slurry - Fill 1,102' (24" casing in 29.25" I.D.
casing 1,102' to surface)
1,102 lin. ft. x 1.525 cu. ft./lin. ft. =
1,681 cu. ft.

Total Cubic Ft. Requirements:

Lead Slurry - 316 cu. ft.
Light weight slurry - 4,065 cu. ft. + 1,681 cu. ft. =
5,746 cu. ft.

IN SACKS:

Lead slurry - 316 cu. ft. - 3.22 cu. ft./sk. =
98 sks.

Light weight slurry - 5,746 cu. ft. - 10.0 cu. ft./sk. (avg.) =
575 sks.

CEMENT DATA:

Laboratory data on lead and light weight slurries are attached. Please refer to these reports for full data and test results. The following is a review of the basic light weight slurry parameters.

Weight -	"0" psi	surface conditions	8.0 lbs./gal.
	1,000 psi	downhole conditions	8.5 lbs./gal
Slurry yield -	"0" psi	surface conditions	10.33 cu. ft./sk.
	1,000 psi	downhole conditions	9.68 cu. ft./sk.

calculation yield - average 10 cu. ft./sk.

Thickening Time @ 80°F. BHCT - 10 hrs. 40 minutes

Compressive strength @ 80°F., atmospheric
2 day - 25 psi
7 day - 65 psi

Permeability - 48 md (water)

Porosity - 44.2%

JOB PROCEDURE:

Maximum wellhead pressure = 60 psi Planned rate = 4 BPM

(1) Pump 4,000 gallons bentonite water spacer

(2) Pump 98 sks. lead slurry consisting of HYBC cement, 25% Gel, 10 lbs./sk. Calseal, 1/4 lb./sk. Flocele and 1% Calcium Chloride.

slurry weight = 11.9 lbs./gal.
slurry yield = 3.22 cu. ft./sk.
water requirements = 19 gals./sk.

NOTE: Lead slurry contains 10 millicuries RAC-4 tracer.

(3) Pump 575 sks. light weight slurry consisting of HYBC cement, 217 lbs./sk. Spherelite, 9.4 lbs./sk. Calseal, 12.5 lbs./sk. Gilsonite and 6% Calcium Chloride.

slurry weight = 8.0 lbs./gal. surface
8.5 lbs./gal. @ T.D.
8.25 lbs./gal. average
slurry yield = 10.33 cu. ft./sk. surface
9.68 cu. ft./sk. @ T.D.
10.0 cu. ft./sk. average
water requirements = 33.85 gals./sk.

SPECIAL EQUIPMENT:

Due to the specialized nature of this job and your stated requirements, the following specialized equipment will be used on this job:

(1) 2- 60 psi certified rupture discs.
(2) 0-200 psi wellhead pressure transducer and strip chart recorder.
(3) rate meter and gallon counter for all pumped fluids.
(4) ~~RAC-4~~ Radioactive Tracer to be placed in lead slurry.

Gold 198 2.7 day halflife JMC

SAFETY

Safety is of prime consideration when working on any well, and a safety meeting for consultant, contractor, and all Halliburton personnel will be held before the job starts. We require that any visitor not essential to job operations observe safety procedures and stay in an appointed safe area away from well and equipment.

Richard Leonardi, Radiation Safety Officer, will control the radioactive tracer material placement, associated surveys, and safety requirements.

An on-site waste pit will still be required as previously discussed.

LEGAL

Please note that our standard Work Order Contract and additional Hold Harmless agreement must be signed before work commences.

WATER SOURCE

We will need at least two taps on the 10" fresh water line located at the injection site. Mr. McElrath will confirm this with you.

COST ESTIMATE

Pumping

	Pump Equipment (1500 - 3,000 ft.) (8 hrs)	$ 879.00
	Twin turbine blender (8 hrs.)	1,205.00
	Pump and blend unit mileage (135)	567.00
	Mobil Tank (For spacer and water storage) (8 hrs.)	328.00
Cements		
4,000	gals. Bentonite Spacer	500.00
98	sks. Lead Slurry	1,217.37
575	sks. Light Weight Slurry	71,373.07
	Cement Service Charge	5,661.05
	Cement Delivery (135 miles)	9,792.56
RA Tracer	Gold 198 used in lieu of IR-192 (shorter ½life)	
10	mc ~~RAC-4 (IR-192)~~ Tracer plus delivery	210.00
	Radioactive engineering services (1 day)	500.00
Equipment		
	Rupture Discs and Specialized Readout Equip.	2,500.00
Personnel		
	Supervision (1 day, 2 men)	700.00
	Substinance (10 men, 1 day)	800.00
	TOTAL (EXCLUDING TAXES)	$96,233.05

The unit prices stated in this proposal are based upon our current published prices. The projected equipment, personnel, and material needs, as well as the time needed to complete the job, are estimates only and are based upon the information presently available to us. At the time the work is actually performed, conditions then existing may require an increase or decrease in the equipment, personnel, material needs, and/or job time. Charges will be based upon unit prices in effect at the time the work is performed and the amount of equipment, personnel, materials, and job time actually utilized in the work. Taxes, if any, are not included.

These cementing services may be coordinated through our Felda, FLA District Office. Mr. Rod McElrath is the Field Supervisor. The telephone number is Area Code 813/675-0323.

These radioactive materials services may be coordinated through our Tyler TX District Office. You may contact Mr. Richard Leonardi at 214/593-6142.

We are pleased to have this opportunity to present this proposal for your consideration. If you accept our proposal, it is understood and agreed between the parties that all of said services and materials will be furnished in accordance with the terms and conditions of Halliburton Services' regular work orders applicable to the particular item. In this connection, it is understood and agreed that Customer will continue to execute Halliburton Services usual field work orders and/or tickets customarily required by Halliburton Services in connection with the furnishing of said services and materials.

In addition to our Work Order, a Hold Harmless document must be executed and approved before work can commence.

We look forward to being of service to you. For additional information, discussion and/or clarification, please advise.

Submitted by,

Bruce D Thomas

Bruce D. Thomas
Division Engineer

BDT/ss

cc: Mr. Pat J. Broussard
Mr. Bob Graham
Mr. Jack Hilton
Mr. Gary Cormier
Mr. Jim Haney
Mr. Rod McElrath
Mr. Joe Macaluso
Mr. Lynn Onan

HALLIBURTON SERVICES

DRAWER 1431, DUNCAN, OKLAHOMA 73536

CHEMICAL RESEARCH AND
DEVELOPMENT DEPT.

REGINALD M. LASATER, Manager
KNOX A. SLAGLE, Assistant Manager
RONNEY R. KOCH, Assistant Manager

April 23, 1985

Mr. Thomas M. McCormick
CH2M Hill, Inc.
Hillsboro Executive Center N.
350 Fairway Drive, Suite 210
Deerfield Beach, Florida 33441

RE: Repair of Margate Injection Well No. 1; City of Margate, Florida

Dear Tom:

Pursuant to your request during the staff meeting on April 9, 1985, enclosed please find data related to compressive strength and permeability of Type I (Class A) cement. This should be consistent with that of High Yield Basic Cement. Also included is a sample of SPHERELITE.

Please note that additional permeability data is currently being generated using Type II cement to complete your request and will be available shortly.

Sincerely,

David Onan

David D. Onan
Senior Chemist
Cement Section - CRD

RRK L.T.W

DDO/jc

Enclosure

cc: B. D. Thomas
R. R. Koch
D. K. Smith
C. R. George
L. T. Watters

PERMEABILITY OF VARIOUS CEMENTING COMPOSITIONS TO WATER (Millidarcies)

SLURRY COMPOSITION	Water Gal./Sk.	80°F.(1) 1 Day	80°F.(1) 7 Days	80°F.(1) 28 Days	100°F.(1) 1 Day	100°F.(1) 7 Days	100°F.(1) 28 Days	120°F.(1) 1 Day	120°F.(1) 7 Days	120°F.(1) 28 Days	140°F.(1) 1 Day	140°F.(1) 7 Days	140°F.(1) 28 Days
CLASS A CEMENT (COMMON PORTLAND)													
Neat	5.2	0.102	*	*	0.005	*	*	*	*	*	*	*	*
4% Bentonite	7.7	0.423	*	*	0.116	*	*	0.075	*	0.001	0.020	0.005	0.005
25 Lbs. Gilsonite	6.2	0.791	*	*	0.234	*	*	0.398	*	*	0.019	*	0.002
20% Diacel D	13.5	**	0.304	0.003	**	0.001	*	**	*	*	0.026	0.002	*
40% Diacel D	25.6	**	1.546	0.002	**	0.007	*	**	*	*	0.059	0.011	*
LR-11 Resin	3.4	**	0.005	0.002	0.017	0.003	*	**	0.003	*	0.004	0.002	*
0.9 Gal. LA-2 (Latex Cement)	6.0	3.00+	*	*	0.097	*	*	0.016	*	*	0.007	0.006	0.004
Pozmix®A Cement—0% Bentonite	4.4	0.530	0.002	*	0.124	*	*	0 039	*	*	0.022	*	*
Pozmix®A Cement—2% Bentonite	5.75	0.748	0.014	*	0.726	0.002	*	0.046	*	*	0.099	*	*
Pozmix®A Cement—2% Bentonite (with 0.9 Gal. LA-2)	4.5	3.00+	0.004	*	0.452	*	*	0.012	*	*	*	*	*
CLASS C CEMENT (HIGH EARLY)													
Neat	6.3	0.030	*	*	0.002	*	*	*	*	*	*	*	*
3% Bentonite	8.3	0.006	*	*	0.011	*	*	*	*	*	0.003	0.003	0.016
25 Lbs. Gilsonite	7.3	0.202	*	*	0.078	*	*	0.049	*	0.002	0.017	0.003	0.005
LR-11 Resin	3.4	**	0.003	0.002	0.010	0.002	*	**	0.001	*	0.010	*	*
0.9 Gal. LA-2 Latex	6.0	0.086	*	*	0.003	*	*	*	*	*	0.002	*	0.002
Pozmix®A Cement—0% Bentonite	5.1	0.420	*	*	0.116	*	*	0.014	*	*	0.006	*	*
Pozmix®A Cement—2% Bentonite	6.1	1.466	0.002	*	0.147	0.002	*	0.044	*	*	0.016	*	*
CLASS E CEMENT (RETARDED)													
Class D—neat	4.5	——	——	——	0.223	*	*	——	——	——	1.240	*	*
Class D—4% Bentonite	7.1	——	——	——	0.077	0.003	*	——	——	——	0.032	0.003	0.004

* Less than 0.001 millidarcies
** Specimen strength too low to permit measurement of permeability
(1) Atmospheric Pressure

ENGLISH / METRIC UNITS

PORTLAND - API CLASS A

With Various Percentages of Bentonite

These data are based on averages for three brands of API Class A Cement. The bentonite used in these tests was the regular Wyoming type and meets the new API performance requirements given in API Standards 10A.

Percent Bentonite	Water Requirement Gals/Sk	Water Requirement Cu Ft/Sk	Viscosity 0-20 Min.	Weight Lbs/Gal	Weight Lbs/Cu Ft	Volume Cu Ft/Sk
0	5.2	0.70	4-12	15.6	117	1.18
2	6.5	0.87	10-20	14.7	110	1.36
4	7.8	1.04	11-21	14.1	105	1.55
6	9.1	1.22	13-24	13.5	101	1.73
8*	10.4	1.39	12-19	13.1	98	1.92

THICKENING TIME — HOURS:MINUTES
(Pressure-Temperature Thickening-Time Test)

Per Cent Bentonite	API Casing Tests 4,000'	6,000'	8,000'	API Squeeze Tests 2,000'	4,000'	6,000'
0	3:00+	2:25	1:40	2:14	1:32	1:01
2	2:25	1:48	1:34	2:25	1:29	0:56
4	2:34	1:57	1:32	2:26	1:18	0:58
6	2:35	1:45	1:22	2:16	1:26	0:56
8*	2:44	1:50	1:24	2:31	1:28	0:58

COMPRESSIVE STRENGTHS — PSI

Percent Bentonite	12 HOURS TEMPERATURE - ° F. 60°	80°	100°	120°	24 HOURS TEMPERATURE - ° F. 60°	80°	100°	120°	72 HOURS TEMPERATURE - ° F. 60°	80°	100°	120°
0	80	580	1035	1905	615	1905	2610	3595	2050	4125	6150	6650
2	55	455	635	1280	365	1090	1520	2040	1185	2840	3350	4110
4	20	220	375	780	225	750	1015	1380	960	1775	2430	2800
6	15	85	245	500	85	360	730	925	615	1170	1610	1710
8*	15	50	155	310	60	265	510	610	425	720	1045	1215

* For bentonite concentrations greater than 8%, see modified cement data in this section.

API CLASS A CEMENT
Salt - 3.0 Percent
HR-7 - 0.4 Percent

SLURRY PROPERTIES

Water Ratio Gal./Sk.	Bentonite Percent	Slurry Viscosity Initial	Slurry Viscosity 20-Min.	Slurry Weight Lbs./Gal.	Slurry Volume Cu.Ft./Sk.
8.40	6	2	11	13.8	1.67
9.04	8	3	11	13.6	1.76
9.90	10	2	10	13.4	1.89
10.78	12	3	10	13.1	2.18
11.65	14	5	10	12.9	2.24

FLUID LOSS TESTS *

Filter Media - 325 Mesh Screen

Bentonite Percent	cc's per 30 Minutes 100 psi	cc's per 30 Minutes 1000 psi
6	176	402
8	133	394
10	184	340
12	176	366
14	82	330

* - Note - The fluid loss from slurries dehydrating in less than 30 minutes are calculated from the formula in API RP 10B and should be considered as approximate values.

HIGH PRESSURE THICKENING TIME

Casing-Cementing Schedules

Bentonite Percent	Thickening Time - Hours:Minutes 1000 feet	4000 feet	6000 feet	8000 feet
6	3:43	2:55	2:10	2:00
8	4:00+	3:10	2:30	2:25
10	4:00+	2:30	2:12	1:58
12	4:00+	2:31	2:05	1:47
14	4:00+	2:20	1:49	1:27

COMPRESSIVE STRENGTH - PSI

Bentonite Percent	80° F. Atmos. Pressure 24 Hrs.	80° F. Atmos. Pressure 48 Hrs.	140°F. 3000 psi 24 Hrs.	170°F. 3000 psi 24 Hrs.
6	560	1175	1250	1540
8	550	1170	1155	1185
10	425	985	900	930
12	360	815	880	755
14	345	765	870	745

API CLASS A CEMENT

Tests represented by the following data were made on only one sample of API Class A Cement and should be used as a guide in selecting the desired slurry properties.

SLURRY PROPERTIES
Used for Subsequent Data

Percent Bentonite	Water Gals/Sk	Water Cu Ft/Sk	Slurry Weight Lbs/Gal	Slurry Weight Lbs/Cu Ft	Slurry Volume Cu Ft/Sk
8	9.7	1.30	13.30	99.5	1.82
10	11.1	1.48	12.95	96.8	2.02
12	12.3	1.64	12.60	94.2	2.19
25	16.2	2.16	12.10	90.5	2.79

THICKENING TIME -- HOURS:MINUTES

API Casing Cementing Schedules

Well Depth Feet	Percent Bentonite	Percent HR-7 0.3	0.4	0.5	0.6	0.7	0.8
6,000	8	3:00+	3:00+	3:00+	3:00+	3:00+	----
8,000	8	2:02	2:20	3:00+	3:00+	3:00+	----
10,000	8	1:49	2:16	3:19	3:00+	3:00+	----
12,000	8	----	1:55	2:56	3:00+	3:00+	----
14,000	8	----	1:52	2:14	3:00+	3:00+	----
16,000	8	----	----	----	----	2:10	3:00+
6,000	10	3:00+	3:00+	3:00+	3:00+	3:00+	----
8,000	10	----	2:50	3:00+	3:00+	3:00+	----
10,000	10	----	1:53	2:12	3:00	3:00+	----
12,000	10	----	1:30	1:44	2:50	3:00+	----
14,000	10	----	----	1:37	2:22	3:00	3:00+
16,000	10	----	----	----	----	1:43	2:05
6,000	12	----	3:00+	3:00+	3:00+	3:00+	3:00+
8,000	12	1:42	2:27	2:30	3:00	3:00+	3:00+
10,000	12	----	1:46	2:19	2:26	3:00+	3:00+
12,000	12	----	----	1:32	2:19	3:05	3:00+
14,000	12	----	----	1:34	2:14	2:50	3:00+
16,000	12	----	----	----	----	2:11	2:04

Well Depth Feet	Percent Bentonite	Percent HR-7 1.0	1.2	1.4	1.6	1.8
4,000	25	3:00+	----	----	----	----
6,000	25	3:00+	3:00+	----	-----	----
8,000	25	3:00+	3:00+	3:00+	3:00+	3:00+
10,000	25	----	3:00+	3:00+	3:00+	3:00+
12,000	25	----	----	3:00+	3:00+	3:00+
14,000	25	----	----	----	3:00+	3:00+

API CLASS A CEMENT

THICKENING TIME -- HOURS:MINUTES
API Squeeze Cementing Schedules

Well Depth Feet	Percent Bentonite	1.0	1.2	1.4	1.6	1.8
2,000	25	3:00+	----	----	----	----
4,000	25	2:50	3:00+	----	----	----
6,000	25	1:06	3:00+	3:00+	3:00+	3:00+
8,000	25	----	2:42	3:00+	3:00+	3:00+
10,000	25	----	----	3:00+	3:00+	3:00+
12,000	25	----	----	----	3:00+	3:00+

COMPRESSIVE STRENGTHS - PSI

24 Hours
Pressure -- Atmospheric

	TEMPERATURE - ° F.								
	140°			160°			180°		
	BENTONITE			BENTONITE			BENTONITE		
Percent HR-7	8%	10%	12%	8%	10%	12%	8%	10%	12%
0.4	1020	705	485	1260	905	645	1290	945	650
0.6	685	540	445	805	725	555	1210	860	750
0.8	*	*	*	*	*	*	*	*	*

72 Hours
Pressure -- Atmospheric

	TEMPERATURE - ° F.								
	140°			160°			180°		
	BENTONITE			BENTONITE			BENTONITE		
Percent HR-7	8%	10%	12%	8%	10%	12%	8%	10%	12%
0.3	1890	1240	945	2140	1360	955	1810	1400	950
0.4	1815	1290	940	1875	1390	1095	1795	1270	930
0.6	1485	1180	920	1665	1295	1065	1545	1205	1000
0.8	1490	1105	945	1670	1225	995	1575	1145	1035

COMPRESSIVE STRENGTHS -- PSI

Curing Pressure - 3,000 psi

	24 HOURS						72 HOURS					
	220° F.			260° F.			220° F.			260° F.		
	BENTONITE						BENTONITE					
Percent HR-7	8%	10%	12%	8%	10%	12%	8%	10%	12%	8%	10%	12%
0.6	1965	1505	1135	2270	1650	1215	2370	1790	1450	2280	1635	1310
0.8	2190	1860	1555	2535	1945	1915	3185	2380	2005	2335	1870	1690

* Not Set.

Appendix F

PERMITS

Terry David

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

SOUTHEAST FLORIDA DISTRICT

P.O. BOX 3858
3301 GUN CLUB ROAD
WEST PALM BEACH, FLORIDA 33402-3858

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

ROY M. DUKE
DISTRICT MANAGER

August 30, 1984

Broward County
UC - Class I Construction/Test

Mr. Thomas Hissom, City Manager
The City of Margate
5790 Margate Boulevard
Margate, Florida 33063

RECEIVED 1 2 SEP 1984

Dear Mr. Hissom:

Attached is Permit No. UC 06-066992, to repair by construction modifications One Class I Injection well. Should you object to the issuance of this permit or the specific conditions of the permit, you have a right to petition for a hearing pursuant to the provisions of Section 120.57, Florida Statutes. The petition must be filed within fourteen (14) days from receipt of this letter. The petition must comply with the requirements of Section 17-103.155 and Rule 28-5.201, Florida Administrative Code, (copies attached), and be filed pursuant to Rule 17-103.155(1) in the Office of General Counsel of the Department of Environmental Regulation at 2600 Blair Stone Road, Tallahassee, Florida 32301. Petitions which are not filed in accordance with the above provisions are subject to dismissal by the Department. In the event a formal hearing is conducted pursuant to Section 120.57(1), all parties shall have an opportunity to respond, to present evidence and argument on all issues involved, to conduct cross-examination of witnesses and submit rebuttal evidence, to submit proposed findings of facts and orders, to file exceptions to any order or hearing officer's recommended order, and to be represented by counsel. If an informal hearing is requested, the agency, in accordance with its rules of procedure, will provide affected persons or parties or their counsel an opportunity, at a convenient time and place, to present to the agency or hearing officer, written or oral evidence in opposition to the agency's action or refusal to act, or a written statement challenging the grounds upon which the agency has chosen to justify its action or inaction, pursuant to Section 120.57(2), Florida Statutes.

Sincerely,

John A. Guidry, Chairman
UIC Technical Advisory Committee

JAG:my/42

Enclosure

cc: USGS/Tampa
South Florida Water Management District
Broward County Environmental Quality Control Board
CH_2M Hill
DER - Tallahassee
USEPA, Region IV - Attn: Lloyd Woosley

DER Form 17-1.201(7)
Effective June 1, 1984

RECEIVED SEP 1 1 1984

RULES OF THE ADMINISTRATIVE COMMISSION
MODEL RULES OF PROCEDURE
CHAPTER 28-5
DECISION DETERMINING SUBSTANTIAL INTERESTS

PART II
FORMAL PROCEEDINGS

28-5.201 Initiation of Formal Proceedings.

(1) Initiation of formal proceedings shall be made by petition to the agency responsible for rendering final agency action. The term petition as used herein includes any application or other document which expresses a request for formal proceedings. Each petition should be printed, typewritten or otherwise duplicated in legible form on white paper of standard legal size. Unless printed, the impression shall be on one side of the paper only and lines shall be double-spaced and indented.

(2) All petitions filed under these rules should contain:

(a) The name and address of each agency affected and each agency's file or identification number, if known;

(b) The name and address of the petitioner or petitioners, and an explanation of how his/her substantial interests will be affected by the agency determination;

(c) A statement of when and how petitioner received notice of the agency decision or intent to render a decision;

(d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate;

(e) A concise statement of the ultimate facts alleged, as well as the rules and statutes which entitle the petitioner to relief;

(f) A demand for relief to which the petitioner deems himself entitled; and

(f) Other information which the petitioner contends is material.

****

A petition may be denied if the petitioner does not state adequately a material factual allegation, such as a substantial interest in the agency determination, or if the petition is untimely. (Section 28-5.201(3)(a), FAC)

DER Form 17-1.201(7)
fective November 30, 1982

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

SOUTHEAST FLORIDA DISTRICT

P.O. BOX 3858
3301 GUN CLUB ROAD
WEST PALM BEACH, FLORIDA 33402-3858

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

ROY M. DUKE
DISTRICT MANAGER

PERMITTEE:
Mr. Thomas Hissom, City Manager
The City of Margate
5790 Margate Boulevard
Margate, Florida 33063

I.D. NUMBER: 5006P60052
PERMIT/CERTIFICATION NUMBER: UC 06-066992
DATE OF ISSUE: August 31, 1984
EXPIRATION DATE: February 28, 1985
COUNTY: Broward
LATITUDE/LONGITUDE: 26°14'00"N/80°12'00"E
SECTION/TOWNSHIP/RANGE:
PROJECT: UIC Construction/Repair Permit for City of Margate, Florida

This permit is issued under the provisions of Chapter 403,.Florida Statutes, and Florida Administrative Code Rule 17-28. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents attached hereto or on file with the Department and made a part hereof and specifically described as follows:

CONSTRUCT: Repair by construction modifications One Class I injection well. The 24" to 30" monitoring annulus space shall be completely filled with nitrogen entrained cement as supplied by Halliburton Service Company.

IN ACCORDANCE WITH: Application for Permit to Construct a Class I Injection Well dated, March 14, 1983 and Plans and specifications dated, February, 1983 (none are attached).

LOCATED AT: 6441 N.W. 9 Street, Margate, Broward County, Florida.

TO SERVE: Standby disposal of treated effluent from the City of Margate, Waste Water Treatment Plant, Broward County, Florida.

SUBJECT TO: General Conditions 1-15 and Specific Conditions 1-9.

DER Form 17-1.201(5)
Effective November 30, 1982

RMITTEE:

I.D. Number:
Permit/Certification Number:
Date of Issue: August 31, 1984
Expiration Date:

ERAL CONDITIONS:

. The terms, conditions, requirements, limitations, and restrictions set forth herein are "Permit Conditions" and as such are binding upon the permittee and enforceable pursuant to the authority of Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is hereby placed on notice that the department will review this permit periodically and may initiate enforcement action for any violation of the "Permit Conditions" by the permittee, its agents, employees, servants or representatives.

. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the department.

. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey any vested rights or any exclusive privileges. Nor does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit does not constitute a waiver of or approval of any other department permit that may be required for other aspects of the total project which are not addressed in the permit.

. This permit conveys no title to land or water, does not constitute state recognition or acknowledgement of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the state. Only the Trustees of the Internal Improvement Trust Fund may express state opinion as to title.

. permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or aquatic life or property and penalties therefor caused by the construction or operation of this permitted source, nor does it allow the permittee to cause pollution in contravention of Florida Statutes and department rules, unless specifically authorized by an order from the department.

. The permittee shall at all times properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by department rules.

The permittee, by accepting this permit, specifically agrees to allow authorized department personnel, upon presentation of credentials or other documents as may be required by law, access to the premises, at reasonable times, where the permitted activity is located or conducted for the purpose of:

a. Having access to and copying any records that must be kept under the conditions of the permit;

b. Inspecting the facility, equipment, practices, or operations regulated or required under this permit; and

c. Sampling or monitoring any substances or parameters at any location reasonably necessary to assure compliance with this permit or department rules.

Reasonable time may depend on the nature of the concern being investigated.

If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately notify and provide the department with the following information:

a. a description of and cause of non-compliance; and

b. the period of noncompliance, including exact dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the department for penalties or revocation of this permit.

. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source, which are submitted to the department, may be used by the department as evidence in any enforcement case arising under the Florida Statutes or department rules, except where such use is proscribed by Sections 403.73 and 403.111, Florida Statutes.

. The permittee agrees to comply with changes in department rules and Florida Statutes after a reasonable time for compliance, provided however, the permittee does not waive any other rights granted by Florida Statutes or department rules.

. This permit is transferable only upon department approval in accordance with Florida Administrative Code Rules 17-4.12 and 17-30.30, as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the department.

. This permit is required to be kept at the work site of the permitted activity during the entire period of construction or operation.

. This permit also constitutes:

,etermination of Best Available Control Technology (BACT)
( ) Determination of Prevention of Significant Deterioration (PSD)
( ) Certification of Compliance with State Water Quality Standards (Section 401, PL 92-500)
( ) Compliance with New Source Performance Standards

. The permittee shall comply with the following monitoring and record keeping requirements:

a. Upon request, the permittee shall furnish all records and plans required under department rules. The retention period for all records will be extended automatically, unless otherwise stipulated by the department, during the course of any unresolved enforcement action.

b. The permittee shall retain at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation), copies of all reports required by this permit, and records of all data used to complete the application for this permit. The time period of retention shall be at least three years from the date of the sample, measurement, report or application unless otherwise specified by department rule.

c. Records of monitoring information shall include:

- the date, exact place, and time of sampling or measurements;
- the person responsible for performing the sampling or measurements;
- the date(s) analyses were performed;
- the person responsible for performing the analyses;
- the analytical techniques or methods used; and
- the results of such analyses.

. When requested by the department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts not submitted or were incorrect in the permit application or in any report to the department, such facts or rmation shall be submitted or corrected promptly.

PERMITTEE:
Mr. Thomas Hissom, City Manager

I.D. Number: 5006P60052
Permit/Certification Number: UC 06-066992
Date of Issue: August 31, 1984
Expiration Date: February 28, 1985

SPECIFIC CONDITIONS:

1. During the repair period allowed by this permit daily progress reports shall be submitted to the Department and the Tchnical Advisory Committee each week. The report shall include but is not limited to the following:

   A. Provide a summary interpertation of both the CBL and gamma log. (24 inch casing for background information).

   B. Provide a summary discription of work performed during cementing of the annulus.

   C. Description of work and type of testing accomplished.

   D. Description of any construction problems that develop and their status.

   E. Accurate records of the amount of any material such as Cement, Gel, $CaCl_2$, Cal Seal, Foamer, N_2, Freshwater, Iodine 131, and Bentonite.

2. The cementing program shall be submitted by the engineer at least fifteen (15) days prior to the date the cementing is scheduled and approval must be received before cementing begins. The format for the estimate shall be submitted at the first cheduled meeting with the TAC. The cementing program shall be designed with the use of Florida Class H (ATSM Type II) cement.

3. The permittee and/or the engineer shall schedule an initial TAC meeting to be held prior to construction/repair start-up but after the contractor has been selected. Scheduling of future meetings shall be scheduled for the purpose of reviewing any problems that may arise during the repair effort or upon completion of the repair effort; but, prior to application for a permit to operate the well.

4. A professional engineer, registered pursuant to Chapter 471, Florida Statutes (F.S.) must be retained throughout the construction/repair period to be responsible for the construction/repair operation and to certify the projects completion. On-site (around-the-clock) monitoring of the construction/repair operation shall be provided by the engineer. The Department must be notified immediately of any change in engineer.

5. Issuance of the construction permit does not obligate the permitting authority to authorize operation of the well, unless the well and surface appurtenances qualifies for an operation permit.

IITTEE:
M. Thomas Hissom, City Manager

I.D. Number: 5006P60052
Permit/Certification Number: UC 06-066992
Date of Issue: August 31, 1984
Expiration Date: February 28, 1985

SPECIFIC CONDITIONS:

6. If any problems develop that may seriously hinder compliance with this permit, construction progress or good construction practice the Department shall be notified immediately. The Department may require a written report describing in detail what problems have occurred, the remedial measures applied to assure compliance and the measures taken to prevent recurrence of the problem.

7. After completion of construction/repair and testing, a final report shall be submitted to the Department and the TAC with an application for a Class I well operation permit.

8. The Department shall require operational testing demonstrating that the well can absorb the design and peak daily flows that are expected over the next five years, prior to granting approval for operation.

9. During this construction/repair period the permittee shall prepare or shall have the engineer of record prepare an operation and maintenance manual including emergency procedures for the use of operations, maintenance personnel, technicians, laboratory personnel and others, as appropriate, the manual shall include but is not limited to:

A. Instructions for the safe and reliable operation of the injection system.
B. Description and/or drawings of the basic engineering design of the continuous flow measuring/monitoring equipment.
C. Sampling and monitoring procedures.
D. Emergency procedures for handling abnormal events.
E. Shut down and start up procedures.
F. Preventive maintenance schedule.
G. Schedules and procedures for calibration of monitoring instruments.
H. Standardized test procedures for performing the specific injectivity test.

Issued this 31st day of August, 1984

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

Roy M Duke

Roy M. Duke
District Manager

JG

DER Form 17-1.201(5)
Effective November 30, 1982

Appendix G

RESOLUTIONS

CITY OF MARGATE, FLORIDA

RESOLUTION NO. 5350

A RESOLUTION OF THE CITY OF MARGATE, FLORIDA, APPROVING INDEMNIFICATION AND HOLD HARMLESS AGREEMENT - HALLIBURTON SERVICES (DEEP WELL PROJECT).

BE IT RESOLVED BY THE CITY COMMISSION OF THE CITY OF MARGATE, FLORIDA:

SECTION 1: That the City Commission of the City of Margate, Florida, hereby approves indemnification and hold harmless agreement with HALLIBURTON SERVICES for deep well project.

SECTION 2: That the Mayor and City Manager are hereby authorized and directed to execute said agreement on behalf of the City of Margate, a copy of said agreement being attached and specifically made a part of this Resolution.

SECTION 3: That this Resolution shall become effective immediately upon its passage.

PASSED, ADOPTED AND APPROVED THIS 3rd day of October, 1984.

MAYOR

ATTEST:

Shirley J. Laughman

CITY CLERK

RECORD OF VOTE

Donohue Aye

Goldner Aye

Starr Aye

Anton Aye

Weisinger Aye

INDEMNIFICATION AND HOLD HARMLESS

In consideration of Halliburton Services, a division of Halliburton Company, under subcontract for the CH$_2$M. Hill Company of Gainesville, Florida, performing radioactive tracing on disposal wells for the City of Margate, Florida, said City of Margate, Florida agrees to indemnify and hold harmless Halliburton Services and the Halliburton Company as follows:

The City of Margate, Florida shall be responsible for and secure Halliburton against any liability for injury to or death of persons, other than employees of Halliburton, or damage to property (including, but not limited to, injury to the well), or any damages whatsoever, irrespective of cause, growing out of or in any way connected with the use of radioactive material in the well hole, unless such damage shall be caused by the willful misconduct or gross negligence of Halliburton.

However, the City of Margate shall only be responsible and liable up to the limits of its insurance and shall not be liable for any risk excluded by same.

AGREED TO THIS 4th day of October, 1984.

CITY OF MARGATE, FLORIDA

Approved by Res. #1550 10/3/84

ATTEST:

Shirley J. Baughman

CITY CLERK

BY: MAYOR LEONARD WEISINGER

Thomas H. Hissom

BY: CITY MANAGER THOMAS H. HISSOM

APPROVED AS TO FORM:

EUGENE M. STEINFELD

HALLIBURTON SERVICES, a division of HALLIBURTON COMPANY

BY:

REVIEWED
OPERATIONS
LEGAL 12/14/84
FINANCIAL

RIDER TO CH_2M HILL SERVICE PURCHASE

ORDER NO. BC 3397, PROJECT NO. FC 16718.A2

It is hereby mutually agreed that Paragraph 4 of the preprinted terms and conditions on the reverse side of Purchase Order No. BC 3397 shall be deleted in its entirety and that the terms and conditions of Halliburton Services work order contract no. 594366 shall govern.

Agreed to this 12/26/84 day of __________, 1984.

CH_2M HILL

BY: Thomas M. McCormick

THOMAS M. McCORMICK

Agreed to this 1-15-84 day of __________, 1984.

HALLIBURTON SERVICES, A DIVISION OF HALLIBURTON COMPANY.

BY: [signature]

REVIEWED

OPERATIONS ______

LEGAL 12/18/84

FINANCIAL ______

CITY OF MARGATE, FLORIDA

RESOLUTION NO. 5469

A RESOLUTION OF THE CITY OF MARGATE, FLORIDA, APPROVING HOLD HARMLESS AGREEMENT WITH HALLIBURTON SERVICES RE(REPAIR OF EXISTING DEEP WELL PROJECT).

BE IT RESOLVED BY THE CITY COMMISSION OF THE CITY OF MARGATE, FLORIDA:

SECTION 1: That the City Commission of the City of Margate, Florida, hereby approves hold harmless agreement with HALLIBURTON SERVICES regarding repair of deep well project.

SECTION 2: That the Mayor and City Manager are hereby authorized and directed to execute said agreement on behalf of the City of Margate, a copy of said agreement being attached and specifically made a part of this Resolution.

SECTION 3: That this Resolution shall become effective immediately upon its passage.

PASSED, ADOPTED AND APPROVED THIS 27th day of March, 1985.

MAYOR

ATTEST:

CITY CLERK

RECORD OF VOTE

Donohue Aye

Varsallone Aye

Anton Absent

Weisinger Aye

Goldner Aye

HOLD HARMLESS AGREEMENT

In consideration of Halliburton Services, a division of Halliburton Company, under subcontract for Morton Pump & Supply Company, performing cementing services on disposal wells for the City of Margate, Florida, said City of Margate agrees to hold Halliburton Services and Halliburton Company harmless as follows:

The City of Margate shall be responsible for and secure Halliburton against liability for damage to property of the City of Margate, (including, but not limited to injury or loss of the well) irrespective of cause, growing out of or in any way connected with the cementing of annular space of Margate disposal well IW-1, unless such damages shall be caused by the willful misconduct or gross negligence of Halliburton.

The City of Margate further agrees to be bound by the terms and conditions of the Halliburton Services work order contract with the exception of Paragraphs A, C, D, G & J. HH

Bg

In the event that the provisions of Florida Statutes 725.06 are applicable to the work to be performed under this agreement, the City of Margate's liability assumed herein shall be limited to $2,000,000.00.

AGREED TO THIS ________ day of March ________, 1985.

Approved to by Res. No. 5469
dated, March 27th, 1985.

ATTEST:

Shirley J. Baughman

CITY CLERK

CITY OF MARGATE, FLORIDA

Benjamin Goldner

BY MAYOR BENJAMIN GOLDNER

APPROVED AS TO FORM:

[signature]

EUGENE M. STEINFELD

Thomas H. Hissom

BY: CITY MANAGER THOMAS H. HISSOM

HALLIBURTON SERVICES, a division
of HALLIBURTON COMPANY

BY: PATRICK J. BROUSSARD

REVIEWED
OPERATIONS
LEGAL 3/20/85 gom
FINANCIAL

100M-1-82-SW-B-10296

HALLIBURTON
SERVICES
A Division of Halliburton Company
DUNCAN, OKLAHOMA 73536

FORM 1908 R-3

WORK ORDER CONTRACT AND PRE-TREATMENT DATA

ATTACH TO
INVOICE & TICKET NO. ____________

DISTRICT ______________________________ DATE ____________

TO: HALLIBURTON SERVICES YOU ARE HEREBY REQUESTED TO FURNISH EQUIPMENT AND SERVICEMEN TO DELIVER AND OPERATE

THE SAME AS AN INDEPENDENT CONTRACTOR TO: ______________________________
(CUSTOMER)
AND DELIVER AND SELL PRODUCTS, SUPPLIES, AND MATERIALS FOR THE PURPOSE OF SERVICING

WELL NO. __________ LEASE ____________________ SEC. __________ TWP. __________ RANGE __________

FIELD __________ COUNTY __________ STATE __________ OWNED BY ____________________

THE FOLLOWING INFORMATION WAS FURNISHED BY THE CUSTOMER OR HIS AGENT

FORMATION NAME ____________________ TYPE __________

FORMATION THICKNESS __________ FROM __________ TO __________

ER: TYPE ____________________ SET AT __________

TOTAL DEPTH __________ MUD WEIGHT __________

BORE HOLE ______________________________

INITIAL PROD: OIL ______ BPD, H_2O ______ BPD, GAS ______ MCF

PRESENT PROD: OIL ______ BPD, H_2O ______ BPD, GAS ______ MCF

	NEW USED	WEIGHT	SIZE	FROM	TO	MAX. ALLOW P.S.I.
CASING						
LINER						
TUBING						
OPEN HOLE						SHOTS/FT.
PERFORATIONS						
PERFORATIONS						
PERFORATIONS						

REVIOUS TREATMENT: DATE __________ TYPE ____________________ MATERIALS ____________

TREATMENT INSTRUCTIONS: TREAT THRU TUBING ☐ ANNULUS ☐ CASING ☐ TUBING/ANNULUS ☐ HYDRAULIC HORSEPOWER ORDERED ______

CUSTOMER OR HIS AGENT WARRANTS THE WELL IS IN PROPER CONDITION TO RECEIVE THE PRODUCTS, SUPPLIES, MATERIALS, AND SERVICES

THIS CONTRACT MUST BE SIGNED BEFORE WORK IS COMMENCED

As consideration, the above-named Customer agrees:

~~(a) To pay Halliburton in accord with the rates and terms stated in Halliburton's current price lists.~~

(b) Halliburton shall not be responsible for and Customer shall secure Halliburton against any liability for damage to property of Customer and of the well owner (if different from Customer), unless causec the willful misconduct or gross negligence of Halliburton, this provision applying to but not limited to subsurface damage and surface damage arising from subsurface damage

(c) ~~Customer shall be responsible for and secure Halliburton against any liability for reservoir loss or damage, or property damage resulting from subsurface pressure, losing control of the well and/c well blowout unless such loss or damage is caused by the willful misconduct or gross negligence of Halliburton.~~

(d) ~~Customer shall be responsible for and secure Halliburton against any and all liability of whatsoever nature for damages as a result of subsurface trespass, or an action in the nature thereof arising fr a service operation performed by Halliburton hereunder.~~

(e) Customer shall be responsible for and secure Halliburton against any liability for injury to or death of persons, other than employees of Halliburton, or damage to property (including but not limitec injury to the well), or any damages whatsoever, irrespective of cause, growing out of or in any way connected with the use of radioactive material in the well hole, unless such damage shall be causec the willful misconduct or gross negligence of Halliburton.

(f) Halliburton makes no guarantee of the effectiveness of the products, supplies or materials, nor of the results of any treatment or service

~~Customer shall, at its risk and expense, attempt to recover any Halliburton equipment, tools or instruments which are lost in the well and if such equipment, tools or instruments are not recover Customer shall pay Halliburton its replacement cost unless such loss is due to the sole negligence of Halliburton. If Halliburton equipment, tools or instruments are damaged in the well, Customer s pay Halliburton the lesser of its replacement cost or the cost of repairs unless such damage is caused by the sole negligence of Halliburton. In the case of equipment, tools or instruments for mar operations Customer shall, in addition to the foregoing, be fully responsible for loss of or damage to any of Halliburton's equipment, tools or instruments which occurs at any time after delivery Customer at the landing until returned to the landing, unless such loss or damage is caused by the sole negligence of Halliburton.~~

(h) Because of the uncertainty of variable well conditions and the necessity of relying on facts and supporting services furnished by others, Halliburton is unable to guarantee the accuracy of any cr interpretation, research analysis, job recommendation or other data furnished by Halliburton. Halliburton personnel will use their best efforts in gathering such information and their best judgm in interpreting it, but Customer agrees that Halliburton shall not be responsible for any damages arising from the use of such information except where due to Halliburton's gross negligence or wi misconduct in the preparation or furnishing of it.

(i) Halliburton warrants only title to the products, supplies and materials and that the same are free from defects in workmanship and materials. THERE ARE NO WARRANTIES, EXPRESS OR IMPLIED, MERCHANTABILITY, FITNESS OR OTHERWISE WHICH EXTEND BEYOND THOSE STATED IN THE IMMEDIATELY PRECEDING SENTENCE. Halliburton's liability and Customer's exclus remedy in any cause of action (whether in contract, tort, breach of warranty or otherwise) arising out of the sale or use of any products, supplies or materials is expressly limited to the replacement of su products, supplies or materials on their return to Halliburton or, at Halliburton's option, to the allowance to the Customer of credit for the cost of such items. In no event shall Halliburton be liable special, incidental, indirect, punitive or consequential damages.

(j) ~~Upon Customer's default in payment of Customer's account by the last day of the month following the month in which the invoice is dated, Customer agrees to pay interest thereon after default at highest lawful contract rate applicable but never to exceed 18% per annum. In the event it becomes necessary to employ an attorney to enforce collection of said account, Customer agrees to pay collection costs and attorney fees in the amount of 20% of the amount of the unpaid account.~~

(k) This contract shall be governed by the law of the state where services are performed or equipment or materials are furnished.

(l) Halliburton shall not be bound by any changes or modifications in this contract, except where such change or modification is made in writing by a duly authorized executive officer of Halliburto

I HAVE READ AND UNDERSTAND THIS CONTRACT AND REPRESENT
THAT I AM AUTHORIZED TO SIGN THE SAME AS CUSTOMER'S AGENT.

SIGNED ______________________________

CITY OF MARGATE, FLORIDA

RESOLUTION NO. 5470

A RESOLUTION OF THE CITY OF MARGATE, FLORIDA, APPROVING HOLD HARMLESS AMENDMENT TO AGREEMENT WITH MORTON PUMP & SUPPLY RE: REPAIR OF EXISTING DEEP WELL PROJECT.

BE IT RESOLVED BY THE CITY COMMISSION OF THE CITY OF MARGATE, FLORIDA:

SECTION 1: That the City Commission of the City of Margate, Florida, hereby approves hold harmless amendment to agreement with MORTON PUMP & SUPPLY regarding repair of existing deep well project.

SECTION 2: That the Mayor and City Manager are hereby authorized and directed to execute said agreement on behalf of the City of Margate, a copy of which is attached and specifically made a part of this resolution.

SECTION 3: That this Resolution shall become effective immediately upon its passage.

PASSED, ADOPTED AND APPROVED THIS 27th day of March, 1985.

MAYOR

ATTEST:

CITY CLERK

RECORD OF VOTE

Donohue Aye

Varsallone Aye

Anton Absent

Weisinger Aye

Goldner Aye

CONTRACT FOR THE REPAIR OF THE MARGATE DEEP INJECTION WELL, IW-1, FOR THE CITY OF MARGATE, BROWARD COUNTY FLORIDA.

SCOPE OF WORK

Repair of the Margate Deep Injection Well IW-1 shall be accomplished by the filling of the annular space between the 24 inch diameter effluent conduit and the 30 inch diameter intermediate casing with spherelite cement grout as supplied and placed by the Halliburton Services Company.

The Contractor shall be responsible for contracting with, facilitating, and coordinating the work of the Halliburton Services Company, and the Schlumberger Limited Company.

The Contractor shall provide all labor, supplies and equipment necessary for performing the work detailed below. The steps to be taken for the repair of Margate IW-1 DIW shall be as follows:

1. Collection of baseline data.

   a) Perform T.V. Survey, Caliper, and Gamma Logs for baseline data.

   b) Supress the Artesian Head of the Annulus and of the 24" effluent conduit by the injection of heavily weighted saline water.

   c) Perform Cement Bond Sonic Log by Schlumberger.

   d) Modify the existing well-head by welding two additional 2-inch I.D. standard pipe thread couplings with gate valves into the 24"/30" annulus.

2. Repair of the Well by the Bullhead injection of Spherelite Cement into the annulus.

   a) Injection of Spherelite Cement by Halliburton Services, lead cement to be tagged with a Radioactive Tracer.

   b) Perform gamma log during Cementing.

   c) Following Completion of the Cement job, perform Temperature Log.

3. Confirmation of Repair of the Well.

a) If the well has come alive during step 2, the contractor shall again suppress the artesian head of the 24-inch effluent conduit.

b) Perform Geophysical Logging, Cement Bond Sonic Log, Caliper Log, Gamma Log.

4. Demobilize equipment and clean the site of any debris generated during the repair.

COMPENSATION:

General Contractor's Compensation for work performed under the contract shall be as follows:

1. for the services of each man working at the site, $20.00/hr. Personnel are to be assigned to the site only at the express direction of the Engineer;

2. for materials, equipment, and services for supression of the Artesian head of the well and the annulus - $1600.00/day;

3. for materials, equipment and services during geophysical logging, exclusive of geophysical logging service billings, $1000.00/day;

4. for mobilization and demobilization of equipment and personnel, complete $2000.00/day;

5. for overhead and billing costs for processing of subcontractor's invoices, 12% of subcontractor's invoice.

Estimates Subcontractor's costs:

Halliburton - Cementing Subcontractor	-	$93,000.00
Schlumburger - Sonic bond log	-	$14,000.00
Deep Venture - TV service company	-	$ 8,000.00

Upon completion of the work noted in the scope and upon submittal of invoices from the subcontractors, the Contractor shall submit an application for payment. Payment shall be made to the Contractor within 30 days of approval of the submittal.

GENERAL CONDITIONS:

CONTRACT EXECUTION AND BONDS:

The Contractor shall, during performance of the services covered by this agreement, maintain worker's compensation in accordance with the laws of the state of Florida, and shall furnish certificates of insurance showing that he has auto and general liability coverage of 1 million for death and injury and $500,000.00 property damage.

The Contractor shall indemnify, defend and hold harmless the City from all suits, claims or actions arising at law or at equity or in any other form whatsoever, whether alleged because of the actions of Contractor, his employees and agents and any subcontractor or where alleged to have been based on any actions of the City of Margate, its agents or employees, arising out of this agreement. However, said indemnification shall only be to the extent of the limits of the insurance provided herein. The City of Margate shall be named as an additional insured for all insurance provided.

However, the City of Margate shall hold Morton Pump & Supply Company harmless for damage to property of the City of Margate (including, but not limited to injury or loss of the well), irrespective of cause, growing out of or in any way connected with the cementing of annular space of Margate disposal well IW-1, unless such damages shall be caused by the willful misconduct or gross negligence of either Halliburton or Morton Pump & Supply Company.

The City of Margate further agrees to the following:

a. Morton Pump & Supply Company shall not be responsible for and the City of Margate shall secure Morton Pump & Supply Company against any liability for damage to property of the City of Margate and of the well owner (if different from the City of Margate), unless caused by the willful misconduct or gross negligence of Morton Pump & Supply Company, this provision applying to but not limited to subsurface damage and surface damage arising from subsurface damage.

b. The City of Margate shall be responsible for and secure Morton Pump & Supply Company against any liability for injury to or death of persons, other than employees of Morton Pump & Supply Company, or damage to property (including, but not limited to injury to the well), or any damages whatsoever, irrespective of cause, growing out of or in any way connected with the use of radioactive material in the well hole, unless such damage shall be caused by the willful misconduct or gross negligence of Morton Pump & Supply Company.

c. Morton Pump & Supply Company makes no guarantee of the effectiveness of the products, supplies or materials, nor of the results of any treatment or service.

d. Because of the uncertainty of variable well conditions and the necessity of relying on facts and supporting services furnished by others, Morton Pump & Supply Company is unable to guarantee the accuracy of any interpretation, research analysis, job recommendation or other data furnished by Morton Pump & Supply Company. Morton Pump & Supply Company personnel will use their best efforts in gathering such information and their best judgement in interpreting it, but the City of Margate agrees that Morton Pump & Supply Company shall not be responsible for any damages arising from the use of such information except where due to Morton Pump & Supply Company's gross negligence or willful misconduct in the preparation or furnishing of it.

e. Morton Pump & Supply Company warrants only title to the products, supplies and materials and that the same are free from defects in workmanship and materials. There are no warranties, express or implied, of merchantability, fitness or otherwise which extend beyond those stated in the immediately preceding sentence. Morton's liability and the City of Margate's exclusive remedy in any cause of action (whether in contract, tort, breach of warranty or otherwise) arising out of the sale or use of any products, supplies or materials is expressly limited to the replacement of such products, supplies or materials on their return to Morton Pump & Supply Company or, at Morton Pump & Supply Company's option, to the allowance to the City of Margate of credit for the cost of such items. In no event shall Morton Pump & Supply Company be liable for special, incidental, indirect, punitive or consequential damages.

f. This contract shall be governed by the law of the state where services are performed or equipment or materials are furnished.

g. Morton Pump & Supply Company shall not be bound by any changes or modifications in this contract, except where such change or modification is made in writing by a duly authorized executive officer of Morton Pump & Supply Company.

The contractor shall comply with all federal, state and local laws, regulations, and ordinances applicable to the work covered by this contract.

Approved by Resolution No. 5470
3-27-85

CITY OF MARGATE, FLORIDA

BY: MAYOR BENJAMIN GOLDNER

ATTEST:

BY: CITY MANAGER THOMAS H. HISSOM

CITY CLERK

APPROVED AS TO FORM:

MORTON PUMP & SUPPLY COMPANY

EUGENE M. STEINFELD

BY: Morton D. Tiley