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Chevron Safely Disposes One Million Barrels of NORM in Louisiana Through Slurry Fracture Injection

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Abstract

During the past 50 years, storage pits and adjacent land around the Bay Marchand facility near Port Fourchon, Louisiana, had accumulated large deposits of non-hazardous drilling and production waste containing naturally occurring radioactive material (NORM). This material primarily included drill cuttings, drilling mud, produced sand, saltwater, pipe scale, crude oil and precipitates. To remediate this site, Chevron chose to re-inject the material into the deep subsurface through on-site Slurry Fracture Injection (SFI). This process provided greater environmental security than alternative surface pit or landfill disposal, and at much lower cost than off-site transport and disposal options.

More than 1 million barrels of pit soil and canal bottoms was safely disposed into a single well during two years of injection concluding in March 2000. Solid waste was mixed with water to create a slurry and injected down-hole above formation parting pressure into a weakly consolidated sandstone formation at depths from 4400 to 5000 feet. Injection operations were episodic, generally taking place for 11 hours per day, 5 days per week. This allowed formation pressure to decline each day to initial reservoir pressure. The project was designed and extensively monitored to maintain and verify containment within the permitted interval. Down-hole pressure was continuously monitored, allowing analysis of daily fall-off pressure. Waste containment was confirmed through a combination of shut-in pressure analysis, periodic step-rate tests, and periodic gamma logs and temperature surveys.

In addition to improved environmental protection provided by this technology, the on-site operation was a fraction of off-site disposal costs to Chevron. This paper describes the project design and permitting, injection operations, containment monitoring and analysis, and project economics.

Introduction

The Bay Marchand oil field is located just offshore of southern Louisiana. The field began production in 1949 and has been operated by Chevron for most of its life. Oil production came onshore at the Bay Marchand Terminal in Port Fourchon (Figure 1). Oil production was processed through a series of pits into the 1980's to separate water and other materials from the oil. Over time the pits accumulated drill cuttings, drilling mud, produced sand, salt water, pipe scale, crude oils and precipitates, all of which contained small amounts of naturally occurring radioactive material (NORM)[1,2]. The elements of concern were uranium-238, thorium-234 and radium-228.

The three processing pits were located at the east end of the California Canal (Figure 2). These pits were hydraulically isolated, which prevented any radioactive materials from leaching into the adjacent canal, particularly radium which is very soluble in salt water. To the southeast the Dead End Canal also contained substantial quantities of NORM and NOW (non-hazardous oilfield waste) mixed into canal bottom soils. This contamination was primarily due to overflows from discharge and processing pits at the material handling facility located adjacent to the canal.

The remediation project was composed of two phases: excavate and backfill the Bay Marchand pits, and remediate the bottom of the Dead End Canal. The Bay Marchand pits were excavated between October 1997 and September 1998 with the material injected into disposal well City of New Orleans #2 (CNO#2) using the Slurry Fracture Injection (SFI) process. The Dead End Canal was drained and excavated from February 1999 to March 2000. The canal bottom was excavated to an average depth of 6 ft, to a maximum of 12 ft in any given area. A total of 371,600 bbls of material were excavated from the Bay Marchand Pits, and 623,100 bbls of canal bottoms were excavated from the Dead End Canal.

In addition to the pit and canal materials, small volumes of tank bottoms, produced water and other NORM contaminated production wastes were disposed in well CNO#2. The total volume of these non-hazardous oilfield wastes was 20,970 bbl of liquids and 6,120 bbl of solids. The total volume of solids disposed over the course of the project was 1,000,800 bbl, contained in 2,949,700 bbl of slurry.

SFI was the chosen disposal technique since it provided permanent NORM disposal, minimized environmental liability, and was the most cost-effective of the options considered, particularly when compared to barging the solids to a NORM approved landfill.

Technology Summary

Many types of oilfield waste that are integrally associated with exploration and production activities, such as drill cuttings, produced sand, tank bottoms, sump material, and crude contaminated surface soil, can be economically disposed of in an environmentally sound manner through re-injection into an appropriate subsurface formation. In this process, solids are mixed into a slurry with fresh or produced water and injected at high pressure into suitable sand formations. The carrying fluid bleeds off rapidly, leaving behind a pod of solid waste permanently entombed by the natural earth stresses.

On-site, deep well injection of exploration and production wastes provides significant environmental and economic advantages over traditional landfill disposal for oilfield wastes. These include:

1. Improved protection for surface and groundwater;
2. Little impairment of surface land use;
3. Reduced long-term liability risk to waste generator;
4. Reduced transportation and disposal costs.

The use of deep well injection has expanded significantly in recent years. For example, large-scale E&P waste injection operations have taken place in Canada[3], Alaska[4], California[5], and in the North Sea.

High volume injection projects often involve annual injection exceeding several hundred thousand barrels of waste for several years. The critical engineering management goals for such operations are to:

1. Maintain waste containment in the target formation (environmental management);
2. Sustain long-term injectivity with minimum equipment repairs and well workovers (cost management); and
3. Maximize formation storage capacity and well life (asset management).

Achieving these goals requires appropriate system design, formation selection, well completion design, operating practices, and continuous monitoring and analysis[6]. It also requires close cooperation and open communication between the operator, engineering analysts, and regulatory agencies. Such close collaboration was one of the keys to the success of this project.

Permitting Requirements

The well CNO#2 was the first disposal well in Louisiana permitted for deepwell injection above fracturing pressure. The Louisiana Department of Natural Resources (LDNR) established the following items for project permitting and ongoing project operation:

- Appropriate selection of permitted injection zone
- Demonstration of well integrity
- Demonstration of hydraulic fracture containment
- Continuous monitoring and analysis

Over the course of the project the LDNR did apply additional operating guidelines, specifically:

- Minimum and maximum operating pressures
- Fixed slurry injection rates

These operating guidelines were applied primarily to verify there would be no fracture height growth above the permitted interval.

Based on its experience with the Fourchon SFI project, the LDNR is establishing new permitting and approval guidelines for future SFI projects

Site Geology & Injection Well

Site Geology. The regional structure of southern Louisiana is composed of southward dipping sedimentary formation, which are interrupted in various places by salt domes, salt ridges and normal faults[7]. In the Fourchon area the clastic sediments were laid down in a fluvial-deltaic environment. The target SFI zone was located in an environment of alternating sandstones and marine shales. The formations are of Miocene age (~24 million years) which means the sands are still poorly consolidated and poorly cemented. This is an advantageous condition for SFI since less energy is required to part the sandstone for waste placement.

The geologic column observed in well CNO#2 was as follows. From surface to 2000-ft depth shales were dominant, either as massive shales or shaly sands. Between 2000 ft and 2650 ft the “1500 ft” and “1800 ft” sand layers are present, which produce oil elsewhere. A 600-ft thick massive shale was located below 2650 ft. From 3250 ft to 5300 ft the geologic column is dominated by alternating sands and shales varying from 10 ft to 150 ft thick.

Injection Well. Injection well CNO#2 was drilled and completed in September 1997. The dimensions of the well are listed in Table 1.

The well was first completed with 3 ½” tubing and perforations at 4960 - 5000 ft. This will be referred to after this point as “Completion #1”. The targeted injection zone was a sand 114 ft thick. This set-up was used for slurry injection from November 1997 until early May 1998. At this time the casing was found to be crushed slightly at 4614 ft due to a thin sand pressuring up and shearing. This will be discussed in more detail below.

The well was worked over in May 1998 and finished as Completion #2: using 4 ½" tubing, with perforations at 4520 - 4560 ft. Larger tubing was used to reduce the amount of friction occurring in the well. Additional perforations were added in January 1999 between 4560 and 4602 ft, but subsequent logs showed these additional perforations were always covered by solids settled in the well. The target sand formation in Completion #2 was 42 ft thick (4506 - 4548 ft).

Injection Operations

The contaminated materials to be disposed of came from two locations: the Bay Marchand Terminal Pits, and the canal bottom soils of the Dead End Canal (Figure 2). The Bay Marchand pits were excavated between October 1997 and September 1998. Pit soils were dug out using hydraulic excavators and placed onto a conveyor belt, which took the material to the screen decks and mixing equipment. The processing and injection equipment was located adjacent to the Bay Marchand pits.

The north end of the Dead End Canal was dammed and drained for excavations between February 1999 and March 2000. These contaminated soils were dug from the canal bottom and pumped through a pipeline to a holding barge beside the injection equipment. From the barge the soils were run through a series of screen decks to separate the oversize material such as shells, rocks, organic materials, etc.

Water from the California canal was added to the screened soils to make a slurry containing 20% to 70% solids. After the slurry was completely mixed, two to four triplex pumps were used to pump the slurry at high pressures into the injection well. Typical injection rates were between 8 and 16 bpm.

Slurry injection episodes lasted for 9 to 11 hours typically, followed by shut-in periods of 13 to 15 hours (longer on weekends) (Figure 3). The philosophy of episodic injections is that formation stresses and fluid pressures that build up during injection are allowed to relax and dissipate during the shut-in period. Multiple injection episodes also allows for separate analysis of each injection and shut-in period, which means the behaviors of hydraulic fractures, the waste pod, and the formation can be diagnosed.

Containment Monitoring & Analysis

Definition of Containment. SFI must be contained within a designated zone so injected wastes will not interact with other natural resources such as oil bearing formations or freshwater aquifers. The injection zone permitted by the LDNR for this project was between 3880 and 5000 ft depths. It was not intended to use this entire column for injection, but to inject in the lower portion, reserving the upper portion as a buffer zone.

The permitted interval was composed of interbedded sands and shales of various thicknesses. The low permeability shales blunt upward fracture growth and prevent vertical fluid communication. If fractures do break through shales, the high permeability sands drain fluid away from the fracture tip, reducing the energy available for additional fracture growth.

In order to prove containment, monitoring and analysis have to demonstrate that hydraulic fractures were restricted in height growth at the wellbore and also at the furthest fracture extremities.

Monitoring & Analysis Techniques. A number of monitoring techniques were used to determine the behavior of hydraulic fractures and the waste pod:

- Gamma ray logs
- Temperature logs
- Bottomhole pressure monitoring
- Indicator pressure analysis
- Pressure fall-off analysis
- Injection pressure analysis
- Step rate tests

Since the injected wastes contained NORM, passive gamma ray logging showed clearly the placement of waste adjacent to the wellbore. Temperature logs were used as confirmation since the injected slurries were colder than the formation. These were the principal methods of determining the height of waste placement.

Bottomhole pressure (BHP) monitoring was used to infer the behavior of fractures and the waste pod at significant distance from the well. Indicator pressures were tracked over the history of the project. These values included:

- Average injection pressure (BHP_{inj})
- Instantaneous shut-in pressure (ISIP)
- Shut-in pressure at 12 hours (SI_{12hr})
- Minimum shut-in pressure (SI_{min}).

Pressure fall-off analysis yielded information about the waste pod in terms of permeability, skin, and fracture length. Afterflow (the combination of wellbore storage and fracture storage) and other leakoff artifacts were also tracked.

Injection pressures were analyzed to a limited degree using 3-D fracture models. Step rate tests were run at 1 to 6 month intervals to determine fracture extension rate and pressure.

Unfortunately, the swampy conditions around the injection well prevented the use of surface tiltmeters. Tiltmeters are used to determine orientation and dip of hydraulic fractures.

Completion #1. The injection well was initially perforated between 4960 and 5000 ft with the intention of injecting wastes into a sand layer 120 ft thick. Gamma ray logs three months after injections started showed that a much larger interval was receiving waste (Figure 4).

Cement Bond Logs. Between 4500 and 5000 ft the cement bond was in poor condition, particularly below 4770 ft (Figure 4). In this part of the well numerous thick sand zones were present among the shale units. After initial cement placement, it appears some cement migrated from the shale zones into the adjacent high-permeability sand zones. This left poor cement bonds along the shales and better bonds along the sands. Above 4500 ft the well had fewer sand units and exhibited better cement bonds (Figure 5). The poor cement bonds provided an excellent flow channel for injected slurries to travel upward along the wellbore.

Gamma ray and temperature logs of February 27 & 28 indicated that the primary waste storage zones were 4890 - 5000 ft and 4690 - 4830 ft. Minor storage zones which were localized to the near-wellbore region appear throughout the 4530 - 4890 ft interval.

Indicator pressures for Completion #1 are shown in Figure 6. Average injection pressures ranged between 3580 and 3940 psi, which corresponds to fracturing gradients of 0.73 to 0.80 psi/ft. The 12-hour shut-in pressures (SI_{12hr}) were in the range of 2180 to 3440 psi (0.44 to 0.70 psi/ft). Day-to-day variations in SI_{12hr} grew quite marked after mid-January 1998.

It is particularly interesting to note that the minimum shut-in pressures declined uniformly from 2290 to 2180 psi (0.47 to 0.44 psi/ft). This may indicate that the target zone was slightly overpressured, and communication with overlying formations bled off the excess pressure.

In early May 1998 there was an abrupt loss of ability to inject slurry through the well. A workover followed, during which the casing was found to be pinched by 1 inch diameter at 4614 ft. At this depth a 4 ft thick sand was present in a thick shale unit. It appears that the upward migration of pressurized fluids along the wellbore pressured up this thin unit and caused it to fail in shear, which damaged the casing. This thin sand failure mode was also observed in two Canadian SFI projects[8,9].

Completion #2. During the May 1998 workover the lower part of the well was plugged off and the well was perforated at 4520 - 4560 ft for Completion #2. The target sand interval was 44 ft thick and located between 4504 and 4548 ft.

Cement bond was particularly good above this injection zone (Figure 5). From 4420 to 4550 ft the cement bond was in excellent condition, mainly because shales were dominant between 4200 and 4500 ft. Only thin sands of less then 10 ft thickness were present in this interval, and they did not interfere with the cementing process as occurred in Completion #1.

Gamma ray and temperature logs were performed at one to three month intervals throughout Completion #2 (Figure 5). From June 1998 to March 2000 the top of the primary waste storage zone rose from 4500 ft to 4440 ft in a series of steps. Each step corresponded to fracture height growth into each of four thin sand layers. The depth of the bottom of the primary waste storage zone could not be determined since solids were always deposited in the well, covering at least half of the perforations. Thus, it is not known if some of the waste material was injected into the sand formations below 4560 ft.

It can be seen in the gamma ray log that there was a small amount of waste material placed between 4190 and 4330 ft (Figure 5). This first appeared in the July 15, 1999 gamma log. The shape of the signal never changed in any of the subsequent logs, and no anomalies were ever noted in the temperature logs. Based on these findings, it appears that this waste placement was a one-time event that occurred in May, June or July 1999, and was located exclusively along the wellbore. Otherwise, no waste placement into the formations occurred above 4440 ft during Completion #2.

Since the gamma ray and temperature logs showed good containment near the wellbore, evidence was required to confirm that far-field containment was also achieved. Indicator pressures, pressure fall-off analyses, and injection pressure behavior provided that evidence. It was found that these datasets showed good correspondence with changes in the injection zone behavior observed by the gamma ray and temperature logs.

Indicator pressures for the full history of Completion #2 are shown in Figure 7. The overall range of average injection pressures was between 3350 and 3700 psi, corresponding to fracturing gradients of 0.77 to 0.86 psi/ft. Not shown on the graph are ISIPs, which ranged between 3250 and 3600 psi (0.75 to 0.83 psi/ft). The 12-hour shut-in pressures (SI_{12hr}) varied between 1955 and 3200 psi (0.45 to 0.74 psi/ft). The lowest shut-in minimum (SI_{min}) pressures observed throughout this project phase were consistently 1955 psi (0.45 psi/ft), even in March 2000.

The greatest daily variability in indicator pressures was observed in June and July 1998. From February 1999 until March 2000 all indicator pressures showed more consistent behavior, with several periods of rising and falling pressures. On comparison with the gamma and temperature logs the following correlations appear:

- Injection pressures tended to rise while the height of the primary injection zone remained the same.
- Injection pressures fell when the active zone started to break through the overlying 5 to 30 ft thick shale into an upper thin sand unit.
- Shut-in pressures tended to rise while the height of the active injection zone remained the same.
- Shut-in pressures started to fall at about the same time as expansion of the injection zone into the overlying thin sand was completed.

Based on these observations the Completion #2 history was divided into five periods. The dates and corresponding height of the primary injection zone are shown in Table 2. The transition dates are also marked on Figure 7.

Pressure fall-off data were analyzed both quantitatively and qualitatively to assess changes in waste pod behavior. Thirty-eight shut-in episodes were analyzed. Very few of the shut-ins showed classical linear or radial flow behavior[10,11] (e.g. Figures 8 and 9). However, they did provide good qualitative understanding of the interaction between hydraulic fractures, the waste pod, and the virgin sand formation.

Afterflow effects dominated the behavior of the pressure fall-offs. "Afterflow" in this context is equal to the sum of wellbore storage and fracture storage effects. Wellbore storage occurs due to the decompression and expansion of fluid in the well after pumping has stopped. Fracture storage causes fluid to leakoff across the fracture face after pumping has stopped. This can be caused by the high compressibility of the waste pod around the fracture, or by slow dewatering and consolidation[12] of the recently injected clays and silts.

The measured values of afterflow (C_S) were between 0.1 and 13.0 bbl/psi. This is four orders of magnitude larger than estimated wellbore storage (2.4×10^{-4} bbl/psi), meaning practically all of the afterflow was caused by fracture storage effects.

Even though large afterflow effects distorted the data, analyses of permeability and skin were still performed. Estimates of the waste pod and virgin formation permeabilities were obtained, as summarized in Table 3. Waste pod permeability was determined from Horner plots or numerical modeling and was typically between 4 and 35 md.

Native sand formation permeability was determined either from late time data as reservoir pressure was approached, or in early-time data if hydraulic fractures had good communication beyond the waste pod as shown by the radial type curve in Figure 9. Formation permeability estimates were between 200 and 14000 md, but the true value was probably in the 500 to 2000 md range.

Fracture half-length was determined from the shut-in data where linear flow appeared to be present. The overall spread of values was 180 to 2980 ft.

In addition to estimating fracture lengths from linear flow behaviour, the behavior of hydraulic fractures relative to the waste pod was also summarized (Table 4). This qualitative summary was based on the shapes of the log-log derivative plots, permeability and skin values, and other shut-in activities such as pressure spikes. The trends in qualitative shut-in behavior corresponded quite well with changes of injection zone height observed in the logs and also with the indicator pressure analyses.

Pressure spikes showed up frequently in some time periods. Pressure spikes are caused by differential leakoff of the fracture, creating trapped overpressure zones which abruptly reopen adjacent closed zones in order to redistribute fluid and pressure. Large pressure spikes were prominent when placement of wastes into new sand zones started to occur, especially in June-September 1998, and January-March 2000 (Figure 10).

Injection pressures were more time consuming to analyze, and were not looked at as comprehensively as the shut-in pressures.

In addition to summarizing the average injection pressure of each day, the pressure vs. time plots were also looked at. Uniform slope pressure declines of 0.5 to 3 hours duration were observed on several occasions indicating fracture height growth. The most significant periods when this was observed were August 13, 1999 and January 24-February 5, 2000. Both occasions corresponded with breakthrough of the primary injection zone into overlying thin sands, as indicated by the gamma ray and temperature logs.

Three-dimensional fracture modeling was tested on ten injection days in October 18-29, 1999. Due to uncertainty in determining closure pressures, several modeling scenarios were used. Net pressures were in the range of 150 to 600 psi, and the modeled fracture half-lengths were between 200 and 850 ft. Daily changes in Young's modulus, permeability, and fracture complexity were apparent, but this may be an artifact of closure stress uncertainty[13].

Containment Analysis Summary. The quality of the casing cement bond directly determined how well contained the injected slurries were to the target sand formations. Above Completion #1 the longest section of good cement bond was 20 ft. Directly above Completion #2 there was at least 80 ft of good cement bond, which provided excellent containment of the SFI process. In this well the quality of the bond was dictated by the thickness and relationship of sandstones to the adjacent shales.

Completion #1: The primary zones of waste placement were 4890 - 5000 ft and 4690 - 4830 ft. Secondary placement localized to the near-wellbore region occurred throughout the 4530 - 4890 ft interval.

Completion #2: By the end of the project the primary waste placement interval was 4440 - 4560 ft (and possibly deeper). It is felt this is also representative of the waste placement in the far-field, since changes in placement height observed at the wellbore corresponded to changes in pressure behavior.

Description of Waste Pod

Slurry injection into soft, high permeability formations creates a relatively thick fracture and dilation zone, providing grater storage capacity than traditional thin fractures generated in hard rock. Laboratory observations[14,15] and field observations[6] indicate that significant damage and deformation (microcracking, multiple dendritic fracturing, and dilation) occurs along the length of a propagating fracture. Fracture or "parting" of weakly consolidated media with near zero shear strength, therefore, is dominated by energy dissipated deforming, shearing, and dilating material over a large area[16].

In contrast to normal stimulation operations in low permeability rock, during waste injection in high porosity media subsequent conductivity in the created process zone is often less than or equal to the native formation conductivity. Stresses tend to increase and permeability tends to decrease within this fracture and dilation zone, as indicated by increasing net pressure and less rapid bleedoff after shut-in. With repeated injection the fracture will break out of this zone in a different orientation. Net pressure and shut-in behavior then returns to previous conditions. This process is illustrated by a sequence of injection episodes at Fourchon, as shown in Figure 11.

Successive injection episodes eventually create fracture and process zones at varying orientations around the injection well, forming a heterogeneous waste pod. Reduced fracture conductivity, combined with increased stress within the waste pod, often results in new fractures being created with repeated injection episodes at orientations varying over a range of 30 to 60 degrees. Although no fracture orientation measurements were conducted at Fourchon, rotation of vertical fractures around an injection well has been observed during the Mounds project[17] and during a Terralog SFI project in Canada[8].

Space for placing the solid wastes in the formation is created by filling pores in the waste pod with fine grain materials and by compressing the soft surrounding formation. To illustrate this additional storage capacity with a simple example, assume the waste pod is ellipsoidal in shape. The volume of solids (V_{solids}) contained in the waste pod can be estimated as follows:

$$V_{solids} = (4/3\ \pi\ a\ b\ c)\ (\ f + C_t\ Ds\ )\ ff$$

where:

a = waste pod half-width, ft
b = waste pod half-length, ft
c = waste pod half-height, ft
f = initial formation porosity
Ct = formation compressibility, psi^{-1}
Ds = change in stress due to packing, psi
ff = empirical coefficient to account for actual pore space taken up by waste, typical values 0.1 to 0.2.

During Completion #2, 722,000 bbl (4.05×10^6 ft^3) of solids were disposed in an interval of 80 ft thickness. Assuming that the ellipsoid was half as wide as it was long, initial porosity was 23%[2], and ff was 10%, the maximum half-length of the waste pod was 1450 ft. The average reduction in porosity in this scenario is equal to 2.3% (compressibility effects were negligible).

Project Economics and Environmental Impact

The economics of on-site SFI relative to other methods of NORM disposal is extremely attractive. The CNO#2 injection well was located adjacent to areas to be remediated, resulting in significant cost savings relative to transportation.

At the Fourchon location, total cost to dispose of the NORM contaminated soil was about $19 per barrel of soil. This cost includes the injection well, site preparation, excavation and remediation, and facilities for the injection process. Approximately $11 per barrel of this can be considered incremental costs due to the SFI process, with the balance considered a sunk cost irregardless of the method of disposal (e.g., the site preparation, excavation, and remediation costs). Considering that bids for off-site disposal of this same NORM contaminated soil were upwards of $100 per barrel, excluding excavation costs, the project was extremely cost-effective. Average costs for off-site NORM disposal reported recently range from $15 to $420 per barrel.[18]

The environmental impact of the SFI process has proven to be essentially nonexistent, making it a preferred method of disposal relative to other disposal options. For example, disposal of the one million barrels of NORM contaminated soil at an offsite facility, likely in the neighboring state of Texas, would have required as many as 200 barges loaded with the soil to be transported hundreds of miles along south Louisiana waterways, greatly increasing the potential of an environmental spill or other safety hazard.

Conclusions

The following conclusions were drawn from the experience of the Chevron-Fourchon Slurry Fracture Injection (SFI) project:

1. Large volumes of contaminated soils (~1,000,000 bbl) can be disposed successfully using the SFI process. SFI is both cost-effective and environmentally friendly.
2. Continuous monitoring of bottomhole pressures and frequent use of well logging can permit comprehensive interpretation of waste placement in the formations around the injection well.
3. High quality cement bonds of significant height are required to maintain waste containment in the target formation, and to provide extended life span of the injection well.
4. Repeating injection episodes of low-permeability materials into poorly consolidated sandstones causes SFI fracturing processes and interpretation to vary somewhat from conventional hydraulic fracturing.
5. Changes in the trends of injection and shut-in pressures corresponded closely to changes in slurry placement as determined from the wellbore logs. This correlation indicates that fracturing heights in the near-wellbore and in the far-field were consistent, and no out-of-zone fracturing occurred in the far-field without initiation adjacent to the wellbore.

Recommendations for Future SFI Projects

In light of the conclusions, companies wishing to pursue SFI and regulatory bodies should be prepared for the following:

1. Permit the formations around the injection well with the following classifications: injection zone, confining zone and containment zone. The injection zone is the formation into which waste materials are directly injected. The confining zone contains formations which may accept waste materials, but is intended to block upward fracture growth. The containment zone is the shale barrier which blocks all communication with overlying beneficial resources. This graded classification of formations permits maximum protection of usable water & other resources, yet permits flexibility in the fracturing program.
2. Use a well cementing program that maximizes cement bond quality.
3. Institute a monitoring program which includes, at a minimum, the following: tracking of slurry volumes, recording of bottomhole and surface pressures, and regular logging using temperature, gamma ray and/or tracer logs. Tiltmeter or microseismic monitoring should be considered if warranted.
4. Frequent analysis of pressure and logging results is essential. The analyses should be provided to the regulatory body at regular intervals to permit open communication between the regulatory body and the project managers.

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Table 1: Dimensions of injection well CNO#2

Vertical Well	Completion #1 (Oct 97 – May 98)	Completion #2 (May 98 – Apr 00)
Drive Pipe: Depth Outer Diameter	0 – 183 ft 16.0 in	
Surface Casing: Depth Outer Diameter	0 – 1006 ft 10.75 in	
Production Casing: Depth Outer Diameter	0 – 5300 ft 7.625 in	
Tubing: Depth Outer Diameter	0 – 4957 ft 3.5 in	0 – 4515 ft 4.5 in
BHP Sensor Depth	4911 ft	4321 ft
Packer Depth	4933 ft	4408 ft
Perforations	4960 – 5000 ft	4520 – 4560 ft (Initial) 4520 – 4602 ft (After Jan 99)

Table 2: Injection periods during Completion #2 based on logs

Dates	Primary Injection Zone
June 1 - September 8, 1998	4500 - 4560 ft
February 5 - April 30, 1999	4490 - 4560 ft
May 2 - October 22, 1999	4450 - 4460 ft 4490 - 4560 ft
October 25, 1999 - January 21, 2000	4480 - 4560 ft
January 24 - March 20, 2000	4440 - 4560 ft

Table 3: Summary of pressure fall-off analyses for Completion #2

Analysis Property	Range of Values
Assumed formation height	100 ft (All cases)
Waste Pod Permeability (k) Skin (S)	4 to 35 md -6.2 to -3.8
Native Sand Formation Permeability (k) Skin (S)	200 to 14,000 md -2.5 to +30
Fracture Half-Lengths (X_f)	180 to 2980 ft
Afterflow (C_S)	0.1 to 13.0 bbl/psi

Table 4: Pressure fall-off behavior during Completion #2

Dates	Pressure Fall-off Behaviour
June 1 - September 8, 1998	• Hydraulic fractures typically contained in waste pod. • Many pressure spikes: differential leakoff & closure
February 5 - April 30, 1999	• Radial type curve of high permeability in early shut-ins (long fractures) • Little pressure spiking (uniform waste pod leakoff)
May 2 - October 22, 1999	• Far-field perm rarely observed (short fractures) • Little pressure spiking (uniform waste pod leakoff)
October 25, 1999 – January 21, 2000	• Fractures alternated between shorter and longer than waste pod • Little pressure spiking • Waste pod quite large indicated by slow leakoff behaviour (SI_{12hr})
January 24 - March 20, 2000	• Large pressure spiking dominant (differential leakoff behaviour)

Figure 1: Location of Port Fourchon, Louisiana

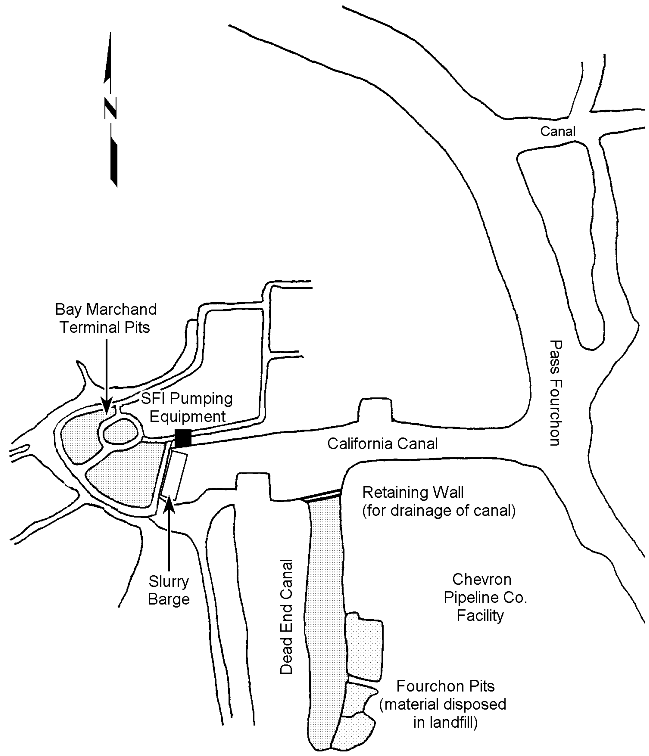

Figure 2: Fourchon (Bay Marchand Facility) site map

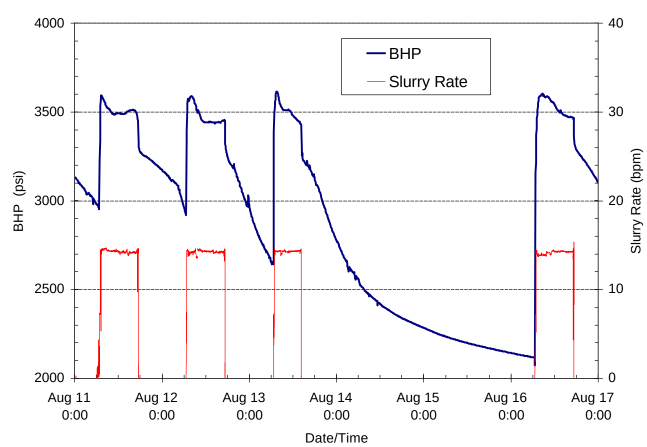

Figure 3: Example of successive injection and shut-in periods

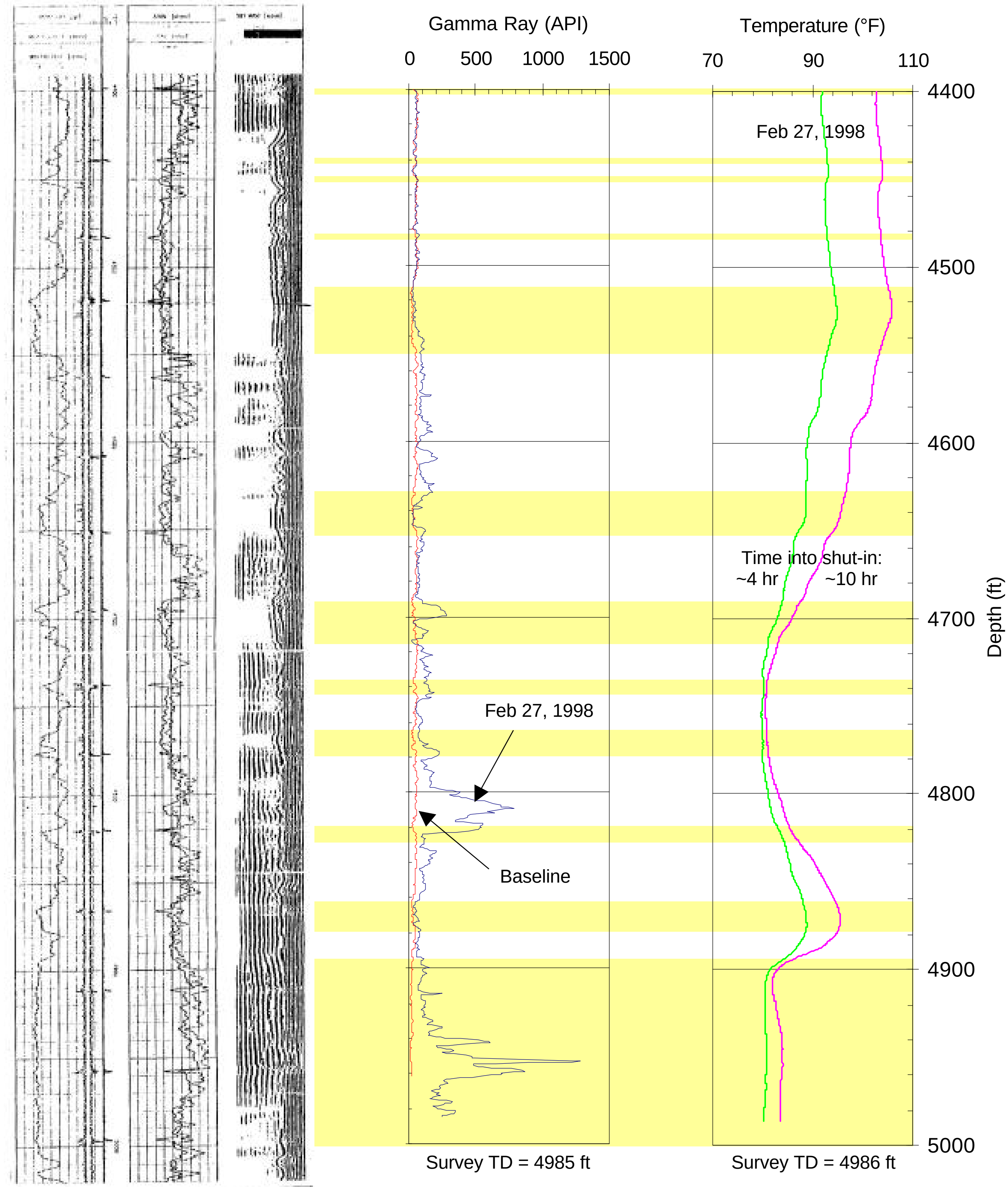

Figure 4: Completion #1 logs – Cement bond, gamma ray, and temperature logs (Yellow shading indicates sand zones)

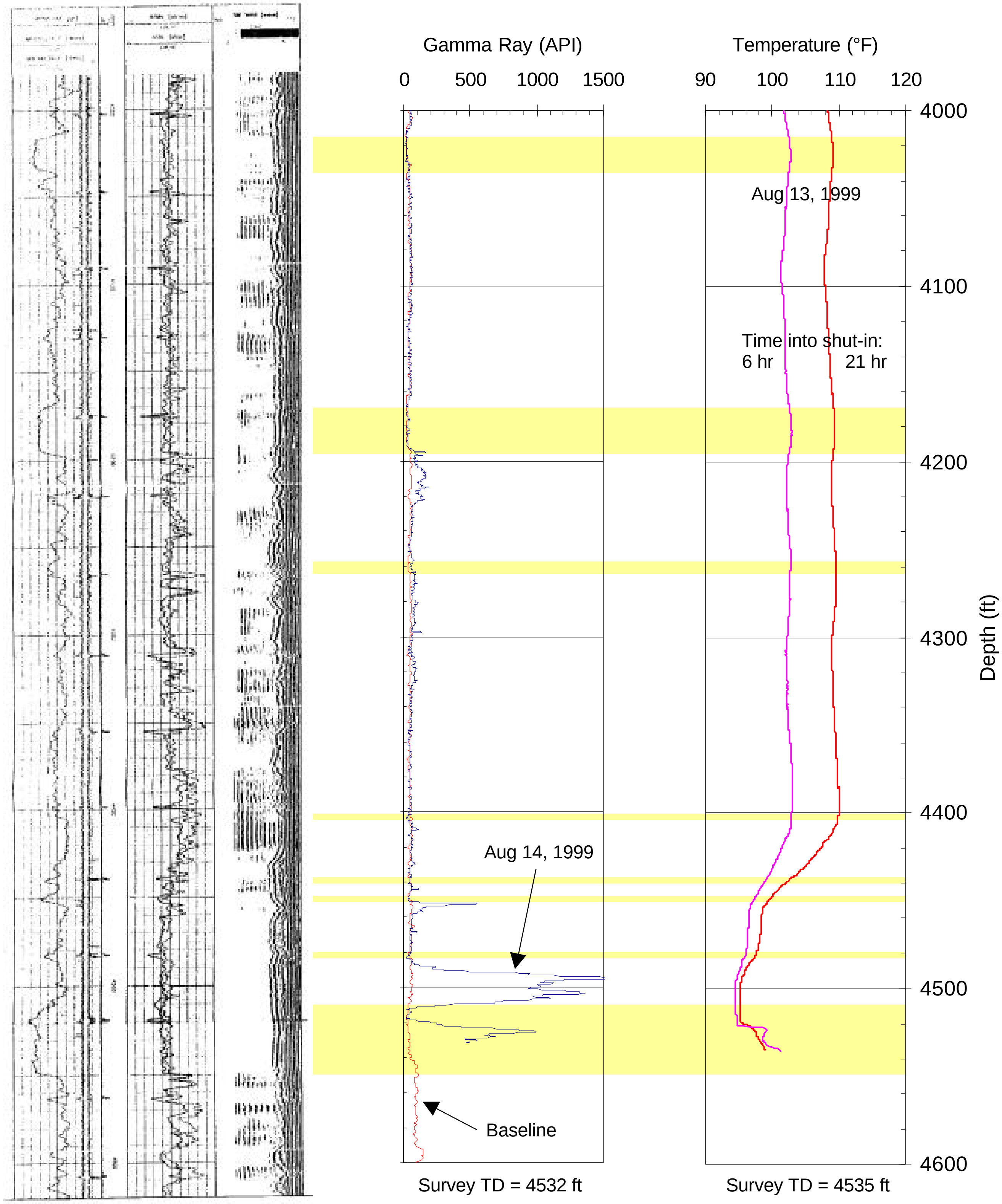

Figure 5: Completion #2 logs – Cement bond, gamma ray, and temperature logs (Yellow shading indicates sand zones)

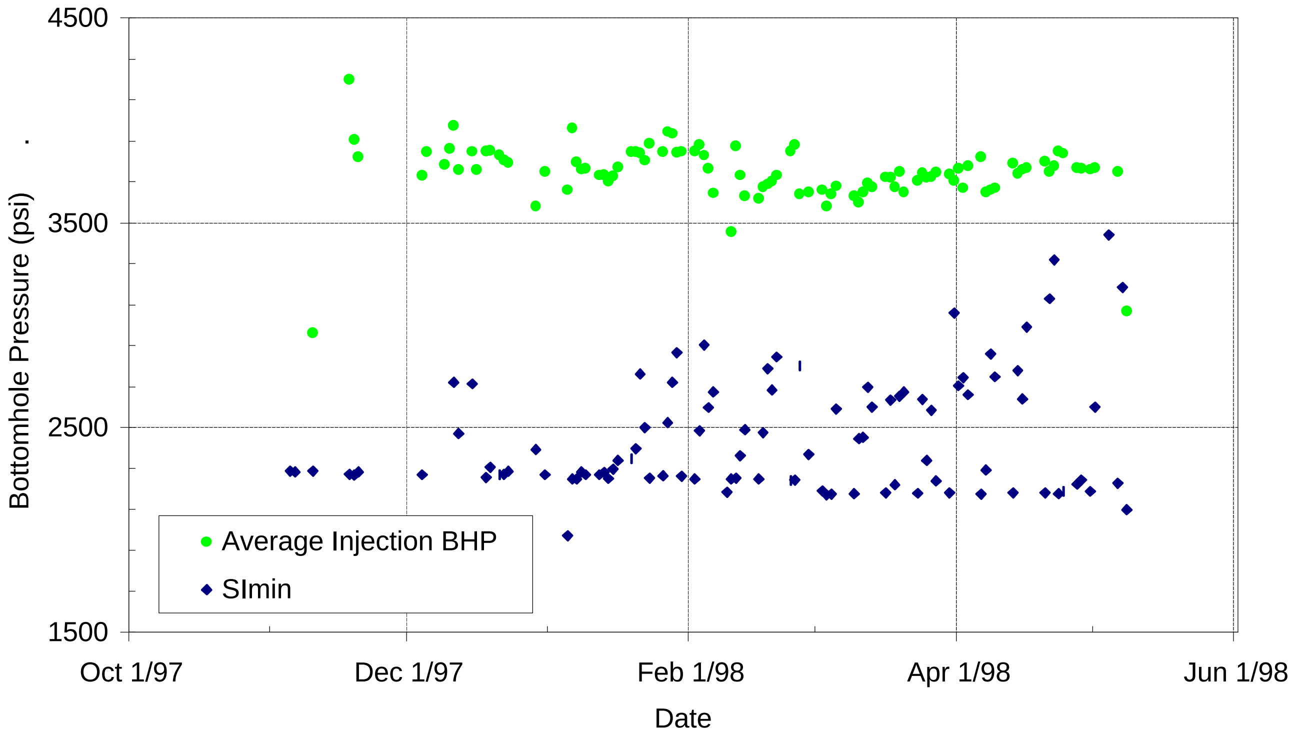

Figure 6: Indicator pressures for Completion #1

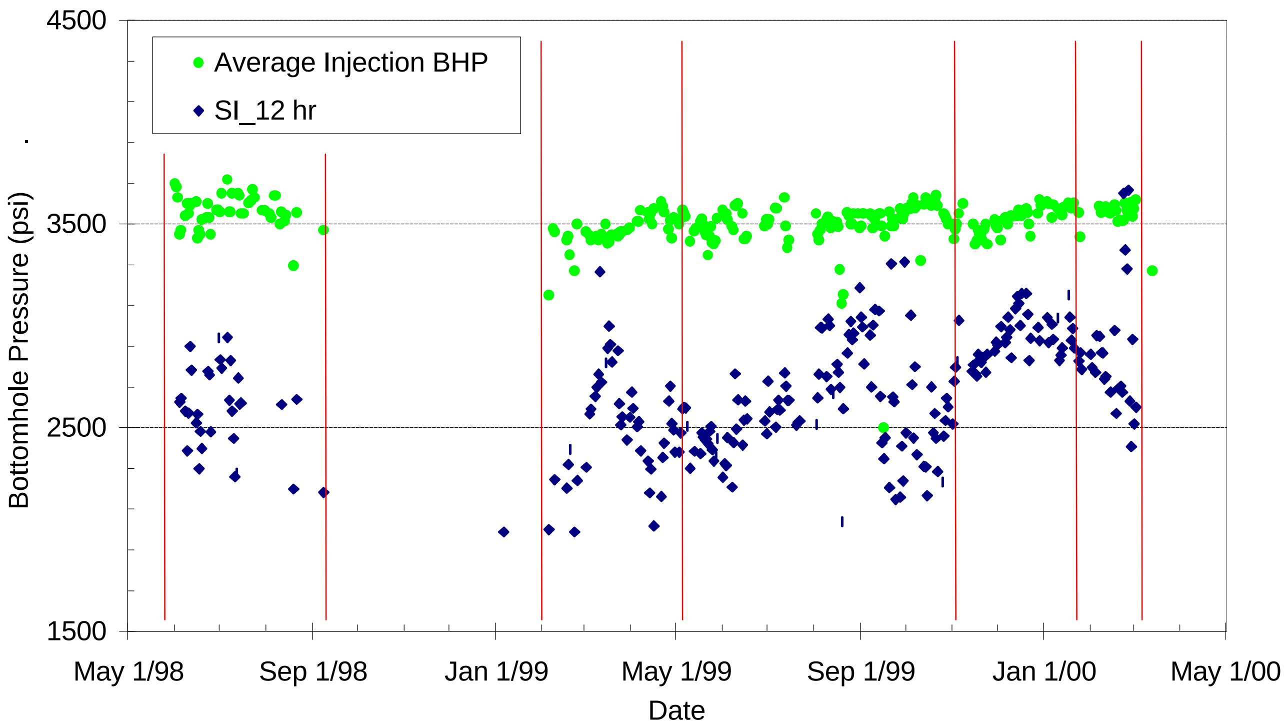

Figure 7: Indicator pressures for Completion #1 (Vertical lines correspond to dates in Table 2)

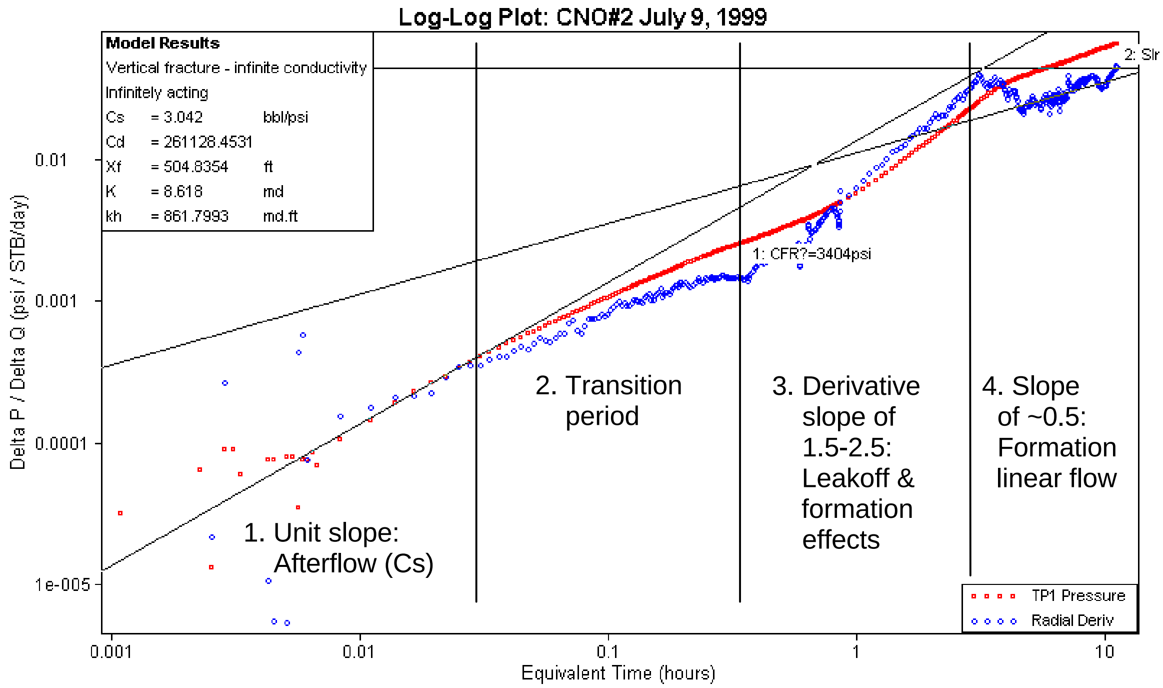

Figure 8: Log-log plot of July 9, 1999 pressure fall-off

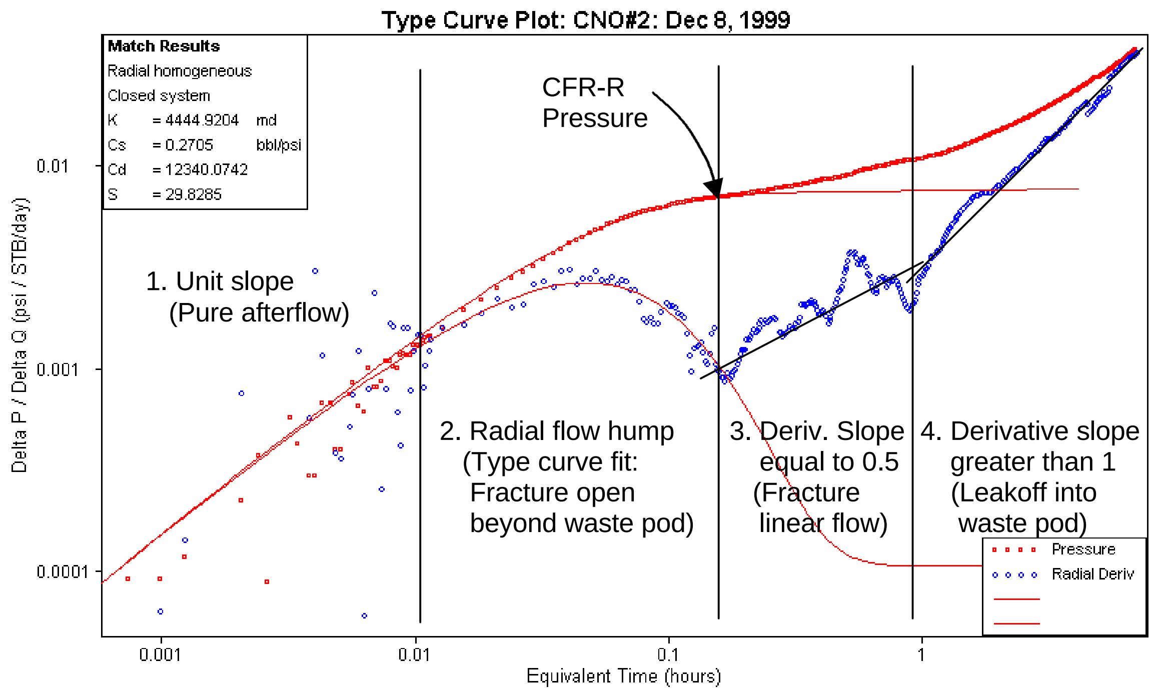

Figure 9: Log-log plot of December 8, 1999 pressure fall-off

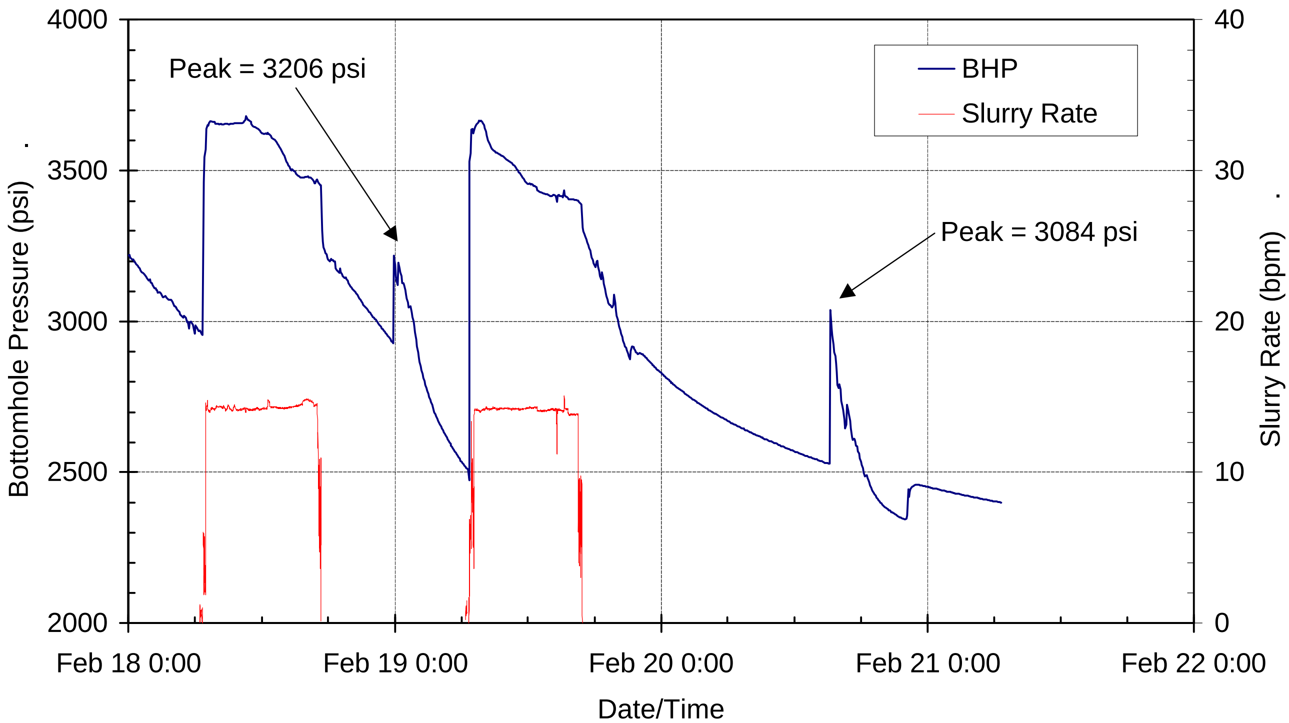

Figure 10: Examples of pressure spikes during shut-ins (February 2000)

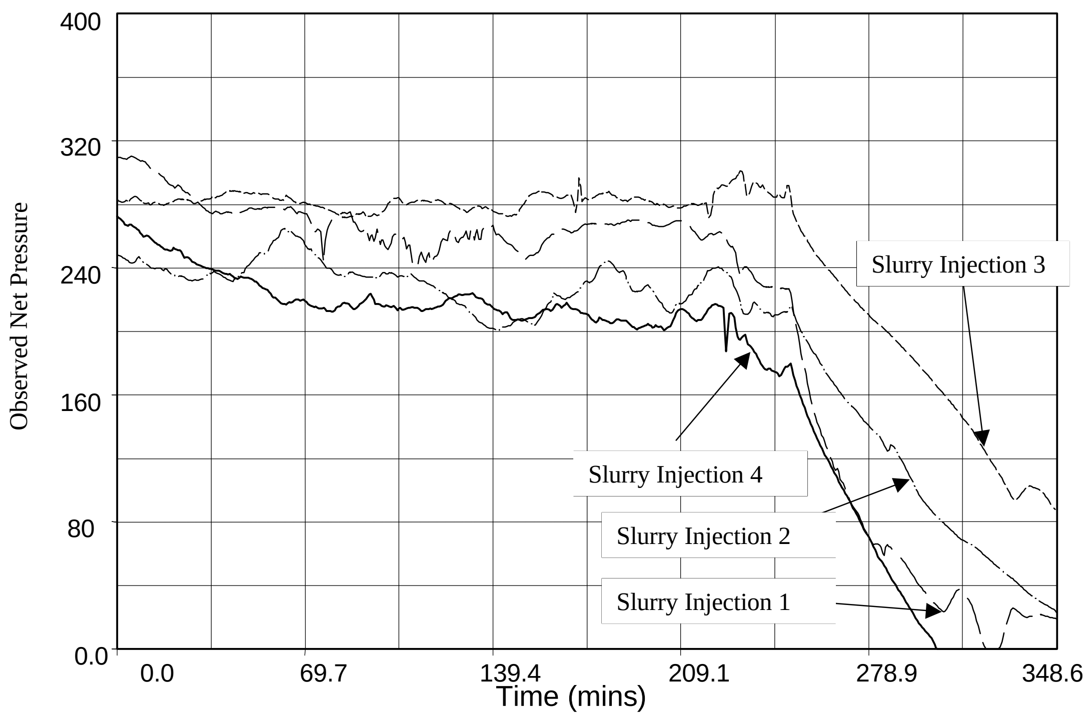

Figure 11: Varying net injection and shut-in pressures for sequential injection episodes at Fourchon.