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## Leak Testing and Implications of Operations to Locate Leak Horizons at West Hackberry Well 108

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## **ABSTRACT**

The Strategic Petroleum Reserve site at West Hackberry, Louisiana has historically experienced casing leaks. Numerous West Hackberry oil storage caverns have wells exhibiting communication between the interior 10¾ × 20-inch (oil) annulus and the “outer cemented” 20 × 26-inch annulus. Well 108 in Cavern 108 exhibits this behavior. It is thought that one, if not the primary, cause of this communication is casing thread leaks at the 20-inch casing joints combined with microannuli along the cement casing interfaces and other cracks/flaws in the cemented 20 × 26-inch annulus. An operation consisting of a series of nitrogen leak tests, similar to cavern integrity tests, was performed on Cavern 108 in an effort to determine the leak horizons and to see if these leak horizons coincided with those of casing joints. Certain leaky, threaded casing joints were identified between 400 and 1500 feet. A new leak detection procedure was developed as a result of this test, and this methodology for identifying and interpreting such casing joint leaks is presented in this report. Analysis of the test data showed that individual joint leaks could be successfully identified, but not without some degree of ambiguity. This ambiguity is attributed to changes in the fluid content of the leak path (nitrogen forcing out oil) and possibly to very plausible changes in characteristics of the flow path during the test. These changes dominated the test response and made the identification of individual leak horizons difficult. One consequence of concern from the testing was a progressive increase in the leak rate measured during testing due to nitrogen cleaning small amounts of oil out of the leak paths and very likely due to the changes of the leak path during the flow test. Therefore, careful consideration must be given before attempting similar tests. Although such leaks have caused no known environmental or economic problems to date, the leaks may be significant because of the potential for future problems. To mitigate future problems, some repair scenarios are discussed including injection of sealants.

## **Acknowledgements**

The authors would like to acknowledge Norman Warpinski, Ray Finley, and S.J. Bauer of Sandia National Laboratories, and Robert Myers of the United States Department of Energy for their valuable suggestions concerning additional ways, other than gas-production rate, to detect nitrogen gas leaks; for help in displaying the data; and for participating in discussions regarding fluid flow and the strain of the lithology surrounding the wells and caverns. Finally, the authors would like to acknowledge Tim Peterson for his assistance in assembling this document.

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## Acronyms

bbbl	Barrel
CIT	cavern integrity test
DOE	Department of Energy
scf	Standard cubic feet
SNL	Sandia National Laboratories
SPR	Strategic Petroleum Reserve
WH	West Hackberry

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## 1.0 INTRODUCTION

This report describes pressure communication tests conducted on a storage cavern well at the West Hackberry Site of the US Strategic Petroleum Reserve (SPR). The SPR is managed by the Department of Energy's (DOE's) Office of Fossil Energy. Today, the SPR holds the largest emergency oil stockpile in the world. The infrastructure and crude oil together represent more than a \$20 billion national investment. Maintenance of this infrastructure is essential to assure the readiness of the oil stockpile.

### 1.1 Background

The Energy Policy and Conservation Act, established in December 1975, provided the legislative authorization for the SPR. The objective of the SPR is to provide the nation with an emergency supply of crude oil that will diminish US vulnerability to the effects of a severe interruption of supply. The oil is stored in underground salt caverns located along the US coastline near the Gulf of Mexico. As of this writing, the SPR stores nearly 570 million barrels of crude oil in 62 storage caverns at four sites. These sites, which are convenient to many US refineries and distribution points, are:

- Bryan Mound, Texas. This storage facility near Freeport, Texas has storage capacity of 232 million barrels and an inventory of 215 million barrels.
- Big Hill, Texas. This storage facility near Beaumont/Winnie, Texas has a storage capacity of 170 million barrels and an inventory of 87 million barrels.
- Bayou Choctaw, Louisiana. This storage facility near Baton Rouge/Plaquemine, in Iberville Parish, Louisiana has a capacity of 76 million barrels and an inventory of 72 million barrels.
- West Hackberry, Louisiana. This storage facility near Lake Charles/Sulfur, in Cameron Parish, Louisiana has a storage capacity of 222 million barrels and an inventory of 193 million barrels.

This report describes testing conducted at the West Hackberry site. This storage facility occupies 565 acres of land and is situated above the West Hackberry salt dome. The location was selected for the SPR because the site's existing brine caverns could be readily converted to oil storage. The site has 22 underground solution-mined storage caverns. Appendix A contains more specific information about the SPR and this site.

The West Hackberry site contains five original caverns that were purchased from Olin Corp (WH 6, WH 7, WH 8, WH 9, and WH 11). These caverns were present at the time of the 1980 site-characterization study (Whiting and Beasley, 1980). Additionally, the site includes 17 additional caverns that were leached within the salt dome by contractors to the DOE. Sixteen are single-well caverns (WH 101 through WH 116) where, by definition, the oil and brine strings connect to the same wellhead. The last (WH 117) is a two-well cavern. All 17 of these additional caverns are rather symmetrical; significant deviations from the original design shapes have not occurred (Magorian et al., 1991). The 17 additional caverns have two casing strings that penetrate, and are cemented into, the salt. These casing strings are the 20-inch casing and the 26-inch casing. All of the single-well caverns have similar well designs. The 20-inch production casing was coupled with threaded casing collars in all but one case, WH 103, where the casing string was welded. The 26-inch casings are welded in all of the caverns. A well-completion configuration diagram of WH 108, the cavern discussed in this report (see Section 1.2) is shown

in Figure 1. The 20- × 26-inch annulus is capped at the surface and pressure can be bled down. A pressure gage is affixed to the cap. Figure 2 provides a more detailed diagram of the well components that fall within the salt formation.

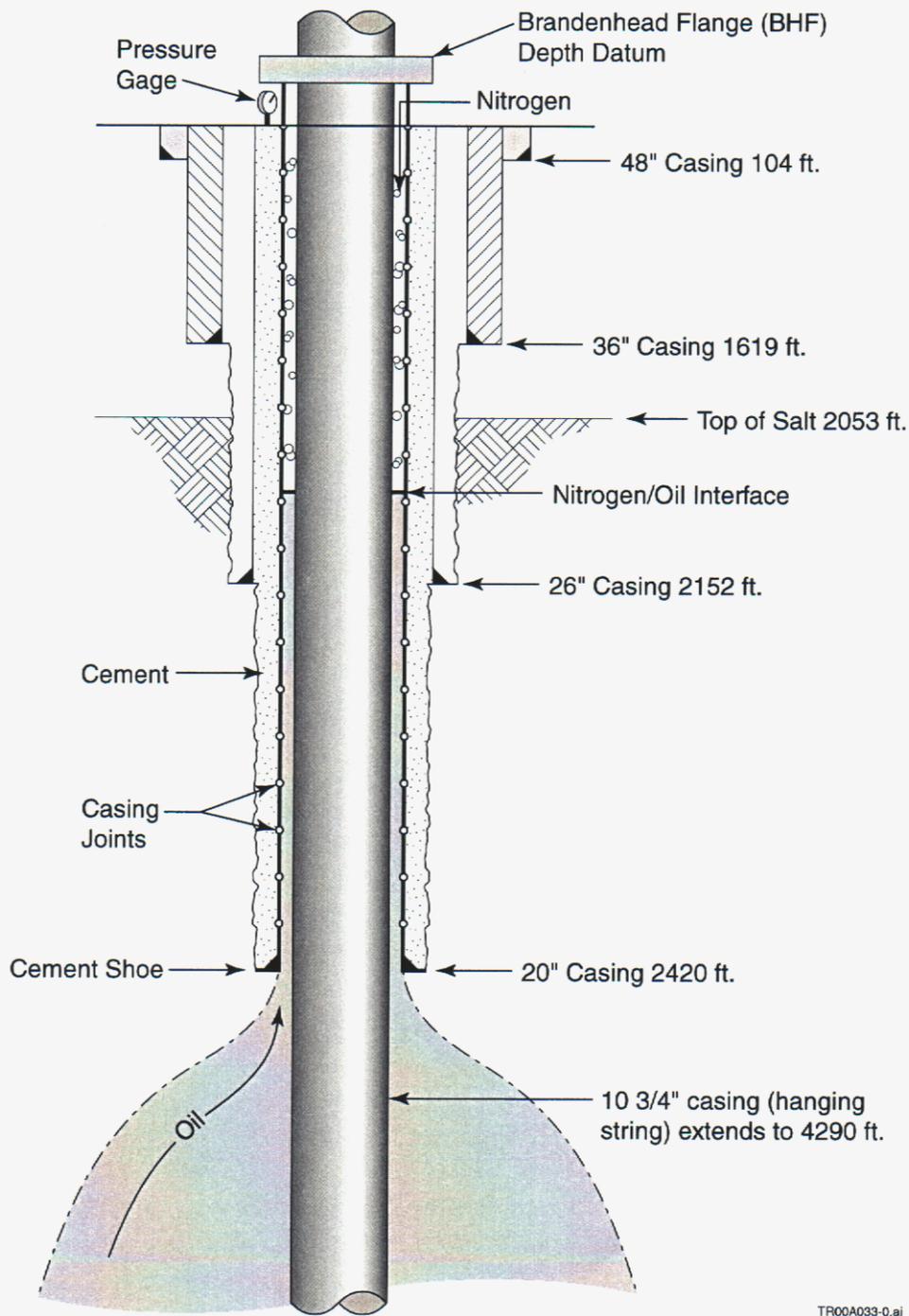


Figure 1. Profile of West Hackberry 108 Well Configuration.

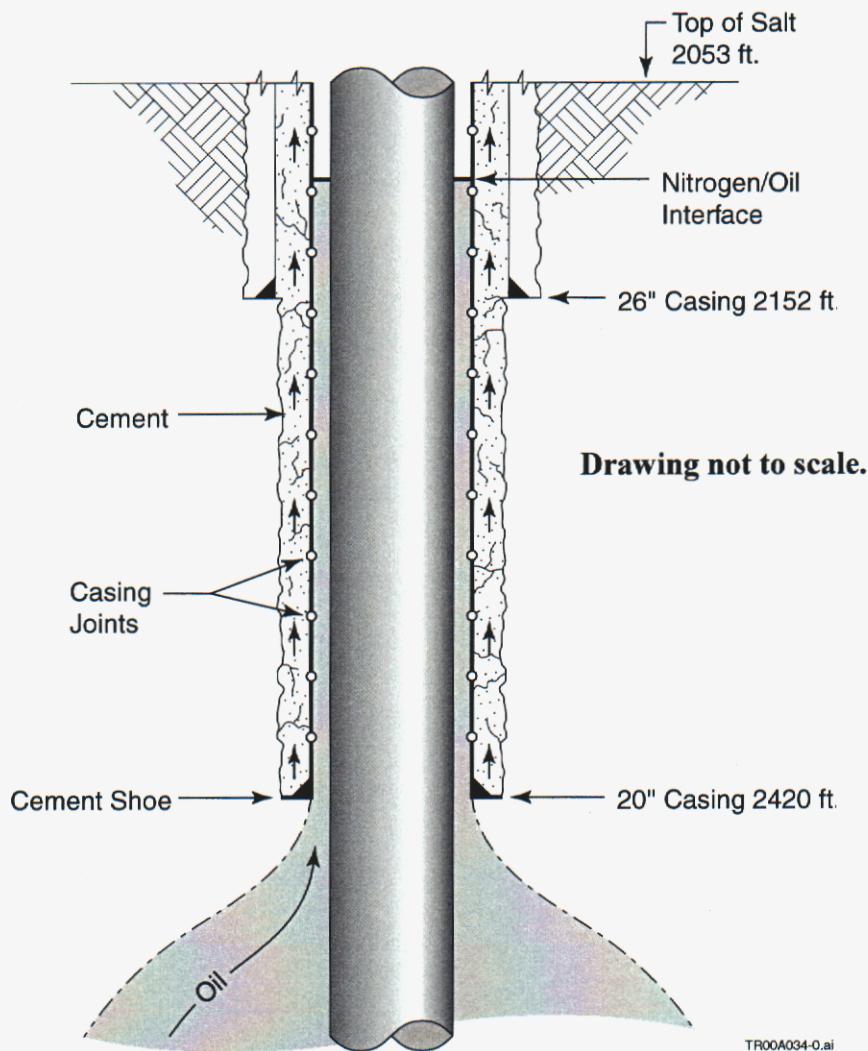


Figure 2. Profile View of West Hackberry 108 Showing Possible Leak Paths.

## 1.2 Purpose and Scope

The SPR site at West Hackberry historically has experienced casing leaks (Matalucci, 1994; Badalamenti, 1994; Bauer and Sattler, 1998).

The initial pressure tests on the newly created West **Hackberry wells, prior to cavern leaching**, showed brine leak rates in excess of 100 bbl/year for most of the wells (Goin, 1981). Thread leaks, particularly those at shallow depths, were confirmed with tracer dye, indicating that many of the wells were leaking to the surface along the 20-x 26-inch annulus. In an attempt to reduce the leak rate to acceptable limits, half of the leaking wells received **epsal**, a commercial sealant, applied either at the location of the thread leak or injected directly into the 20- x 26-inch annulus. WH 108 tested at brine leak rates of 128 and 95 bbl/year (the latter fitting into 100 bbl/year leakage criteria with the states of Louisiana and Texas), and did not undergo treatment with **epsal** at that time.

Numerous West Hackberry oil storage caverns indicate continued pressure communication between the interior 10 3/4- x 20-inch (oil) annulus and the outer “cemented” 20- x 26-inch annulus. In the worst cases, the outer annular pressure appears to follow the oil pressure rather closely, as shown in Figure 3. In cavern integrity tests, when the annular pressure does follow the pressure inside the pressure in the 10 3/4-inch annulus, a pop-off valve is inserted into the 20- x 26-inch annulus. Pop-off pressure is set at 1000 psi because of the burst pressure requirements of the 26-inch casing.

West Hackberry caverns 101, 102, 105, 107, 108, 109, 110, and 116 exhibit this type of pressure communication behavior. (The locations of these caverns are provided in Appendix A.) The pressure behavior exhibited by some of the annuli in other West Hackberry caverns, such as Cavern 113, suggests that this type of communication also exists, but to a lesser degree, in other caverns. A primary cause of this pressure communication may be the result of thread leaks in the 20-inch casing combined with the presence of microannuli along the cement casing interfaces, or the presence of other cracks or flaws in the cemented 20 x 26-inch annulus (see Section 4.3).

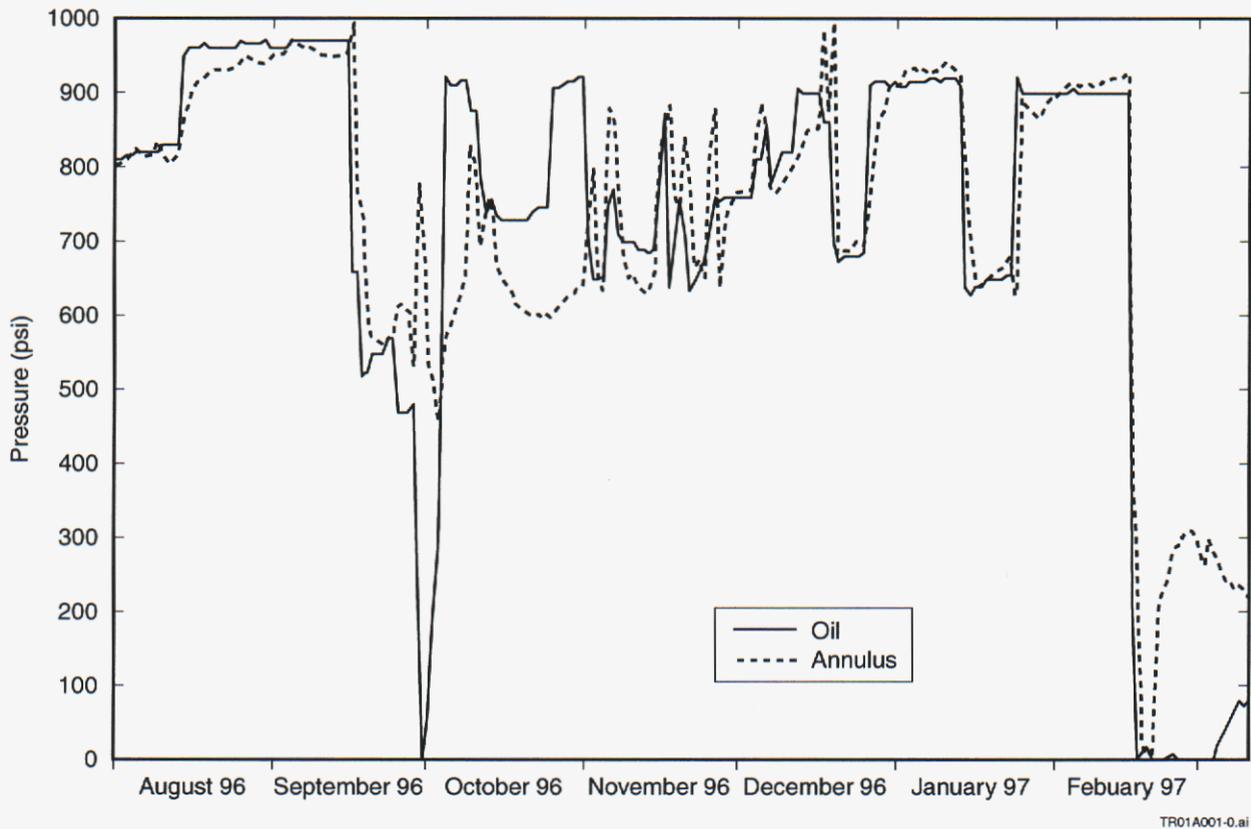


Figure 3. Comparison of Oil and Annulus Pressures in WH 108 during 1996 and 1997.

To test this hypothesis, an operation was undertaken to locate casing leak horizons in the upper portion of the 20-inch casing of WH 108. Another purpose of the operation was to verify that the casing leaks did indeed occur at casing joints. In reality, the operation consisted of performing nitrogen leak tests with attendant analyses. Any future attempt to remediate these types of leaks would require knowledge of the leak horizons.

According to our hypothesis, these leaks were expected to occur in the threads at one or more of the collars of the cemented 20-inch casing. The leaks were presumed to then feed into microannuli in the cemented 20- $\times$  26-inch annulus that connected to the surface, as shown in Figure 2. WH 108 has an annualized leak rate of 40 barrels of oil per year (Piechocki, 1999). Although the casing leaks have resulted in no known environmental or economic problems related to possible oil leaks, the potential exists for oil leaks in the future. Thus, we felt it was prudent to increase our understanding and quantify the situation if possible.

The goal of the well testing operation was to identify the nature, location, and magnitude of the leaks, and to consider remediation options. Multiple casing thread leaks were inferred from the data, although the inference is not without ambiguity. This ambiguity is caused by changes in the liquid contents of the leak path. These changes are caused by the flow of nitrogen cleaning out small amounts of oil from the leak path, and perhaps caused by changes in the leak path itself. This operation and the subsequent analysis of the resulting data confirmed a methodology for identifying and interpreting such casing joint leaks.

### 1.3 Report Structure

This report gives a description of the leak test operation, which was conducted similarly to that of a cavern integrity test (CIT) (Crotogino, 1995; CH2M Hill, 1995).<sup>1</sup> An analysis of the recorded nitrogen pressure data versus time, which was used to determine leak location, follows the experiment description section. This section outlines how the data are displayed (gas-production rate, wellhead pressure, and time derivative of wellhead pressure as a function of time, and horizon of the nitrogen-oil interface within the 10 $\frac{3}{4}$   $\times$  20-inch annulus). The analysis breaks down the results into three phases. In each phase, attempts were made to locate leaks in specific intervals of the WH 108 well, as follows:

- Phase 1: 500–486 ft depth,
- Phase 2: 1002–391 ft depth, and
- Phase 3: 1504–370 ft depth.

The equation for calculation of the nitrogen-oil interface is provided in the analysis section (Section 3). A mass balance equation for nitrogen loss by metering versus calculated nitrogen loss is also provided. The analysis section is followed by a discussion of the results, which center on (1) the unexpectedly large nitrogen production rates obtained in this operation, (2) a reexamination of the nitrogen-to-oil volume equivalent, and (3) a close examination of possible leak paths from all casing joints. In the following section, discussions of remediation of these leaks are made, based on the results of this study.

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<sup>1</sup> In a CIT, nitrogen gas is injected into the oil string and pushed down into the top part of the open hole, which is about 50 ft below the casing shoe in the chimney of the cavern, but well above the cavern top itself. At West Hackberry 108, the oil is in the 10  $\frac{3}{4}$   $\times$  20-inch annulus (see Figure 2). The metered amount of nitrogen injected into the known casing volume is crosschecked. The volume of the top part of the open hole is measured with each CIT. The nitrogen gas is allowed to pressure/temperature stabilize for 48 hours. The location of the nitrogen-oil interface is then measured with a density log and is measured again after a predetermined test period, depending on cavern volume and well history. The net loss of nitrogen mass is calculated from the pressures and interface locations at the beginning and end of the test. This loss of nitrogen gas is converted to barrels of oil/year using an assumed ratio of 10 bbl nitrogen (at pressure)/1 barrel of oil (Goin, undated, discussed in Section 4.2).

A commercial nitrogen pumper is used for the nitrogen pressurization of the oil annulus. A commercial logging company provides the logging service. A density log is run in the center brine pipe that is sensitive to detection of the location of the nitrogen-oil interface in the oil annulus.

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## 2.0 EXPERIMENT, OPERATION

### 2.1 Description of Operation

The setup for this leak testing operation was essentially that of a CIT. The oil in the  $10\frac{3}{4} \times 20$ -inch annulus was pressurized and pushed down, progressively in 500-ft increments, in a CIT-like operation. The nitrogen-oil interface was pushed down successively to 500 ft, 1002 ft, and 1504 ft—three stages identified as Phase 1, Phase 2, and Phase 3, respectively. The valve on the cemented  $20 \times 26$ -inch annulus was left open to the atmosphere to allow the nitrogen to escape; escaping nitrogen was metered. The nitrogen-oil interface rose back toward the surface primarily as a result of the leaks.

The testing process is simple in principle and in practice. As the nitrogen-oil interface rises, the oil may cover or temporarily fill an existing leak. If this happens, the leaking of the nitrogen gas effectively could be shut down because of the great difference in viscosity between oil and nitrogen. If there is only one leak in the area where the interface traverses, the leak is stopped, and as such, thus no more nitrogen should flow or be metered out the annulus. When there are multiple leaks, then the metered leak, used to measure the gas-production rate out the annulus, would be expected to diminish incrementally, as the nitrogen-oil interface rises and the oil shuts off each leak. The partial or total shutdown of a leak by the more viscous oil could also influence the behavior of the wellhead pressure and its time derivative (see below, Section 2.2). To summarize the three phases of the test:

Phase 1: First depression and rise of nitrogen-oil interface, 0–500 ft. Phase 1 was conducted from June 24 to July 6, 2000. In Phase 1, the nitrogen-oil interface was lowered to 500 ft.

Phase 2: Second depression and rise of the nitrogen-oil interface, 1002–391 ft. Phase 2 of the operation ran from July 6 to September 6, 2000. In Phase 2, the nitrogen-oil interface was lowered to 1002 ft.

Phase 3: Third depression and rise of the nitrogen interface, 1504–370 ft. Phase 3 ran from September 6 to September 29, 2000. In Phase 3, the nitrogen-oil interface was lowered to 1504 ft.

Information on the conduct of the operation is summarized in Table 1. In all three phases, time considerations prohibited bringing the nitrogen-oil interface to the surface.

Table 1. Summary of Conduct of the Operation and Information on Initial Gas-production rates and Driving Pressures

Phase	Initial Wellhead (Driving) Pressure	Initial Depth	Initial Gas-Production rate	Final Wellhead (Driving) Pressure	Final Depth (Estimated)	Final Gas-Production rate
1	1084	500	~150	1091	486	~140
2	1257	1002	~1400	1069	391	~750
3	1401	1504	~8500	958	370	~4250

## 2.2 Outline of Analysis

The data provided by the West Hackberry cavern engineer were analyzed. These data consisted of daily spreadsheets correlating time with wellhead (oil) pressure, metered nitrogen gas out the annulus, gas-production rate, and estimated location of nitrogen-oil interfaces. Locations of the joints in the 20-inch casing were also provided from well construction records. Decreases in the rates of gas production were evaluated to see if they coincided with the horizons of casing joints. If this correspondence occurred, then the drop in the nitrogen production rate was interpreted as a leak through the casing joint. Not only was the gas-production rate versus estimated nitrogen-oil interface horizon analyzed for leaks, but the wellhead/oil pressure curves and the time derivative of the pressure (versus the nitrogen-oil interface horizon) were examined. DynMcDermott Petroleum Operations analyzed the production data separately (Piechocki, 2000; see Section 4.1).

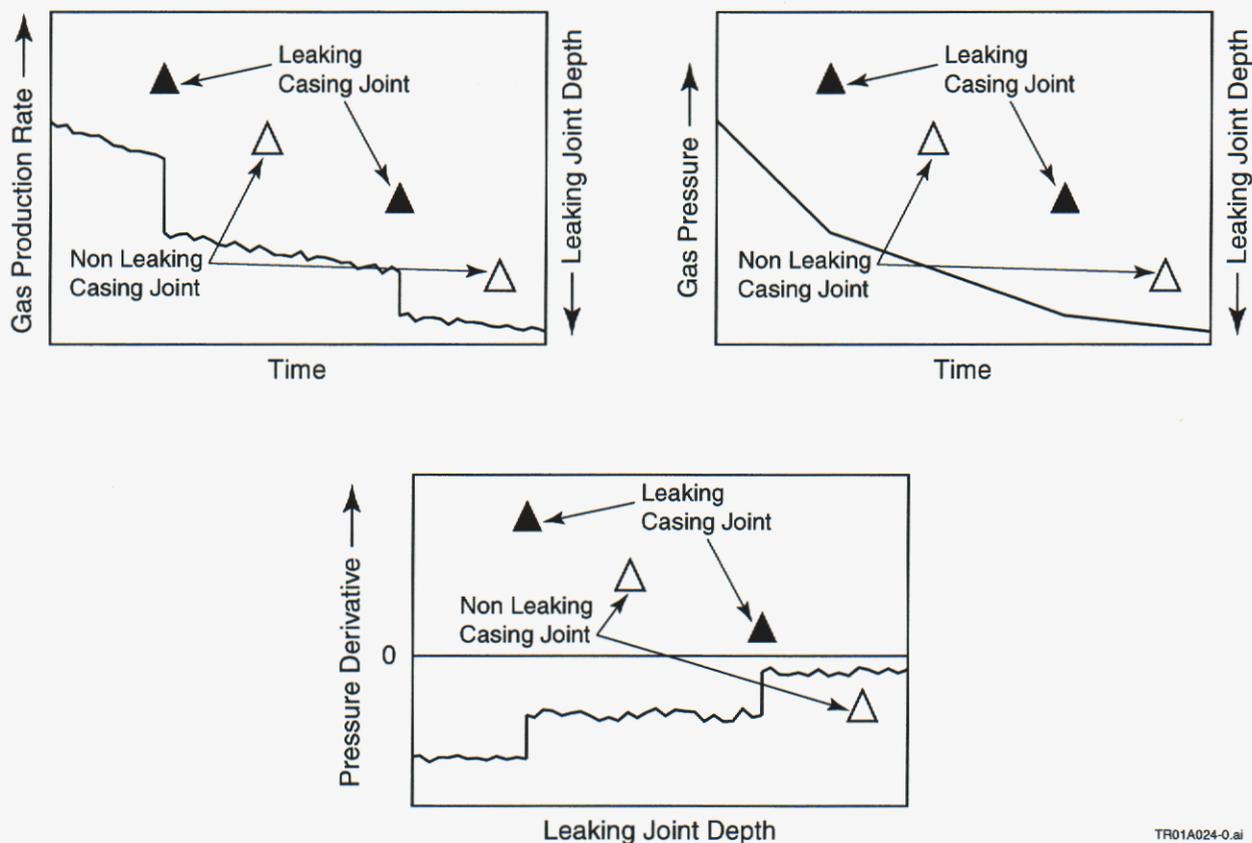
During much of the operation, the wellhead pressure was constantly decreasing because of loss of nitrogen through multiple leaks. As the nitrogen-oil interface rises and covers a thread leak, the nitrogen leak at that casing joint is stopped and any remaining nitrogen leaks are inferred to leak above that level. As leaks are stopped, the decrease of nitrogen pressure, as measured at the wellhead, will slow down. A momentary inflection, which appears as a flattening of the wellhead pressure curve at the location of a casing joint, is interpreted as evidence of a casing leak. Examples of this are shown in the figures associated with Sections 3.1.2 and 3.1.3.

The display of time derivative (change versus time) of the wellhead pressure was usually negative. When a leak is covered up by the rising nitrogen-oil interface, the time derivative of the wellhead pressure curve should, momentarily at least, become less negative. A momentary increase of the derivative of the wellhead pressure curve at the location of a casing joint is interpreted as evidence of a casing leak. Examples of this are shown in the figures associated with Sections 3.1.2 and 3.1.3. The display of these three variables (leak rate, pressure, and the time derivative of pressure versus time) forms a basis for much of the analysis in this report.

A generic and much simplified schematic representation of gas-production rate, gas pressure, and pressure derivative curves is shown in Figure 4. This figure shows how the interpretation was made for leaking casing joints. At the start, the nitrogen-oil interface is pushed down. The system is then allowed to leak nitrogen through the annulus. The nitrogen-oil interface rises and covers the casing leaks.

The display of these variables versus time could show some change resulting from a leak. If the leak is small, then the influence on wellhead pressure versus time and the derivative of the wellhead pressure versus time will be commensurately small. The interpretation of the data is obtained from the three types of data displays. Ideally, the three data displays should note leaks at the same horizons. Signatures characteristic of larger leaks are easier to interpret and identify than smaller leaks. This correspondence of the leak signatures from the different variables does not always occur especially for the smaller leaks, but there is some measure of correlation (see below, Section 3.1.3).

The display of the nitrogen gas-production rate was more intuitive. Leaks that are interpreted as "large" are noted where possible, and even a rough estimate of the leak rate is attempted in those cases. These estimates are thought to be valid only within 25% to 40% because of the rather large fluctuations in the gas-production rate.



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Figure 4. Generic Representation of Suspected Leaks, Gas-Production Rate, Pressure, and Pressure Derivative Curves.

The system of the leaking casing threads is quite complex and includes competing effects such as multiple leaks (of varying sizes) and salt creep. One effect of creep is to raise the pressure in the cavern. Creep does not affect the casing leaks directly, but it does increase the pressure in the cavern, while leaks decrease the pressure (see below, Section 3.1).

The nitrogen gas, leaking and flowing rapidly through casing threads and microannuli continually, cleans the oil out of the narrow leak paths. The oil exiting the annulus is captured in a tank at the surface. During this cleanout process (described in more detail in sections 3.1.2, 3.1.3, and 4.1) the gas-production rates, and even the oil/wellhead pressure, become temporarily erratic as pressure pulses remove oil from the leak paths. Cleaning the oil out of the microannuli and cracks in the cemented annulus is thought to be a probable mechanism; thus the leak rates would increase over time. Other potential mechanisms include dilation of existing microfractures and microannuli or the creation of such flow paths because of the large nitrogen pressures induced on the cement, particularly at shallow depths where the cement is initially unstressed. Fluctuations in the measured pressure and leak rate made interpretations of leaks from the displays of the data difficult.

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## 3.0 RESULTS AND ANALYSIS

### 3.1 Results

The interpretation of the gas-production rate curves suggests leaks at the horizons noted below.

#### 3.1.1 Phase 1

In Phase 1, the nitrogen-oil interface was lowered to 500 ft. What were perceived as slow casing leaks, although not directly observed, caused the nitrogen-oil interface to rise only to 486 ft. The nearest casing joint was still 10 feet higher. Therefore, the display of the gas-production rate showed no interpretable change in leak rate because of the limited amount of interface movement. The implication from the gas-production rate is that there must be a leak (or leaks) somewhere above the nitrogen-oil interface.

In general, a constant leak rate was observed in this portion of the operation (see Figure 5), following an initial spike in gas-production rate during the startup of the test.

Fluctuations were observed in the measured gas-production rate, usually between 125 and 225 standard cubic feet per day (scf/d). These fluctuations could be attributed to changes in the characteristics of the flow path, or to the relative quantities of gas and oil in the flow path, or to possible variations in the characteristics of the flow path itself.

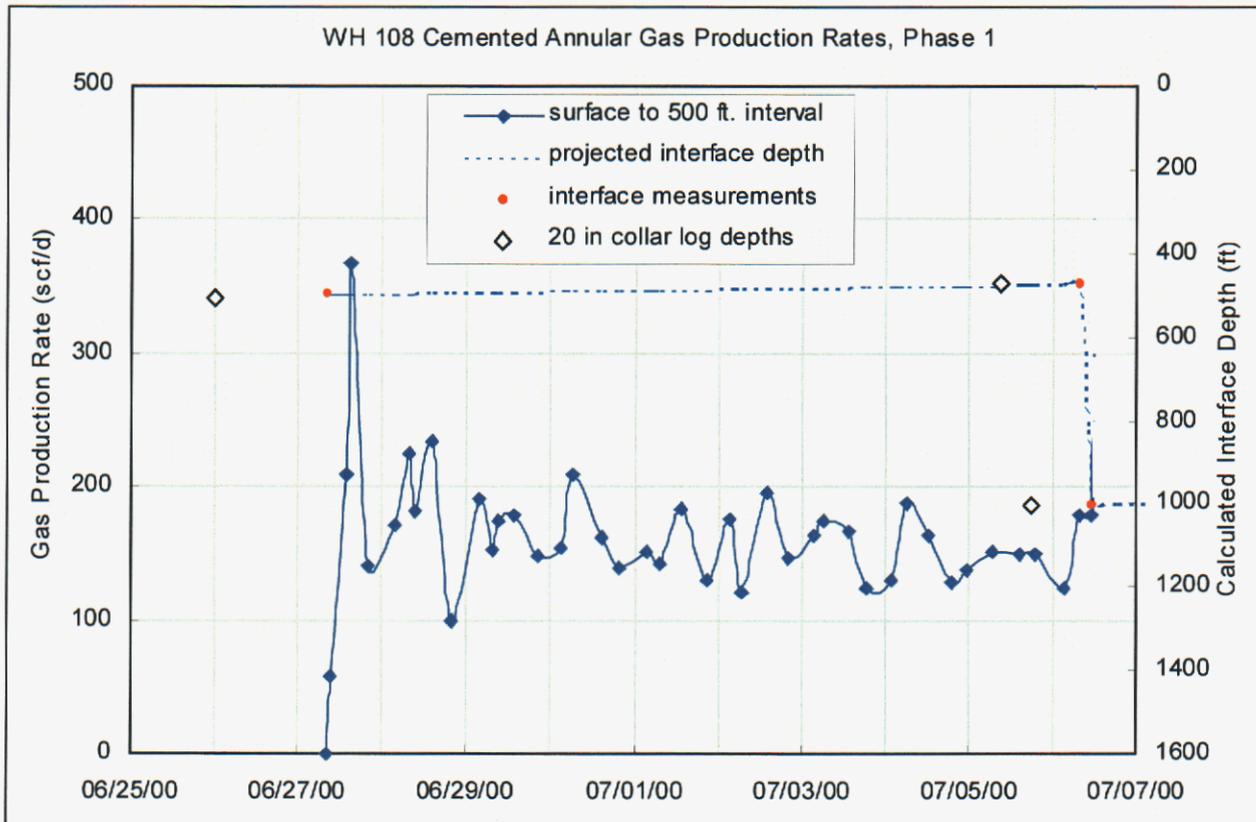


Figure 5. West Hackberry 108 Cemented Annular Gas-Production Rates, Phase 1.

Apparently, the leak (or leaks) above the interface horizon was slow enough that the effects of creep, not the leaks, were a significant contributor to the pressure behavior. The initial Phase 1 wellhead pressure was 1084 psi. The final pressure was 1091 psi, an increase of 7 psi. This phase of testing was the only phase that exhibited pressure increase. The operation ran for approximately 10 days. The increase of pressure resulting from creep and thermal expansion of the cavern fluids has been estimated from Caveman Software (Ballard and Ehgartner, 2000) as approximately 1.0 psi per day during Phase 1. Cavern pressurization rates and their accompanying upward interface movement rates are presented in Table 2 for WH 108. The measured pressurization rate of 0.7 psi per day and upward interface velocity of 2.5 ft per day exceeded the amounts predicted to result from creep and leakage. Phase 1 is the only part of the operation in which creep is a significant contributor to interface motion and wellbore pressures. Leakage dominated the responses during Phases 2 and 3. The metered gas flow was only  $1.44 \times 10^3$  scf.

Table 2. Predicted Cavern Pressurization Rates and Upward Movement of Interface in the Absence of Any Leakage

Phase	1 start	1 end	2 start	2 end	3 start	3 end
Cavern Pressurization Rate (psi/day)	1.079	1.036	1.050	0.820	1.093	0.838
Upward Interface Motion (ft/day)	0.49	0.44	0.87	0.32	1.21	0.28

### 3.1.2 Phase 2

In Phase 2, the nitrogen-oil interface was lowered to 1002 ft. Casing leaks caused the nitrogen-oil interface to rise to 391 ft. The initial Phase 2 wellhead pressure was 1256 psi. The final pressure was 1069 psi. The operation ran for 31 days with an average pressure drop of 6 psi per day, which is almost an order of magnitude greater than the daily pressure rise resulting from creep. With such gas production and pressure drops, creep considerations are not a significant factor in the discussion. Pressure drops of 100 psi were seen in 24 hours as oil covered the casing joints.

During Phase 2, the gas-production rate increased during the first part of the test and then decreased. The interface rose steadily the entire time. The increase in gas-production rate may be regarded as a transient response following the pressurization from Phase 1 to 2, whereby the pressure was increased from 1090 to 1257 psi. A similar observation was made in Phase 1, when the pressure abruptly increased during the initial part of the test. This response suggests that additional oil is removed from the leak paths and perhaps that the flow path is changed as a result of the increase in pressure. Perhaps the microannuli along the casing and cement have dilated, or perhaps fractures in the cement are propped open. The increase in pressure could also result, in part, from the elastic response of the 20-inch casing. The pressurization of the casing and its cemented annulus could squeeze fluid out of the flow path. The observed transient response, regardless of its associated mechanism, wanes as the nitrogen-oil interface moves upward and the pressure in the well decreases. After the transient increase, flow rates decrease in a linear trend, suggesting that if thread leaks are the cause of leakage their magnitude must, in general, be similar.

In Phase 2, breaks on the nitrogen production rate curve, hence suspected leaks, were interpreted at the following casing joint horizons: 713 ft (~150 scf/d), 673 ft and 634 ft (~100 scf/d), 592 ft (~100 scf/d), 550 ft and 476 ft (~100 scf/d). See Figure 6 and Table 3.

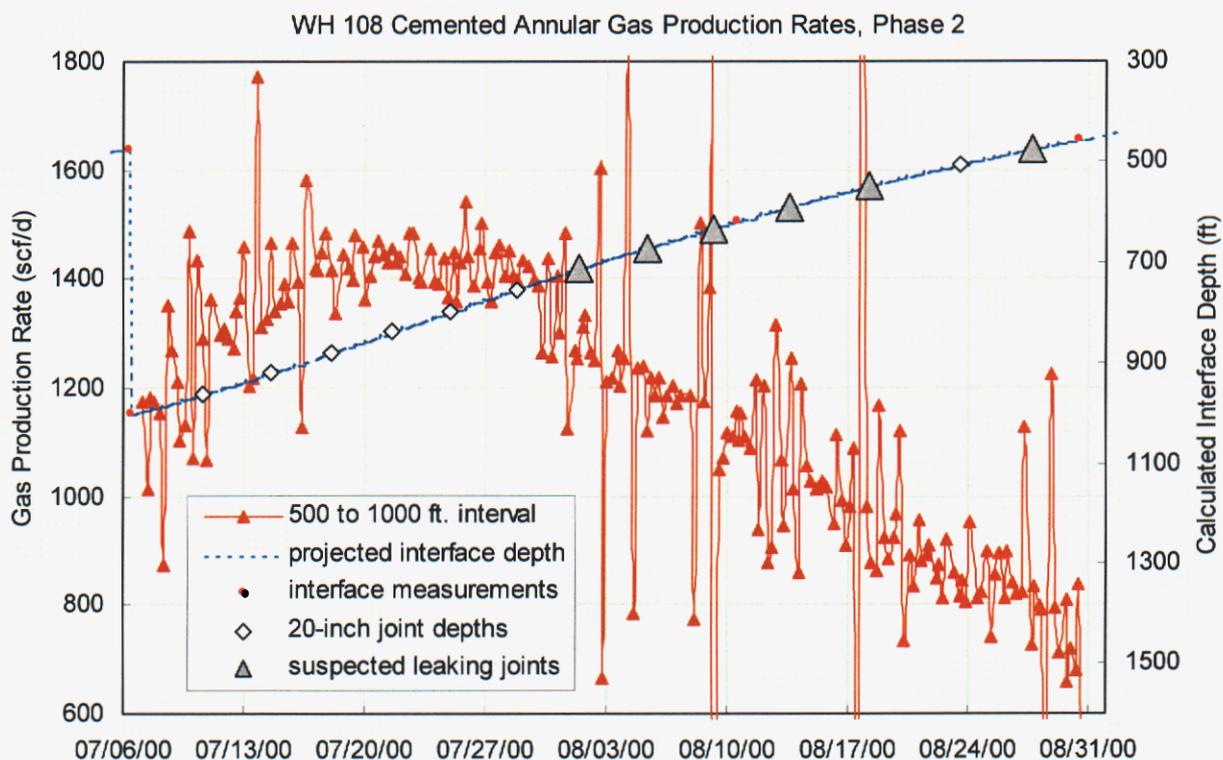


Figure 6. West Hackberry 108 Cemented Annular Gas-Production Rates, Phase 2.

As shown in Figure 7, an abrupt decrease is seen in the rate at which the pressure decays. This situation occurs at approximately 700 ft and may indicate a significant casing leak nearly coincident with the casing joint at 713 ft. Other much smaller inflections in the display of the wellhead pressure, hence suspected leaks, were interpreted at the following casing joint horizons: 963 ft, 920 ft, 879 ft, 673 ft, and 634 ft. See Figure 7 and Table 3.

As noted earlier, a fundamental shift occurs at a depth of approximately 700 ft, indicating a significant leak at that location. The depressurization rate drops from approximately 2.5 psi/day to 1.0 psi/day, suggesting that at least 50 percent of the total leakage is through the casing joint nearest 700 ft, probably the joint at 713 ft. This abrupt change was obscured in the gas-production rate data (Figure 6) because of the transient conditions occurring at that time. Other, much smaller changes in the time derivative of wellhead pressure curve became less negative at the following casing joint horizons: 963 ft, 920 ft, 879 ft, 713 ft, 673 ft, 634 ft, 592 ft, 550 ft, and 476 ft. See Figure 8 and Table 3. The behavior of the derivative of the wellhead pressure at these horizons may be interpreted as small casing joint leaks.

The difficulty in interpreting small leaks at particular casing joints results from a lack of sensitivity in the ability to measure changes in the metered gas flow rate or in the pressure data as the interface crosses a casing joint, since these measurements represent the accumulated response of the entire nitrogen column, which crosses many casing joints (approximately 1 every

40 ft). The sensitivity of the three metrics used in this report (gas flow rate, pressure, and pressurization rate) was evaluated by comparing the change in these metrics as the interface crossed a particular casing joint. Because multiple readings were taken (every 3 to 9 hours), the metrics were averaged for the interface positions halfway between casing joints to the joints above and below each casing joint. The changes are noted in Figures 9, 10, and 11 for the respective metrics considered in this report.

Table 3. Suspected Location of Casing Joint Leaks

20-inch Joint Depths (ft)	This Study						DM <sup>1</sup> Study	
	Phase 2			Phase 3 <sup>2</sup>			Phase 2	Phase 3
	Gas Production Display	Wellhead Pressure Display	Pressure Derivative Display	Gas Production Display	Wellhead Pressure Display	Pressure Derivative Display	Gas Production Display	Gas Production Display
34								
74								
114								
155								
190								
231								
273								
312								
355								
392								
433				•		•		
476	•		•	•		•	•	
507					•			
550	•		•	•		•	•	
592	•		•	•		•		
634	•	•	•	•		•	•	
673	•	•	•	•		•	•	
713	•		•	•		•	•	
756						•		
798						•		
838					•			•
879		•	•					•
920		•	•			•		•
963		•	•					
1004						•		
1043				•				•
1083						•		
1122								•
1163						•		
1204								
1244				•	•			•
1282						•		•
1320								•
1360						•		•
1401								
1442								
1483								
1523								

<sup>1</sup> DM = DynMcDermott Petroleum Operations (Piechocki, 2000)

<sup>2</sup> Phase 1: interface moves 500-485 ft. Phase 2: interface moves 1002-391 ft. Phase 3: interface moves 1404-393ft. Because of such a large leak rate in Phase 3, relatively few data points were captured; consequently there is less sensitivity in the curves displayed from this portion of the operation.

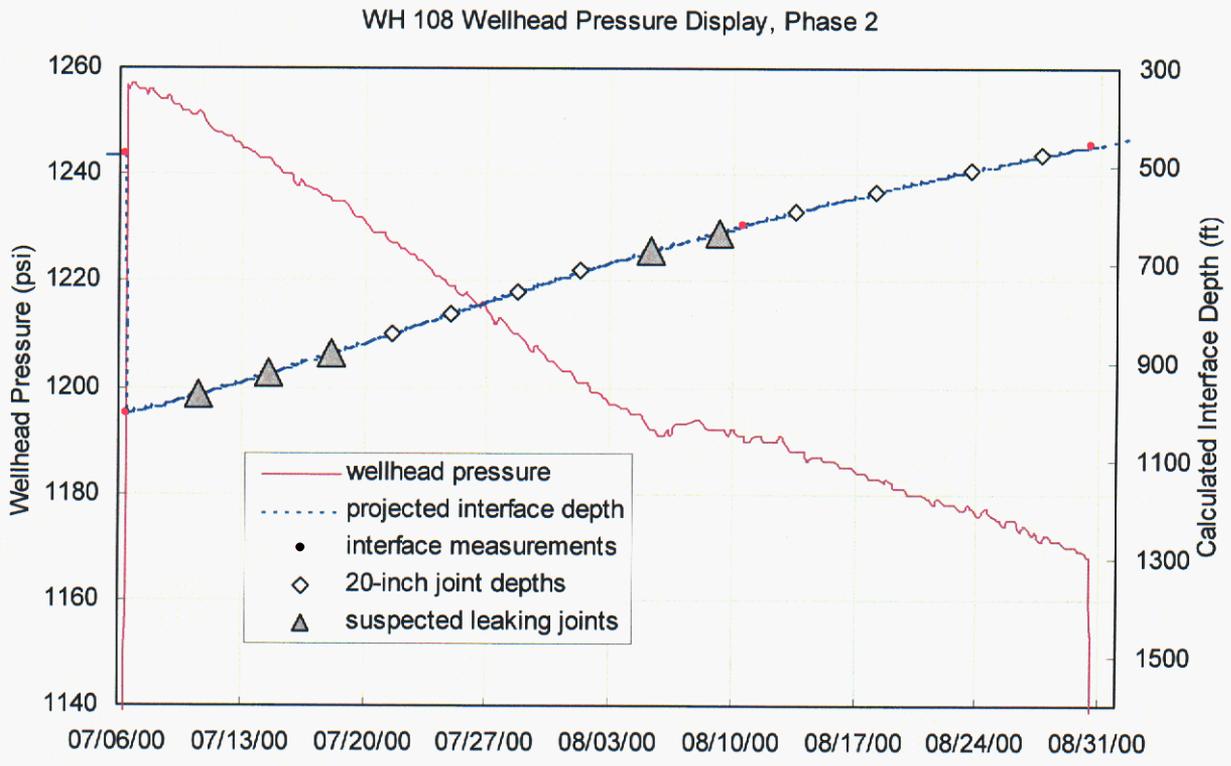


Figure 7. West Hackberry 108 Wellhead Pressure Display, Phase 2.

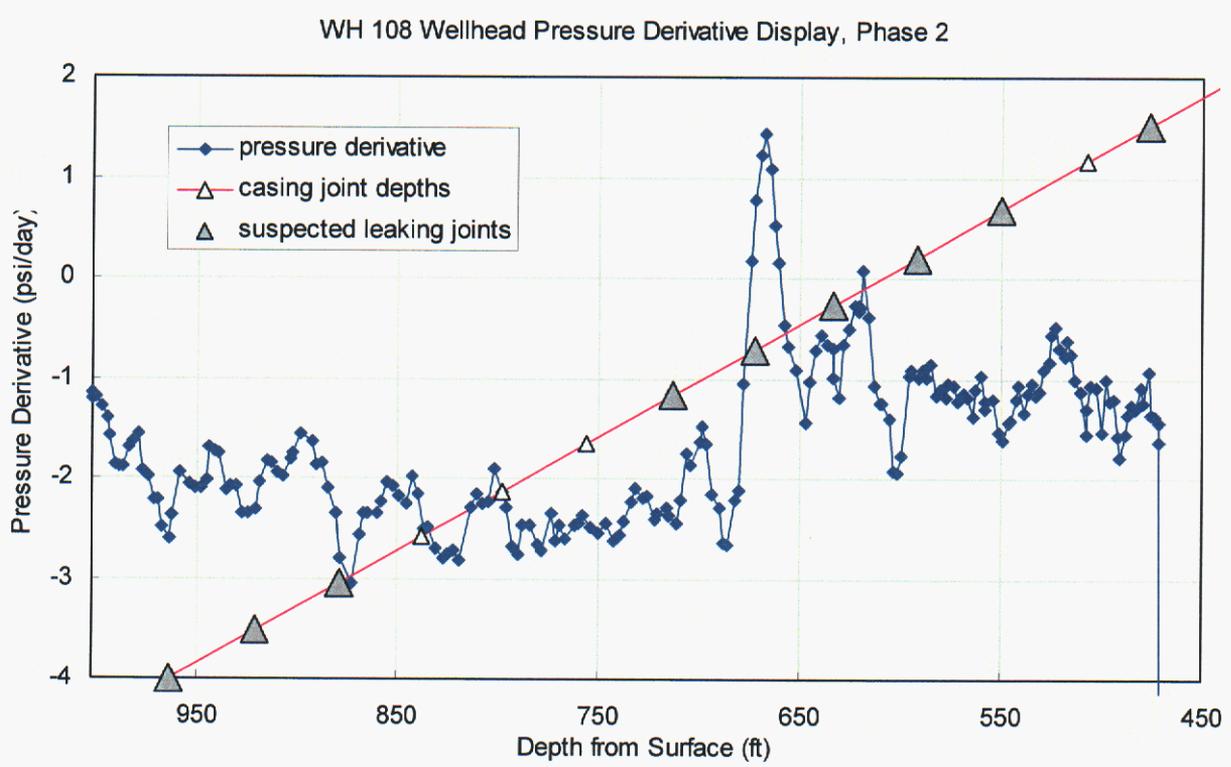


Figure 8. West Hackberry 108 Wellhead Pressure Derivative Display, Phase 2.

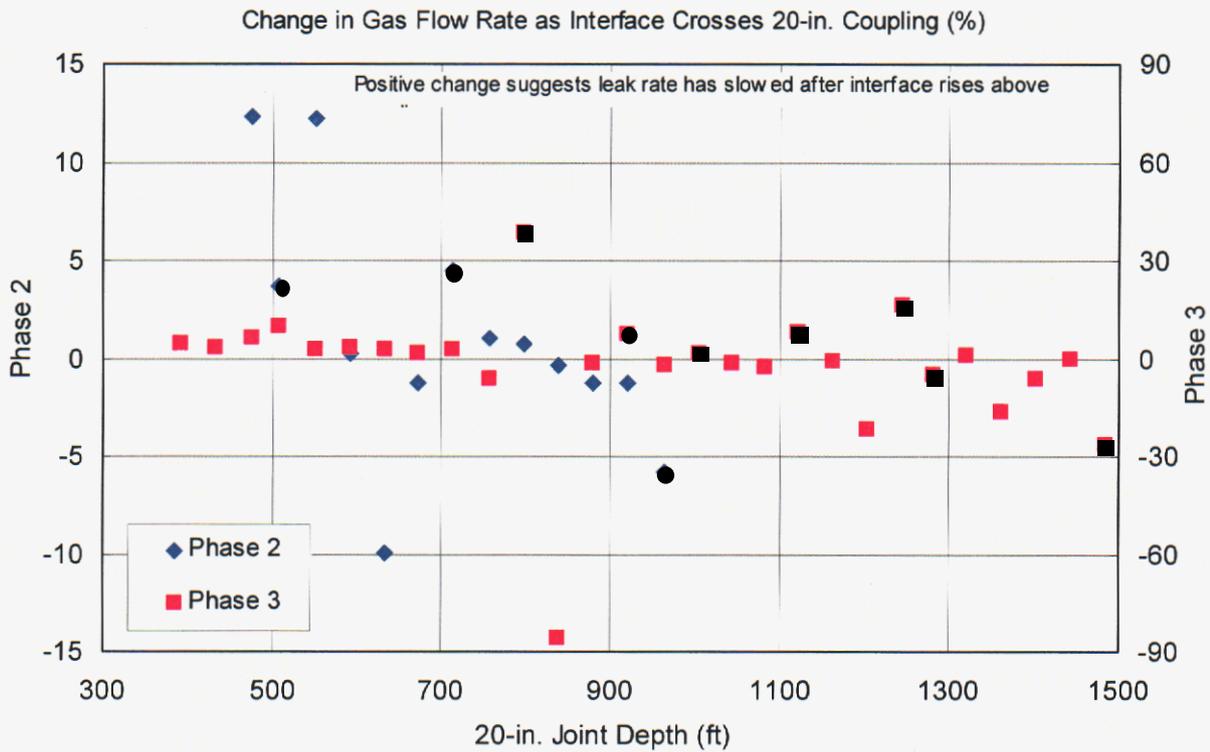


Figure 9. Difference between Gas Flow Rates as Interface Moves above Casing Joint.

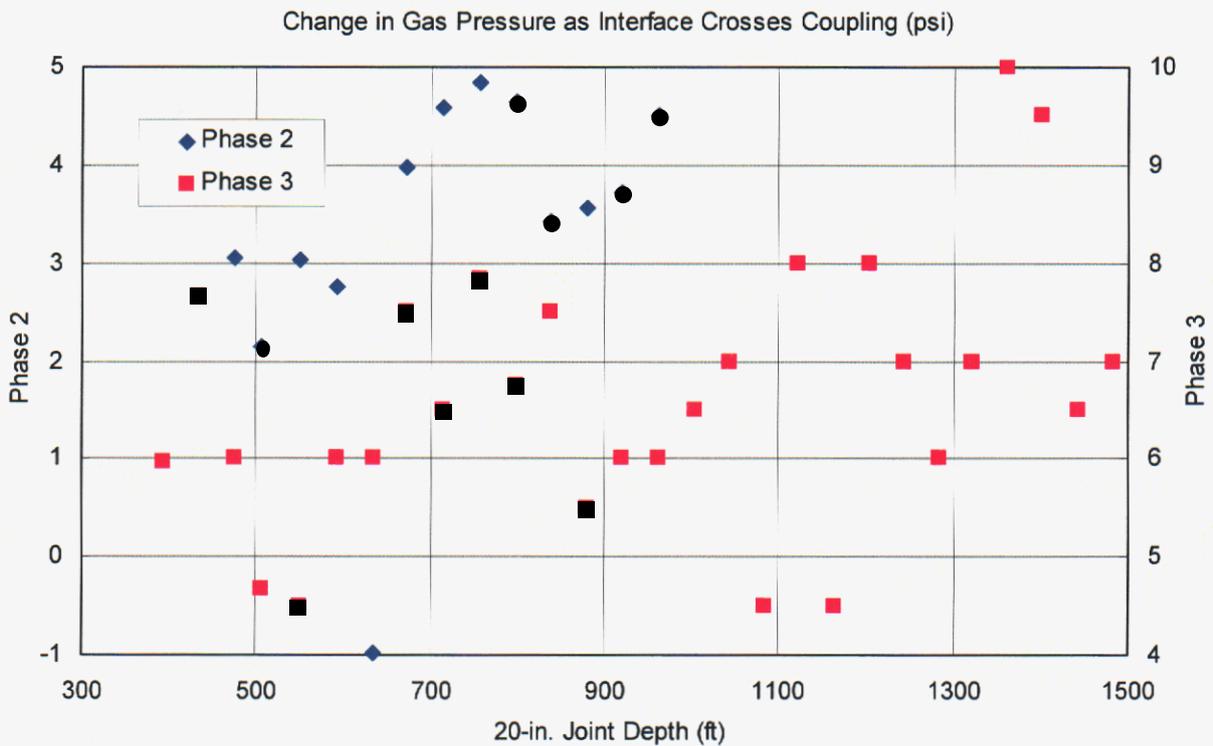


Figure 10. Difference between Pressures as Interface Moves above Casing Joint.

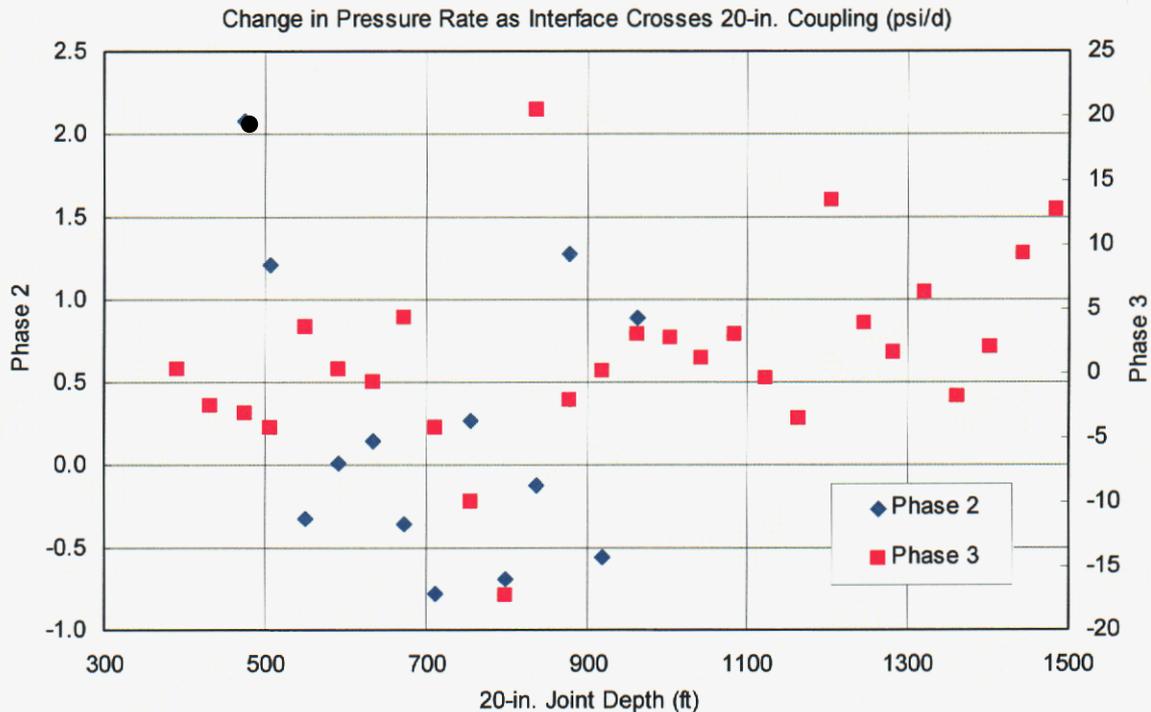


Figure 11. Difference between Pressure Rates as Interface Moves above Casing Joint.

In Figure 9, a positive change suggests that the leak rate has slowed, whereas a negative change suggests the rate has increased as the interface moves across a casing joint. Both Phase 2 and 3 results are shown. The large scatter in data, both positive and negative, suggests the measurement is not sensitive enough to discern leakage across individual joints. On the other hand, most of the prominent positive changes are at casing joints where large leaks exist (Figure 6, Table 2) so this approach at least implicates some of the larger leaks. In Figure 10, a negative change suggests pressure increases after the interface rises above a potential leak although the pressure could remain constant or decrease at a lower rate depending on the exact circumstances. Again, the large scatter in the measurements does not allow accurate judgments to be made unless a particular data point falls well out of the normal variation, which does not appear to occur. The more negative numbers are often from the casing joints where larger leaks exist, (Figure 6, Table 2) so this approach at least may implicate some of the larger leaks. Similar results in Figure 11 show a large variation in changes to the measured pressurization rates. Negative change suggests a smaller leak rate after the interface rises above a casing joint or an implied leak. The more negative numbers arise mostly from casing joints where larger leaks exist, (Figure 6, Table 2) thus this approach at best may implicate at least some of the larger leaks.

A difficulty in discerning leakage as the interface crosses casing joints may result, in part, from a lag time between the time the casing joint is sealed off by the interface oil and the time at which the leakage rate actually decreases at the surface. Figures 12, 13, and 14 plot the measured flow rate in the annulus (at the surface) in comparison to abrupt changes in pressure that generally occurred during transitions between test phases. Figure 12 shows that the lag time after the first, major pressure increase (Phase 1 to 2) was approximately one day. This time shortened to a few hours for the subsequent pressure change (Phase 2 to 3).

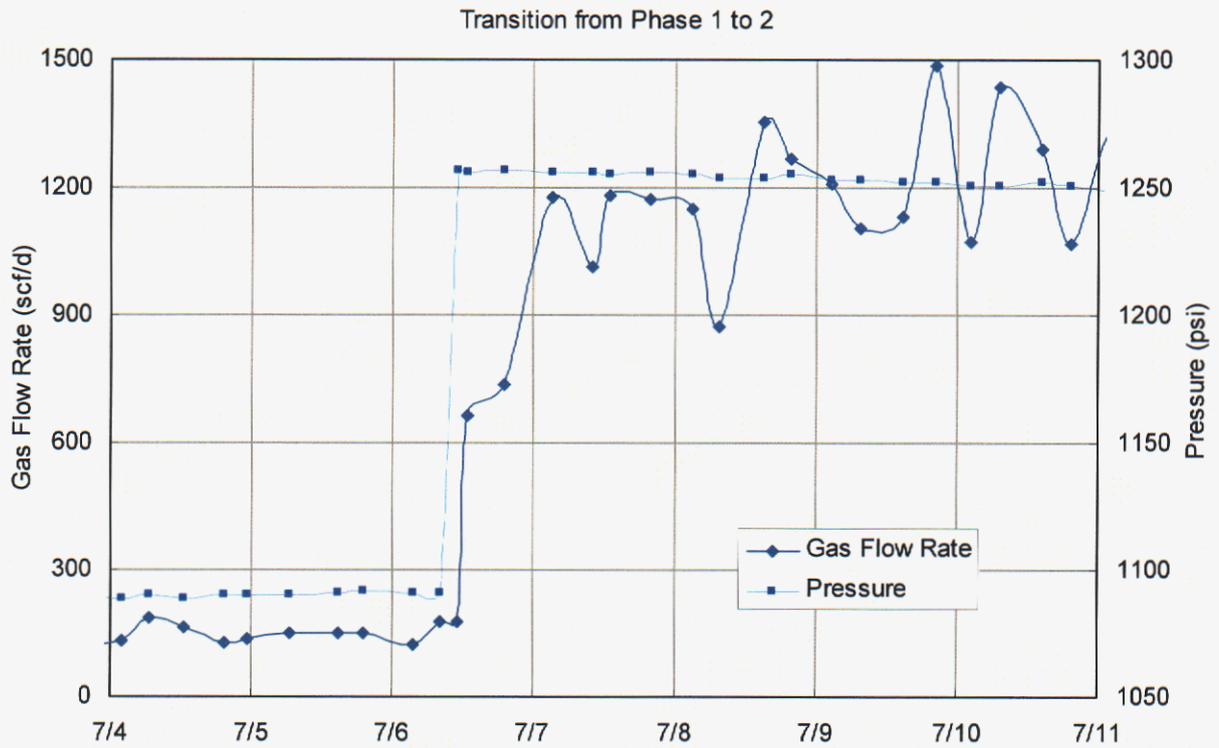


Figure 12. Lag Time between Measured Flow Rate and Pressure Change (Phase 1 to 2).

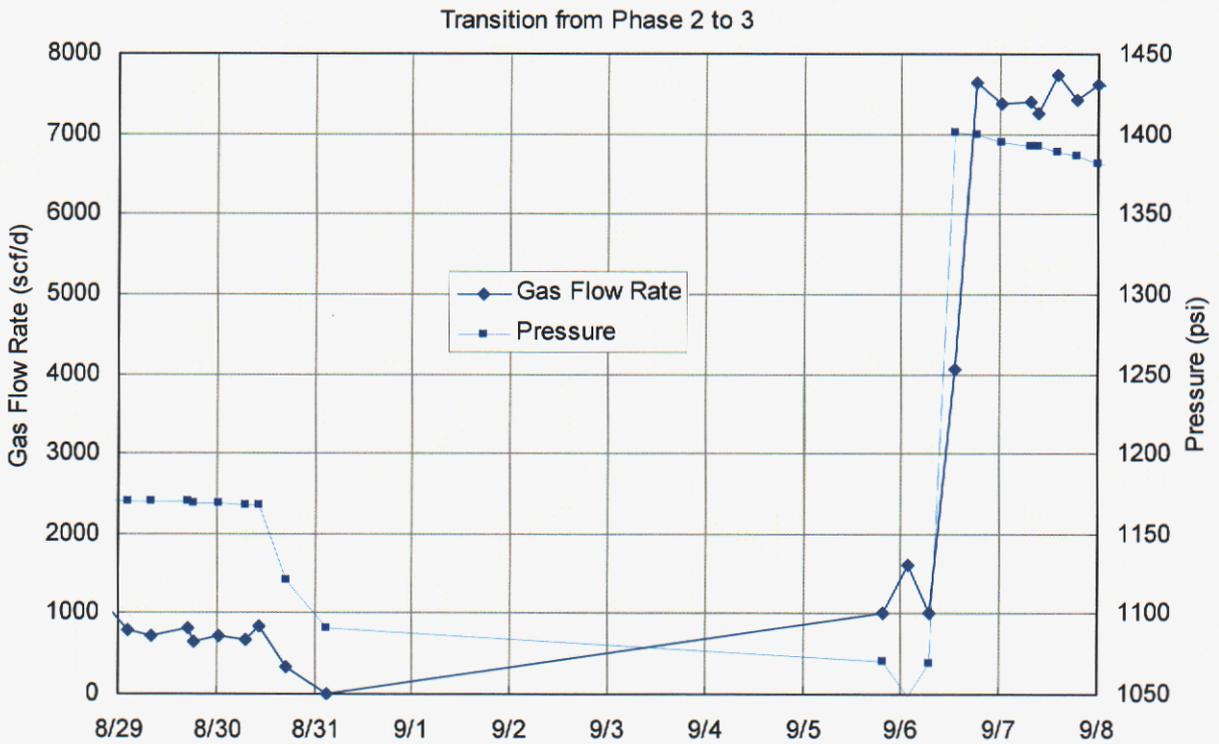


Figure 13. Lag Time between Measured Flow Rate and Pressure Change (Phase 2 to 3).

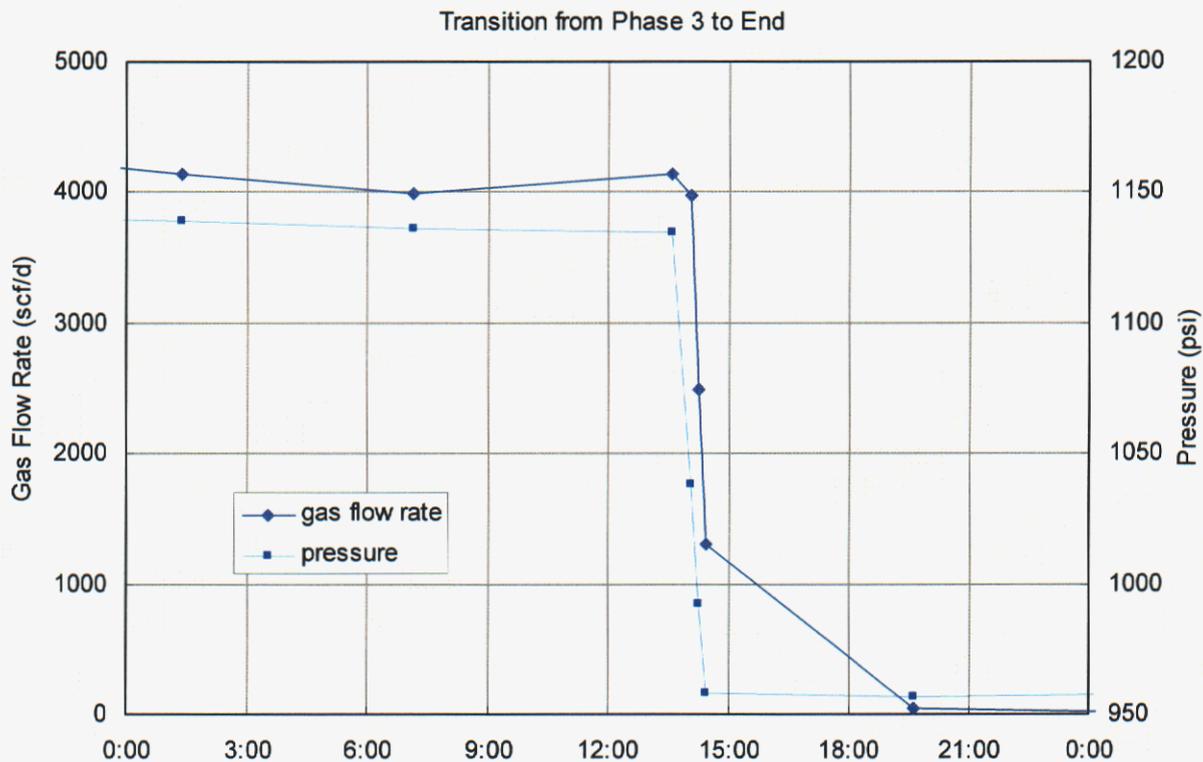


Figure 14 Lag Time Between Measured Flow Rate and Pressure Change (Phase 3 to end).

The time at which the interface crosses individual casing joints varies from approximately 2 days to 4 days during Phases 3 and 2, respectively. Thus, from a theoretical point of view, the interface moved sufficiently slow enough to allow changes in the leak rate to be measured across individual casing joints. This response suggests that other reasons, such as changes in the flow path characteristics or the relative amounts of fluid (oil/ nitrogen), are responsible for the lack of resolution.

This situation was markedly different from the results of Phase 1. Phase 2 casing leaks were interpreted from changes in the gas-production rate as the interface rose across multiple casing joints. The gas-production rate started out at about 1100 scf/d, rose over 10 days to about 1400 scf/d, and then leveled off for a period. The initial rise in the gas-production rate was interpreted as changes in the amount of fluids in the leak path or the cemented 20 × 26-inch annulus. Afterward, the gas-production rate began declining as leak horizons were covered, incrementally decreasing the gas-production rate. Moreover, the leak driving pressure was also decreasing as a result of the leaks.

Transient fluctuations in the gas-production rate were observed, up to a few hundred scf/d. These fluctuations were also attributed to the oil cleanout process from the leak paths.

In Phase 2, both SNL and DynMcDermott detected a leak horizon above 500 ft, at casing joint locations of 476 ft. This leak was not detected in Phase 1. Also the gas-production rate had increased markedly, from fluctuations around 150 scf/d in Phase 1 to a rate of around 1400 scf/d in Phase 2. This increase is noteworthy and is highlighted in Section 4.1.

When Phase 2 of the operation was concluded, the gas was still leaking at approximately 750 scf/d. This rate implies the presence of additional casing joint leaks above the 391-ft horizon.

### 3.1.3 Phase 3

In Phase 3, the nitrogen-oil interface was lowered to 1504 ft. Casing leaks caused the nitrogen-oil interface to rise to 370 ft. The initial Phase 3 wellhead pressure was 1401 psi. The final pressure was 979 psi. Creep considerations, unimportant in Phase 2, were even less important in Phase 3.

In Phase 3, breaks on the nitrogen production rate curve, and hence suspected leaks, were interpreted at the following casing joint horizons: 1244 ft (large), 1043 ft (~500 scf/d), 713 ft (~400 scf/d), 673 ft, 634 ft (~400 scf/d), 592 ft (~300 scf/d), 550 ft (~300scf/d) 476 and 433 ft. See Figure 15 and Table 3.

Inflections in the display of the wellhead pressure, and hence suspected leaks, were interpreted at the following casing joint horizons: 1244 ft, 838 ft, and 507 ft. See Figure 16 (where suspected leak horizons at the inflections of wellhead pressure are noted) and Table 3.

The time derivative of the wellhead pressure became less negative at the following casing joint horizons: 1360 ft, 1282 ft, 1163 ft, 1083 ft, 1004 ft, 920 ft, 798 ft, 756 ft, 713 ft, 673 ft, 634 ft, 592 ft, 550 ft, 476 ft, and 433 ft. See Figure 17 and Table 3. The behavior of the derivative of the wellhead pressure at these horizons was interpreted as a casing leak.

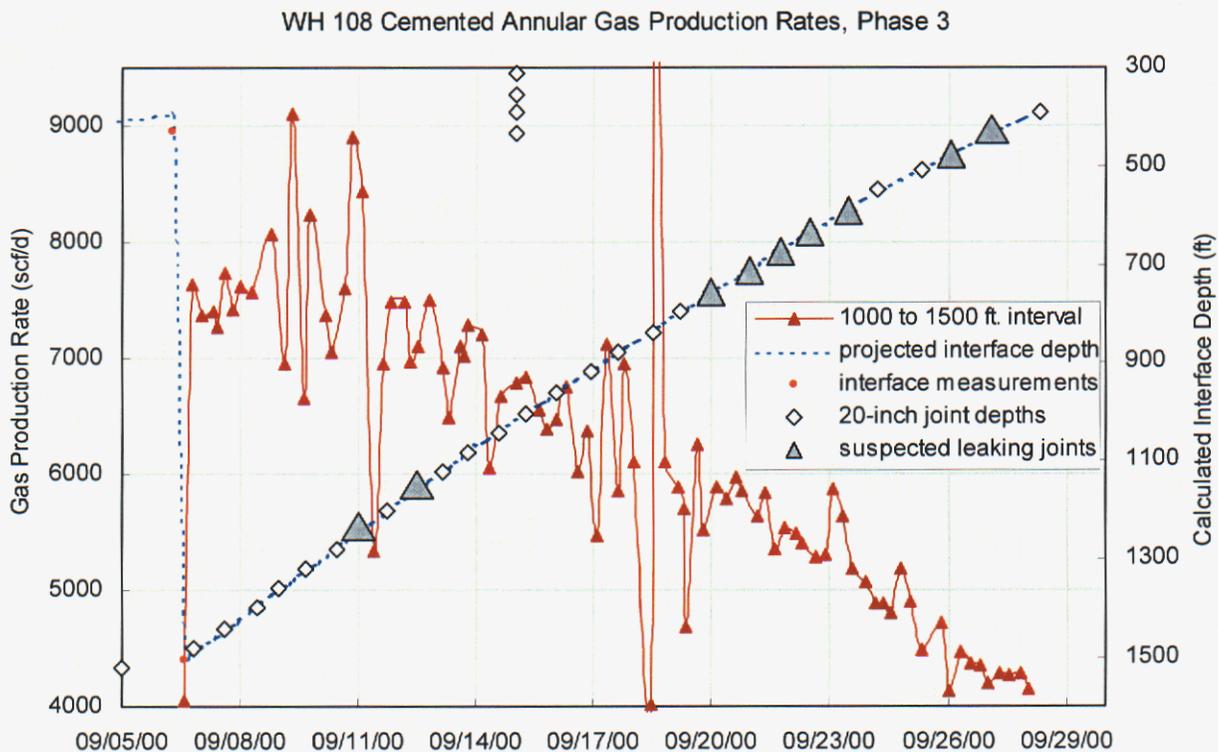


Figure 15. West Hackberry 108 Cemented Annular Gas-Production Rates, Phase 3.

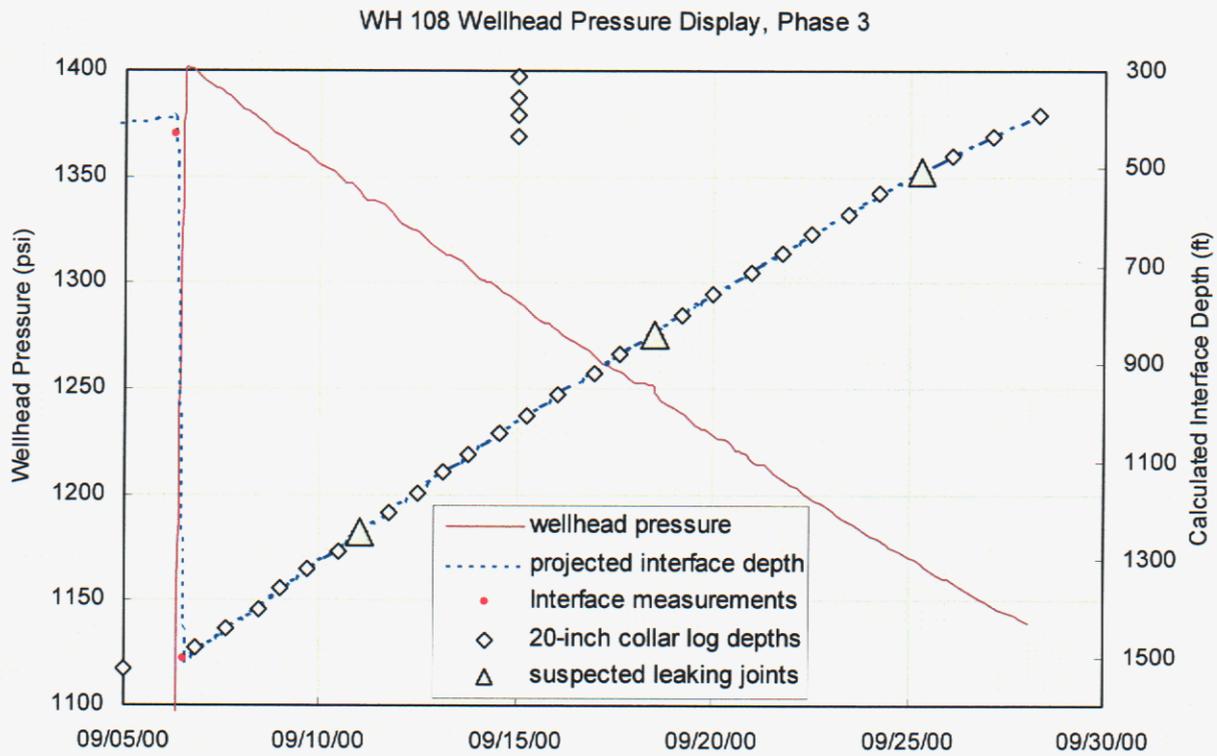


Figure 16. West Hackberry 108 Wellhead Pressure Display, Phase 3.

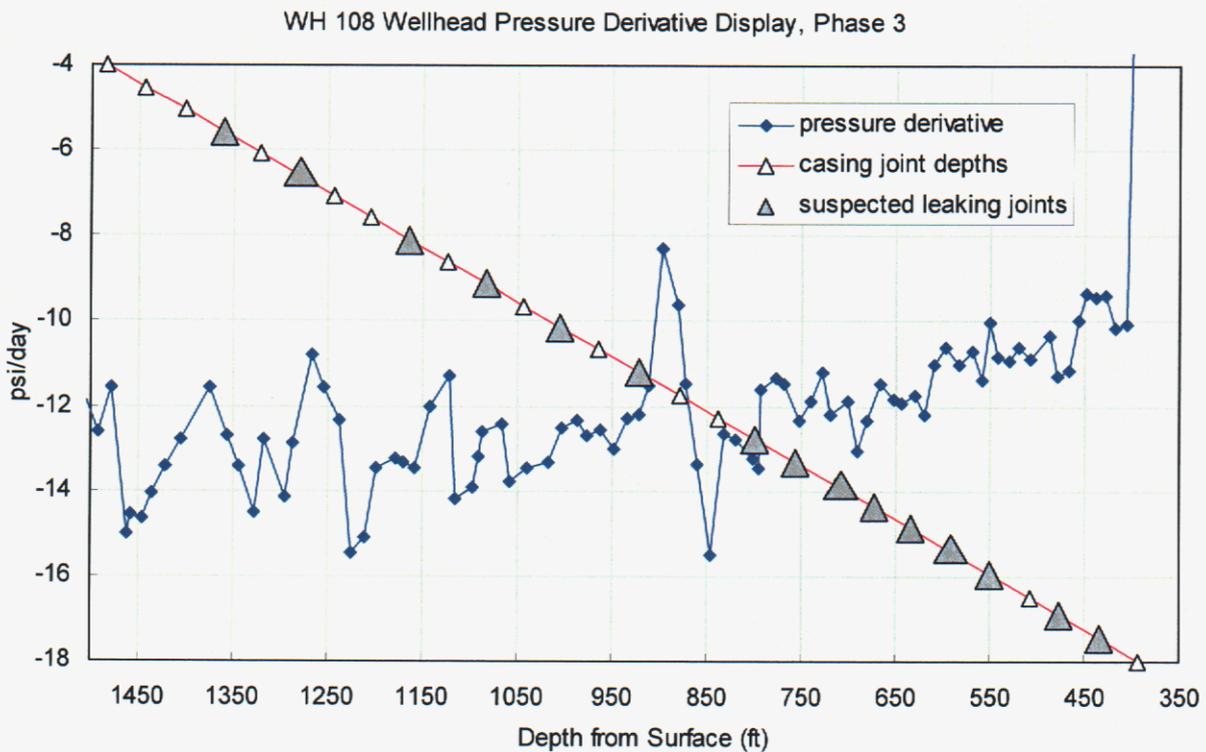


Figure 17. West Hackberry 108 Wellhead Pressure Derivative Display, Phase 3.

New leaks were observed at casing joint locations in the 1504 to 1000-ft interval. Leaks not seen in Phase 2 were also observed at casing joint locations above 1000 ft for the first time: at 963 ft and 798 ft (DynMcDermott also observed a leak at 879 ft for the first time). The initial gas-production rate started around 7500 scf/d, declining (as the nitrogen-oil interface crossed numerous leaks) to around 4100 scf/d. Because of such a large leak rate, the nitrogen-oil interface rose quite rapidly in a short time. As a result, fewer data points were obtained during this period of rapid rise in the nitrogen-oil interface. Consequently, there is less sensitivity in the curves displayed from this portion of the operation.

Transient fluctuations in the gas-production rate were observed, up to a couple of thousand scf/d. These fluctuations were attributed to the cleanout of oil from the leak paths, resulting in a pulsing action of the pressure fluctuations.

The gas-production rate increased even more markedly in this phase: from approximately 150 scf/d in Phase 1, to around 1400 scf/d in Phase 2, to approximately 8500 scf/d in Phase 3 (see section 4.1). Initial wellhead pressures,  $P_{wh}$ , for the three phases were 1084, 1257, and 1401 psia, respectively, for the interfaces at 500 ft, 1002 ft, and 1504 ft. The increase was summarized in Table 1. When Phase 3 of the operation was concluded, the gas was still leaking at approximately 4200 scf/d, which implies that there were additional leaks above the 370-ft horizon.

The abrupt decrease noted in the rate at which the pressure decays in Phase 2 (Figure 7) was not noted in Phase 3 (Figure 15).

## 3.2 Data Analysis

### 3.2.1 Nitrogen-Oil Interface

The location of the nitrogen-oil interface,  $L_i$ , can be estimated using the following equations:

$$P_i = P_{\text{initial}} + g_{\text{oil}} \times L_i \quad (3-1)$$

where:

$$P_i = P_{wh} \exp L_i / RT \quad (3-2)$$

and:

$P_{\text{initial}}$	=	Oil pressure just before operation
$P_i$	=	Interface pressure at time interface horizon is estimated
$g_{\text{oil}}$	=	Oil gradient in cavern = 0.37 psi/ft
$R$	=	Gas constant = 55.16 ft °R (Rankine)
$T$	=	Temperature in °R
$P_{wh}$	=	Wellhead pressure at time interface horizon is estimated (recorded automatically).

The locations of the interface in Phase 3 were derived from a numerical solution of Equations 3-1 and 3-2, above. The location of the interface agrees quite well with that interpolated from actual interface measurements. Differences between the two methods of interface localization were less than seven feet.

The estimate of the location of the nitrogen-oil interface in Phase 2 was calculated from interpolating and extrapolating the actual interface measurements actual interface measurements.

### 3.2.2 Mass Balance, Comparison of Metered Nitrogen with Volume Loss

A mass-balance, calculated loss from nitrogen volume loss in the well versus metered nitrogen was undertaken for consistency. A comparison of the metered volume to the calculated volume was made. Calculated nitrogen loss to the atmosphere was determined from the nitrogen volume loss from each phase per the following equations:

$$\Delta V = \left( V_0 - \frac{V_f P_f}{P_0} \right)_0 \quad (3-3)$$

where:

- $\Delta V$  = Volume loss from nitrogen leak (ft<sup>3</sup>)
- $V_0$  = Initial volume
- $V_f$  = Final volume
- $P_0$  = Wellhead pressure
- $P_f$  = Wellhead pressure

and

$$V_{\text{atm}} = \left( \frac{P_0}{14.7} \times \Delta V \times \frac{T_{\text{atm}}}{T_0} \right) = 1.56 \times 10^5 \text{ scf} = \text{calculated nitrogen loss} \quad (3-4)$$

where:

- $\Delta V$  = Volume of casing
- $T_{\text{atm}}$  = Estimated average atmospheric temperature, 80°F=540°R (estimated average)
- $T_0$  = 100°F=560°R (estimated temperature at depth)
- $V_{\text{atm}}$  = Calculated nitrogen loss converted to atmospheric pressure.

The assumption is made that all temperatures remain constant. On the average, it is a reasonable approximation; moreover, the results are only relatively weak functions of temperature. The results are presented in Table 4. These numbers are close to the calculated volume.

Table 4. Comparison of Measured and Calculated Leak Rates

Phase	P start (psi)	P end (psi)	Interface start (ft)	Interface end (ft)	Calculated Leakage (scf)	Measured Leakage (scf)	Difference (scf)	Difference/Measured (%)
1	1084	1091	500	475	2178	1441	737	51.1
2	1257	1191	1002	621	46013	46216	-203	-0.4
	1191	1168	621	457	18639	18321	318	1.7
3	1401	1135	1504	370	133000	135210	2220	1.6

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## 4.0 DISCUSSION

### 4.1 Successive Increase in the Nitrogen Production Rate

The operation described in this report and the work of Piechocki (2000) independently arrived at similar conclusions about locating leaking casing joints, although the two methods do not always identify the same joint in Phases 2 and 3. This report interprets leaks based on measured leak rates and pressure data by one or more of three methods: interpreting the displays of the gas-production rate, wellhead pressure, and the derivative of well pressure. Sometimes interpretations of two or three methods suggest the same casing joint leak horizons. The important result is that multiple leaks are interpreted from the data of this operation by different displays and by different investigators. By inference, the location of different leaking casing joints also implies that microannuli in the 20 × 26-inch cemented annulus are leak paths to the surface. Thus, a methodology for determining and interpreting casing joint leaks has evolved and is described in this paper. As mentioned, the instability in the gas-production rate introduces a degree of ambiguity into the results. The fact that the two methods do not always identify the same leaking joints suggests that the interpretation of these data is accompanied by some degree of ambiguity. It is felt that the argument is made that there are leaks at least at some casing joints. The analysis indicates that the identification of larger casing joint leaks involves a smaller degree of ambiguity than the identification of smaller leaks.

Successive depression of the nitrogen-oil interface produced a dramatic increase in gas-production rate, which cannot be explained, by the slight pressure increases. As the nitrogen-oil interface traversed the same horizons from one phase of the operation to the next, the increase in flow rate was marked. However, the increases on the wellhead pressures, which drove the leaks in the three phases, were small relative to the respective increases in leak rates. For example, at the 500-ft horizon in Phases 1, 2, and 3, the gas-production rates were approximately 150, 850, and 5,200 scf/d with respective driving pressures of approximately 1084, 1168, and 1177 psi. Gas-production rates for the various test phases are plotted as a function of interface location in Figure 18. The semi log plot illustrates the order of magnitude increase in production rate for equivalent interface horizons.

The data are also plotted in Figure 19, and the linear portions of the curves for Phases 2 and 3 are extrapolated to see if any leaks might exist at the top of the casings, since it is possible that a portion of the leakage may be explained by communication at that location. The results are inconclusive but on average suggest a low leak rate at or near the top of the casing string, if the linear extrapolation were to hold. A leaking casing joint (or joints, closely spaced) near the top might be consistent with such an interpretation of test results. No leaks appear at the wellhead or piping above ground.

An earlier investigation suggested that the pressure dependence of the leak rate was a logarithmic function of pressure (Sattler, 1999b). A portion of this investigation is included in Appendix B. Figure 20 plots the leak rate as a function of pressure. The nitrogen production rate increases much more rapidly than was expected from the few percent increase in pressure. The pressure cycling occurring as a result of the operation (i.e., repeated nitrogen injection and bleed-down from leaks) may be responsible for the dramatic rise in leak rate from one phase to the next. It is likely that the microannuli in the 20 × 26-inch cement job (see Figure 2) expand or dilate during

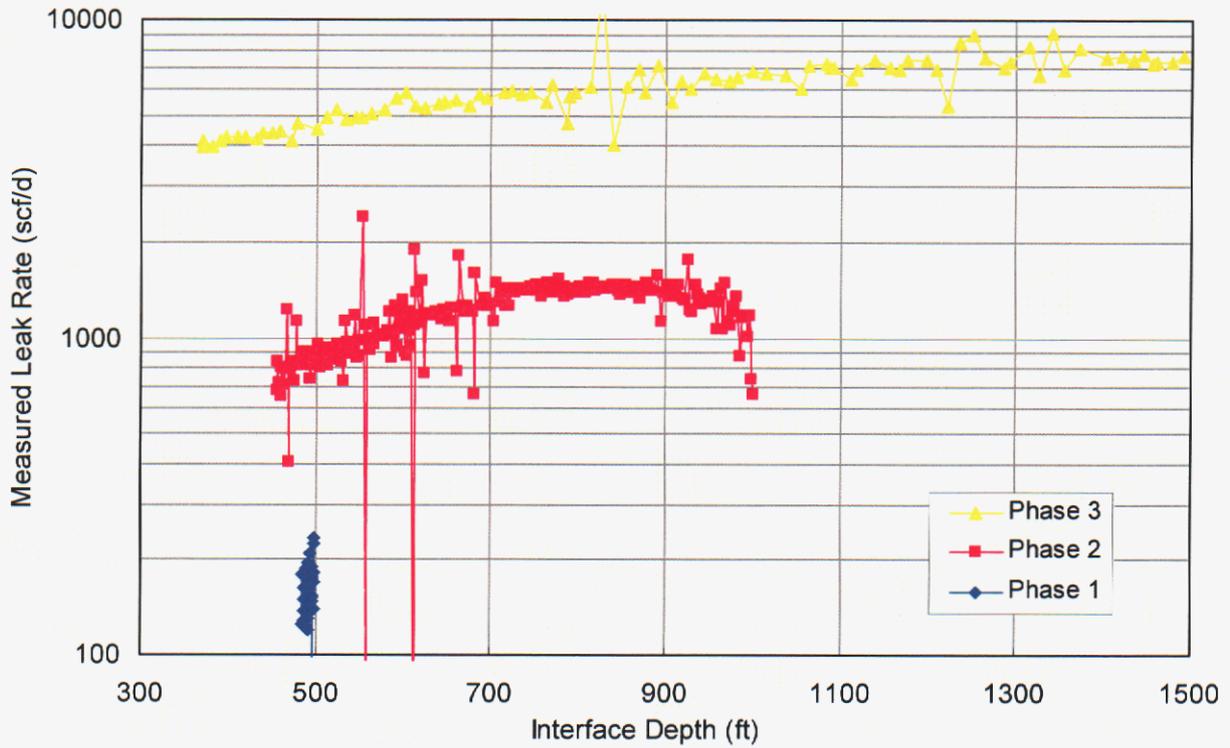


Figure 18. Leak Rates as a function of interface Depth.

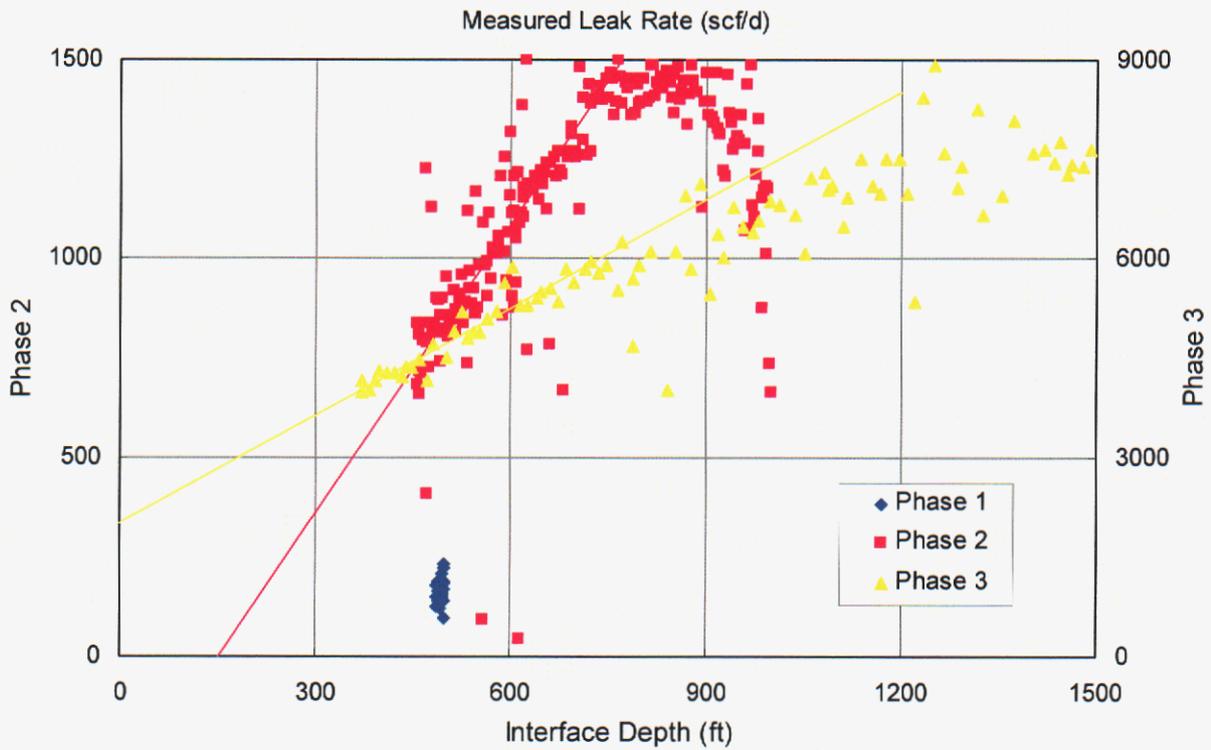


Figure 19. Extrapolated Leak Rates to Top of Casing.

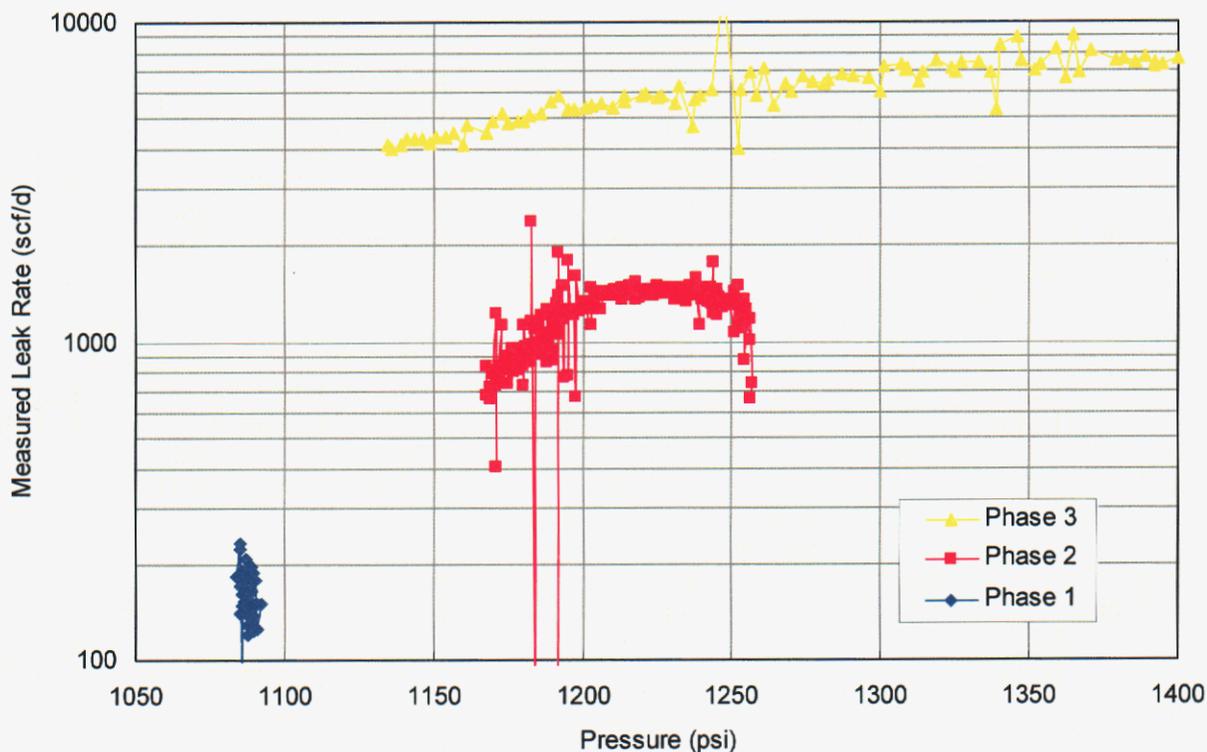


Figure 20. Leak Rates as a Function of Pressure.

the nitrogen injection and shrink during the bleed-down. The dilation is expected because the nitrogen pressures are likely well in excess of the in situ stresses of the cement. In such a case, the asperities in the cement would hold the cracks or microcracks open as pressure is removed, thus creating an irreversible situation. This is particularly true near in the upper portion of the casings, where the cement is at a low or an unstressed condition prior to the injection of nitrogen. This mechanism may enhance a purge of oil from the microannuli. Thus, successive propping of cracks and dilation of microannuli could result in an adverse consequence from such testing, if the deformations are irreversible after unloading. These mechanisms involving the cement in the annulus could open up greater paths to the leaking casing joints.

With successive traverses of the nitrogen-oil interface, leaks are identified that were not observed earlier. So many casing joints appear to be involved that all casing thread leaks could be considered suspect. Perhaps the relatively high pressures coupled with the pressure cycling caused oil to be removed from the thread joints and thus opened more leaks.

One event very likely to occur under normal operating conditions in WH 108 is that oil would once again seep into the cemented annulus over time. Once again the oil would tend to retard nitrogen leakage. The cracks would still be small, and the high-viscosity oil would plug the cracks; thus WH 108 would be virtually in the same physical state as it was before the test, provided the physical dimensions of the flow path remain unchanged.

Finally, one interpretation of the test results is simply a single leak, located at or near the top of the casings, which is pressure-dependent. The aperture of the leak path could successively prop open during the incremental pressure increases accompanying each test phase. During each test

phase, as the pressure decreases the aperture size shrinks, and head drop across it decreases which explains the decreased leakage rates. Leakage rates can be shown to be indirectly proportional to aperture size. Some aperture flow models suggest a relation between aperture sizes to the cubic power with flow rate. Without any direct observations underground, and in the absence of defining data, any such models or combinations thereof can be hypothesized. Although this single-leak interpretation is inconsistent with the existing interpretation of the test results, mention of this pressure-dependent single-leak model is warranted in light of the ambiguity that accompanies the test results.

The abrupt pressurization rate drop from approximately 2.5 psi per day to 1.0 psi per day—noted in Phase 2 and suggesting that at least 50 percent of the total leakage is through the joint closest to 700 ft—was not observed in Phase 3. This feature would have been expected to manifest itself in both Phases 2 and 3. This abrupt change was obscured in the gas-production rate data (Figure 6) because of the transient conditions occurring at that time. On the basis of change in the amounts of fluid in the leak path from one phase to the next, and perhaps even the physical characteristics of the leak path itself, multiple leaks would not necessarily be expected to increase proportionally from one phase to the next.

#### 4.2 Reconsideration of the "Classical" Nitrogen to Oil Volume Ratio

In this operation, approximately 37,000 barrels of nitrogen gas, at standard conditions, were metered out the annulus, most during Phase 3. The tank that collected the oil expelled from the annulus observed after this operation contained no more than about 25 gallons (0.6 bbl) of oil. It is assumed for the purpose of the estimates below that most of the oil expelled through the annulus was expelled during Phase 3. Compressing the gas with an “approximate average” pressure over all phases of the operation, 1150 psi, and dividing by the amount of oil collected, provides:

$$37,000 \text{ bbl nitrogen} \times 14.7 \text{ psi} / 1150 \text{ psi} / 0.6 \text{ bbl oil} =$$

a nitrogen gas-to-oil equivalent volume of 790.

A comparison can also be made between a typical Phase 3 nitrogen gas production of 7500 scf/d with the 40 bbl/yr measured maximum leak rate for WH 108 from previous measurements (Piechocki, 1999). Annualizing the gas-production rate, compressing the gas to the working pressure during the operation, and dividing by the estimated annular oil leak volume, provides:

$$7500 \text{ scf/d} \times 365 \text{ d/yr} \times \text{bbl} / 5.61 \text{ scf} \times 14.7 \text{ psi} / 1200 \text{ psi} / 40 \text{ bbl/yr} =$$

a nitrogen gas-to-oil equivalent volume of 150,

where the “approximate average” pressure for Phase 3 is ~1200 psi.

It is thought that the differences of this ratio in two cases from the same well are significant in the two-phase (oil and gas) flow from WH 108. The ratio of the nitrogen volume to that of oil can be quite different from the equivalent volume factor of 10 that is normally used. This often-quoted factor of 10 was based on a study by Ken Goin (Goin, undated memo). Practice has shown that number can be rather conservative. The estimates above are from the same well over

the same leak path but probably with differing leak paths since the latter measurement was probably made in conjunction with a CIT starting from below the casing shoe and involving additional casing leaks and paths up through the cemented 20 × 26-inch casing.

This flow of fluids through the cemented 20 × 26-inch annulus is thought to be more like laminar flow, (long paths up through cracks in the cement). In fact, Goin (undated memo), in the development of the above work, suggested an equivalence factor of approximately 300 for laminar flow. Although flow theory suggests that much higher ratios are possible, it must be realized that the ratio or equivalence is strongly path- and gas-dynamic-dependent and will vary from case to case; it can even vary within the same cavern.

Most discussions of the WH 108 casing leaks centered upon or implied the existence of fluid flow paths up through casing joint threads and even more through cracks in the cemented annuli. The casing and cavern are in geologic media, much of it in a salt dome, and consideration should be given to this ratio when nitrogen or oil travels through this medium.

This situation can be illustrated by considering the permeability testing conducted at Weeks Island prior to converting a room and pillar mine to oil storage (Acres, 1987). Permeability tests were conducted in boreholes located in the mine and on the salt core extracted from them. For each test, nitrogen was first used to determine the permeability, followed by the use of fuel oil. The results were presented in terms of intrinsic permeability, which is theoretically independent of the type of fluid used in the test. The results, presented in Figure 21, show good agreement with the theory on average; however, a considerable variability exists, as shown by the order-of-

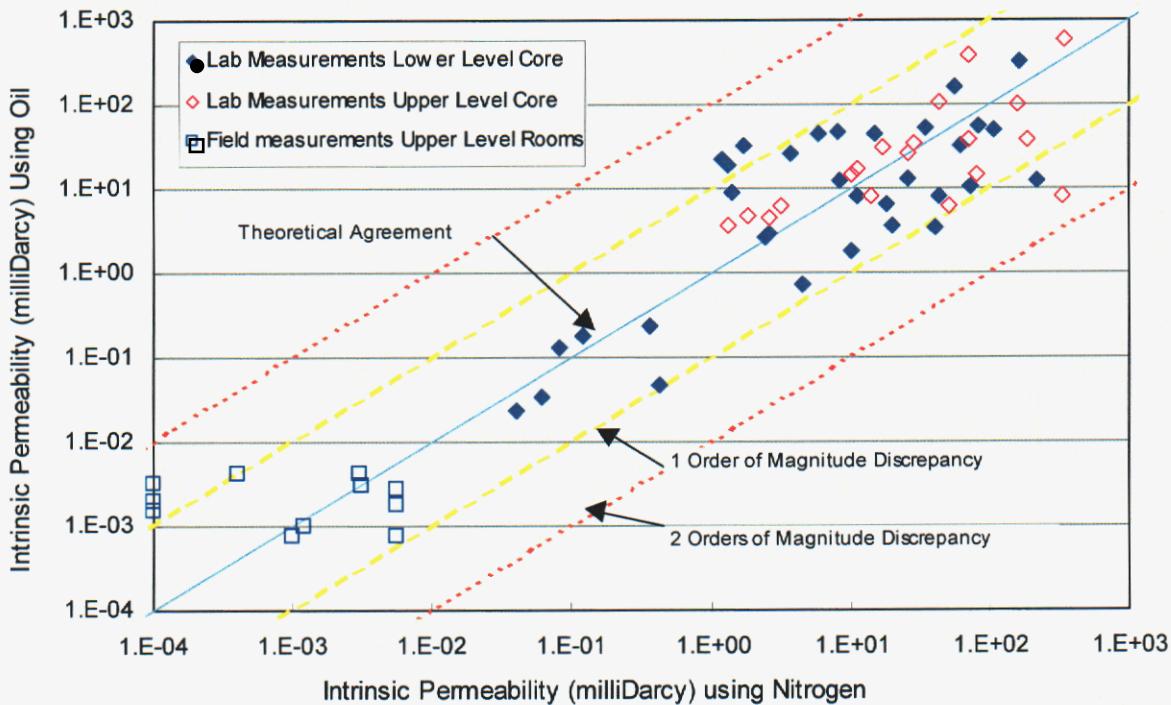


Figure 21. Permeability Data from Weeks Island Tests.

magnitude lines on the plot. The data suggest that the use of any theoretical ratios in converting nitrogen to oil-leak rates when in competent geologic formations should be tempered by the uncertainty noted in well controlled laboratory tests and field measurements.

In situations where the leak geometry and fluid properties are well defined (unlikely) or at least roughly approximated (much more likely), a more realistic and invariably less conservative nitrogen gas-to-oil equivalent volume factor can be used. An example of this is to use a parallel plate, laminar flow approximation for oil or gas streaming up a cemented annulus. Other flow models based on compressible flow through fractures, porous media, and threads are discussed by Hinkebein (1992). These models were used in an attempt to interpret a casing leak in West Hackberry 109 and suggest a nitrogen-to-oil leak rate ratio of approximately 200 (Todd, 1994), slightly larger than the ratio of 150 suggested above. In situations where turbulent flow is possible the nitrogen to oil ratio may be much smaller. (Ehgartner, 2002).

### **4.3 Possible Leak Pathway to the Environment**

The question arises: With these casing leaks, is there a possible oil pathway to the environment? If the path to the metering at the 20 × 26-inch annulus is through the casing joint threads and along microannuli to the surface, the question of a possible pathway to the environment should be reconsidered. One micro-annular path is along the boundary between the 20-inch casing and the cement. In time, the twenty-year-old cement may pull back from the casing. Pressure cycling during normal operation cycles and during CITs would exacerbate this situation.

Because the 20-inch casing extends 268 ft below the 26-inch casing (see Figure 2), there are eight to nine casing joints below the 26-inch casing shoe. (The recent operation was only able to discern casing joint leaks above 1500 ft.) There is a strong likelihood that any leaks in this area below the 26-inch casing would communicate with the 20 × 26-inch annular pressure monitoring at the surface. Microannuli along the cement-casing interface are thought to be the common paths. If an annular pressure reading is present at the surface, there is a leak, probably at the casing joints. There is no guarantee, however, that all the leak paths are up the 20 × 26-inch annulus, especially if the leaks are at 20-inch casing joints below the 26-inch shoe. Besides microannuli along the casing, there could be other cracks in the cement running in different directions (see Figure 2). These cracks could be web-like in nature.

When the 20-inch casing was hung, up to 0.3 millistrains\* was set in the top sections of the casing before it was cemented in. This may be a factor in the leakage of these casing joints. A recent study (Sobolik and Ehgartner, 2002) shows that up to 1.0 millistrain may occur in the formations surrounding the casing. This strain could be transmitted to the cemented strings through the casing cement. We know there are casing leaks at the top of the geologic column consistent with the hanging of the casing and with the modeling described in Sobolik and Ehgartner, 2002. This same report suggests that casing joint leaks would be exacerbated at the top and bottom of the 20-inch casing string, including that portion below the 26-inch casing string.

Two factors would mitigate such potential leaks to the environment: (1) Experience has shown that the relatively high viscosity of oil retards significant production of gaseous product in all instances observed in CITs and similar tests. (2) After the West Hackberry wells were

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\* Strain is defined as the change in length over the original length. A millistrain is simply that quantity divided by 1000.

established, the salt is presumed to have crept in around the wells at these depths, and around their associated cement jobs. (The 26-inch casing penetrates the salt in the wells with the threaded casing joints, which assures that no 20-inch casing joints contact the caprock.) The salt itself is an additional barrier against potential casing collar leaks that would not be contained by the surface equipment associated with the 20 × 26-inch annulus. Thus, the mechanical characteristics of the salt formation provide an additional barrier to the environment. Still, the fact remains that casing joints are potential leak sites.

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## 5.0 APPROACHES TO THE PROBLEM

As noted in Section 1.2, the phenomenon of leaking casings at West Hackberry to date has resulted in no known environmental or economic problems at the SPR. However, many of the joints in the 20-inch casing are known to leak. In fact, so many of the joints have been found to leak that all casing joints can be considered suspect, as mentioned in Section 4.1. Some of these 20-inch casing joints are located below the 26-inch casing. If these particular casing joints are leaking, there is no guarantee that all leakage would be up the 20 × 26-inch annulus. In light of the results from this operation, review of possible mitigation methods should be mentioned.

### 5.1 Alternative Solutions

In this section, four approaches to the problem are provided, with comments on each. These approaches are injection of a sealant, expandable casing, a robotic welder, and a liner.

#### 5.1.1 Seal Tite Approach/Injection of Sealant

An attempt was made to seal the leaks in WH 109, another leaking well, with a proprietary compound (Sattler and Bauer, 1999). Seal Tite International has successfully used its compounds for sealing hydraulic leaks throughout the oil and gas industry. A proprietary Seal Tite compound was inserted into the nitrogen stream of WH 109 in conjunction with a CIT. The nitrogen-oil interface was pushed down near the cement shoe (Figure 2) of the 20-inch casing. The sealant was designed to follow the nitrogen. When the nitrogen leaked out the casing threads, the sealant would follow. The sealant was expected to plate out on the edges of the leak as a result of pressure drop and eventually seal the leak.

DynMcDermott and SNL agreed that the attempt to seal WH 109 by this Seal Tite compound failed because leak rates, which were ~400 bbl/yr nitrogen (Sattler and Bauer, 1999), were too slow. In fact, personnel from Seal Tite International had asked to apply their technique on a well with a greater leak rate, WH 107, which was leaking at  $\sim 5.5 \times 10^4$  bbl /year nitrogen (SPR Integrity Test Report, 1999). In Phase 3 of the present test, WH 108 was producing even more nitrogen than WH 107, approximately  $5.3 \times 10^5$  bbl/yr, assuming an average rate of 8000 scf/d.

One possible technique would be to apply this Seal Tite procedure to WH 108, pressure cycling in a manner similar to this operation. In this case the pressure cycling would eventually result in the nitrogen-oil interface being depressed to and residing at the cement shoe. A pill of Seal Tite sealant would be set on top of the oil. The rapid rise of the nitrogen-oil interface, with the pill on top of the oil, would assure all casing joints would be covered with sealant in a reasonable time. The pill could be refreshed from the surface, as appropriate.

Cycling would allow nitrogen adequate time to clean out at least the larger leaks before applying the sealant. Annular nitrogen leak rates of 8000 scf/d were already achieved. If sealing procedures were similar to what was established in this operation, total nitrogen flow rates even greater than 8000 scf/d might be achieved. The large leak rates would purge the leak paths of oil and perhaps allow better infusion of a sealant into the leak path. The nitrogen-oil interface would be depressed to near the cement shoe. Individual leak rate estimates exceeding 100 scf/d (i.e.,  $\sim 6.5 \times 10^3$  bbl nitrogen/yr) were common in this operation. Perhaps leaks of this size are large enough to be sealed by the Seal Tite method. The larger individual leaks in WH 108, Phase

3, were estimated well over an order of magnitude higher than the entire leak on WH 109. The nitrogen-oil interface can be estimated as before, as the interface is allowed to rise.

After such an operation, the cavern should be operated in a normal manner. The well should set for three to six months for oil to imbibe in any potential leak paths as before. At that time the well can again be tested for leaks with the expectation that the larger leaks in WH 108 will have been sealed.

No work-over would be necessary. Primary costs, in addition to Seal Tite, would be for nitrogen and for the DynMcDermott logging contractor for the nitrogen-oil interface measurement. The nitrogen and logging costs are usually nominal because these companies are effectively on retainer.

However, with this method it is conceivable that some sealant from the (presumably) larger leaks could work its way into the annulus and plug certain annular leak paths that originate below where a leak path is sealed (see Figure 2). This could cut off other leaks below this annular plug. It is possible that we could have (undiagnosable) pockets of pressure below this sealant plug, which would create a potentially unacceptable situation. Leakage below any plug would not register on the annular pressure gage. The annular pressure gage is our only indicator of a casing leak. A similar but unacceptable result would be achieved by attempting to seal the annulus from the surface, thus eliminating the pressure monitoring of the annulus and ignoring any underlying leaks.

### **5.1.2 Expandable Casing**

Another, more extensive and expensive approach is to use an expandable casing. The hanging string is removed and an entire string of expandable casing is lowered against the 20-inch casing. A mandrel is run up the casing string, and it is expanded against the 20-inch casing. This expandable casing technique has not been developed for the 20-inch casing, but it has been used successfully for smaller sizes. Conceivably, this technique could be developed for the larger casing but the technique is not available for remediation in the relevant SPR casing sizes at this time. Whether this technique would work when the original casing is out of round should be investigated. The manufacturer has established some guidelines for this approach. Whether or not this approach is preferable to a cemented liner in terms abating the leak or flow rate is not certain at this time.

### **5.1.3 Welding Robot**

This technique of a robot welder is commonly used in horizontal pipeline applications. A patent search is being made to see if any robot welders are used in vertical pipes. If a suitable robot system were developed, the casing joints could be welded during scheduled workovers. Such welding would have to be conducted in water or in an inert nitrogen atmosphere. Safety procedures would have to be carefully developed. Obviously this repair would require a workover to remove the hanging string. This fix, if developed, could be performed in conjunction with a workover of one of the leaking casing strings.

Such welding is usually conducted horizontally on pipelines and, in principle, could be adapted to a vertical situation. Even if a partial success were attained, the procedure would not cut off pressure monitoring of the 20 × 26-inch annulus or block any annular leak path to the surface.

#### **5.1.4 Liner**

The original fix of inserting a liner (smaller casing string) within the 20-inch casing is always available and viable. This option is, however, expensive and it compromises the cavern hydraulics (oil flow during a drawdown).

### **5.2 Summary of Approaches**

The application of a sealant is felt to be intrinsically unreliable. The industry has not developed expandable casing to the size needed, and with the limited potential market that 20-inch casing represents it is uncertain when or if such a product will be developed. A robotic welder shows the most promise, but to our knowledge there is no off-the-shelf system available today that is suitable for SPR needs. Because this technique is viable, developments in the technology should be followed as the technology matures.

An attempt could be made with a CIT operation to see if there are casing joint leaks in the 20-inch casing string below the 26-inch casing, but such an operation would require higher nitrogen pressures than those used in the tests described in this report and may well exacerbate the leakage problem. Although leaking horizons may be located, as was done in this study, there is no guarantee that the cleanout/path change will not create the ambiguity seen in this study. On the contrary, with presumably longer leak paths the instability in the nitrogen flow rate and pressure drop may become worse, making interpretations more difficult. Nonetheless, this approach avoids the pressure cycling used in this operation. Even though nitrogen production rates increased greatly from one phase to the next, commensurate pressure increases were small in these phases, which implies that the cycling itself figures prominently in the phenomena observed in this test. In any event, previous CIT tests have already demonstrated that this lower region has a low or nonexistent leak rate. This leaves the upper portion of the casing for consideration. As discussed above, because of the low inherent stresses in the cement at shallow depths, the injection of high nitrogen pressures would likely increase any leakage rates and is therefore not advised, particularly over a substantial test duration.

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## 6.0 CONCLUSIONS

The testing on West Hackberry Well 108 verified the presence of leaks from the inner 20-inch casing into the outside annulus. The leaks were shown to progressively worsen as the test proceeded. The initially measured leak rate at 500 ft was approximately 150 scf/d, but increased to 800 and 4700 scf/d during Phase 2 and 3 testing, respectively. The pressure during this time increased by only 30 percent (from 1084 to 1401 psi).

The reason for the factor of 30 increase in leakage is thought to result from a change in the relative amounts of oil in the leak path and from a change in the characteristics of the leak path. Changes in leak path characteristics could result from any dilatancy of a microannulus or fractures in the flow path resulting from the pressures required to push the interface down during the testing. The test pressures started at 1080 psi and increased to as high as 1400 psi. These pressures may be significantly greater than the stresses in the cement annulus, particularly at shallow depths. The pressures may have been sufficient to prop open existing flow channels. The flow rate from very small cracks and fractures can be pressure dependent.

During the test phases where the interface dropped across multiple casing joints (Phases 2 and 3), the measured leakage rate decreased. Observations of the nitrogen production rate, and to a lesser degree the pressure curve and its derivative, suggest that this decrease results from fewer casing joint leaks being exposed to the nitrogen. After an initial transient, a linear decrease in rate was measured, suggesting that most if not all joints in this region of the casing were involved. Although some casing joints appear to leak more than others, the involvement of many casing joints would tend to create a smooth decrease in the measured leak rate.

The attempts made to distinguish changes in leak rates as the interface moved across casing joints was successful, but the interpretations have a degree of ambiguity. The inability to measure smaller changes in the measured flow rates and pressures was in part probably responsible for this ambiguity. Measuring these changes in a background of production rate instability also contributed to the ambiguity. Although a lag time was measured between pressure changes and the metered outflow, the test duration was probably adequate to mute this effect. Examination of general pressure trends indicated a fundamental shift during Phase 2, suggesting a well-defined leak, but test results in Phase 3 indicated no such change. Thus even a marked trend was not reproducible from one phase of the test to the next. This may, again, be a result of changes in the leak path or the relative amounts of fluids in it. Regardless of the cause, it is not known whether the leakage is a result of one or multiple leak paths from the casing joints through the cemented annulus.

Given the increased leakage rates that resulted from this test, any future testing should be carefully considered. At this time, these leaks pose no economic or environmental problem and in the short term none are foreseen. However research and analysis of the application of any new leak isolation technologies should be reported to the SPRPMO on an annual basis.

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## APPENDIX A: THE STRATEGIC PETROLEUM RESERVE

The Strategic Petroleum Reserve (SPR) is an emergency supply of crude oil stored in underground salt caverns along the US coastline at the Gulf of Mexico. The SPR holds nearly 570 million barrels of crude oil at four sites. This report concerns one of the four sites, West Hackberry, which is located in Cameron Parish, Louisiana and has a storage capacity of 222 million barrels. The current West Hackberry inventory is 193 million barrels.

The storage facility occupies 565 acres over the West Hackberry salt dome. An aerial view of the site is shown in Figure A-1. This location was selected as a storage site early in the SPR program because of its existing brine caverns, which could be readily converted to oil storage, and because of its proximity to the Texoma Interstate Pipeline system (now converted to gas transmission).

Development of the West Hackberry site was initiated in 1977 and completed in 1988. The site has 22 underground solution-mined storage caverns. A plan view of the site is provided in Figure A-2. Five of the caverns existed at the time of site purchase in 1977. These caverns were filled with oil in 1978. The remaining 17 caverns were leached from the salt dome in the following decade (Munson et al., 1998). Cavern profiles are known from sonic surveys conducted during site characterization. The leached caverns at West Hackberry—including the subject of this report, WH 108—are cylindrical in shape and generally extend to depths of about 4500 feet (Magorian et al., 1991).



Figure A-1. Aerial View of West Hackberry SPR Site.

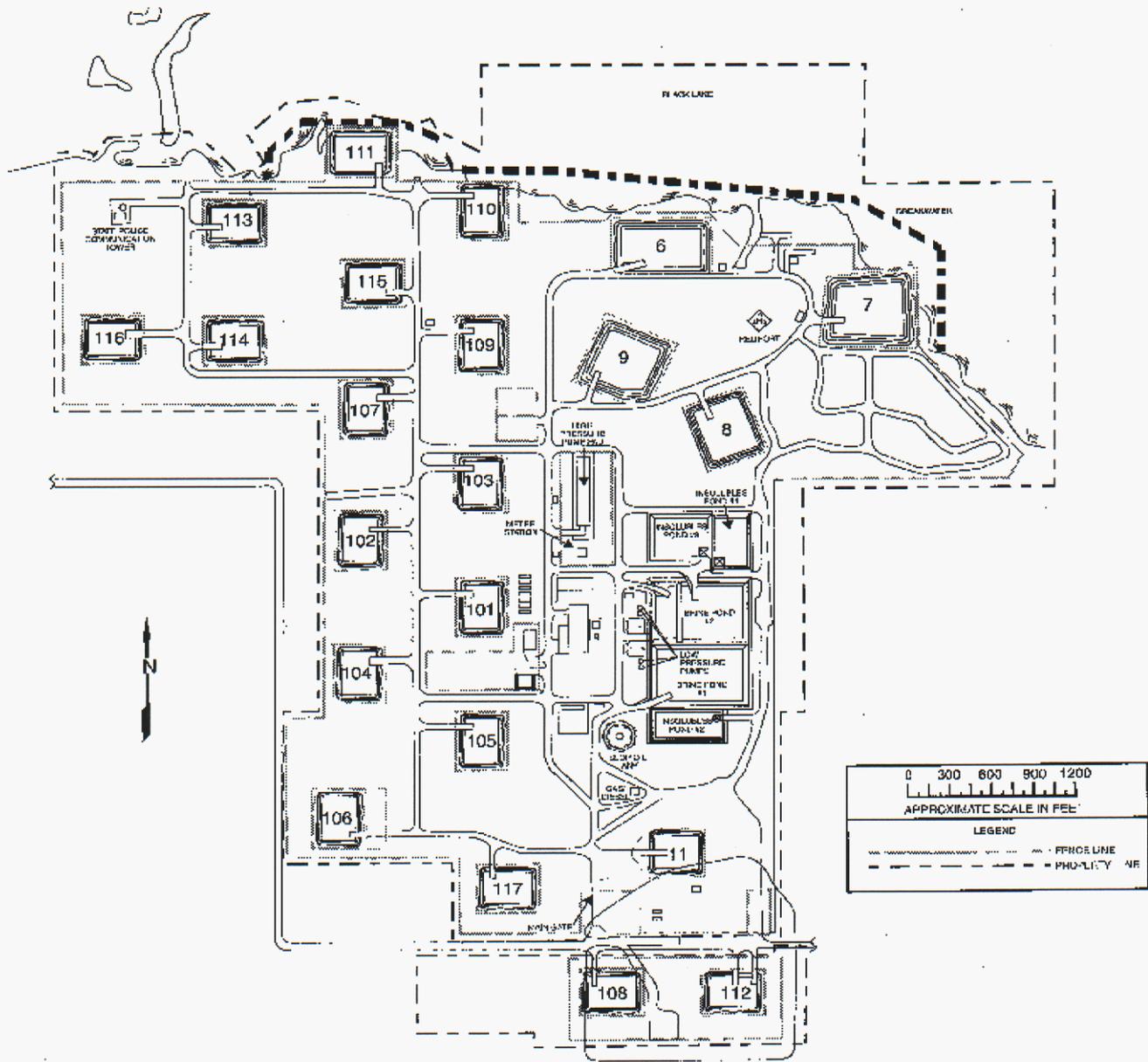
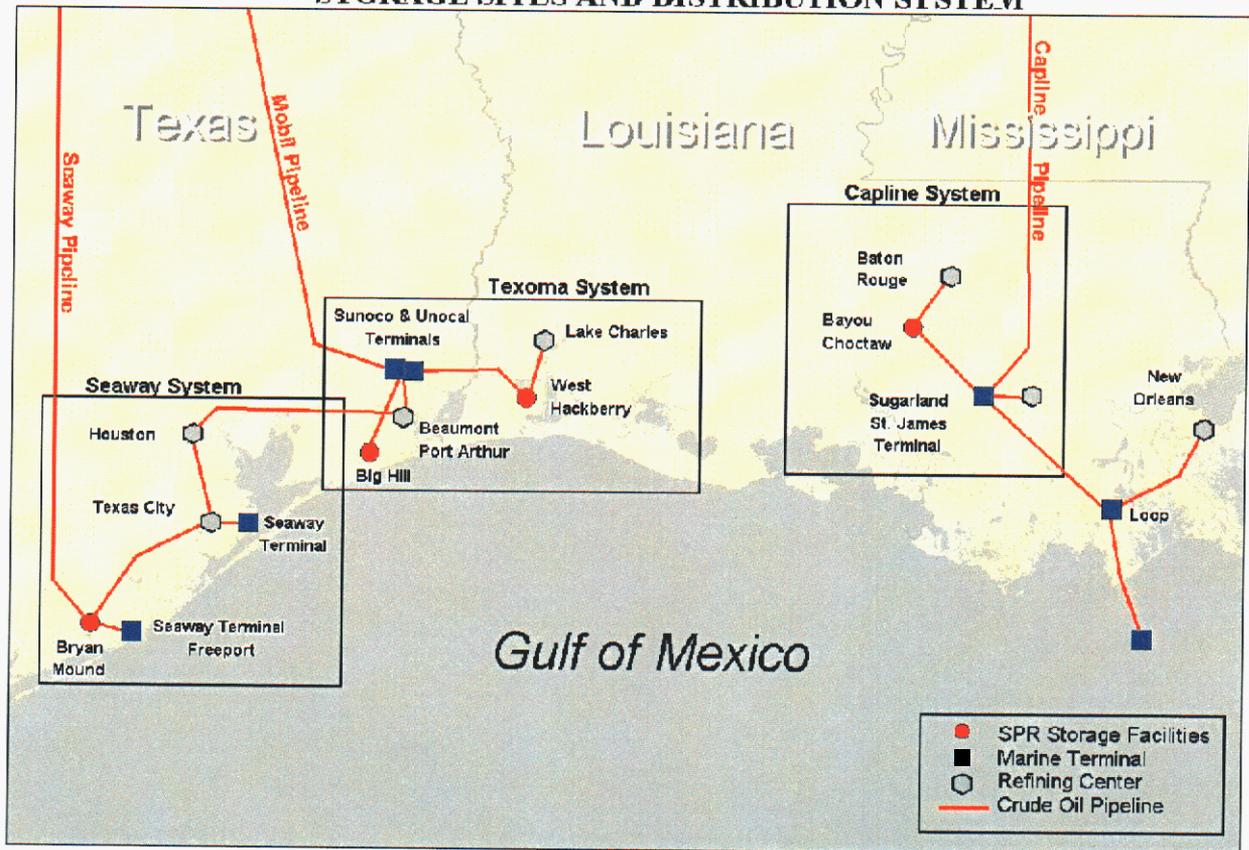


Figure A-2. Plan View Showing Well Locations at West Hackberry SPR Site.

West Hackberry is connected to the Sun Marine Terminal at Nederland, Texas via a 43-mile pipeline. It is connected to the Texaco Pipeline System at Lake Charles, Louisiana via a 14-mile pipeline. These pipelines enable West Hackberry to receive crude oil from suppliers and distribute it to refiners. The distribution system and its connection to the four SPR storage sites are shown in Figure A-3.

## STORAGE SITES AND DISTRIBUTION SYSTEM



SP 27592 ppt

Figure A-3. SPR Storage Sites and Distribution System.

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## APPENDIX B: VELOCITY ESTIMATE FROM A STREAM FLOW CALCULATION WITH A COMPRESSIBLE FORM OF THE BERNOULLI EQUATION SHOWING A LOGARITHMIC DEPENDENCE ON DRIVING PRESSURE

The compressible form of the Bernoulli equation can be used to calculate the velocity. Implicit in such calculations is that (1) the effect of the annulus on the gas flow is small compared to the effect of stream flow through the 20-inch casing joints into the throat of the annulus (otherwise we might hear supersonic flow at the frac tank on the surface); (2) the gas is a perfect gas; (3) the flow of the gas through the 20-inch casing joint into the 20 × 26-inch annulus is frictionless; (4) the flow of the gas through the 20-inch casing joint is presumed to be steady; and (5) effects of temperature are negligible. The compressible Bernoulli equation is written as:

$$\left( \frac{dP}{\rho} + \frac{gz + V_2}{2} \right)_{20\text{-inch casing joint}} = \text{constant} = \left( \frac{dP}{\rho} + \frac{gz + V_2}{2} \right)_{\text{throat of annulus}} \quad (\text{B-1})$$

where:

$P$	=	nitrogen (driving) pressure
$P_{atm}$	=	atmospheric pressure, 14.7 psia
$P_{20\text{-inch casing joint}}$	=	driving pressure in 20-inch casing
$P_{ann}$	=	annular pressure, back pressure, on leak, approximately 100 psia
$\rho$	=	density of nitrogen gas
$\rho_{atm}$	=	the density of nitrogen gas at standard conditions = 0.072 lb/scf
$g$	=	the gravitational constant
$V$	=	velocity of gas.

The velocity of gas inside the 20-inch casing is presumed to be negligible. Potential energy terms involving elevation,  $z$ , in this geometry are small compared to the other terms.

Furthermore, the density ( $\rho$ ) is expressed as a function of pressure,

$$\rho = \rho_{atm} \left( \frac{P}{P_{atm}} \right) \quad (\text{B-2})$$

With these simplifications, the Bernoulli equation is integrated to a reference pressure and written as:

$$\frac{P_{atm}}{\rho_{atm}} [\ln P]_{20\text{-inch casing joint}} = \frac{P_{atm}}{\rho_{atm}} \left[ \ln P + \frac{V^2}{2} \right]_{\text{throat of annulus}} \quad (\text{B-3})$$

With these simplifications it is seen that the velocity (and amount) of escaping gas depends on the logarithm of the nitrogen pressure and any annular backpressure.

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