



## **Investigation of Hybrid Deepwater Production Systems**

**FINAL REPORT**  
**Cooperative Agreement 1435-01-97-CA-30879**

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## **EXECUTIVE SUMMARY**

This project, the “Investigation of Hybrid Deep Water Production Systems,” was initiated by a three-year cooperative agreement between the Minerals Management Service and LSU. Dr. Stuart L. Scott was the principal investigator. It was intended to complement another project with the same name and focus funded by the Louisiana Board of Regents, LSU, and Chevron. Both projects were to use field-scale experiments and analytical modeling to investigate the problems associated with subsea, multi-phase production systems.

Multiple complications were experienced with both projects including termination of the Louisiana Board of Regents project after one year, Dr. Scott’s resignation from LSU, designation of new project investigators, reduction in project scope, and finally the MMS decision to withhold funding for the third year of the project. Nevertheless, significant progress was accomplished during the first year and one-half of the project as reported in Appendix 3 and in the subsequent year and one-half as reported in previous progress reports. This report will describe the results and implications of the study performed for the final year and one-half of the MMS-sponsored project.

The focus of this report is the experiments that were conducted to assess the previous method proposed by Scott et al for the detection of leaks in deep water, multi-phase pipelines. Six field-scale, multi-phase flow tests were conducted in June, 2000 to compare a small leak with a no-leak condition during each test. These tests at least qualitatively demonstrate the feasibility of Scott’s concept. Specifically, knowing the characteristic pressure loss versus throughput in a line without a leak provides a basis for determining the presence of a leak by measuring pressure loss and flowrate out of the line. If the pressure loss is higher than expected for that flowrate, a leak is a likely possible cause. A leak at the mid-point of a 9,640 foot long flow loop with a rate exceeding 16 percent (from Test 03b) of the flow out of the line was readily detectable.

Visual observation of leaking gas or oil is the most common leak detection method for an in-service line. However, leaks from lines in deep water will be difficult to detect visually unless the leak is very large and creates a noticeable slick or plume. Consequently, other means of leak detection must be considered for more sensitive, timely detection of leaks in deepwater. The tests in this study were conducted on land and do not allow evaluation of visual detection methods in deepwater. However, the experimental results do provide a basis of comparison for a variety of more sensitive leak detection methods.

The most sensitive leak detection method is hydrostatic testing with liquid. However, this requires that the line be taken out of service and filled with liquid. The next most sensitive method is comparative measurements of the rate in and out of the line. The method proposed by Scott is less sensitive but only requires a pressure sensor rather than a meter at the upstream end of the line, which is much more feasible for lines originating at a subsea well. Finally, routine safety shutdown systems rely on a pressure sensor to detect a reduction in pressure at the upstream end of the line to detect a leak. For any high deliverability well or flow source, the change in line pressure for even a significant leak may be very small. Consequently, this is the least sensitive of the leak detection methods considered.

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## **INTRODUCTION**

### **Importance of Deepwater Oil and Gas Operations**

In 1999, deepwater operations accounted for about 45 percent of all of the oil production and about 15 percent of all gas production in the Gulf of Mexico<sup>1</sup>. As recently as 1996, less than 20 percent of the oil production and very little gas came from deepwater production. Consequently, industry operational experience in deep water is limited. In addition, the water depths where these activities are being conducted are also increasing with many fields in water depths greater than 2,000 feet proposed for development in the next few years. Thus, the levels of operational activity and actual production from deep and ultra-deep water are increasing very rapidly and warrant increasing attention.

Another important aspect of deepwater development is the high productivity of the wells. Deepwater Gulf of Mexico wells are routinely being designed to produce 10,000 bopd, and several have achieved even higher rates. A well at Troika recently produced in excess of 30,000 bopd during a test. In comparison, the 1979 IXTOC 1 blowout in Campeche Bay, Mexico was about 30,000 bopd initially and created a slick that reached Texas beaches several hundred miles away. Therefore, individual wells and fields have significantly greater potential for causing pollution or other hazards than more traditional U.S. land or offshore operations.

### **Importance of Leak Detection**

The large total production from deepwater activities and high productivity of individual wells give emphasis to the importance of identifying and correcting any release of hydrocarbons from these operations. One potential source of such releases is leaking subsea pipelines.

Leak detection in typical flowlines and oil and gas pipelines on the outer continental shelf has relied primarily on one of two simple methods. The principal method has been visual observations of an oil slick or sheen or gas plume or bubbles on the water surface during either routine manned operations nearby or from regular overflights. Low pressure safety shutdowns have provided the second method, which is useful primarily for relatively rapid reaction to line breaks or leaks large enough to cause a significant reduction in the line operating pressure.

Deepwater lines pose additional complications for leak detection. Fluids from a leak will be both dispersed over a much larger area and weathered by traveling through the water column, and therefore are harder to detect. Line pressure during a leak is influenced by the opposing head of the seawater, which means that the reduction in line pressure due to even a large leak or break may be relatively small. The recent rapid increase in total production from deepwater activities and the very high well productivities achieved, particularly from subsea wells, suggest that the frequency and size of deepwater leaks will also increase. Considering the difficulty of detecting leaks in deepwater pipelines, the potential consequences of deepwater leaks, and the increasing levels of deepwater activity, the risks associated with pipeline leaks have increased dramatically in recent years and will continue to increase without offsetting improvements in technology or methodology.

## **Original Project Description**

This project, "Investigation of Hybrid Deep Water Production Systems," was initiated by a three-year cooperative agreement between the Minerals Management Service and LSU effective September 30, 1997. Its purpose was to help Louisiana, MMS, and the oil industry assess the potential problems with hybrid production systems offshore Louisiana. Dr. Stuart L. Scott was the principal investigator.

The project began as a complement to another project with the same name and focus funded by the Louisiana Board of Regents (through their LEQSF program), LSU, and Chevron. It was to be a field-scale experimental and modeling investigation of the problems associated with subsea, multi-phase production systems. Specifically, a multi-well production manifold header system and production separators were to be installed to complement the wells and flow loop already existing at the Petroleum Engineering Research and Technology Transfer Laboratory to create an analog of an offshore production system. These facilities were to be used to "investigate: 1) methods of monitoring multi-phase wellbore/flowline systems for detection of partial blockages or leaks; 2) field-scale hydrate formation experiments; 3) combining multi-phase flow streams from several wells; and 4) techniques for stabilizing end-of-line flow rates," see Appendix 2.

## **Project History**

The Louisiana Board of Regents project was begun in June 1997 and was fully funded during the first year. This complementary project with the Minerals Management Service officially began September 30, 1997. The specific tasks identified in the original project budget were 1) experimental and modeling work for multi-phase blockage and leak detection (from Tasks 1 & 2 of LEQSF project), multi-phase flow through bends and fittings (from Task 2 of LEQSF project), single phase blowdown experiments (related to Task 2 of LEQSF project), modeling flow in a subsea manifold/header system (from Task 4 of LEQSF project), experiments on multi-phase blowdown of a pipeline (from Task 2 of LEQSF project), and experiments on multi-phase flow in a subsea manifold/header system (from Task 4 of LEQSF project).

Progress on both projects from June 1997 to June 1998 was described in an Interim Progress Report to the Board of Regents dated June 26, 1998. The major activity undertaken directly for this project during that period was a Deepwater Production Workshop held in Baton Rouge on March 31, 1998. Progress after the first year has been limited and slow. Multiple complications and changes in the project were experienced in late 1998 and early 1999. These included failure of Chevron to deliver second year funds, the resultant cancellation of the Board of Regents project, major electrical system failures and university construction at the well facility interfering with experiments, and resignation of the project PI, Dr. Stuart Scott, effective January 6, 1999. A summary of progress accomplished during the period June 1, 1998 through January 6, 1999 was described in an Interim Progress Report to the Board of Regents dated January 11, 1999. Both interim progress reports, five related technical papers, and three related MS theses were transmitted to MMS with a quarterly progress report dated May 20, 1999. A final progress report for the Board of Regents project was completed January 3, 2000 and is included as Appendix 2. Progress subsequent to January 1999 is the subject of this report.

## Background for Current Effort

Pursuant to Dr. Stuart Scott's resignation, LSU proposed that John Rogers Smith serve as project PI. On May 28, 1999, LSU received approval for this proposal and a contract modification obligating the second year funds for the project. On May 27, 1999, Smith and John M. Griffin, Co-Investigator, of LSU submitted a proposed work plan for the second project year, as described in the following section. The specific objective of this plan was to evaluate the multi-phase leak detection approach published by Scott, et al<sup>4</sup>, using field-scale experiments.

Given the loss of most of the project sponsorship, funding, and personnel, the overall scope of this work plan was reduced from that in the two original complementary projects. It focused on designing and conducting experiments using the flow loop at PERTTL to evaluate leak detection concepts for multi-phase flowlines. This focus was selected with the knowledge that modeling of multi-phase leaks was completed during the first year of the project and that experimental validation of these models had been impossible due to electrical problems and construction at the well facility. In addition, undetected flowline leaks had the greatest direct environmental and safety consequences of the original proposed tasks. The relevance of this focus on leak detection is at least partially validated by subsequent MMS calls for "white papers" on projects to improve leak detection methods.

A "white paper" proposing additional experimentation and analysis of leak detection concepts to be performed as the third year of the project was submitted July 21, 2000. LSU was advised verbally on September 12, 2000 that this proposal was declined. Therefore, the project was officially terminated after two years of funding on the original project completion date, September 30, 2000. The following sections of the report describe the work completed by the authors during the second year of funding.

## OBJECTIVE AND PROPOSED WORK PLAN

The objective of the work plan proposed for this project was "field-scale verification of multi-phase leak detection." This verification was to focus on the evaluation of the method developed by Scott for detecting the presence of a leak in a multi-phase flowline. The evaluation was based on field-scale testing of actual leaks in a multi-phase line. The following four steps were planned to conduct the evaluation.

1. Adapt Scott's published model<sup>4</sup> for detecting a pipeline leak for multi-phase flow for use with field data in field units. This model accommodates four flow regimes (stratified, wavy, annular, and slug flow). As with previous single phase models<sup>5,6</sup>, the model requires only outlet multi-phase flow ( $q_{sc}$ ), pressure at beginning ( $P_{in}$ ) and end of the flowline ( $P_{out}$ ).

$$q_{sc} = F_{leak} (F_{2-\phi})_q (CZTf_{SG2} \frac{L_p}{d^5})^{-0.5} (P_{in}^2 - P_{out}^2)^{0.5}$$

As proposed by Scott, a log-log plot of  $(P_{in}^2 - P_{out}^2)$  vs. flow out divided by two phase flow efficiency ( $q_{sc}/F_{2-\phi}$ ) for a no-leak condition provides a baseline of data. A leak condition generates data that departs from baseline.

2. Design the physical experiments. A series of preliminary flow tests were conducted in January and May, 2000. The contribution of these tests was primarily establishing a basis for

developing the procedure used in the tests described herein. This procedure was implemented in June, 2000 when the six (6) tests described herein were conducted. The six June tests are the focus of this report.

Water and natural gas comprise the two phases. The anticipated pressure at which flow tests will be conducted is limited by the 600 psi gas sales line which supplies LSU's 9,460 foot long, 3.64 inch internal diameter, flow loop. Rates were selected to duplicate those ranges commonly expected in a similar size deepwater flowline. The leak location duplicates previous work and occurs at the midpoint of the flow loop. Single phase meters are used to measure gas and liquid flows individually before injection into the upstream end of the flow loop. A low pressure separator and single phase gas and liquid meters are used for measurement of flow out of the two phase line.

3. Conduct the experiments. This will include setup for separation and metering of gas and water. Pressure, gas and liquid rate data will be collected via a multi-channel I/O port using LabView software.
4. Evaluate the experimental results. Data with and without a leak will be displayed using the presentation developed by Scott et al. The presentation will establish a baseline for the no leak case on a log-log plot of  $(P_{in}^2 - P_{out}^2)$  vs.  $q_{sc}/F_{2-\phi}$ . Data collected with a leak should show a departure from this baseline.

## FIELD-SCALE EXPERIMENTS

### Calibration of Instruments

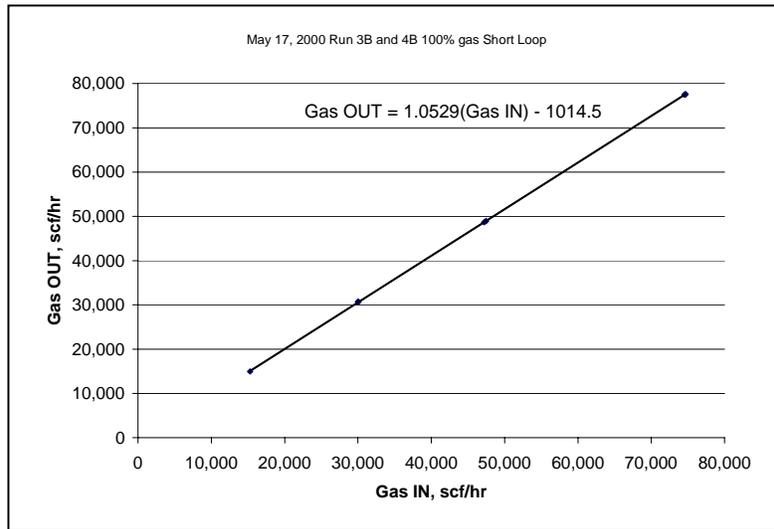
The first requirement for the field-scale experiments was calibration of the instrumentation. Primary instrumentation included the two gas (in and out) and two liquid meters (in and out) and the pressure transducers on each end of the flow loop.

The inlet gas was measured with a 2 inch Daniel Senior orifice meter, Cat. No. D148 (1.503 inch I.D. with fitting taps), equipped with a 1.00 inch orifice plate and Rosemount static and differential pressure transducers. Inlet flow was calculated using a Daniel model 2231 flow computer. The outlet gas was measured with a 4 inch, 300# ANSI, 320-V Daniel, Schedule 40, Junior orifice meter with flange taps, equipped with a 2.75 inch orifice and Rosemount static and differential pressure transducers. Outlet flow was calculated using a Daniel model 2500 flow computer. Both meters were calibrated by using a dead weight tester to calibrate static pressure and differential pressure transducers. Appropriate coefficients for each run and orifice were then entered into the flow computers to calculate flowrates. Temperatures were measured with a thermometer in a well adjacent to the meter.

After calibrating the meters independently, small differences in the two gas meters were identified by comparing the gas out meter reading with the gas in meter reading while flowing at a constant rate directly from the inlet meter through the choke and separator into the outlet meter. Flow was not routed through the flow loop so that steady state conditions could be achieved more rapidly and reliably. A relationship between the gas rates measured with outlet meter and with the inlet meter was identified as shown in Figure 1. This relationship was then used to

define an equation to adjust the gas rate out to equal the gas rate in when both were known to be the same as shown below. This adjustment was made to all of the measured gas rate out data to enable direct comparison of the gas rates through the two meters.

$$\begin{aligned} \text{Corrected Gas Rate Out} &= \text{Gas Rate In} \\ &= (.9498 \times \text{Measured Gas Rate Out}) + 963.5 \text{ scf / hr} \end{aligned}$$



**Figure 1 - Measured Gas Rate Out vs. Rate In**

A differential pressure sensor was also located in the vent line and used to detect when a leak was occurring. Metering of the actual leak rates would have required an additional separator and additional liquid and gas meters. Although this was not possible with the available equipment, it could have helped to identify, or to make corrections for, problems that were encountered with the gas rate measurements.

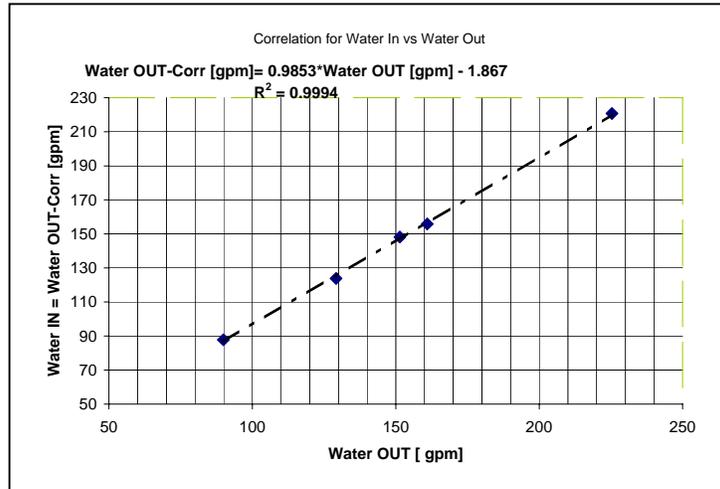
Liquid flowrates in and out of the flow loop were measured with 6 inch Foxboro magnetic flow meters. These were equipped with Model 2806 Magnetic Flow Tubes and IMT 25 I/A Series Magnetic Flow Transmitters. Liquid flow meters were calibrated by comparing meters with known tank fill up volumes. Small remaining differences in the two liquid meters were measured by pumping through both meters at several constant liquid rates and comparing the meter readings. These differences were remedied by correcting the outlet meter reading in the same manner used for the gas meters using the following equation, see also Figure 2.

$$\begin{aligned} \text{Corrected Water Rate Out} &= \text{Water Rate In} \\ &= (.9853 \times \text{Measured Water Rate Out}) - 1.867 \text{ gpm} \end{aligned}$$

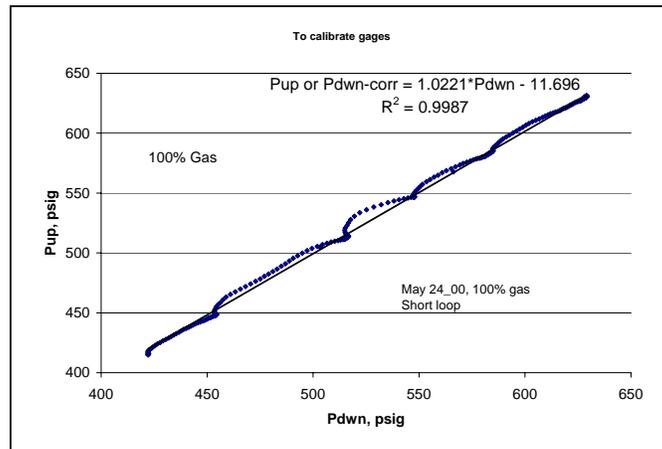
Two Rosemount pressure transducers were used to measure the upstream ( $P_{IN}$  or  $P_{UP}$ ) and downstream ( $P_{OUT}$  or  $P_{DN}$ ) pressures, and therefore also the pressure drop, in the flow loop. Once pressure transducers were calibrated by programming the internal computer against a dead weight tester, minor adjustments were made by setting the  $P_{IN}$  meter as the baseline and

correcting the  $P_{OUT}$  meter to agree with it while at static conditions with a gas-filled pipeline. See the following equation and Figure 3.

$$\text{Corrected } P_{OUT} = P_{IN} = (1.0221 \times P_{OUT}) - 11.7 \text{ psi}$$



**Figure 2 - Correction of Water Out Meter**



**Figure 3 – Correction of Downstream Pressure Transducer**

The use of corrected pressure measurements to determine pressure loss along the flow loop could have easily been supplemented by making the same measurement with a differential pressure transducer. Given that the inlet and the outlet of the flow loop are in close proximity, this could have provided a measure of pressure loss independent of the inlet and outlet pressure calibrations. This measurement would theoretically be a much more sensitive, accurate, and repeatable for the small differential pressure across the line than the difference in pressures from two high pressure transducers.

The output of the flow computers and pressure transducers was then connected to a LabView data collection system. The flow loop was then hydrostatically tested with water to detect leaks. Minor exposed flange leaks were detected and corrected. A small leak in the buried section of the flow loop was also detected but was not found until after these tests were completed. A more thorough description of the leak and other test complications is provided in a subsequent section titled "Complications Encountered". With these preparations complete, the next step was to define the test conditions.

### **Defining Test Conditions**

Six (6) two-phase flow tests were conducted with both no-leak and leak flow conditions. All tests, except Test 05b and Test 06b, had three flow periods. They were:

1. "Before leak" designates flow data collected during the period prior to opening up the pipe line at its midpoint and allowing flow through the leak path.
2. "During leak" designates flow data collected during the period with the leak path open. The leak was through a 1/8 inch diameter orifice mounted on top of the flowline then through a short section of two inch pipe to a six inch diverter pipe open to the atmosphere. This allowed the leak to be observed. An igniter was placed at the end of the diverter and the leaking gas was burned. Flow through the leak path resulted in lower flowrates downstream of the leak than upstream of the leak giving the intended conditions to assess leak detection methods based on rates.
3. "After leak" designates flow data collected during the period after closing the leak and allowing flow conditions to return to normal as in the before leak period.

## **TEST RESULTS**

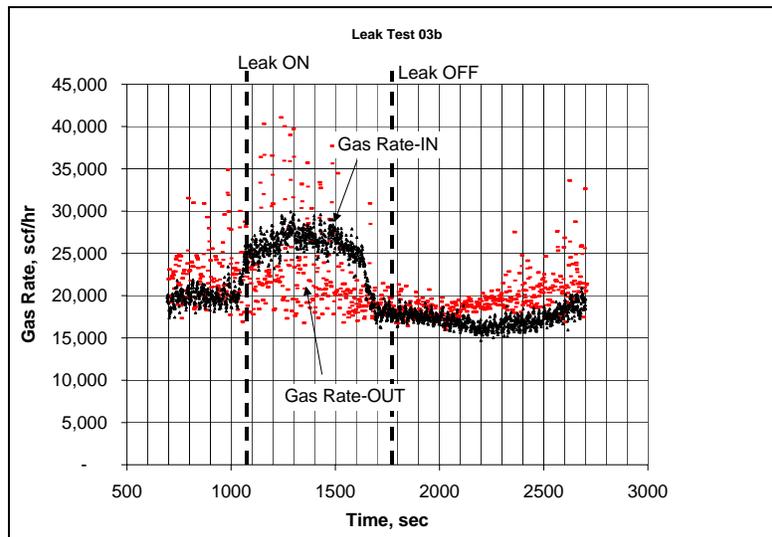
### **Processing Test Data**

The erratic nature of gas rate exiting the flow loop required a smoothing technique. A leak condition saw the gas rate entering the flowline to suddenly rise while the exit rate remained essentially unchanged. The rise in gas rate in with an accompanying constant water rate entering meant the GLR increased. Each of these phenomena is discussed in the sections below.

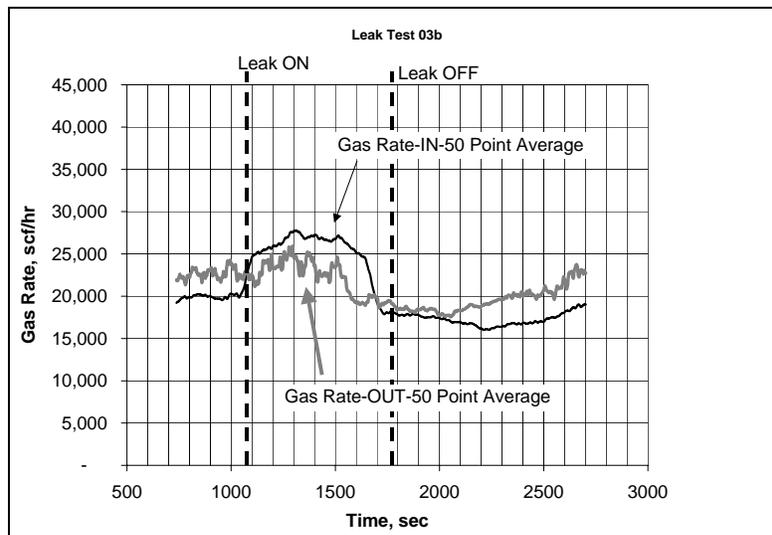
### **Averaging to Smooth Data**

Smoothing of data, especially gas out data, was necessary due to large fluctuations in gas rate at the meter. Gas out was metered down stream of a Swaco® high capacity mud-gas separator. This separator enabled the gas and water to be separated and metered conventionally. The erratic flow from the separator meant that fluids were apparently entering the separator in slugs and /or elongated bubbles. Slugging was more severe at higher gas rates. Comparison to a published flow regime map<sup>3</sup> indicates that this would be expected over the range of gas and liquid velocities in these tests. The gas and water exiting the separator also came in slugs despite the relatively large volume of the separator. The effect of slugging is illustrated in Figure 4 below which shows the Gas Rate-OUT fluctuating wildly to either side of the more stable Gas Rate-IN data. In most tests, the liquid rate out data was even more erratic, varying from zero to more than two hundred gallons per minute.

Erratic data was smoothed using a fifty point moving average and provided a more useful representation of the data from a steady-state viewpoint as shown in Figure 5 that is based on the same data as Figure 4. The smoothing allowed determination of which tests were most likely to be useful and of quasi-steady state periods with a given test. Without smoothing, the flow rate out data was sometimes too erratic to detect the unequal flowrates in and out that were indicative of a leak condition. The 50 point average was not used to aid in the detailed analysis of the data by only in test and data selection.



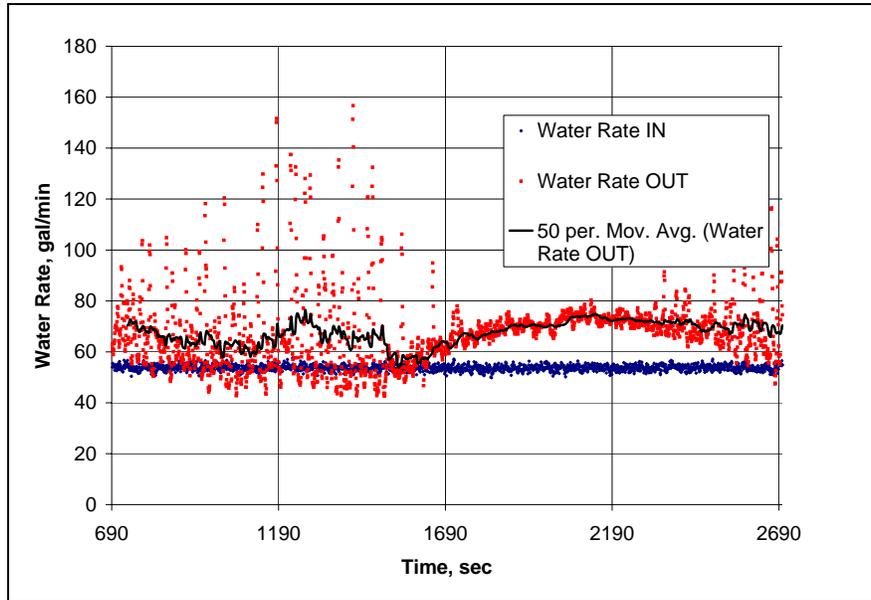
**Figure 4 - Fluctuation in Gas Rate Out, Test 3b**



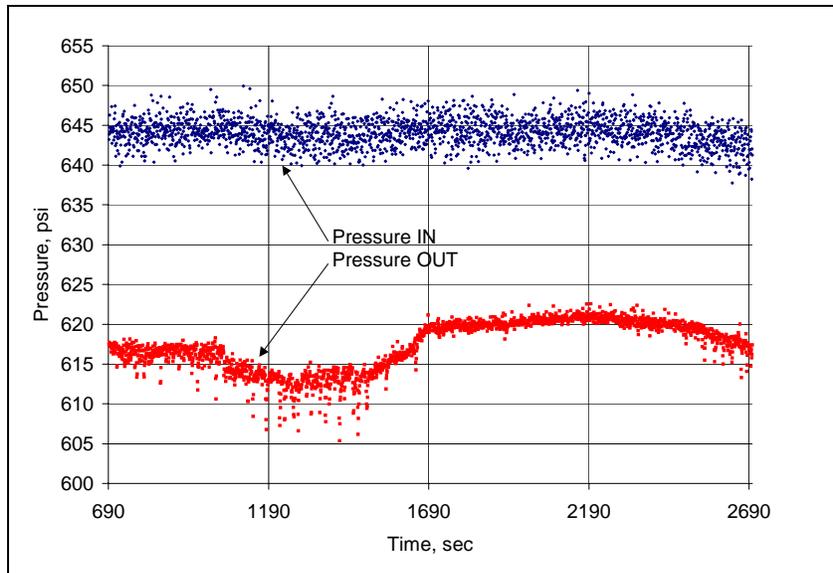
**Figure 5 – Rate Data Smoothed with 50 Point Running Average, Test 3b**

Smoothing of the water rate out and pressure data was also required. Both were also smoothed using 50 point running averages. The water rate data for Test 3b is shown in Figure 6, with both instantaneous and averaged rate out shown. The pressure in and out data for Test 3b before being smoothed is shown in Figure 7.

Even after smoothing with 50 point running averages, there are somewhat periodic fluctuations in flow as evident in the gas out data in Figure 5. Subsequent analysis and processing of the data showed that some of this fluctuation occurred with a 300 second period. Consequently, a smoother trend for much of the data collected in these tests by using a 300 second running average. However, this requires a relatively steady state condition to exist for over five minutes to be observable. The actual processing used to do the analysis herein will be identified in the section describing the analysis.



**Figure 6 – Fluctuation and Smoothing of Water Rate Data, Test 3b**



**Figure 7 – Unsmoothed Pressure In and Out Data, Test 3b**

### Phenomenon of Increasing Gas Rate In during Leaks

The typical test included a relatively stable flow period with no leak followed by a leak condition. The leak condition tends to decrease the pressure in the pipeline, and therefore, to increase the rate delivered to the line. When the rate of gas entering the flowline increased, virtually 100 per cent of the increase exited through the leak. This had the effect of keeping the gas rate exiting the flowline constant. This phenomenon should be expected for our test system where flowrate out was controlled by sonic flow through a fixed (during an individual test) size choke. As long as the line pressure upstream of the choke changed very little, the flow through the choke changes very little. Conversely, there was little pressure drop from the gas pipeline source through the flow loop. Consequently, a small decrease in flow loop pressure can draw a significant increase in flow from the near constant pressure gas supply pipeline. This behavior would also be expected for flowlines connected to high deliverability wells with the choke for rate control at the downstream end.

### Effect on Gas-Liquid Ratio (GLR)

The gas-to-liquid ratio at the exit of the flowline varied during a typical flow test. Table 1 shows that the GLR for two phases entering the flowline increases during a leak. Although the inlet gas flow rate increases, the inlet water rate remains constant because the liquid pump output remained fixed. This was a practical, operational constraint of the current system. Maintaining a constant liquid pump speed was relatively easy. Trying to manually adjust the pump speed in proportion to a rapidly fluctuating gas inlet rate would be essentially impossible. Therefore the constant liquid rate was used. It would be an improvement in the test protocol to increase the pump rate so as to maintain GLR constant simulating the condition expected in the field. However, doing so for these tests was impractical.

It was expected that the outlet GLR would remain relatively constant between leak and non-leak conditions. However, there was substantial variation in liquid rate out during tests such as 3b. This variation may be due to slugging, failure to reach steady-state, or the fact that most of the leaking fluids were gas. The large standard deviation in these measurements reinforces this uncertainty. The large variations during Test 3b are much larger than would be expected to result from normal variations in a sample this large from a statistical perspective. Therefore the variation in GLR out during that test are apparently real for whatever reason.

**Table 1 – Variation in Gas-Liquid Ratio**

	GLR <sub>IN</sub>	GLR <sub>OUT</sub>		GLR <sub>IN</sub>	GLR <sub>OUT</sub>
Test 3b	(avg)	(avg)		(stdev)	(stdev)
Before	258	260		13	67
During	326	286		36	120
After	269	205		58	39

### Complications Encountered

Several complications were encountered during this project that potentially influence the ultimate utility of the results.

1. Despite the calibration of the gas meters against each other, the measured flow rates out during Tests 1b and 2b were significantly greater than the measured flow rates in. There is no explanation for the actual rates being different. Consequently, there was apparently a consistent error in one or both meter readings. One possible explanation is that liquids sometimes collected in the tubing from the orifice meter to the differential pressure sensor. Unfortunately, we have no record of when this occurred in our test notes to determine whether this was in fact the problem. Therefore, the results of Tests 1b and 2b must be used primarily as qualitative rather than quantitative.
2. Hydrostatic pressure testing with water, see Appendix 4, indicated a new, small leak in the flowline just prior to conducting these tests. The measured leak rate at the experimental test pressure was less than 5 gallons per minute of water indicating an equivalent leak diameter of about .08 inches. Although this is significant relative to the test leak diameter of .125 inches, this leak rate was small compared to the 55 gallons per minute being pumped into the line in addition to the gas. Given that the project was nearing its contracted completion date and the time required to find and fix a small leak in this buried line, the no leak tests were conducted ignoring the presence of this leak.
3. The leak was eventually found on the bottom of the line in a buried section of the flow loop about one third of the length from the leak point at the middle of the loop back to the inlet to the loop. It has subsequently been repaired and the line tested to 4,000 psi for 72 hours. However, this project was terminated prior to completion of the repair.
4. Liquid carry-over from the mud-gas separator into the gas outlet meter and flare line has been an intermittent but recurring problem over the last year or more. While there were no instances of excessive water buildup in the flare system during these tests, maintenance conducted after these tests found problems with both mud gas separators. It is possible that liquid carry-over into the outlet gas meter caused erroneous gas outlet readings due to either the accumulation of liquid in the differential pressure sensor tubing or increased differential pressure across the orifice plate or both.
5. The operational cost of conducting these tests was substantial. Rising natural gas costs in particular limited the time that could be allowed for conditions in an individual test to stabilize. Consequently, some tests may not have reached fully steady-state, two-phase flow conditions, especially with regards to liquid holdup and therefore to liquid and gas velocities.
6. This project has had a complicated history, including resignations of the original PI and research associates, withdrawal of other project sponsors, delays in securing second year funding, LSU delays in conducting these experiments, and cancellation of the final year funding. These complications have constrained the extent of the experimentation and analysis completed even within the revised and reduced scope of the project, such that additional tests or analysis of these results beyond that in this report was not possible. Nevertheless, the experimental data and detail provided herein is unique and should be a basis for future analysis at the discretion of the project sponsor.

In spite of these complications, a useful set of six full-scale multi-phase flow tests were conducted on June 1, 2000. The data sets were analyzed using two flow models.

## ANALYSIS OF RESULTS

### Flow Models

Two models were explored for detecting the leaks in these experiments: a simple model and a model developed by Scott et al<sup>4</sup>. The latter motivated this research, as its original intent was to validate the Scott model. Analysis of a simple model simplified the analysis of this data and may find application in recommended field verification trials.

The models are expressed in these relationships:

- Simple model:  $q_{sc-OUT} / (P_{IN}^2 - P_{OUT}^2)^{0.5}$  vs.  $q_{sc-OUT}$
- Scott's model:  $P_{IN}^2 - P_{OUT}^2$  vs.  $q_{sc-OUT} / F_{2-\phi}$

where,

$q_{sc-OUT}$  = gas rate out (at exit of pipeline)

$P_{IN}$  = pressure at beginning of flowline located just upstream of the point where water is injected

$P_{OUT}$  = pressure at exit point of flowline just upstream of the choke

$F_{2-\phi}$  = a two phase friction factor developed by Scott et al, based on multiple parameters

### Simple model

The simple model is represented by a plot of experimental data. By plotting  $q_{sc-OUT} / (P_{IN}^2 - P_{OUT}^2)^{0.5}$  against  $q_{sc-OUT}$ , the experimental equivalent of a combined friction factor, line geometry, and fluid description is plotted versus rate. This characteristic trend for a pipeline with no leak allows detection of a leak when data falling off of the trend is observed. However, it makes no adjustment for changing liquid rates or gas-liquid ratios that would cause a shift in the trend. Therefore it is essentially a single phase model.

### Scott model

Scott's model requires a log-log plot of  $P_{IN}^2 - P_{OUT}^2$  vs.  $q_{sc-OUT} / F_{2-\phi}$ . This plot characterizes the line by plotting loss of pressure versus a gas rate normalized by a calculated two phase friction factor. It should ideally result in one characteristic trend for all possible flow conditions. Data falling off of this characteristic should be indicative of a change in the line itself, such as a leak. The terms ( $P_{IN}$ ,  $P_{OUT}$ , and  $q_{sc-OUT}$ ) are experimental data while the term ( $F_{2-\phi}$ ) is computed using several steps. The steps involving the equations with field units and an example follows.

### **Example of Scott Model Calculation**

Initially all flow tests were to be conducted in the annular flow regime as the corresponding mathematical models were inserted into an Excel® spreadsheet. This analysis was applied to all six flow tests. However, the HT-400 pump for injecting water was not able to pump the low flow rate of water required to achieve annular flow, consequently, flow tests were in the slug flow regime. This required a different set of corresponding mathematical models, as described below. While the source of mathematical models for both flow patterns was Wallis<sup>7</sup>, slug flow models were less straightforward. Consequently, modifications were made as described below. The equations behind the Excel® spreadsheet including the method adapted herein for computing friction factor ( $f_{SG}$ ) to be used in Scott's model are described below.

Step 1. Collect Raw Data

Cum Time	P <sub>IN</sub>	(Q <sub>G</sub> ) <sub>OUT</sub>	(Q <sub>W</sub> ) <sub>OUT</sub>	(Q <sub>W</sub> ) <sub>SC IN</sub>	P <sub>OUT</sub>
(sec)	(psig)	(scf/hr)	(gal/min)	(gal/min)	(psig)
756	642	17,249	81	54	616

Step 2. Correct Raw Data and convert units

(psig)	(gal/min)	(scf/hr)	(ft <sup>3</sup> /hr)
P <sub>OUT-Corr</sub>	(Q <sub>W</sub> ) <sub>SC OUT-Corr</sub>	(Q <sub>G-OUT</sub> ) <sub>SC</sub>	(Q <sub>W</sub> ) <sub>SC OUT-Corr</sub>
618	77	17347	621

Step 3. For the following constants for all data

d, diameter of flow line, ft	0.3033
M, molecular weight	16.99
T <sub>OUT</sub> , temperature, degrees R	550
Z, gas deviation factor	0.95
C <sub>f</sub> , assumed for 2-φ	0.005
C <sub>1</sub> , assumed for slug flow	1.2
V <sub>B</sub> , assumed for slug flow, ft <sup>3</sup>	.2
A <sub>p</sub> , cross sectional area of flow	0.07227
μ <sub>g</sub> , gas viscosity, cp	.014
T <sub>s</sub> , degrees R	520
P <sub>s</sub> , psia	15.025

Step 4. Compute gas density

$$\rho_g = \frac{.093MP[psia]}{T_{OUT}[^{\circ}F]Z} = lb / ft^3$$

where  $P = P_{out-corr}$

Step 5. Compute no-slip void fraction,  $\alpha$ , using (Q<sub>G</sub>)<sub>P,T</sub> (ft<sup>3</sup>/hr) and (Q<sub>W</sub>)<sub>SC OUT-Corr</sub> (ft<sup>3</sup>/hr)

$$\alpha = \frac{Q_{G\ OUT\ @\ insitu\ P,\ T-CORR}}{Q_{G\ OUT\ @\ insitu\ P,\ T-CORR} + Q_{W\ SC-CORR}}$$

Step 6. Compute (dp/dz)<sub>SG</sub> directly from Q<sub>g</sub> corrected.

Step 7. Compute (dp/dz)<sub>2-φ</sub>, F<sub>2-φ</sub>, and q<sub>SC</sub> / F<sub>2-φ</sub> as shown below.

The following example calculations are for the actual data at 755.5 seconds from Run 03b.

$$\rho_G = \frac{.093 MP_{OUT-CORR} [psi]}{T_{OUT} [^{\circ}R] Z}$$

$$\rho_G = \frac{0.093(16.99)618 [psi]}{550 [R] 0.95} = 1.87 [lb / ft^3]$$

$$(Q_G)_{P,T-OUT} [ft^3 / hr] = (Q_G)_{SCOUT-CORR} \times \frac{P_s Z T_{P,T}}{T_s P_{aveP,T}}$$

$$(Q_G)_{P,T-OUT} = (17347) \times \frac{15.025 \times .95 \times 550}{520 \times \left( \frac{642 + 618}{2} \right)} = 416 [ft^3 / hr]$$

$$\alpha = \frac{(Q_G)_{P,T-OUT} [ft^3 / hr]}{(Q_G)_{P,T-OUT} [ft^3 / hr] + (Q_w)_{SCOUT-CORR}}$$

$$\alpha = \frac{416 [ft^3 / hr]}{416 [ft^3 / hr] + 621 [ft^3 / hr]} = 0.401$$

$$v_{SG} = \frac{(Q_G)_{P,T-OUT} [ft^3 / hr]}{3600 \frac{sec}{hr} A_p [ft^2]} = [ft / sec]$$

$$v_{SG} = \frac{416 [ft^3 / hr]}{3600 [sec/hr] \times 0.07227 [ft^2]} = 1.598 [ft / sec]$$

$$v_{SL} = \frac{(Q_w)_{SCOUT-CORR} [gal / min] 5.615 [ft^3 / bbl]}{60 [sec/min] 42 [gal / bbl] A_p [ft^2]} = [ft / sec]$$

$$v_{SL} = \frac{77 [gal / min] \times 5.615 [ft^3 / bbl]}{60 [sec/min] \times 42 [gal / bbl] \times 0.07227 [ft^2]} = 2.39 [ft / sec]$$

$$\text{Re} = \frac{20100 \times (Q_G)_{\text{SCOUT-CORR}} (\text{ft}^3 / \text{hr}) \times 24 (\text{hr}) \times M}{1000000 (\text{ft}^3 / \text{mmcf}) \times \mu_g (\text{cp}) \times d (\text{ft}) \times 12 (\text{in} / \text{ft}) \times 28.97}$$

$$\begin{aligned} \text{Re} &= \frac{20100 \times 17347 (\text{ft}^3 / \text{hr}) \times 24 (\text{hr}) \times 16.99}{1000000 (\text{ft}^3 / \text{mmcf}) \times .014 (\text{cp}) \times .3033 (\text{ft}) \times 12 (\text{in} / \text{ft}) \times 28.97} \\ &= 96,315 \end{aligned}$$

$$f_{SG} = .0242 \times \text{Re}^{-.1303} \quad \text{custom Fanning friction factor estimate}$$

$$f_{SG} = .0242 \times 96303^{-.1303} = .00543$$

$$\left(\frac{dp}{dz}\right)_{SG} = \frac{2 f_{SG} \rho_G [\text{lb} / \text{ft}^3] v_{SG}^2 [\text{ft}^2 / \text{sec}^2]}{32.2 (\text{ft} / \text{sec}^2) d (\text{ft})} = [\text{lb} / \text{ft}^2 \text{ per ft of pipe length}]$$

$$\left(\frac{dp}{dz}\right)_{SG} = \frac{2 \times .00543 \times 1.87 [\text{lb} / \text{ft}^3] \times 1.598^2 [\text{ft}^2 / \text{sec}^2]}{32.2 (\text{ft} / \text{sec}^2) \times .3033 (\text{ft})} = 0.00531 [\text{lb} / \text{ft}^2] / \text{ft}$$

$$\left(\frac{dp}{dz}\right)_{2-\phi} = \frac{2 C_f \rho_L [\text{lb} / \text{ft}^3] (v_{SG} + v_{SL}) [\text{ft} / \text{sec}]}{32.2 [\text{ft} / \text{sec}^2] d (\text{ft})} \left[ v_{SL} + \frac{4 d (\text{ft}) A_p (\text{ft}^2) v_{SG} (\text{ft} / \text{sec})}{V_B (\text{ft}^3) C_1} \right]$$

for slug flow

$$\left(\frac{dp}{dz}\right)_{2-\phi} = \frac{2 \times .005 \times 1.87 [\text{lb} / \text{ft}^3] (1.598 + 2.39) [\text{ft} / \text{sec}]}{32.2 [\text{ft} / \text{sec}^2] \times .3033 (\text{ft})} \left[ 2.39 + \frac{4 \times .3033 (\text{ft}) \cdot 0.07227 (\text{ft}^2) \cdot 1.598 (\text{ft} / \text{sec})}{.2 (\text{ft}^3) \times 1.2} \right]$$

$$= 0.7577 [\text{lb} / \text{ft}^2 \text{ per ft}]$$

$$F_{2-\phi} = \sqrt{\frac{\left(\frac{dp}{dz}\right)_{SG}}{\left(\frac{dp}{dz}\right)_{2-\phi}}} = \sqrt{\frac{0.00531}{0.7577}} = .0837$$

$$q_{sc} / F_{2-\phi} = 17,347 / .0837 = 207,250 (\text{ft}^3 / \text{hr})$$

NOTE: Example calculations do not match spreadsheet exactly due to round off error.

where

$\rho_G$  = gas density,  $lb / ft^3$

$M$  = molecular weight of gas phase

$P_{OUT-CORR}$  = corrected pressure at exit point of flowline,  $psia$

$T_{OUT}$  = gas temperature exiting flowline, *degrees Rankine*

$Z$  = gas deviation factor

$(Q_G)_{P,T,OUT}$  = corrected gas flow rate exiting flowline at P, T insitu,  $ft^3 / hr$

$(Q_w)_{SCOUT-CORR}$  = corrected water flowrate exiting flowline at std. conditions,  $ft^3 / hr$

$A_p$  = cross sectional area of pipe,  $ft^2$

$\alpha$  = no slip void fraction

$v_{SG}$  = superficial gas velocity,  $ft / sec$

$v_{SL}$  = superficial liquid velocity,  $ft / sec$

$\left(\frac{dp}{dz}\right)_{SG}$  = calculated single phase pressure gradient,  $psi / ft$

$\left(\frac{dp}{dz}\right)_{2-\phi}$  = calculated two – phase pressure gradient,  $psi / ft$

$F_{2-\phi}$  = two – phase flow efficiency, *unitless*

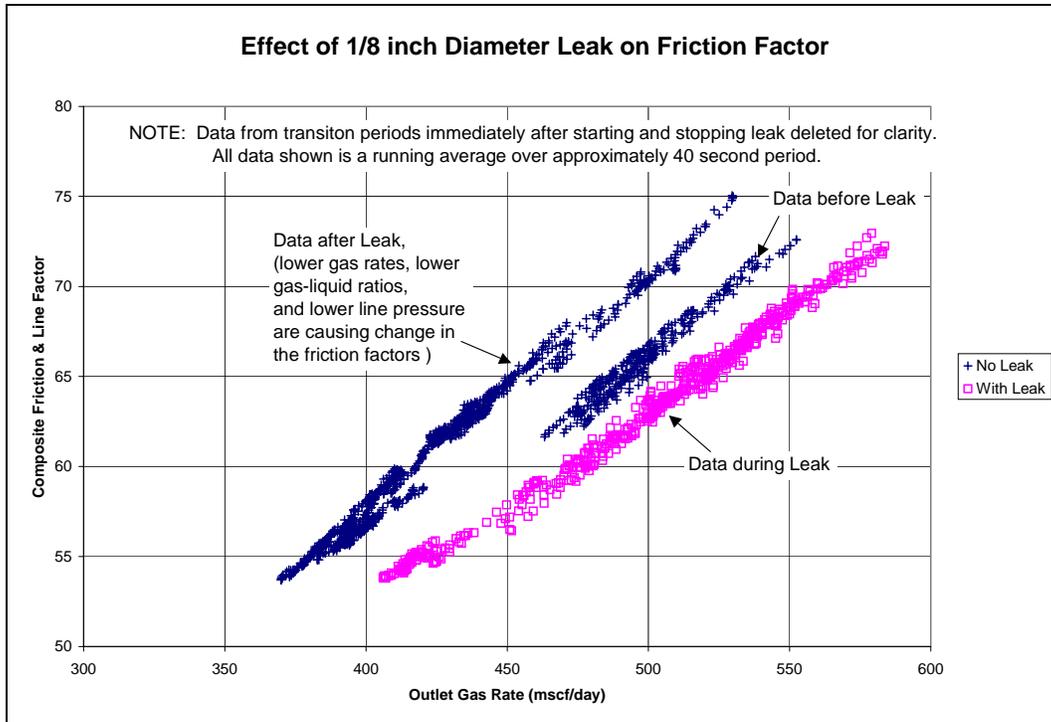
$q_{SC} / F_{2-\phi}$  = gas flow rate out adjusted for two – phase flow efficiency, *std*  $ft^3 / hr$

$q_{SC} = (Q_G)_{SCOUT-CORR}$ , *std*  $ft^3 / hr$

Step 8. Plot  $P_{IN}^2 - P_{OUT}^2 = 642^2 - 618^2 = 30,240 \text{ psi}^2$  on y-axis and  $q_{SC} / F_{2-\phi} = 207,250$  on x-axis of log-log plot. The outcome of this plot is a base line of data for a no-leak condition. As the leak condition develops, the data should become juxtaposed from this base line indicating a leak condition.

### Simple Flow Model Analysis

The simple flow model was envisioned as a rapid way to evaluate the experimental data from a leak detection perspective. One approach that was used initially was to use minimal averaging of the data and to exclude data that was from obvious transition periods. The results from Test 3b were plotted using this approach, and the results were encouraging, see Figure 8. However, the before and after leak data resulted in separate trends, whereas it was expected that these two trends would overlay one another. One possible explanation is that a decrease in the supply pipeline pressure during the after leak period resulted in a lower inlet line pressure. This in turn caused lower inlet gas rate, lower gas–liquid ratio, and probably a change in the two-phase friction factor.

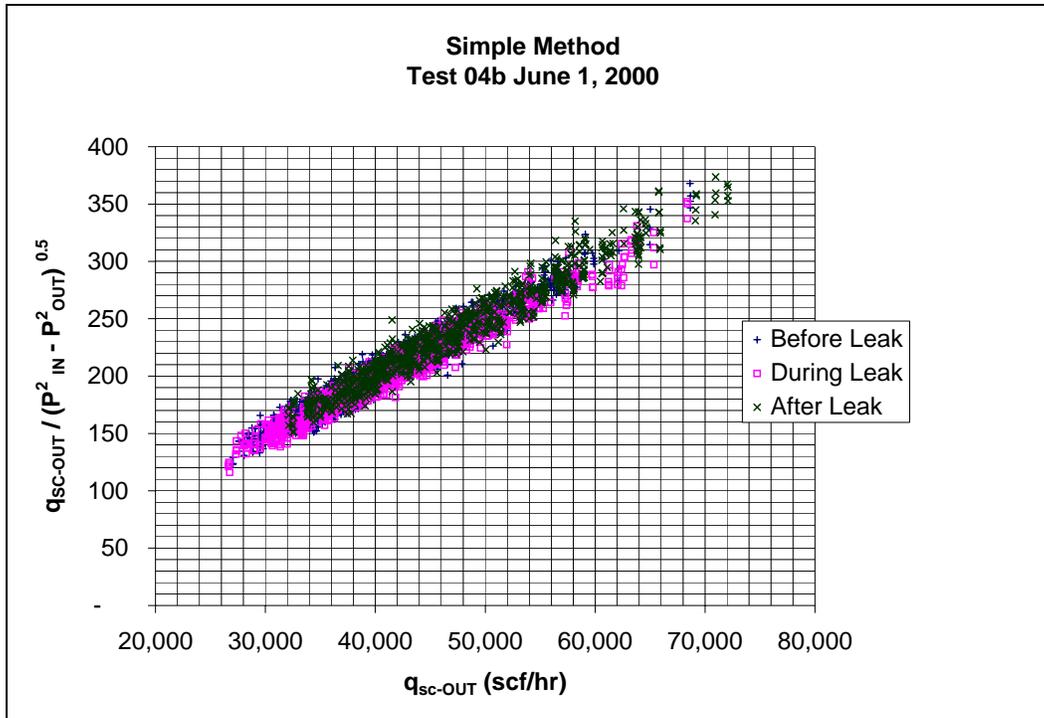


**Figure 8 – Test 3b, Simple Model with 40 Second Running Average**

Results from Tests 4b, 5b, and 6b at higher gas rates were less encouraging. The higher gas rates resulted in larger variations in both gas and liquid outlet flow rates. Leak conditions were almost indistinguishable from the no leak condition on the simple model plots for these tests using either 40-second running averages or instantaneous data without processing, see Figure 9 for an example. The large rate variations were due to the slugging of gas and water exiting the mud-gas separator, probably as a result of increasingly severe slugging in the flow line. Another source of variations causing data scattering was the difficulty in stabilizing the incoming gas rate. Initiating a leak condition caused the incoming gas flow rate to increase, and then returning to a no leak condition caused it to decrease. The time duration for a test to reach completely stable flow conditions was excessive so that this was not feasible, and truly steady-state conditions throughout the entire flow line were probably never reached. Therefore, other averaging schemes and the Scott two-phase model were evaluated as alternatives.

#### Sorting then averaging data

A scheme for sorting data within a given flow condition was devised and used when applying the simple model to all of the test data. While this scheme has no basis in the physical nature of the system, it did provide a way to plot data for ease of visual analysis. Other possible schemes are described in the recommendations at the end of the report.

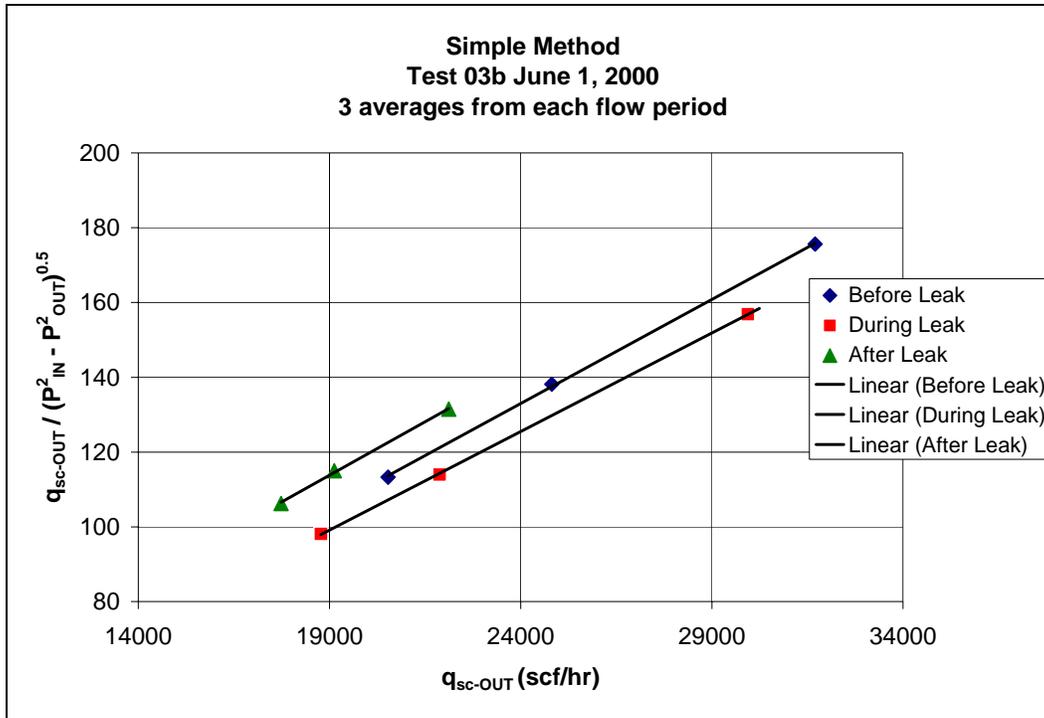


**Figure 9 - Test 04b, Simple Model Without Averaging**

The problem of data scattering, especially the large rapid variations in flow out, was remedied by first separating the data in each test according to whether it was a before-, during-, or after-leak flow condition. Then for each flow condition, the data was sorted by increasing values of gas flow out. The sorted data within each flow condition was then divided into three ranges of gas rate (low, moderate and high) with equal populations. The gas flow rate out ( $q_{sc-OUT}$  also designated as  $q_{sc}$  on the Figures) and  $q_{sc-OUT} / (P_{IN}^2 - P_{OUT}^2)^{0.5}$  values were then averaged over each range. In summary, the data was

- (1) divided into three flow conditions (where available),
- (2) sorted by  $q_{sc-OUT}$  (also designated as  $q_{sc}$  on the figures) for each flow condition,
- (3) the sorted data for each flow condition was then divided into three groups with an equal number of data points,
- (4) average values of  $q_{sc-OUT}$  and  $q_{sc-OUT} / (P_{IN}^2 - P_{OUT}^2)^{0.5}$  were determined for each of resulting nine groups, and
- (5) the averages were plotted as exemplified in Figure 10.

The averages for each of the nine groups of data for Test 3b are shown in Figure 10. This demonstrates this processing scheme increased the clarity of the plots for the simple model.



**Figure 10 – Test 03b: Simple Model with Averages from Sorted Data**

Presentation and discussion of the simple flow model data

The displacement of the data in the *During* leak condition is below the *Before* leak condition. This relationship is consistent in all tests and is logical given that the  $q_{sc-OUT} / (P_{IN}^2 - P_{OUT}^2)^{0.5}$  term at any gas rate out should decrease during a leak condition. This is because the increased gas flow rate in the flow line upstream of the leak increases the pressure drop in that section of the line. Therefore, the measured pressure drop for the entire line increases over what it would be for a given flow rate out when there is no leak. As expected, the displacement of the *During* leak data is also below the *After* leak data.

It was initially expected that the *After* leak condition data would plot overlaying the *Before* leak condition. While this did occur in Test 04b, it was not the case in other tests. This is possibly explained by the inability of the physical system to stabilize after the changes in flow. With additional time, a steady state condition would likely be realized. However, more time waiting for stable flow would have meant higher expense due to cost of gas.

Some tests were not suitable for analysis owing to unstable flow or inaccurate gas metering, i.e., gas rate entering the flowline did not match gas rate exiting the flowline during conditions without a leak. Had flow been allowed to continue and the measured differential pressures been accurate, these rates should have eventually matched. Inaccuracy and difficulty in measuring gas flow rates during the test phase meant Tests 01b, 02b, and 06b were not as useful for analysis as the other three tests. The highest rate test, Test 06b, showed the greatest fluctuations. Three tests showed matching gas rates entering and exiting the flowline (3b, 4b, and 5b). Appendix 1A – Simple Plots are the results of all flow tests plotted using the simple model and the averages from the sorted data.

Simple model Test 01b displayed the expected displacement from the *Before* to the *During* leak condition, thus indicating a leak condition. However, this test was not a conclusive representation of the leak phenomenon as gas rate entering and exiting the flowline prior to the leak condition, unfortunately, did not match.

Test 02b had all three flow conditions. It was expected that the *After* leak condition would plot so as to overlay the *Before* leak condition; this did not occur. This discrepancy between *Before* and *After* leak condition may be explained by the time required to regain steady-state two-phase flow conditions in the flow line.

Test 03b, like 02b, shows the obvious displacement of trends, and the *After* leak condition is clearly distinguishable from the *During* leak condition. In this case, even the simple plot gives a strong indication of the *During* leak condition.

Tests 04b and 05b are similar. Test 04b has all three flow conditions while Test 5b has no *After* leak condition. Both are high rate flow tests (30,000 to 55,000 scf/hr). The overlay of the *Before* and *After* leak conditions are finally realized in Test 04b. This is most likely due to the relatively constant GLR observed in the *Before* and *After* conditions for this test. Another visible difference in the plot of Test 04b is that the displacement of the data during the leak is slight. Detection of a constant diameter leak at higher gas rates was expected to be more difficult because the percentage of the gas flowing through the leak decreases.

Also conducted at a higher rate, Test 05b demonstrates a slight shift in the position of data during the leaks. No *After* leak condition data was recorded in this test.

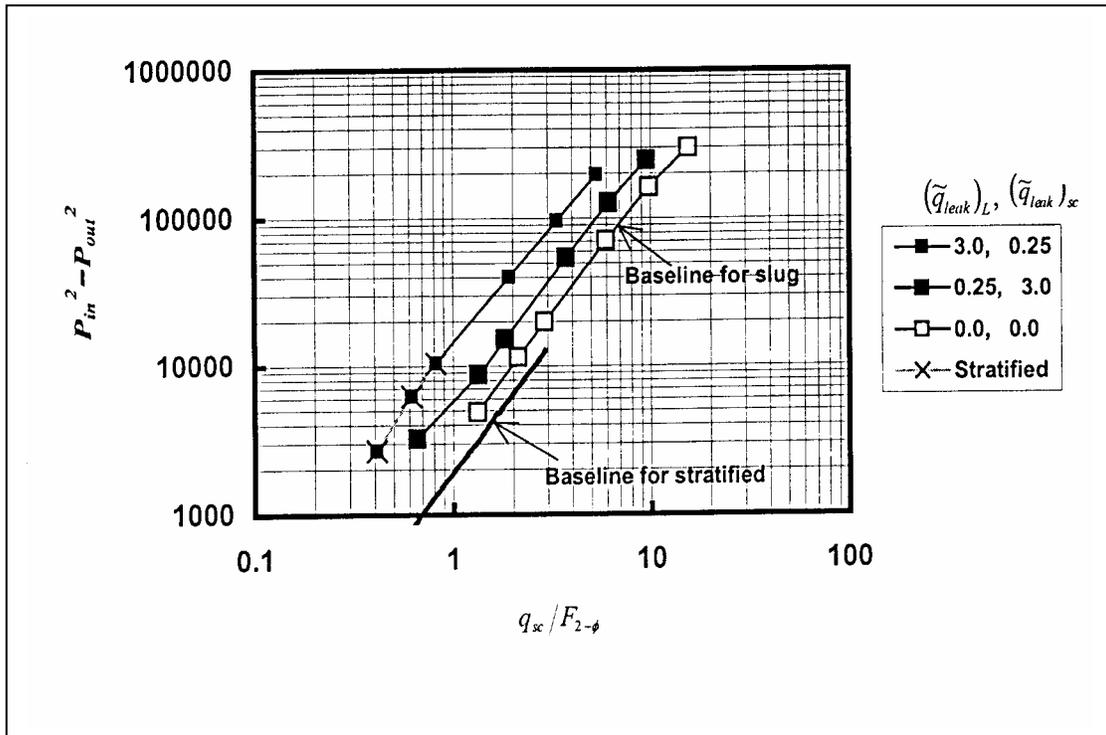
The sixth and final test of the series, Test 06b, was not useful due to extreme fluctuations in the gas rate out. Distinguishing the *During* leak condition from the *After* leak condition was difficult even when comparing measured flowrates in and out. The leak condition was evident after averaging the data, which allowed calculation of the leak rate as about 10 percent of the rate out. Plotting the sorted and averaged data for the simple model, the *During* and *After* leak conditions almost overlaid each other. Consequently, this technique is not likely to be useful for detection of a leak equal to or less than 10 percent of the line throughput.

### **Scott Two-phase Flow Model Analysis**

Data from Tests 03b, 04b, and 05b were plotted for  $P_{IN}^2 - P_{OUT}^2$  vs.  $q_{sc-OUT} / F_{2-\phi}$  on log-log scale as per Scott et al<sup>4</sup>. The intended advantage of this approach for multi-phase flow line is to account for changes in both liquid and gas phases, and ultimately the resulting change in flow patterns, as well as just the change in gas flow rate. Therefore conceptually, this approach should provide a more definitive, consistent no-leak trend for a multi-phase line than is possible with a single-phase model.

This plot characterizes the line by plotting loss of pressure versus a gas rate normalized by a calculated two phase friction factor. It should ideally result in one characteristic trend for all possible flow conditions. Data falling off of this characteristic should be indicative of a change

in the flow line itself, such as a leak. An example of the leak and no-leak trends are shown in Figure 11 from Scott et al<sup>4</sup>.

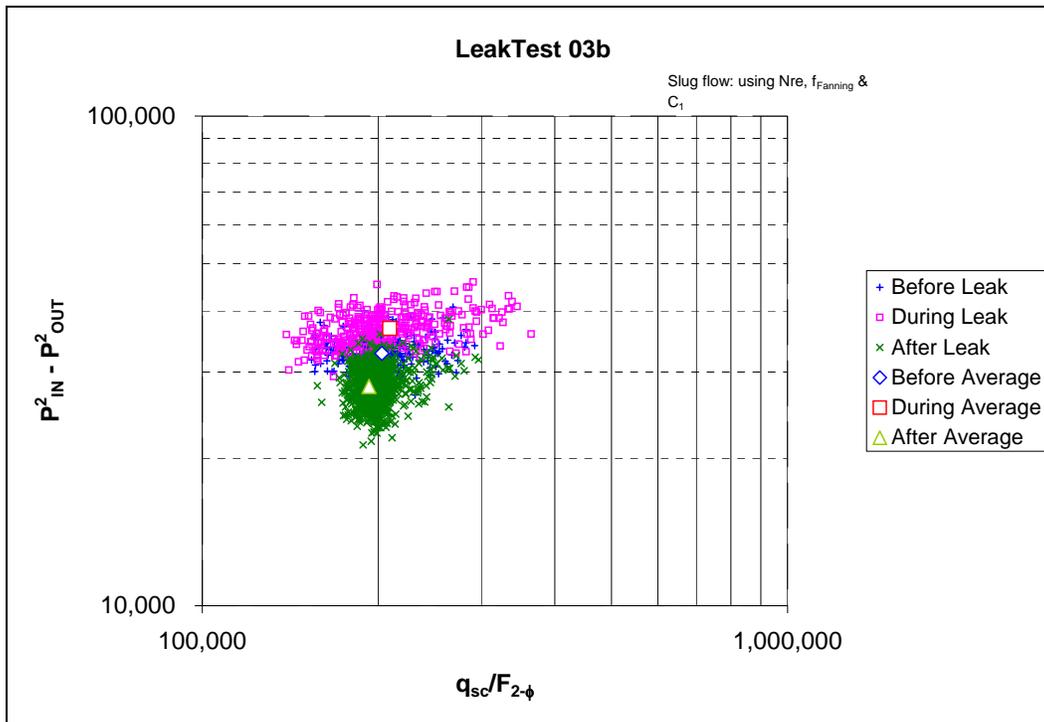


**Figure 11 – Characteristic Trends Predicted by Scott et al<sup>4</sup> Model**

The calculation of the two-phase flow efficiency factor,  $F_{2-\phi}$ , is extremely tedious as described earlier in the section “Example of Scott Model Calculation.” A comprehensive application of Scott’s model would include conditional computations using different sub-models depending on the flow pattern. This analysis is based solely on the sub-model proposed by Wallis<sup>7</sup> for the slug flow regime. The superficial liquid and gas velocities for Tests 3b, 4b, and 5b are indicative of an elongated bubble or slug flow pattern. In addition, severe slugging was evident, even downstream of the large mud-gas separator that should have smoothed the measured discharge rates, during Tests 4b and 5b.

#### Instantaneous data

The parameters of the Scott plot were calculated using instantaneous data, collected about once per second, and plotted on a log-log scale. An example of this type plot for Test 3b is shown in Figure 12. Similar to previous plots, data from the first 200 seconds after a transition between leak and no-leak conditions was excluded. This method seems to group the data somewhat more tightly than shown with the simple plot in Figure 8, but some of this effect is apparently just due to plotting on log-log paper. There also appears to be less separation between the clouds of leak and no-leak data than with the simple plot. Plots for Tests 4b and 5b, see Appendix 1B, displayed even less distinction between leak and no-leak conditions as expected at the higher flow rates through the line.



**Figure 12 – Test 03b: Scott Model with Instantaneous Data**

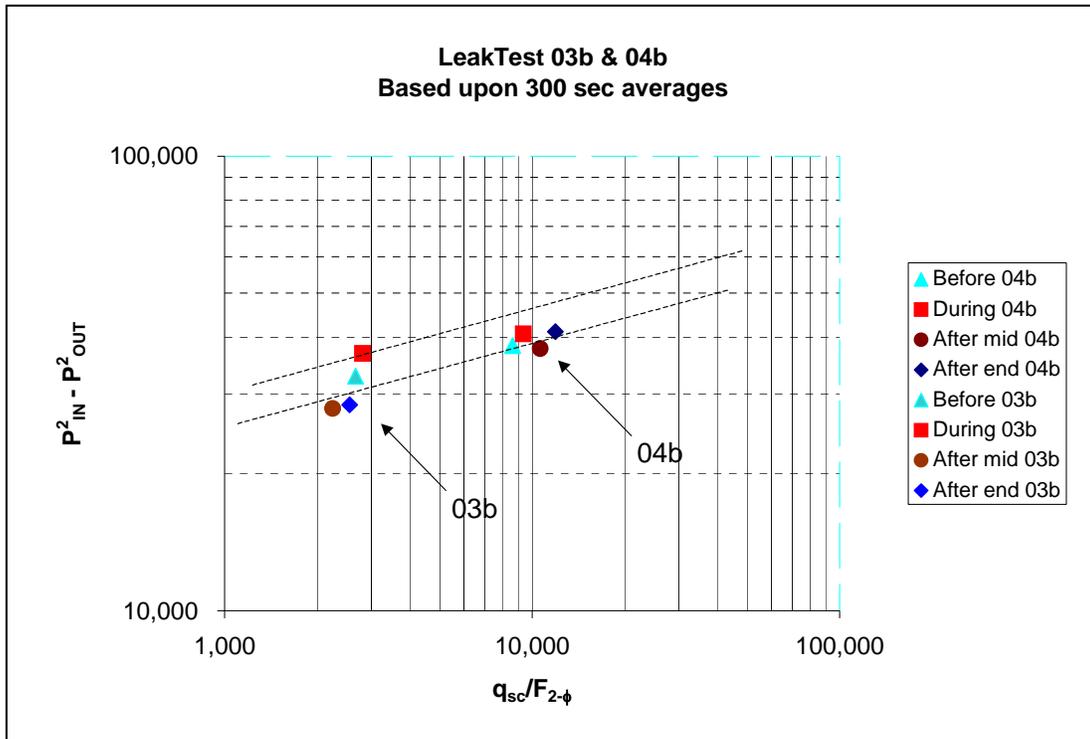
At this point, improved leak detection using the Scott model had not been realized, and the variation in flow through the line did not show up as a characteristic trend on the plot. Given that the use of a two-phase approach to distinguishing the leak from the no-leak condition should give a more positive indication than the simple, single-phase approach, additional methods of applying the Scott model were considered.

#### Averaging steady-state data

A second approach was applied to data from Tests 03b and 04b. A steady-state condition for each of the three flow periods was visually identified using a plot of the gas inlet rate versus time. A relatively stable flow rate for 300 seconds (points) was identified and the data collected during that 300 second duration was averaged. The data was analyzed according to Scott's model, and the results plotted. In Test 3b, the expected displacement of the leak condition from the no-leak condition was observed using this technique, as shown by the large, open symbols on Figure 12. However the expected alignment of the *Before* and *After* leak data points along a characteristic trend was not observed. In fact, a trend through the two average no-leak points extrapolates close to the average leak point.

A similar analysis was performed on Test 4b, and the results combined with those from Test 3b, as shown in Figure 13. Given the availability of more than 600 seconds of relatively stable conditions during the *After* leak period, more than one 300 second average was calculated. The average conditions for four time periods from each test were plotted, and together, the two tests define a trend somewhat like that predicted by Scott et al. Specifically, the no-leak trend is for

increasing pressure drop with increasing rate, and the leak condition lies above and to the left of the no-leak trend. Also, at a higher throughput the relative fraction of flow to the leak is smaller and the leak condition lies closer to the no-leak trend. Although the calculated leak rates for Test 3b and 4b both imply a leak equivalent to roughly 16 percent of the flow out, the leak in Test 4b is essentially undetectable. In reality, the leak rate in Test 3b was almost certainly underestimated, and the leak was greater than 16 percent. In any event for Test 4b, the no-leak conditions neither create a definitive no-leak trend nor does the apparent trend have the predicted slope. Consequently at this level of analysis, the concept proposed by Scott et al appears feasible, but its practical application is not yet developed or proven.



**Figure 13 – Test 03b & 4b: Scott Model with 300 second Averages**

Statistical trends

Dinis et al<sup>5</sup> proposed using statistical methods to define flow line characteristics for detection of single-phase liquid leaks. While development of such a method for multi-phase systems is outside the scope of this work, a simple check of this concept was made using the “trend-line” function of Excel®. An example of logarithmic trend fits for *Before*, *During*, and *After* leak data from Test 3b is shown in Figure 14. The separation between the three trends is more distinctive than the separation between the clouds of instantaneous data. Therefore, use of statistical analysis of such scattered and erratic data could potentially provide a more conclusive means of distinguishing variation within a very scattered trend from an actual shift in the trend.

This same kind of analysis was applied to Test 4b and 5b as well. The results are shown on the plots included as Appendix 1b. The data from Tests 3b, 4b, and 5b were also combined to

determine whether an overall trend might be observable. The composite data set and overall trends are shown in Figure 15.

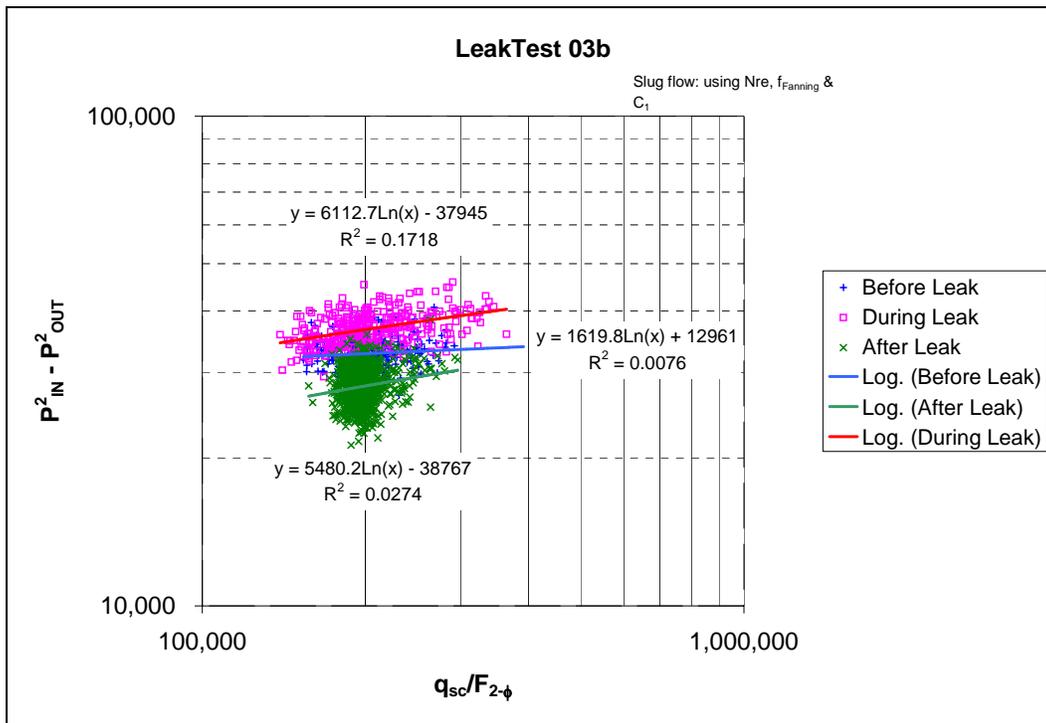


Figure 14 – Test 3b: Trend Lines for Before, During and After Leak Conditions

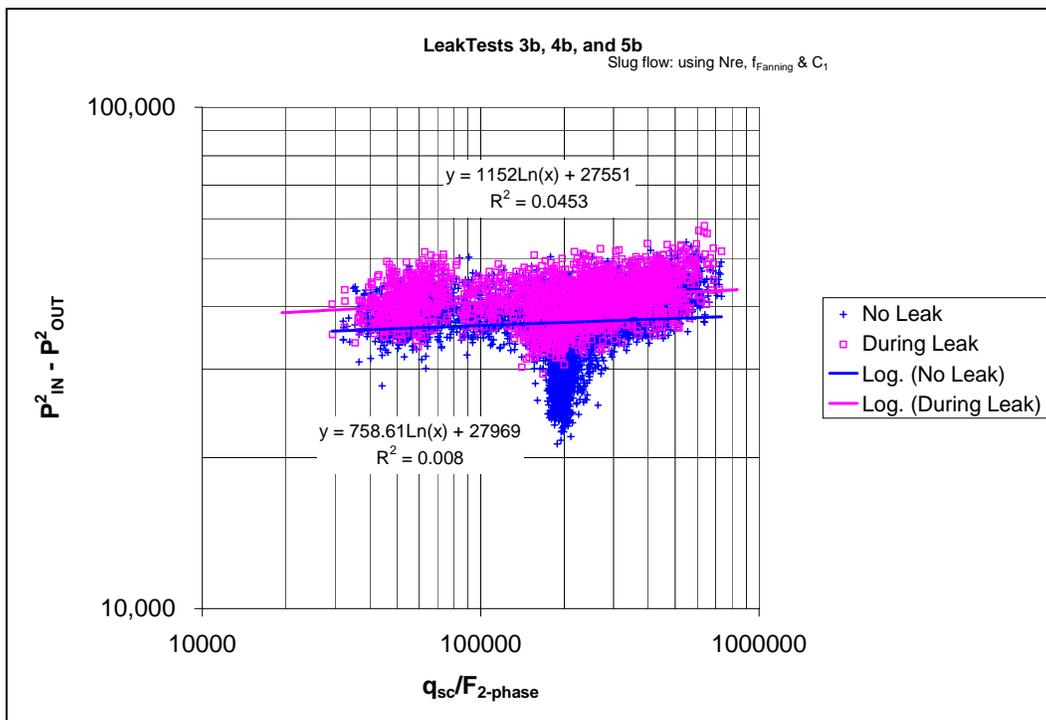


Figure 15 – Composite Tests 3b, 4b, and 5b: Trend Lines for Leak and No-leak Conditions

There are several notable features of these trends. First, the slope or coefficient of each trend is much less than that proposed by Scott et al. One reason resulting from use of the instantaneous data is that the measured flow out varied widely and rapidly due to the slugging in the flowline. This meant that the flow out used to calculate  $q_{sc-OUT}$  and  $F_{2-\phi}$  varied much more than the average flow rate over the length of the flowline. Therefore, the variations in the  $q_{sc-OUT}/F_{2-\phi}$  term on the x-axis of the plot are much larger than in the  $P_{IN}^2 - P_{OUT}^2$  term which is measured over the full length of the flowline. This would tend to force the slope of the measured trend on the log-log plot to flatten out. It is possible that using an average rate over a period of time or running average rates would be much more relevant for performing calculations and generating a plot or an analysis. If so, the slope proposed by Scott et al might be observable.

A second observation about the composite plot is that although much of the leak data appears to overlay the no-leak data, there is a significant separation and difference in slope in the trend lines. A line in service in the field would rapidly develop a much larger base of data than used in these experiments, and would be more likely to operate at near steady-state conditions much of the time. Therefore, the quality of the statistics for a flowline in the field may be much better than in these experiments. If so, the level of confidence in this approach to leak detection might be significantly improved.

## **COMPARISON TO CONVENTIONAL LEAK DETECTION METHODS**

The most traditional methods of leak detection are visual observation, usually by regular overflights of lines in service, and hydrostatic pressure testing of a line that is out of service. The experimental results provide a basis for comparing these with other leak detection methods.

Visual observation of leaking gas or oil is the most common leak detection method for an in-service line. However, leaks from lines in deep water will be difficult to detect visually unless the leak is very large and therefore creates a noticeable slick or plume. Although these tests were not intended to evaluate visual leak detection methods, they nevertheless lend some insights for comparison. The gas leaks in these experiments were ignited and burned. The flame created by the leak through a .125 inch orifice was observable from several hundred feet away. An occasional slug of water was also observed. However, a similar leak in even moderate water depths would probably be dispersed sufficiently to be essentially undetectable unless associated oil reached the surface and created a sheen or a slick. Our difficulty in visually detecting the smaller corrosion leak that was present on the bottom of the flow loop during all of these tests is also relevant. This leak was only found by walking the line during dry weather and finding an area of wet soil created by a leak continuing over many hours. Although this area was several feet in diameter, it was not easily detected from a distance.

The most sensitive leak detection method is hydrostatic testing of a line filled with liquid. However, this requires that the line be taken out of service. Hydrostatic tests of the flow loop with the corrosion leak present demonstrated a quantifiable leak rate of about 4.5 gallons per minute at 600 psig line pressure. This leak was undetectable by any other means except walking the line after knowing that a leak was present somewhere. Likewise, the first round of hydrostatic testing after repairing this leak indicated a very slow bleed off with time, equivalent to a few gallons per day. Very careful visual inspection of surface fittings identified several connections that were “weeping” slowly, roughly a drop per minute. This size leak would be

completely undetectable by any means other than hydrostatic test or inch-by-inch visual inspection of exposed pipe.

The other common leak detection method in the field besides visual observation, is by “pressure safety low” sensors. These sensors are intended to detect the decrease in line pressure resulting from a leak and to actuate a safety shut-down at the source of flow to the line. Our tests are indicative of the actual drop in line pressure for a multi-phase line due to a .125 inch diameter leak to atmospheric pressure. The rate through the leak was approximately 5,000 scf/hour or about 5 to 25 percent of the actual throughput of the line.

There was very little drop in operating line pressure in response to a leak for the conditions in our system. A summary of the pressure change in the upstream and downstream pressures is given in Table 2. These results demonstrate the difficulty of detecting a moderate size leak by monitoring only changes in line pressure. The magnitude of change from the *Before* leak conditions to the *During* leak condition ranged from 0 to 5 psi at the upstream end of the line and from 1 to 7 psi at the downstream end. This magnitude change would be undetectable under most circumstances in the field. Pressure sensors are not intended to have the sensitivity to detect changes this small. Normal fluctuations in operating pressures due to changing upstream and downstream conditions are frequently larger than this as well. Consequently, the pressure monitoring method of leak detection is unlikely to be useful for detecting anything except very large leaks unless there is a major flow restriction upstream of the leak.

Our system has a high deliverability connection to a gas pipeline as the source, conceptually similar to an unchoked, high deliverability well. Thus, it should be similar to a flowline from a typical, subsea well. A system with a choke at the wellhead, or other major restriction to flow upstream of the leak, would observe a greater decrease in operating pressure for a *During* leak condition. Consequently, this traditional approach would be more practical under those circumstances, which might apply to many flowlines or transportation lines that connect surface facilities. In any event, sensing operating pressure change is the least sensitive of the quantitative leak detection methods described herein.

**Table 2 – Change in Line Pressure due to Leak**

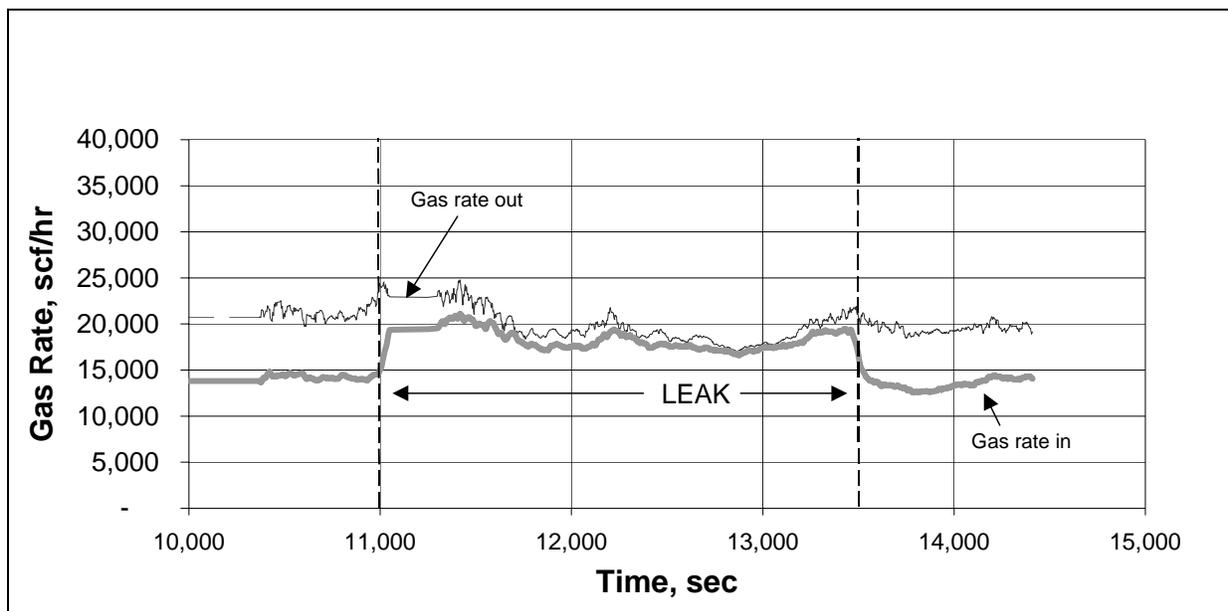
Test Number	Pressure decrease at Inlet (psi)	Pressure decrease at Outlet (psi)
1b	-0.2	1.4
2b	4.9	7.0
3b	0.6	4.0
4b	4.1	6.0
5b	2.5	5.5
6b	2.6	3.5

Another method of detection is comparison of the flowrates into and out of the line. Under steady state conditions, these should be the same. Even with normal fluctuations, the average rates over relatively short periods of time, depending on line volume, should be equal. Consequently, a rate out that is measurably less than the rate in is a strong indicator of a leak. The results of these tests support the validity of this approach. A summary of the leak rates implied by the difference in rate in and rate out for each leak test is shown in Table 3.

Tests 1b and 2b indicate very low leak rates. These rates are unrealistically low as a result of the metering problem described in a previous section. Nevertheless, observation of the trends in rate in and rate out as shown in Figure 16 are enough to conclude the presence of a leak at time of about 11,000 seconds. These trends were detectable, even when at least one meter was clearly out of calibration, because an increase in the rate in without a corresponding increase in rate out clearly indicates flow is being lost, as to a leak.

**Table 3 – Calculated Leak Rates during Tests**

	average Gas <sub>OUT</sub> -corr	Average Leak Rate	P <sub>IN</sub> average	Leak/Gas <sub>OUT</sub> ratio
TEST	[scf/hr]	[scf/hr]	[psi]	
01b	19,393	-80	648	NA
02b	18,167	-1092	646	NA
03b	22,792	3,591	644	0.16
04b	41,964	6,598	622	0.16
05b	45,241	5,525	619	0.12
06b	66,599	4,328	612	0.06



**Figure 16 – Gas Rate In and Out Showing Effect of Leak during Test 01b**

The methods using inlet and outlet pressures combined with outlet rate, such as proposed by Scott<sup>4</sup> and described in the previous sections of this report, are obviously more sensitive than simple monitoring of line pressure. These methods, which detect when frictional pressure loss in the line is more than expected for the rate out of the line, are also less sensitive than the previous method of comparing rates in and out of the line. However, flow in a multi-phase line from a subsea well cannot currently be metered accurately. Therefore, although these methods are less

sensitive than the previous method, they are more appropriate for flowlines from subsea wells because they only require a pressure sensor rather than a meter at the upstream end of the line.

More sophisticated methods could potentially be developed for application when both metering and pressure measurements are possible at both ends of the line. Conceptually, both steady-state and transient analytical methods could be applied to identify and compare leak severity implied by difference from inlet and outlet meters with that implied from pressure drop versus rate. To the best of our knowledge, such methods have not yet been developed.

In summary, the most conventional, real-time, leak detection method is by visual observation or inspection. The sensitivity and effectiveness of this method is directly dependent on the frequency of inspection and the proximity of the inspector to the leak point. Deepwater leaks will almost certainly be difficult to detect with this method. The most sensitive, "off-line," leak detection method is hydrostatic testing. Comparison of rates from inlet and outlet meters was the most sensitive, indirect detection method assessed in these tests. The method proposed by Scott<sup>4</sup> was less sensitive but more applicable for lines from subsea wells. The standard method of monitoring a line for decrease in operating pressure due to a leak was the least sensitive quantitative leak detection method evaluated for the conditions in these tests.

## CONCLUSIONS

The experiments conducted for this study and the analysis of those experiments provide a basis for conclusions about these tests, testing of two-phase leak detection in general, and most importantly, the potential for practical leak detection using the combination of inlet and outlet pressures with the outlet flow rate. Comparative conclusions about leak detection methods in general are also reached.

## Experimental Results

1. Many complications were encountered in conducting these tests, most notably with metering, failure to reach steady-state conditions, and the small corrosion leak in the flow loop. Nevertheless, some of the data recorded was useful for drawing conclusions about leak detection methods.
2. The scattering in the outlet gas rate data due to slugging downstream of the separator generally requires some kind of averaging or trend line analysis to make even a cursory analysis.
3. As expected, leak detection becomes more difficult as the percentage of flow lost to the leak becomes smaller.
4. Measurement of the leak rate in addition to inlet and outlet rates would be complicated, but would have provided a better estimate of leak rate and potentially allowed corrections for inaccurate readings from one of the other meters.
5. Direct measurement of pressure differential along the line would have given a more accurate measurement of pressure loss than taking the difference in inlet and outlet pressures.

## Multi-phase Leak Detection Methods

6. The conceptual basis for the multi-phase leak detection method proposed by Scott has been validated by this study. In all cases except for a leak rate less than 6 percent of the flow out,

a shift in the characteristic trend of rate versus pressure drop was observed when a leak occurred at the middle of the flow line.

7. In addition, a much simpler, single-phase approach to leak detection can also be shown to detect a trend shift due to a leak.
8. However, neither the single- nor the multi-phase approach sufficed to establish a single characteristic trend for the line even after normalizing for changes in line pressure and gas liquid ratio.
9. Consequently, the practical application of the multi-phase method proposed by Scott has not been validated. Also, no significant, practical advantage was demonstrated for the multi-phase approach proposed by Scott versus a single phase approach.
10. Additional work will be required to establish a multi-phase leak detection method that is practical for field application to all possible flow patterns.

### General Leak Detection Methods

11. Hydrostatic testing with a liquid is the most sensitive method of leak detection.
12. Of the methods considered for detecting a leak in a flow line that is in service, the comparison of flow rates in and out of the line is the most sensitive. The methods for analyzing the outlet flow rate and the upstream and downstream pressures to detect a leak, as proposed by Scott et al<sup>4,6</sup> and Dinis et al<sup>5</sup>, is less sensitive and much more complicated. The currently required method of using “pressure safety low” sensors to detect a decrease in line pressure is the least sensitive method evaluated and would not have detected any of the leak conditions in these experiments.

### RECOMMENDATIONS

The factual results of this study support the use of more quantitative methods for early detection of leaks in seafloor pipelines.

1. Consideration should be given to implementing at least a pilot program for using rate in versus rate out data to monitor for leaks in offshore pipelines where inlet metering is technically practical.
2. The practical feasibility of multi-phase leak detection should be investigated further. Additional analysis of the data from this study and of new data for different flow patterns should be performed. Alternative methods to process and analyze the data should be considered including:
  - a) Average outlet rate data over a time period representing the residence time of fluids in the line for comparison with the pressure drop at the mid-point or end-point of that time period.
  - b) Use slug frequency to determine a variable basis for gas bubble volume,  $V_B$ , when calculating two-phase flow efficiency,  $F_{2-\phi}$ , for slug flow.
  - c) Calculate an explicit multi-phase friction factor,  $C_f$ , for slug flow rather than assuming an approximate average value.
  - d) Consider other explicit, “mechanistic” models for calculating two-phase flow efficiency,  $F_{2-\phi}$ , for other flow patterns.
  - e) Use statistical methods, such as that proposed by Dinis<sup>5</sup> for single-phase flow, to establish a line characteristic in the presence of highly variable flow rate data.
  - f) Evaluate a more sophisticated, two-variable, adaptation of a statistical method similar to that proposed by Dinis<sup>5</sup>, with gas-liquid ratio, GLR, as the second variable.

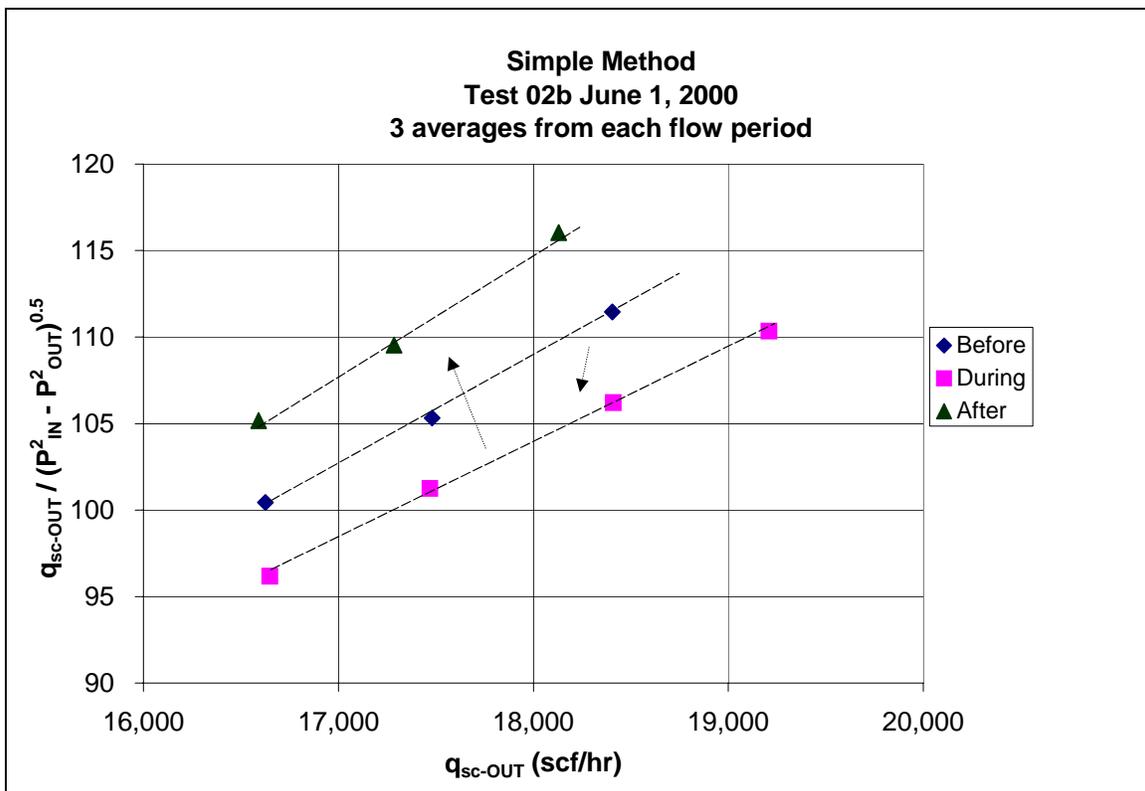
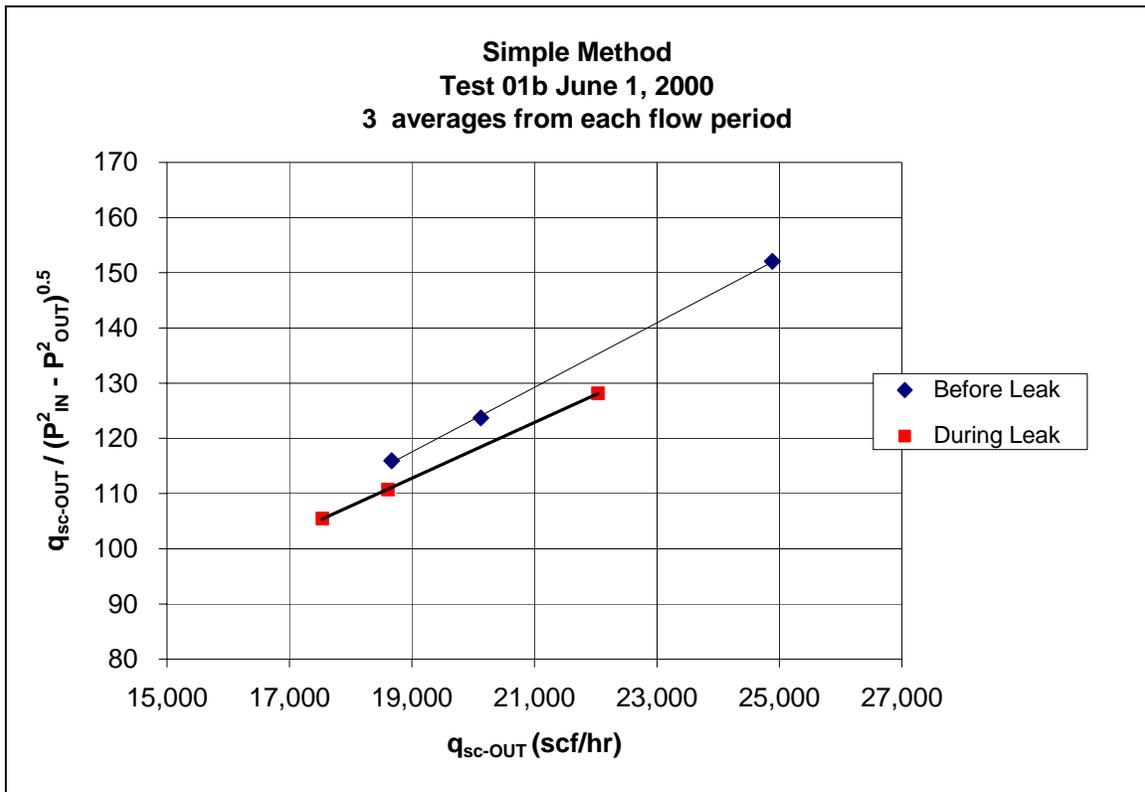
## ACKNOWLEDGEMENTS

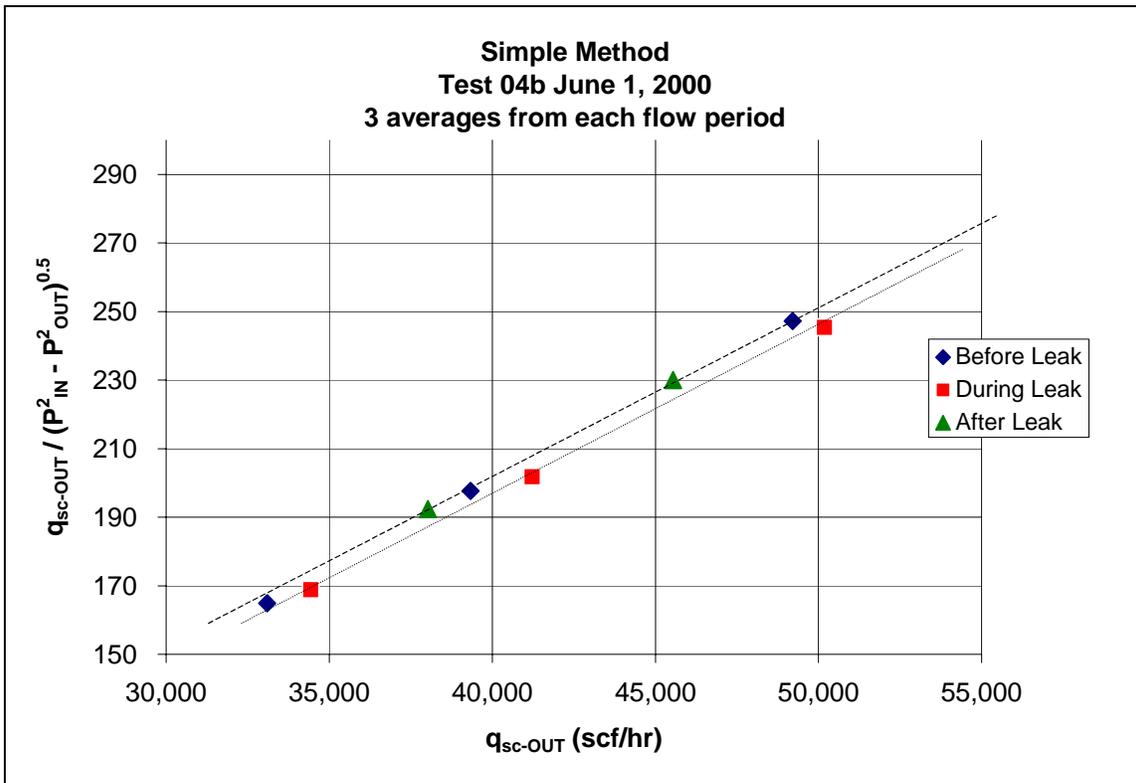
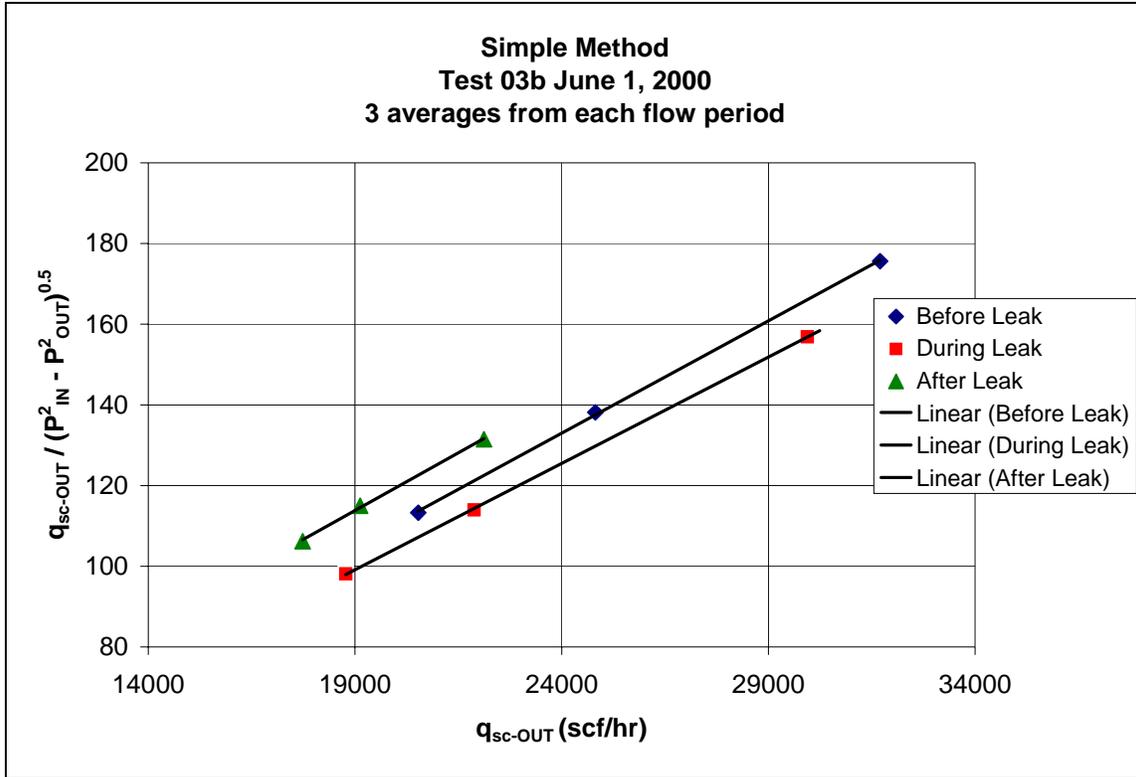
The authors wish to acknowledge the support from Minerals Management Service and Louisiana State University for conducting this project. The cooperation and involvement of Ernie Loftice and other staff at the LSU Petroleum Engineering Research and Technology Transfer Laboratory and of Darryl Bourgoyne, Bourgoyne Enterprises Inc., were indispensable in setting up and conducting these experiments.

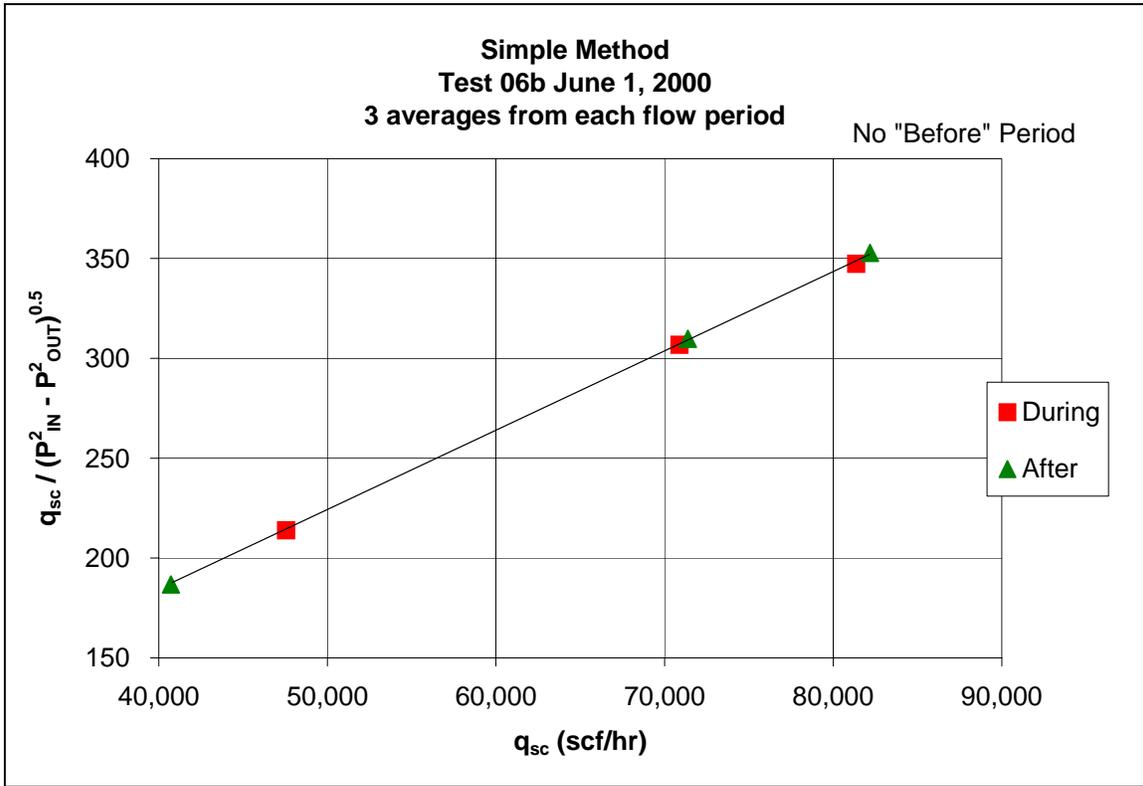
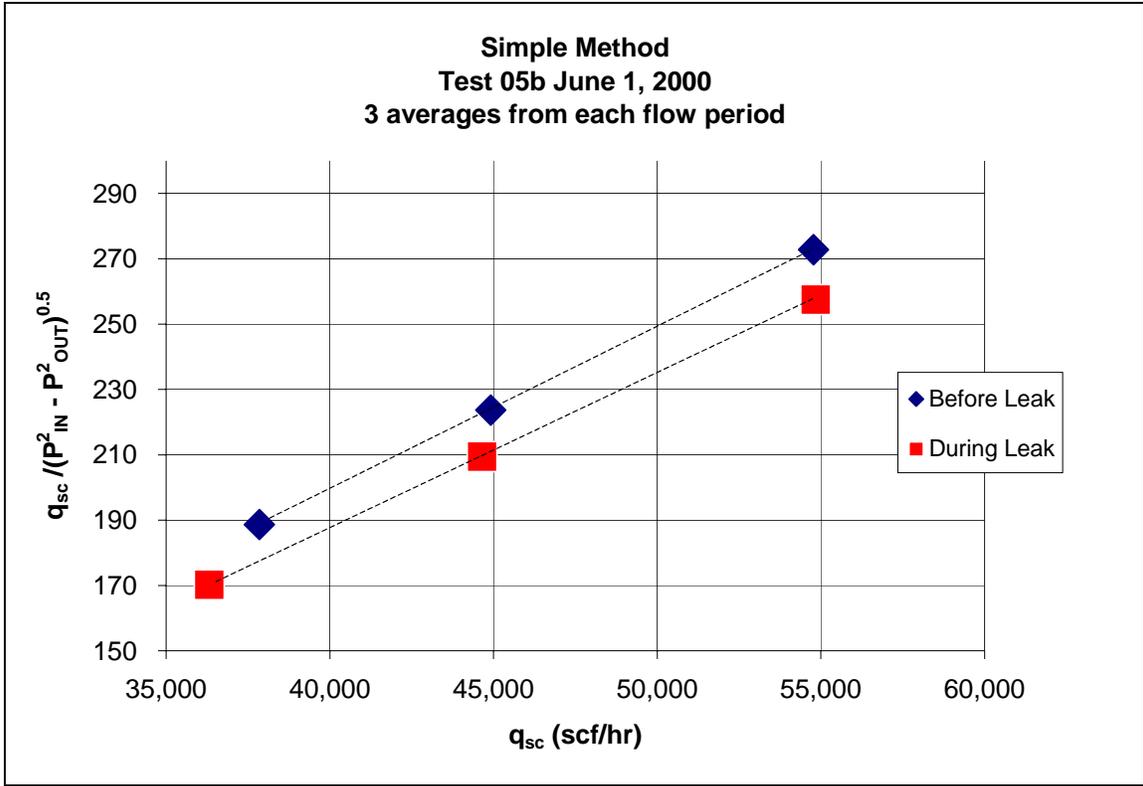
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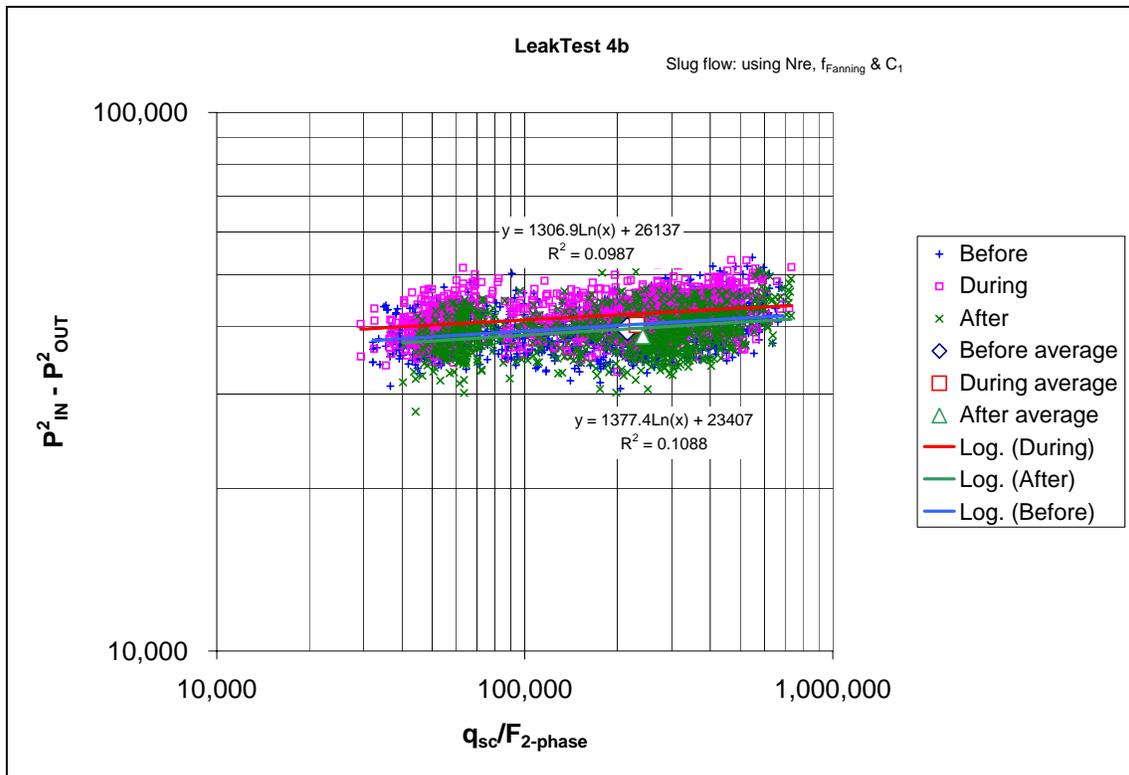
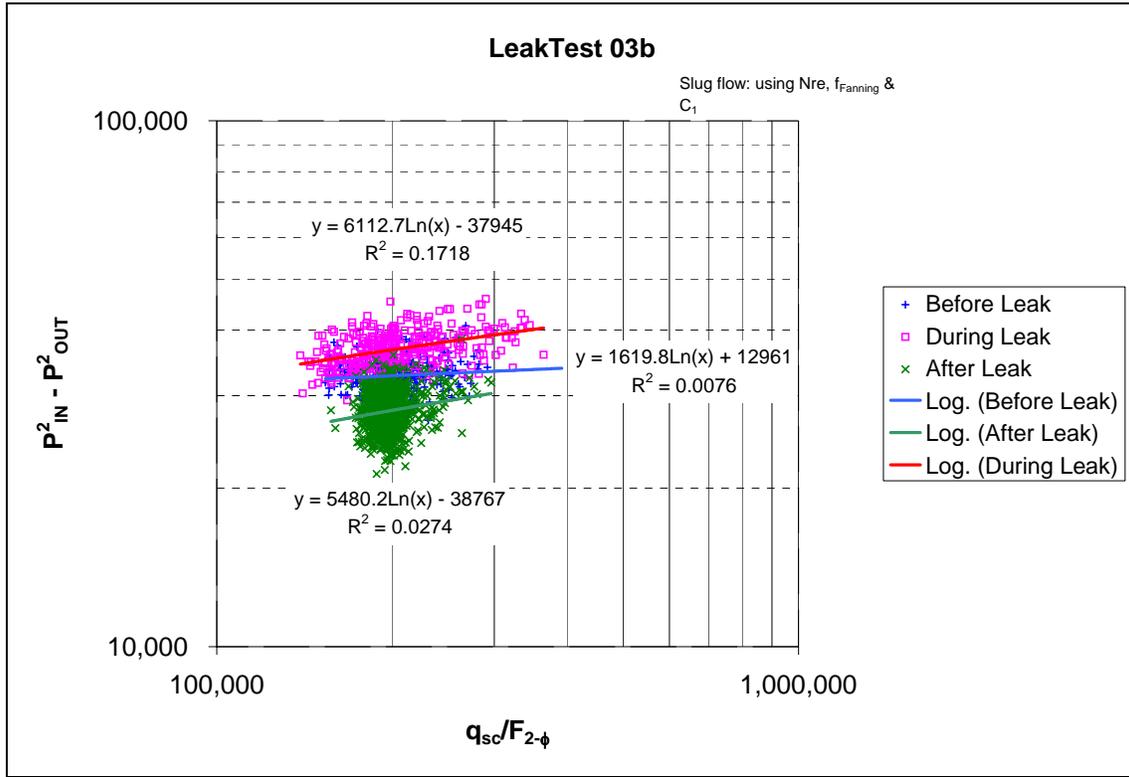
## APPENDIX 1A – SIMPLE PLOTS

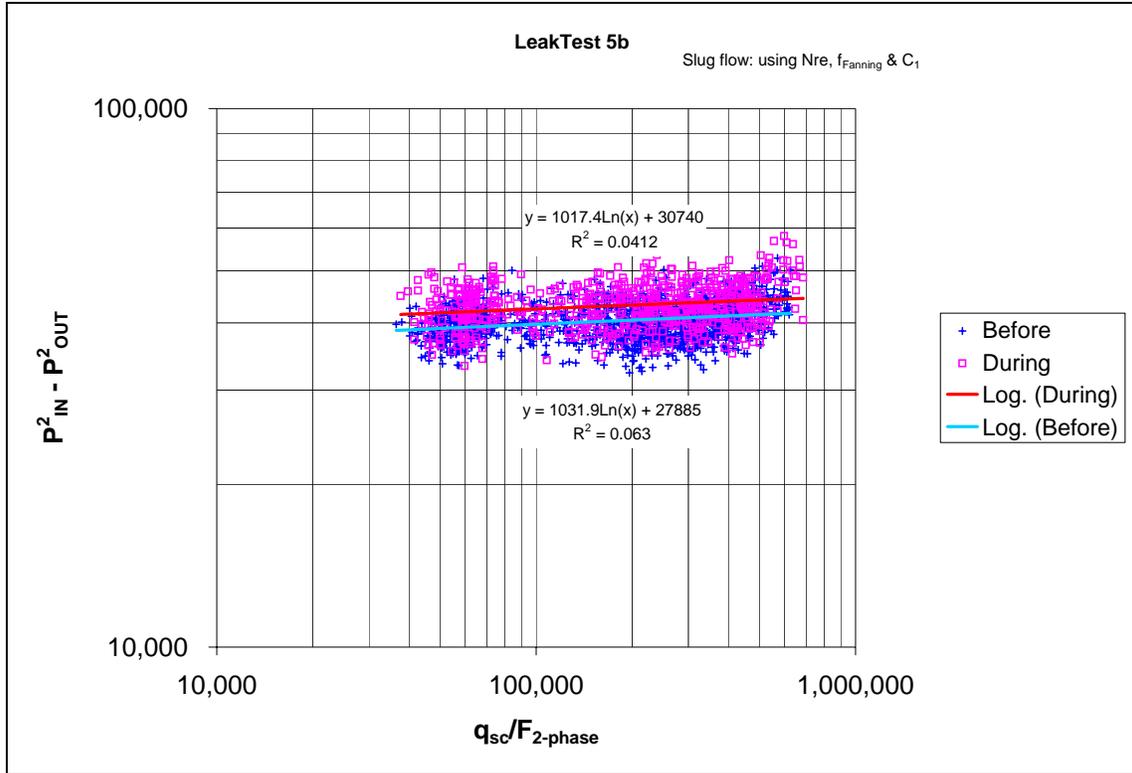






## APPENDIX 1B – SCOTT PLOTS





**APPENDIX 2 - BOR LEQSF PROPOSAL PROJECT SUMMARY**  
**INVESTIGATION OF HYBRID DEEPWATER PRODUCTION SYSTEMS**  
**LEQSF FORM 2**  
(Paper Copy Only)

**APPENDIX 3 – BOR FINAL PROGRESS REPORT**  
**INVESTIGATION OF HYBRID DEEPWATER PRODUCTION SYSTEMS**  
**LEQSF CONTRACT #(1997-2000) RD-A-05**  
**January 3, 2000**  
(Paper Copy Only Begins on Page 41)

**APPENDIX 4 – DATA FILES AND SPREADSHEETS**  
(Electronic file copies only)