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REPEATABILITY AND EFFECTIVENESS OF SUBSURFACE-CONTROLLED SUBSURFACE SAFETY VALVES

FINAL REPORT
SwRI Project No. 18.04772

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EXECUTIVE SUMMARY

Subsurface Safety Valves (SSSVs) are required in all offshore oil and gas producing wells located in Outer Continental Shelf (OCS) water that fall under the jurisdiction of the Mineral Management Service (MMS). The purpose of these valves is to shut off well flow in the production tubing below the mudline in the event of emergencies, such as fire or production tubing separation. One type of SSSV that is used in offshore wells is actuated by a differential pressure created by the well fluid flowing through the valve. These valves, called Subsurface-Controlled Subsurface Safety Valves (SSCSVs), or velocity valves, are sized or configured to close when the loss of tubing backpressure from a disaster causes the well to flow in excess of its normal production rates. Velocity valves are sized using programs developed by the valve manufacturers that predict the closing flow rate for a given valve configuration and well conditions. MMS personnel have raised concerns about the accuracy of these sizing programs to predict the size of the appropriate valves for current well conditions.

The goal of this project was to gather data through testing to develop technically defensible recommendations for the suitability of velocity valves for usage in OCS waters by evaluating the ability of each manufacturer's sizing program to accurately predict the closing points of the valves in single-phase and multiphase flow conditions. This was accomplished by testing a representative sample of velocity valves in controlled laboratory conditions with natural gas and water and then comparing the results with predictions obtained by exercising the manufacturer's sizing programs. The data was then analyzed and organized in a way so that MMS would have a basis to make recommendations concerning the use of velocity valves in OCS waters.

Six valves from three manufacturers were tested in a multiphase flow loop with natural gas and water to produce several closing points with different gas-liquid ratios for each valve configuration. In all, the test matrix included 18 different valve configurations and 163 closing points. The measured valve closing points were compared to the manufacturer's sizing prediction to evaluate the prediction error for each program.

Overall, the test data shows that, on average, the manufacturers' sizing programs overpredict the actual closing points by 29% with a standard deviation of 43%. These values are somewhat misleading because this overall average is dominated heavily by an 80% average error and 18% standard deviation that were produced by one of the manufacturers' programs. The average error for a second manufacturer's program was –3.0% with a standard deviation of 7.8%. The third manufacturer's data is not included here because the manufacturer's valves malfunctioned during the testing and only limited data could be collected. The error data for the more accurate manufacturer's model indicate that it is possible to predict, fairly accurately, the closing points for velocity valves when the downhole conditions are known. The poor performance of the other manufacturer's model, however, shows that the velocity valve sizing accuracy is heavily dependent on which manufacturer's valve and program are used.

As demonstrated by the test results and additional factors described in the report, simply relying on the manufacturer's sizing program provides little certainty that a velocity valve will close when required without actually testing the valve after it is installed. The sizing program can be used effectively for preliminary sizing, but field-testing may be the only way to verify, with any real certainty, that the valve is sized properly and will function when required.

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1. INTRODUCTION

Subsurface Safety Valves (SSSVs) are required in all offshore oil and gas producing wells located in Outer Continental Shelf (OCS) water that fall under the jurisdiction of the Mineral Management Service (MMS). The purpose of these valves is to shut off well flow in the production tubing below the mudline in the event of emergencies, such as fire or production tubing separation. One type of SSSV that is used in offshore wells is actuated by a differential pressure created by the well fluid flowing through the valve. These valves, called Subsurface-Controlled Subsurface Safety Valves (SSCSVs), or velocity valves, are sized or configured to close when the loss of tubing backpressure from a disaster causes the well to flow in excess of its normal production rates.

Velocity valves are sized using programs, developed by the valve manufacturers, that predict the closing flow rate for a given valve configuration and well conditions. MMS personnel have raised concerns about the accuracy of these sizing programs to predict the size of the appropriate valves for current well conditions, or the performance of existing valves in wells with changing conditions, especially when the well fluids include increasing amounts of liquid. Southwest Research Institute® (SwRI®) conducted a project (MMS Contract No. 1435-01-97-CT-30880, SwRI Project 18-1298) for the MMS in 1999 that addressed this issue.

This previous study evaluated two velocity valves from two manufacturers and compared the measured closure rates to the manufacturers' model predictions. This limited study showed that the MMS's concerns about velocity valves might be valid. This current study is intended to be an extension of the previous project to better evaluate the manufacturers' sizing models with the objective of gathering enough information for the MMS to make an engineering judgment regarding the appropriate use of velocity valves in MMS jurisdictions.

1.1 VELOCITY VALVE SIZING MODELS

Velocity valves operate on a simple force balance principle. The valves utilize a choke (sometimes called a bean) to create a differential pressure when fluid is flowing through the valve. The differential pressure acts on a choke/flow tube assembly to produce a force that acts on a valve power spring. When the force generated by the differential pressure exceeds the preset closing force of the power spring, the valve actuates to the closed position, shutting off the well flow.

Properly sizing a velocity valve for an oil well is a difficult procedure requiring information about the well's maximum flowing potential, knowledge of the valve's differential closing pressure, and an estimation of the differential pressure created by the desired closing flow rate for a particular valve configuration. In addition, changing well conditions further complicate the sizing procedure. The consequences of incorrect valve sizing are either premature closures or loss of protection during an operational upset or emergency.

In general, sizing models can be broken down into three major correlations. One correlation is needed to estimate the downhole flowing conditions from measurements taken at the surface. The second correlation is needed to predict the differential pressure across the valve choke required to overcome the spring and friction forces that keep the valve in the open position. The third correlation is needed to calculate the differential pressure across the valve as a function of the liquid and gas flow rates and fluid properties. The valve should close when the calculated differential pressure developed by the flow exceeds the calculated differential pressure required to close the valve. Each of these correlations involves calculations that can contribute to errors in the sizing models.

The first major correlation is required because the downhole flowing conditions at the velocity valve cannot, in most cases, be measured. These values must be estimated using correlations based on the valve setting depth, the tubing ID, the wellhead temperature and pressure, the gas and liquid production flow rates, and the fluid compositions. These calculations are further complicated by the fact that the production flow rates are normally measured in terms such as stock tank barrel (STB) for oil, and standard cubic feet (scf) for gas, which are evaluated at some standard set of conditions rather than the actual well conditions. In oil and natural gas systems, a certain amount of the gas dissolves into the oil at elevated temperatures and pressures. As the produced oil is brought to stock tank or standard conditions, gas evolves out of the oil, and the oil's volume decreases. This phenomenon, commonly called shrinkage, must be accounted for using additional calculations such as the solution gas-oil ratio or oil-formation volume factor correlations.

The second major correlation required for the sizing models calculates the differential pressure required to close the valve. The general operation of a velocity valve can be described by the following proportional relationships:

$$F_{flow} \propto DP \bullet (D^2 - d^2) + C_1 \qquad \text{(Equation 1)}$$

$$F_{spring} \propto K \bullet l \bullet \Delta L + C_2 \qquad \text{(Equation 2)}$$

where F_{flow} = force produced on the valve by the flowing fluid

F_{spring} = force produced by the valve spring to resist closure

DP = differential pressure created across choke by the flowing fluid

D = flow tube outer piston diameter (actual dimension depends on design)

d = choke internal diameter

C_1 = constant that includes other factors that contribute to force, such as fluid momentum or drag. This factor is normally small.

K = spring rate

l = pre-compression of spring (related number of configuration spacers)

ΔL = flow tube stroke (additional spring compression required for valve closure

C_2 = constant related to other factors that contribute to force, such as friction. This factor is normally small.

The velocity valve closes when $F_{flow} > F_{spring}$. These correlations are based on a static mechanical model of the valve and are fairly straightforward.

The third major correlation is required to calculate the differential pressure across the valve choke that is produced from the flowing fluid. In single-phase flow conditions, these calculations are fairly simple. For subcritical, single-phase flows, the differential pressure can be described by the following proportional relationship:

$$DP \propto C_3 \bullet \left(\frac{Q}{d^2} \right)^2 \qquad \text{(Equation 3)}$$

where DP = differential pressure created across choke by the flowing fluid

Q = single-phase flow rate

C_3 = constant related to the fluid properties and choke geometry

d = choke internal diameter

The calculation for multiphase flow is difficult and cannot be described in general terms because there are a variety of different approaches. Some correlations are based on empirical data and others are based on analytical models. In many cases, these multiphase calculations contribute to much of the uncertainty and inaccuracy in the sizing models.

By combining the second and third correlations, we can get a sense of how the valve parameters affect the valve's closing flow rate. Substituting Equation 3 into Equation 1 and then setting Equations 1 and 2 equal to each other, we find the following relationship for the flow rate (Q) as a function of the valve parameters:

$$Q \propto \sqrt{\frac{K \bullet l \bullet \Delta L \bullet d^4}{(D^2 - d^2)}} \qquad \text{(Equation 4)}$$

This simplified expression shows the effect of the valve parameters on the closing flow rate. Velocity valves are normally sized or configured by changing the choke diameter (d), the spring rate (K), and/or the spring spacer length (l) for a given valve model. This is an oversimplified expression that shows only the effects of the valve parameters on the closing flow rate at a particular set of flowing conditions.

1.2 SUMMARY OF PREVIOUS PROJECT

During the project mentioned above, testing was conducted on valves from two different SSCSV manufacturers. Each valve was tested with five different choke and spring/spacer combinations. Each configuration was tested with both single-phase and multiphase conditions with nitrogen and water as the test media. The single-phase tests were conducted by pressurizing the system and then increasing the gas flow rate slowly until the valve closed. For the multiphase tests, a water flow rate was established and then the gas flow rate was increased until the valve closed. For each test point, the water and gas flow rates, static pressure, temperature, and valve differential pressure were recorded.

Summaries of the test results are presented in Table 1.1 and Table 1.2. These summary results show a good indication of the accuracy of each manufacturer's models in predicting the closing rates of their valves. A detailed discussion of the test facility, test procedure, and test results may be found in the Final Report of the above-mentioned MMS project.

Manufacturer A uses one model to predict the closing rates for both oil and gas wells. Manufacturer B uses one model for oil wells, which it defines as having gas-oil ratios less than 40,000 cubic feet per barrel, and another model for gas wells, which it defines as having gas-oil ratios greater than 10,000 cubic feet per barrel.

Table 1.1 shows the results for Manufacturer A's model and valve. The average predicted liquid error varied from –31.9% to 373.6%, and the average predicted gas error varied from –3.3% to 33.7%. Negative errors indicate that the model under-predicted the closing flow rates; the valve actually closed at rates greater than the predicted rates. From an operational and safety standpoint, these negative errors are more serious than positive errors. If a valve is sized with a model that under-predicts the closing flow rates, the installed valve may not close because the well may not be capable of flowing enough fluid to close the valve.

Table 1.2 shows the results for Manufacturer B's model and valve. The errors are all negative, indicating that the model under-predicted the valve closing rates. The liquid errors for both the oil and gas well programs are -100%. This is because the gas flow rates of the test points were higher than the highest gas rate that the model predicted, which was with no water flow. The gas flow rate errors were fairly consistent, varying between –23.3% and –28.3% for both the oil and gas well programs. The errors between the gas and oil well programs showed little significant difference.

Table 1.1 Summary of Results for Manufacturer A's Sizing Model and Velocity Valve.
For the first and last two valve configurations, the manufacturer's model over-predicted the closing rates. For the second and third configurations, the manufacturer's model under-predicted the closing rates.

Choke/Spacer Configuration	Average Predicted Liquid Error (%)	Average Predicted Gas Error (%)	Number of Test Points
Choke A, Spacer C	177.7	19.1	10
Choke B, Spacer A	-11.7	-0.7	15
Choke B, Spacer B	-31.9	-3.3	19
Choke B, Spacer C	243.7	24.5	13
Choke C, Spacer A	373.6	33.7	9
Overall Averages:	150	14.7	

Table 1.2 Summary of Results for Manufacturer B's Sizing Model and Velocity Valve.
For all five valve configurations, the manufacturer's model under-predicted the closing rates.

Choke/Spacer Configuration	Oil Well Program		Gas Well Program		
	Average Predicted Liquid Error (%)	Average Predicted Gas Error (%)	Average Predicted Liquid Error (%)	Average Predicted Gas Error (%)	Number of Test Points
Choke A, Spacer A	-100*	-25.4	-100*	-23.7	18
Choke A, Spacer B	-100*	-27.4	-100*	-28.3	19
Choke A, Spacer C	-100*	-25.2	-100*	-25.2	30
Choke B, Spacer A	-100*	-23.3	-100*	-26.0	18
Choke B, Spacer B	-100*	-24.4	-100*	-28.0	22
Overall Averages:	-100*	-25.14	-100*	-26.2	

*Note: The –100% errors for the water indicate that the model did not predict any water flow at each test point's corresponding gas rate.

The SSCSV sizing procedure recommended in API Recommended Practice 14B - Design, Installation, Repair, and Operation of Subsurface Safety Valve Systems - (API 14B) can be used to put the magnitude of these errors into perspective. In section 4.4, API 14B recommends that velocity valve "closure rates should be no greater than 150 percent but no less than 110 percent of the well test rate." If a midpoint closure rate of 130 percent were selected, a ±20 percent window is left to remain within the recommendation. Many of the sizing errors shown in these tests would cause the valves to fall outside the API 14B recommendation (see Figure 1.1).

The results and conclusions drawn from this study indicated that MMS's concerns about velocity-valve sizing might be valid. Because only two valves were tested in this study, the results were not conclusive, and it was not appropriate to make a decision about terminating the use of velocity valves in OCS waters. Therefore, recommendations from the previous study included conducting further testing to gain enough information to make a clear judgment about the continued use of velocity valves.

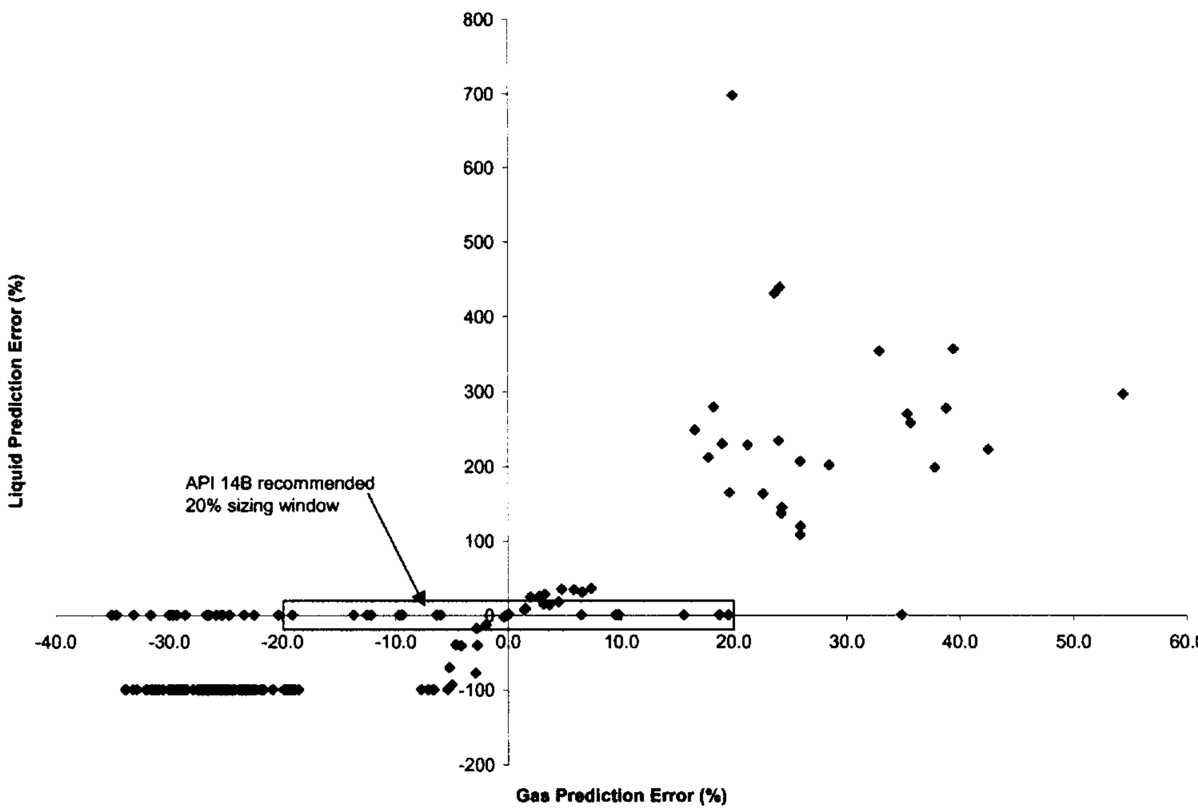


Figure 1.1 Plot of the Percent Error for Each Test Point.
The ±20% sizing window recommended by API 14B is indicated inside the boxed area. Most of the test points fall outside this window.

1.3 CURRENT PROJECT SCOPE

The goals of the current project were to expand on the results gathered in the previous project and develop technically defensible recommendations for the suitability of velocity valves for usage in OCS waters. This was to be accomplished by testing more valves in more field-realistic flow conditions to evaluate the accuracy of the manufacturers' sizing models and evaluate the repeatability of the valves. The project's focus was on evaluating the ability of each manufacturer's sizing program to accurately predict the closing points of the valves in single-phase and multiphase flow conditions. This was accomplished by testing a representative sample of velocity valves in controlled laboratory conditions with natural gas and water and then comparing the results with predictions obtained by exercising the manufacturer's sizing programs. The data was then analyzed and organized in a way to facilitate MMS's objective of making recommendations concerning the use of velocity valves in OCS waters. Since the more important aspect of the project was the evaluation of the sizing programs, the focus of the testing was centered on evaluating the software accuracy and valve repeatability. Therefore, the repeatability was not directly tested, but was assessed through a qualitative analysis of the test data collected for the software evaluation. The goal of this program was to gather and present information and data to the MMS regarding the performance of velocity valves and their sizing models so that MMS could draw conclusions and make decisions regarding their acceptability for use. This report does not attempt to provide any conclusions other than those directly regarding the performance of velocity valves.

2. EXPERIMENTAL APPROACH

Since the intent of this project was to evaluate the accuracy of the manufacturers' sizing programs, the experimental approach was developed to test the valves in conditions as field-realistic as practical, while still allowing for a fair and accurate evaluation of the sizing programs. This was accomplished by understanding how the velocity valves work and, in general, how the manufacturers' sizing programs predict their behavior.

As noted above, the sizing models include three major correlations: the first to estimate the flowing conditions at the velocity valve from wellhead measurements; the second to predict the differential pressure required to close the valve; and the third to calculate the differential pressure generated by the fluid flowing through the valve. Testing all three of these correlations is difficult. The second and third correlations can be evaluated at the same time by testing velocity valves in a multiphase flow loop. The loop can be used to establish, control, and measure the flowing conditions (pressure, temperature, fluid rate, and fluid composition) at the valve. Testing the first correlation, however, would require a vertical tubing section that would be long enough to simulate a downhole safety valve installation. This type of testing would be impractical to perform in a test facility and therefore would require field-testing. Field-testing with valves installed in a downhole application would be more realistic, but it would limit the ability to control the flowing conditions and make the measurements of the downhole conditions at the valve impractical. For these reasons, the testing for this project was conducted in a multiphase flow loop at SwRI and therefore focuses on evaluating only the second and third correlations.

In addition, a decision was made to test with water rather than oil because the sizing programs require that the fluid flow rates be entered in terms of stock tank conditions. Testing with water eliminated the need to calculate the shrinkage of the fluid (described previously) that results from gas coming out of solution when the pressure and temperature are brought to stock tank conditions. Although testing in this manner may not be quite as field realistic, it provides for more accurate measurements, decreases the testing costs, and provides more of a best-case evaluation of the sizing programs. Based on our knowledge of how the sizing models work, we decided that these modifications did not significantly impact the ability to evaluate the manufacturers' programs and provided more accurate measurements, which in turn provided more technically defensible data.

As discussed in the previous section, a decision was made to focus the testing on the software evaluation rather than the valve repeatability to maximize the evaluation of this more important aspect of the project. The repeatability was assessed using the data collected to analyze the sizing program accuracies. By closing each valve with the static pressure and temperature held constant over a range of gas-liquid ratios, the repeatability could be qualitatively assessed by evaluating the trend of the closing points. The decision to not directly measure the repeatability of the valves was not made without basis, but was made with SwRI's knowledge that the valves were repeatable in the last project, and the repeatability is one of the failure criteria of the API Specification 14A verification test for SSCSV products.

2.1 TEST MATRIX

One of the main differences between this project and the previous project was the number of valves in the test matrix. Six valves were selected to provide a representative sample of the valves used in OCS waters. Three manufacturers each agreed to provide two of their most popular valves for a total of six valves. One of the manufacturers actually agreed to provide only one valve on loan for this project; SwRI purchased the second valve to complete the text matrix. The valves were configured with spring, spacer, and choke combinations to match the flowing capabilities of the test facility. Each valve was tested with between 2 and 4 configurations to provide a variety of closing points. Each configuration was tested with between 5 and 8 closing points conducted over a variety of gas-liquid ratios (GLR), which typically ranged from all gas to a GLR of around 2,000. This GLR range represented well conditions for both oil and gas wells.

For each series of tests on a particular configuration, the static pressure and temperature was maintained at a constant level so that each test point could be compared to a common prediction curve. The testing was conducted at ambient temperature with a static pressure of 1,500 psig.

2.2 TEST FACILITY

Testing was conducted at the Multiphase Flow Facility of SwRI. A schematic of the facility may be found in Figure 2.1. A detailed process and instrumentation diagram (P&ID) of the facility can be found in Appendix A.

The flow path in this facility is summarized below.

- Water and natural gas exit the discharge side of the Multiphase Pump (LP01).
- The water and the gas are separated in the high-pressure separator (V001).
- A portion of the water is metered (FE13), filtered (LS01), and returned to the multiphase pump inlet (the multiphase pump requires a minimum of 5% liquid by volume at the pump inlet).
- The temperature of the process fluid at the test section inlet (TE02B) is controlled by cooling the liquid bypass stream with the high-pressure heat exchanger (HX01).
- The gas stream exits the high-pressure separator (V001) and passes through a bank of cyclone separators (to remove any excess water in the gas stream) located in V002.
- The gas exits V002, where the gas is metered in the 6-inch orifice meter (FY01).
- The flow rate through the meter is controlled by the 2-inch control valve (CV11), which allows a portion of the gas flow to return to the pump inlet.
- The flow of water from the high-pressure separator (V001) is controlled using the 2-inch control valve (CV13) and is metered using the 1-inch coriolis meter (FE12).
- The gas and water are combined downstream of the 6-inch valve (GV08).

- The pressure (PT04) and the temperature (TE02B) of the multiphase flow stream are then measured as it enters the vertical test section.
- The flow stream is then filtered (LS01) and returned to the multiphase pump inlet.

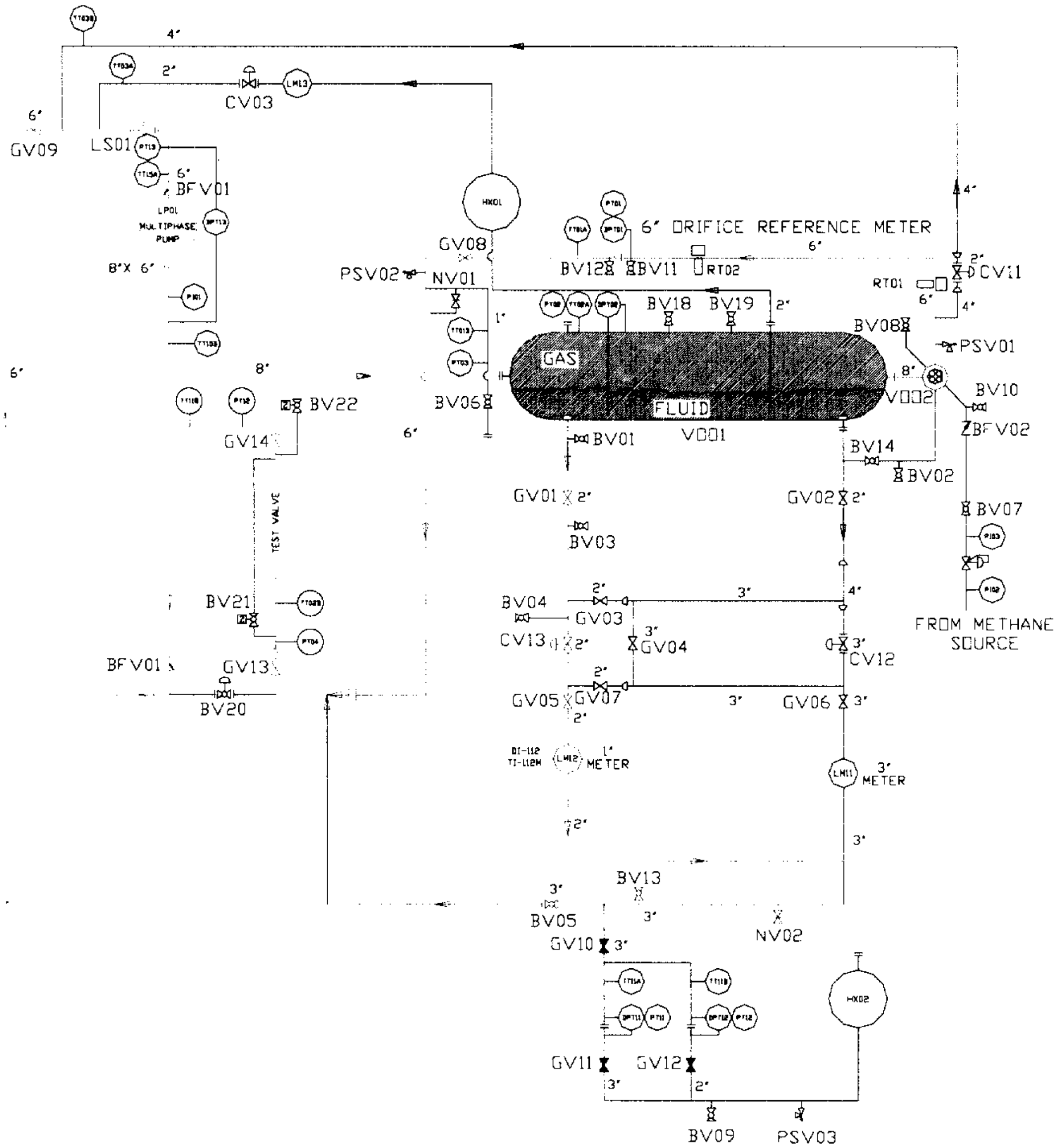


Figure 2.1 SwRI Multiphase Flow Facility Schematic.
The schematic shows the SwRI Multiphase Flow Facility with the test section and associated instrumentation. Multiphase flow sections are shown in green. Single-phase gas and liquid sections are shown in red and blue, respectively.

Figure 2.2 shows a photograph of the SwRI Multiphase Flow Facility. The multiphase pump is shown just to the right of the yellow cover.

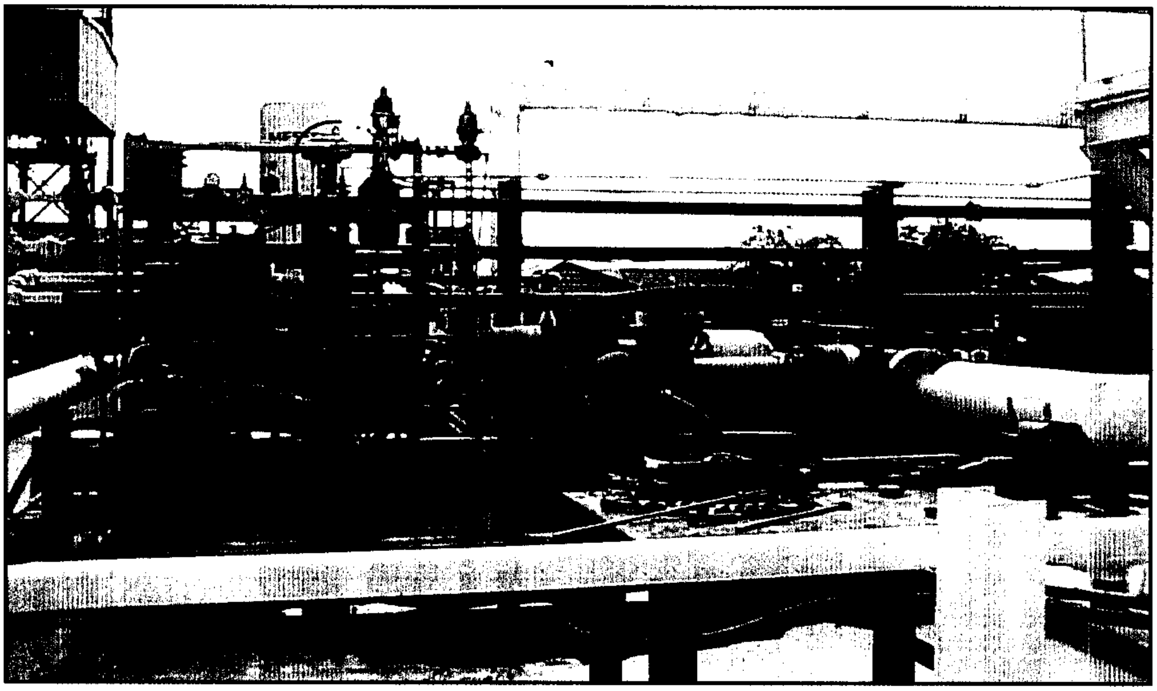


Figure 2.2 SwRI Multiphase Flow Facility.
The multiphase pump is located just to the right of the yellow cover.

Figure 2.3 shows a photograph of the test section. Pressure and temperature transmitters are located at the inlet and the outlet of the test section. The flow enters the test section from the left of the photograph. The pressure and temperature are measured just before the flow enters the vertical test section. A special connector was designed and fabricated so that the test valve could be installed in a long section of properly sized pipe to match the valve's nominal tubing size. The long, vertical test section included adequate upstream and downstream piping to provide proper multiphase flow at the velocity valve. A photograph of the special connector can be found in the inset of Figure 2.3.

2.3 INSTRUMENTATION

A variety of equipment and instrumentation is utilized in the flow facility. Table 2.1 lists the primary equipment and instrumentation, along with the manufacturer and the manufacturer's uncertainty specifications.

The prime mover for the water and gas is the multiphase pump. The pump operates at speeds between 600 rpm and 1,800 rpm, and is capable of producing a differential pressure of up to 250 psig. The pump is also capable of operating with as little as 5% liquid by volume.

The water flow rate is measured using a 1-inch Micro Motion coriolis meter (Model DH100). The flow rate measurement accuracy is better than ±0.4% of reading. The gas flow rate is measured using a 6-inch orifice meter built to the specifications of the latest edition of

AGA Report No. 3. The calibration of the meter was verified at the Gas Technology Institute's Metering Research Facility located at SwRI. For the conditions tested, the accuracy for this meter should be better than ±1.0% of reading.

Rosemount Model 3051TG pressure transmitters are used for pressure measurement throughout the flow loop, while a Rosemount Model 3051 CDE differential pressure transmitter is used to measure the differential pressure across the orifice meter. All temperature measurements are made using a Weed Instruments RTD Model 203-01B.

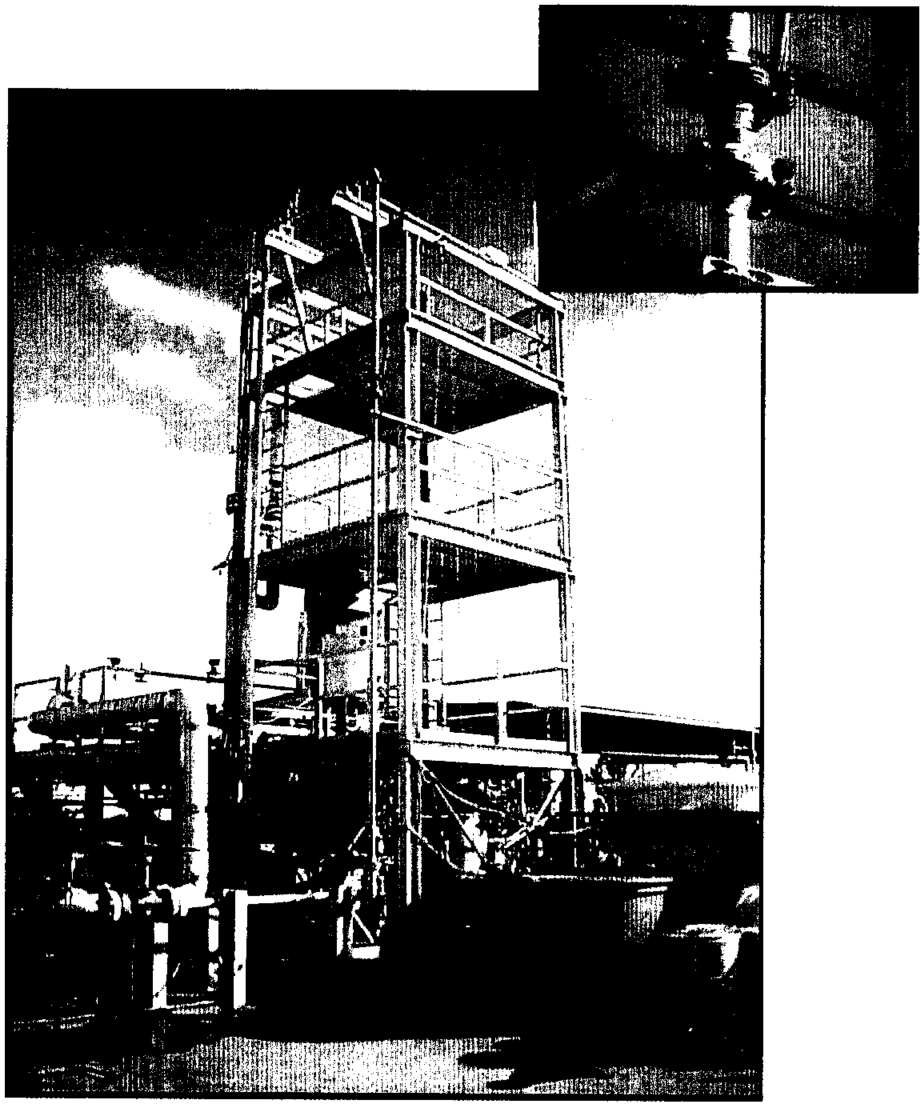


Figure 2.3 MMS Test Section.
Pressure and temperature transmitters are located at the inlet and the outlet of the test section. The flow enters the test section from the left of the photograph. The pressure and temperature are measured just before the flow enters the vertical test section. The inset picture shows the special connector for the test valve.

Table 2.1 Primary Equipment and Instrumentation.
The table shows the manufacturer, model, and accuracy of the primary instrumentation used in the MMS testing, along with the manufacturer and size of the primary equipment.

COMPONENT	DESCRIPTION	MANUFACTURER	MODEL	SIZE	ACCURACY
PT01	Pressure Transmitter	Rosemount	3051TG		±0.075% of span (3 psig)
DPT01	Differential Pressure Transmitter	Rosemount	3051CD		±0.075% of span (0.1875 inches of H_20
TE01A	RTD	Weed Instruments	203-01B		±1.5°F
TT01	Temperature Transmitter	Rosemount	3244MV		±1.5°F
PT02	Pressure Transmitter	Rosemount	3051TG		±0.075% of span (3 psig)
TE02A	RTD	Weed Instruments	203-01B		±1.5°F
TE02B	RTD	Weed Instruments	203-01B		±1.5°F
TT02	Temperature Transmitter	Rosemount	3244MV		±1.5°F
PT04	Pressure Transmitter	Rosemount	3051TG		±0.075% of span (3 psig)
TE11B	RTD	Weed Instruments	203-01B		±1.5°F
TT11	Temperature Transmitter	Rosemount	3244MV		±1.5°F
PT12	Pressure Transmitter	Rosemount	3051TG		±0.075% of span (3 psig)
LP01	Multiphase Pump	Leistritz	L4HK	6"	
V001	High-Pressure Separator	Malone Crawford Tank		22"ID x 15'long	
CV13	Control Valve	Fisher	EHD	2"	
FE12	Liquid Flow Meter	Micro Motion	DH100	1"	±0.40% of reading

2.4 TEST PROCEDURE

Numerous test closures were conducted on each valve. The general procedure for each test is as follows:

1. Stabilize the gas flow at the desired flow rate.
2. Slowly increase the liquid flow, while maintaining the desired gas flow.
3. Continue increasing the liquid flow until the test valve closes.
4. Once the test valve closes, the bypass valve BV20 will automatically open, and the multiphase pump LF01 will shut down.
5. Open the test valve by opening the equalization line across the test valve (BV39).
6. Restart the multiphase pump and continue with the next test point.
7. Review the data log and record the gas flow rate, the liquid flow rate, the temperature, and the pressure at the valve closing point.

A detailed test procedure may be found in Appendix B.

2.5 ERROR CALCULATIONS

The manufacturers' models were assessed by comparing the model predictions and the test closing points for the respective valve configuration. For each test series on a particular valve configuration, the flow conditions (pressure, temperature, and fluid composition) were held constant. In multiphase flow, velocity valves close at an infinite combination of liquid and gas flow rates. The sizing programs were exercised numerous times with numerous gas-liquid ratios to obtain a predicted closing curve at the flowing conditions. Each test point for a particular valve configuration and flowing condition was compared to the respective prediction curve. However, the comparison of the test points to the prediction curve is not straightforward. If the data were all single-phase, the comparison would be simple because the prediction error would be simply the predicted single-phase point minus the single-phase test point. In multiphase applications, this error calculation is not as easy because the prediction is not a single point but is a curve made up of a combination of gas and liquid flow rates. Figure 2.4, which shows a typical prediction curve and a test point, helps illustrate the difficulty of this evaluation. The difficulty is determining at what point on the prediction curve the comparison to the test point should be made. One option is to calculate the errors for each phase separately. For instance, the liquid error could be calculated by finding the point on the prediction curve at which the gas flow rate matches the measured gas flow rate from the test point (shown as the intersection of the prediction curve and the horizontal red line shown in Figure 2.4) and then subtracting the measured liquid rate from the predicted liquid rate at that point on the curve. The gas flow rate could be found similarly. This is how the errors were calculated in the first project.

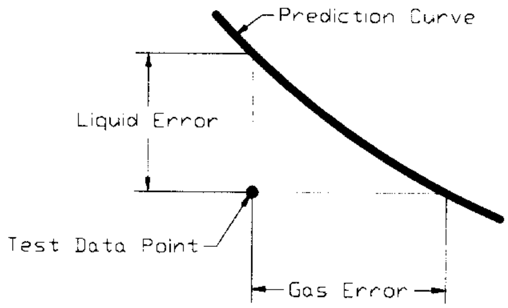


Figure 2.4 Example of a Typical Prediction Curve and a Test Point.
The figure illustrates the difficulty of quantifying the difference between the test data point and the sizing program prediction.

Though fairly straightforward and not inaccurate, this calculation method implies some unrealistic flow conditions. For instance, the liquid error implies that production rate would increase from the test point to the prediction curve along a path (shown vertically in Figure 2.4) that would only include additional liquid flow rate; the gas rate would remain constant. Similarly, the gas error implies that production rate would increase from the test point to the prediction curve along a path (shown horizontally in Figure 2.4) that would only include additional gas flow rate; the liquid rate would remain constant. In reality, the total flow rate would increase in a manner that would include both additional liquid and gas. The exact ratio of gas and liquid cannot be characterized because it would depend on the flowing characteristics of the particular well in which the valve is installed.

One way to quantify this ratio of gas and liquid is to arbitrarily assume that the flow rate increases on a path that is perpendicular to the prediction curve. Figure 2.5 illustrates this method.

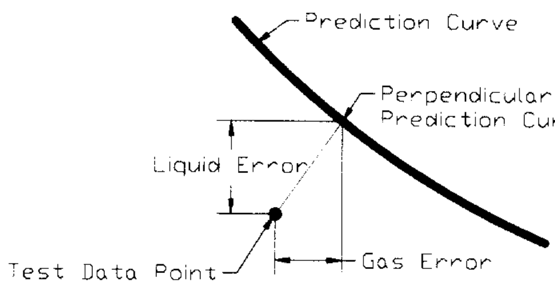


Figure 2.5 An Alternative Method for Evaluating the Prediction Error.
This method assumes that the flow rate increases on a path that is perpendicular to the prediction curve.

This method involves finding the projected point on the prediction curve that falls on a line that passes through the test point and is perpendicular to the prediction curve. The individual phase errors are then calculated by subtracting the measured test point flow rates from the predicted flow rates. The calculated error for this method is less than that calculated using the previous method. This method is a more realistic simulation of the operation of actual wells, but it is still flawed because the "perpendicular path" assumption is made arbitrarily, and in most cases, is not valid. However, without evaluating each individual well installation to determine the true flow path, this is the most logical method for calculating the prediction errors. Also, because with this method the test point is compared to a single point on the prediction curve, the total volume flow rate for each point can be calculated and compared. This provides a single comparison number that is calculated on a total volume basis.

Because of the assumptions made and the uncertainties described above, the data reported in this report includes the comparison based on both methods. The "Gas Only Error" and "Liquid Only Error" are the separate phase errors calculated using the first method. The "Combined Projected Error" is the total volume error calculated using the second evaluation method. For simplicity in the text, the first method is referred to as Method 1 and the second method is referred to as Method 2. Details showing how the errors were calculated can be found in Appendix C.

3. TEST RESULTS

The manner in which the data is presented in this report was influenced by the terms agreed to by SwRI and the MMS with each manufacturer in order to gain access to the test valves and sizing software. In one of the agreements, the manufacturer required that the data "not be publicly disclosed unless sanitized (data correlated to an anonymous supplier) and included with at least one other supplier's set of data." Meeting this requirement was not entirely straightforward because of the nature of how the manufacturers' software worked. One of the manufacturers uses two sizing programs, one for predominantly oil wells and one for predominantly gas wells. Because the safety valve industry includes only a few manufacturers, it would be relatively easy to determine which manufacturer utilizes the two programs. If the results were presented in a manner that separated the results for the two programs, it would, in effect, be revealing the results of that manufacturer. For this reason, the data is presented in a manner that lists the valve configurations in a generic manner without designating a manufacturer, even in an anonymous manner. The results for the two programs of the one manufacturer are listed as separate configurations. Comparisons of the different manufacturers' sizing programs are shown only in scatter plots and in a summary format. Presenting the data in this manner reveals the necessary information while maintaining the anonymity of the manufacturers. Also, note that the referenced "Manufacturer A" and "Manufacturer B" in the summary of the previous project do not correspond to those listed for the data in this current project.

3.1 CURRENT PROJECT TEST RESULTS

For each valve configuration (that is, valve model and size, bean, and spacer), a number of test points (4 to 8) were run over a range of gas and liquid flow conditions. Each series of tests were conducted with a nominal pressure of 1,500 psig and nominal temperature at ambient conditions.

The blue diamond symbols in Figure 3.1 represent valve closing condition data for a typical test series on a particular valve configuration (configuration F4). The figure also includes the prediction curve that was generated using the manufacturer's sizing program for the particular valve model and configuration at the average static pressure and temperature of the test data. Each test point was analyzed and compared to the prediction curve to determine the prediction error. A summary of the errors (range of errors and average error) for each configuration is presented in Table 3.1. Note that in this case the errors were positive, which means that the actual closing rates were lower than the predicted closing rates.

In limited situations, during the testing of some of the valve configurations, test points were recorded that appeared to be inconsistent with the surrounding data. Figure 3.2 is an example of a set of data where all but one of the measured closures appears to follow a trend. In these situations, the test points that fell outside the trend of the remaining test points were considered extraneous and were not included in the analysis. In this case, only the errors associated with the other 5 data points (which were all negative errors) were used to provide the input to Table 3.1. Of the 165 test points collected, only 5 were considered extraneous. This confirmed good measurement techniques and the repeatability of the valve operation.

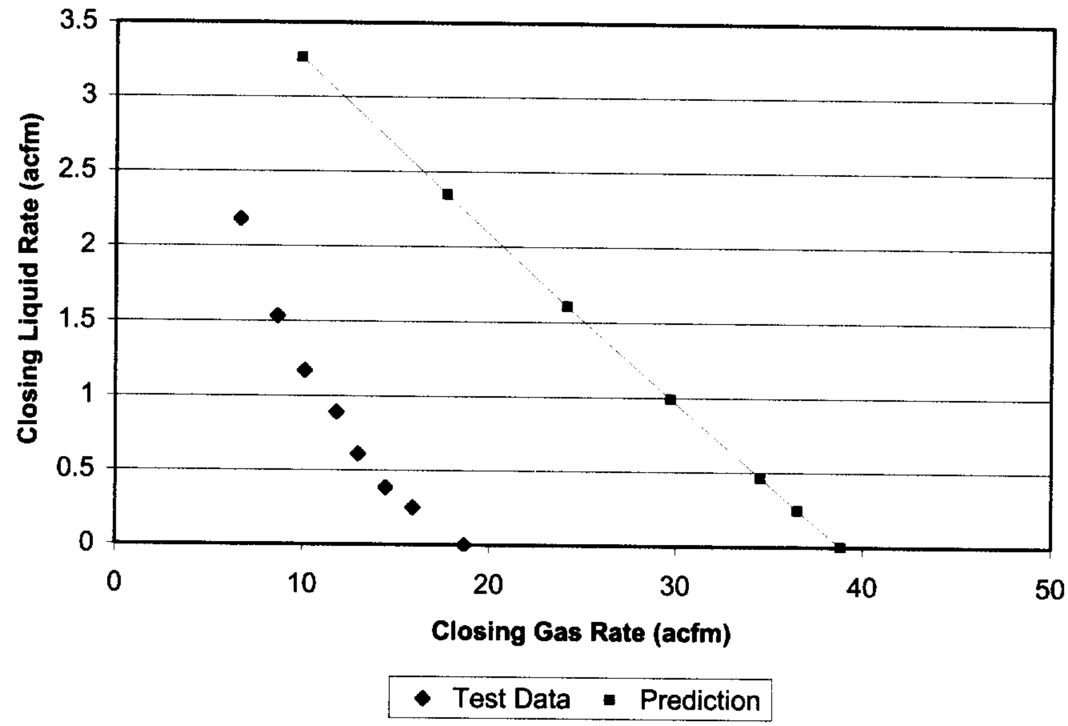


Figure 3.1 Sample Test Data and the Corresponding Prediction Curve for a Valve Configuration.
Each test point was analyzed and compared to the prediction curve to determine the prediction error. The analysis results are summarized in a line in Table 3.1.

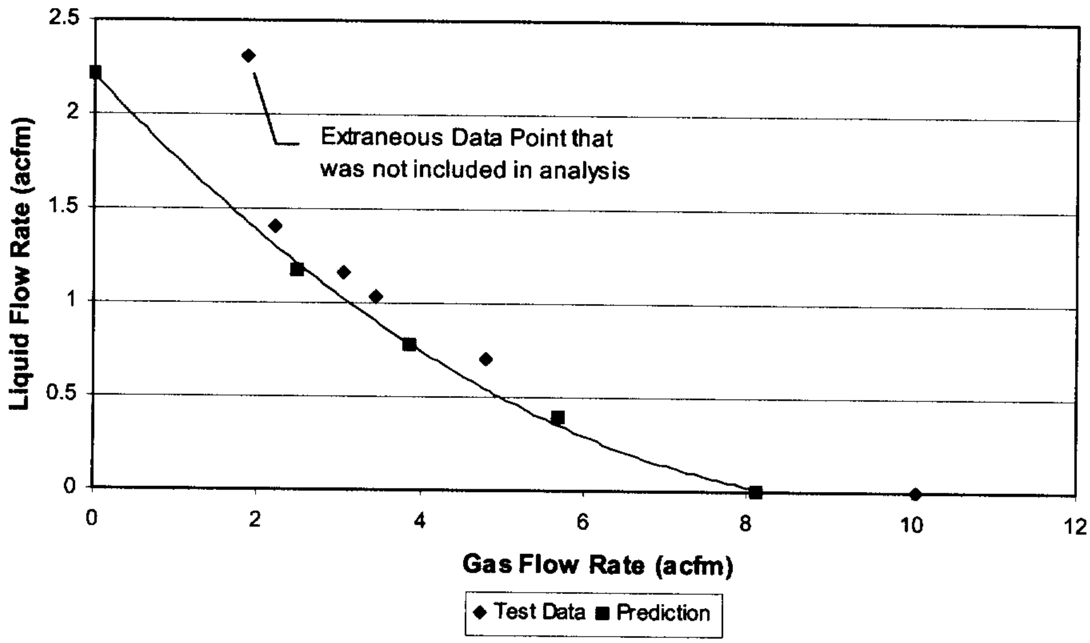


Figure 3.2 Sample Data Set Showing Extraneous Data Point.
A limited number of extraneous data points were recorded in the testing. These points were not included in the data analysis.

Table 3.1 shows 25 different configurations, including the additional configurations for the manufacturer with two sizing programs, as described above. In addition, some of the configurations that were tested are not presented here because the valves malfunctioned and did not operate properly. These malfunctioning valves will be discussed later.

The data in Table 3.1 shows a significant spread for the prediction error among the different valve configurations. For the combined error numbers (from Method 2), the prediction errors ranged from –14% to 101% with an average error of 29% and a standard deviation of 43%. The standard deviation gives an indication of dispersion of the data. Also shown in the table is the average of the absolute value. This gives an indication of how far the prediction is from the actual value (the test point) in an absolute sense. The true arithmetic average is somewhat misleading because it benefits from the fact that some of the errors are positive and some are negative. What is of more value is an indication of how far the predictions deviate from the true value, which is what the average of the absolute values indicates. The 35% value shown in the table indicates that, on average, the predicted values deviate from the actual closing points by 35% on a combined projected volume basis (calculated using Method 2).

The "Gas Only" and "Liquid Only" errors (from Method 1) give a sense of the prediction errors with respect to the individual flow rates of each phase. This data shows significant scatter with the gas-only errors ranging from –39% to 271%, and the liquid-only errors ranging from –524% to 1,575%. Most of this range in values can be attributed to the difference between the performances of the different manufacturers' models, however, the data for the individual manufacturers also shows significant scatter. This is illustrated in Table 3.2, which compares the performance of the three manufacturers' sizing programs.

An important note to realize when analyzing the data is that positive error values indicate that the sizing program over-predicted the closing point (that is, the valve actually closed at a lower flow rate than the model predicted); a negative value indicates that the program under-predicted the closing point (that is the valve actually closed at a higher flow rate than the model predicted). The over-predicting (positive) values are considered more conservative from a safety standpoint because in these cases, the use of the program could lead to a valve being sized to close at a lower flow rate. The under-predicting valves are of more concern from a safety standpoint because in these cases the use of the program could lead to a valve being sized to close at a flow rate higher than expected. In these cases, the valve may never close because the well may not have enough flow potential to close the valve in an emergency situation.

The test data indicate that Manufacturer C's model will, on average, over-predict the actual closing point on a combined projected volume basis by 80% with a standard deviation of 18%. Though this may be conservative, it most likely would produce problems with nuisance closures and loss of production in actual well installations.

Manufacturer A's and Manufacturer B's programs showed significantly better performance by only slightly under-predicting the closing points. On a combined projected volume basis (Method 2), Manufacturer A's and Manufacturer B's programs showed average errors of –4.1% to –6.3% respectively, with standard deviations of 7.8% and 3.0%. Again, these numbers indicated that, on average, the valves closed at slightly higher flow rates than the programs predicted.

Manufacturer B's data is mentioned here; however, strong conclusions should not be made regarding this manufacturer's program because only three configurations are included in the data. The reason for this limited amount of data will be discussed later.

Table 3.1 Summary of Test Results Showing Comparison of Prediction to Test Data for Each Valve Configuration.

Data, which include 25 different configurations and 160 test points, show significant scatter. The overall prediction error average was 29% with a standard deviation of 43%. Positive errors indicate that the predicted closing rates were higher than the actual test results. Negative errors indicate that the actual closing was higher than the predicted closing rates. Data for configurations C2 and D3 are not available because the valves malfunctioned.

Configuration ID	Gas-Only Error		Liquid-Only Error		Combined Projected Error		Number of Valid Test Points
	Range of Error (%)	Average Error (%)	Range of Error (%)	Average Error (%)	Range of Error (%)	Average Error (%)	
A1	-27 to –23	-24	-246 to -83	-134	-15 to -12	-14	5
A2	-23 to –16	-20	-345 to -64	-151	-13 to -9.2	-12	6
A3	-1.5 to 19	11	-12 to 132	75	-0.8 to 11	6.3	5
A4	-20 to –12	-16	-524 to -43	-182	-12 to -7	-9	6
B1	-12 to 2.0	-4.3	-86 to 8.2	-32	-6.7 to 1.1	-2.4	5
B2	-27 to –19	-22	-226 to -61	-120	-15 to -11	-12	6
B3	-27 to –20	-24	-367 to -57	-168	-17 to -12	-14	4
C1	-13 to -4.3	-8.3	-9.2 to -7.1	-8.4	-7.1 to -2.3	-4.4	4
C2	N/A	N/A	N/A	N/A	N/A	N/A	N/A
D1	-19 to –13	-17	-20 to -10	-15	-11 to -6.9	-8.3	5
D2	-39 to -4.7	-15	-12 to -6.1	-8.8	-12 to -2.5	-6.0	6
D3	N/A	N/A	N/A	N/A	N/A	N/A	N/A
E1	130 to 263	211	71 to 799	281	36 to 394	99	8
E2	128 to 271	216	63 to 972	321	70 to 112	101	8
E3	79 to 209	145	123 to 1429	576	43 to 96	75	8
E4	75 to 199	143	124 to 1319	481	41 to 93	74	8
F1	108 to 216	171	44 to 741	251	59 to 90	80	8
F2	69 to 173	132	112 to 1575	490	38 to 81	68	6
F3	85 to 154	125	113 to 1239	442	48 to 76	65	8
F4	108 to 188	156	67 to 924	361	60 to 88	78	8
G1	-5.9 to 0.9	-1.9	-38 to 1.9	-10	-3.4 to 0.5	-1.1	7
G2	-.14 to 13	7.1	-1.2 to 52	22	-0.1 to 7.1	3.9	7
G3	-15 to 9.4	1.6	-122 to 16	-8.0	-8.4 to 4.7	0.8	7
G4	3.2 to 25	13	29 to 126	50	1.8 to 13	7.0	7
H1	-18 to -2.3	-10	-157 to -3.7	-51	-9.3 to -1.2	-5.7	5
H2	-2.0 to 11.5	4.2	-16 to 17	7.1	-1.1 to 6.1	2.2	7
H3	-6.8 to 11	2.7	-54 to 26	-2.0	-3.9 to 6.0	1.4	6
	Average:	60		130		29	
	Std Deviation:	89		324		43	
	Average of Absolute Value:	71		191		35	

Table 3.2 Comparison of Manufacturers' Sizing Programs

Manufacturer C's program showed significantly worse performance than the programs from the other two manufacturers.

	Gas-Only (Method 1)			Liquid-Only (Method 1)			Combined Projected Error (Method 2)			Number of Configura-tions Tested
	Average (%)	Standard Deviation (%)	Average of Absolute Values (%)	Average (%)	Standard Deviation (%)	Average of Absolute Values (%)	Average (%)	Standard Deviation (%)	Average of Absolute Values (%)	
Man. A	-5.0	14	12	-43	106	64	-3.0	7.8	6.7	7
Man. B	-14	9.1	14	-11	3.9	11	-6.3	3.0	6.3	3
Man. C	160	49	160	400	380	400	80	18	80	8
Overall	60	89	71	130	324	191	29	43	35	18

The gas-only and liquid-only data (columns 3 and 5 in Table 3.1) are shown graphically in Figure 3.3. This plot, which shows the separate single-phase errors for each data point, clearly illustrates the dispersion in the data and the differences in the accuracies between the manufacturers' programs.

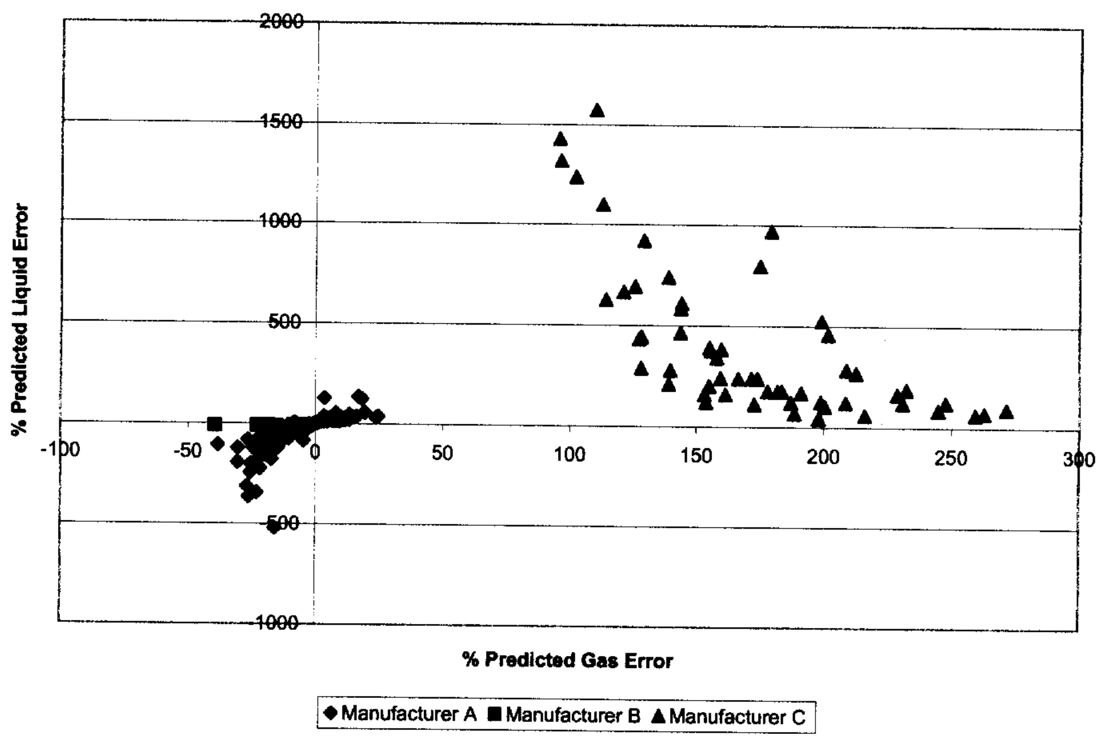


Figure 3.3 Scatter Plot Showing the Prediction Errors for Each Test Point Plotted as a Function of the Separate Single-Phase Errors (Method 1).

One important note to realize is that these error points were calculated using the Method 1 calculations (see Figure 2.3). The liquid errors for each point were calculated by assuming a flow path that included no additional gas, while the gas errors for each point were calculated by assuming a flow path that included no additional liquid. For instance, a point on Figure 3.3 with a gas error of –25% and a liquid error of –100% indicates the following: 1) If the well flow rate were to increase with no additional liquid, the valve would close at a gas flow rate 25% higher than the program predicted, and 2) If the well flow rate were to increase with no additional gas, the valve would close at a liquid flow rate 100% higher than the program predicted. This may not be field-realistic, but it does bound the errors and provides an indication of how accurate the programs would be if used for gas-rich or liquid-rich wells.

Another observation regarding Figure 3.3 is that the magnitude of the liquid errors is almost an order of magnitude higher than the gas errors. This is due to the fact that even for test points with GLRs as low as 2,000 scfd/bpd, the gas to liquid fraction is approximately 3 (that is, the gas volume is three times the liquid volume). This means that small deviations between the liquid prediction and the test data result in large liquid errors. But it also means that the liquid does not contribute significantly to the combined volume error.

A comparison of the manufacturers' software accuracy is also highlighted in Figure 3.4, which shows the combined projected volume error (calculated using Method 2) as a function of the gas-liquid ratio (GLR). This graph clearly shows the difference between Manufacturer C's program and the other two manufacturers' programs. It also shows the range and distribution of GLRs that were tested. As mentioned above, each configuration was tested at the same nominal temperature (ambient) and pressure (1,500 psi) over a range of GLRs to obtain each series of test points.

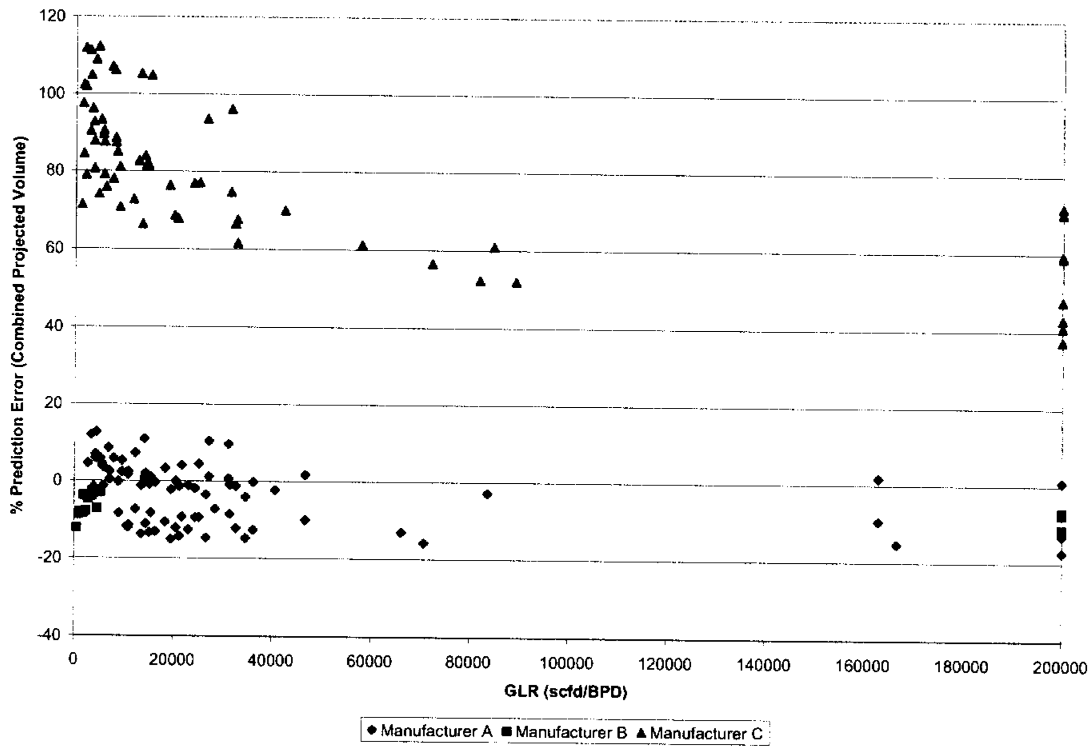


Figure 3.4 Scatter Plot Showing Prediction Error on a Combined Projected Volume Basis as a Function of the Gas-Liquid Ratio (GLR).

The points shown with a GLR of 200,000 are actually all-gas points with true GLRs of infinity. The prediction accuracies do not show a strong dependence on GLR.

Reviewing Manufacturer B's data shows that that not only were a limited number of configurations tested, as mentioned above, but also that the tests were conducted over a limited range of GLR conditions. This reaffirms that only limited conclusions should be drawn regarding the performance of this manufacturer's sizing program.

Another observation that can be made regarding Figure 3.4 is that there is no strong dependence of the prediction accuracy on the GLR. This means that the accuracies of the programs, on a combined projected volume basis, were relatively unchanged over the GLR range that was tested.

One other interesting observation that can be made from the graph is the magnitude of the errors for the all-gas flow cases (shown with GLR of 200,000 on the graph). The graph shows error ranges of approximately 1% to –18% for Manufacturer A, -7% to –10% for Manufacturer B, and 38% to 70% for Manufacturer C. Recall that these points were calculated using Method 2, so they are not the true all-gas prediction errors. These values are actually the difference in the volume between the test point and the perpendicular projected point on the prediction curve (see Figure 2.4). A summary of the true all-gas prediction errors (calculated using Method 1) for all three manufacturers is shown in Table 3.3.

Table 3.3. Summary of Prediction Errors for All-Gas Test Points

The gas-only errors were calculated using Method 1. For all-gas cases, the valves, on average, closed at flow rates 37% lower than the programs predicted.

	Average (%)	Standard Deviation (%)	Average of Absolute Values (%)	Number of Test Points
Mfr. A	-18	11	19	6
Mfr. B	-15	4.1	15	3
Mfr. C	98	24	98	8
Overall	37	61	55	17

One interesting observation about this data is that these prediction errors for the all-gas points are higher than the overall multiphase data for the programs. This is somewhat surprising because one might expect the programs to work better in single-phase conditions. This may indicate that the programs are designed primarily for multiphase conditions and do not work as well at the single-phase limits.

3.2 MANUFACTURER B'S VALVES THAT MALFUNCTIONED

In reference to Table 3.2, Manufacturer B's data includes only three configurations. As mentioned previously, more configurations were tested for this manufacturer, but the valve did not operate correctly, so only a limited set of data could be included in the report. During the testing, the valves worked properly through the first few series of tests but then began to malfunction. The valves continued to malfunction to the point that no data of any value could be obtained. The symptoms of the malfunctioning valves were erratic closing points (shown in Figure 3.4) or the fact that the valve did not open or close completely during the testing.

The manufacturer was contacted and one of their representatives rebuilt one of the valves in the middle of the test program. Even after the rebuilding, the valve continued to malfunction. The second valve tested functioned in a similar manner. Therefore, the valves were returned to the manufacturer for analysis. The manufacturer determined that the problem was caused by a manufacturing problem. The manufacturer offered to repair the valves, but SwRI did not have additional funding to retest the valves. SwRI requested that the manufacturer fund the additional testing, but they declined. The MMS also elected not to provide additional funding for the retesting. This left only a limited amount of data, which is not enough to properly evaluate Manufacturer B's sizing model.

The fact that these valves included a manufacturing problem that caused them to malfunction is of great concern to the researchers. That is, it seems reasonable to be concerned about the performance of products that this company may supply to the field.

3.3 COMPARISON WITH RESULTS FROM PREVIOUS PROJECT

Comparison between the results of this project and the last project can only be made by evaluating the "Gas-Only" and "Liquid-Only" values (calculated using Method 1). The Method 2 calculation was not used in the previous project. In the previous project, one manufacturer showed an average prediction error of 11% for gas and 114% for liquid; the other manufacturer showed an average predicted error of –26% for gas and –100% for liquid. These values do not compare well with the overall average predicted error of 60% for gas and 130% for liquid for the current project. Some of this discrepancy can be attributed to the wide scatter in the error data and the addition of the third manufacturer in the current project. One factor that may contribute to these discrepancies is the difference in the test methods used in the two projects. In the first project, the testing was conducted in a blowdown facility with nitrogen as the gas medium. Modifications to the manufacturers' programs were required to account for the use of nitrogen. The current project was conducted in a multiphase flow loop with natural gas. This testing provided better control of the flow conditions and allowed for the use of the sizing software without modifications. For these reasons, the data for this project should be more accurate.

4. CONCLUSIONS

Overall, the test data show that, on average, the manufacturers' sizing programs overpredict the actual closing points by 29% with a standard deviation of 43% when the error is calculated using the more field-realistic Method 2. These values are somewhat misleading because this industry average is dominated heavily by the 80% average error and 18% standard deviation that were produced by Manufacturer C's program. The average error for Manufacturer A's program was –3.0% with a standard deviation of 7.8%. Manufacturer B's data is not mentioned here because of the limited data available.

One important note, mentioned previously, is the fact that this testing only evaluated two of the three correlations used in velocity valve sizing programs. Recall, that the remaining correlation is used to estimate the downhole flowing conditions from measurements taken at the surface. Errors associated with these calculations and the inaccuracy of field measurements will contribute additional errors. Other factors that affect the ability to properly size velocity valves are the accuracy of estimating the well's maximum flowing potential and the uncertainty of changing well conditions. Considering the performance of Manufacturer B's valves, the reliability of velocity valves must be included with all these factors when evaluating the suitability of velocity valve use in MMS fields.

The error data for Manufacturer A's model, along with the limited data available for Manufacturer B's model, indicate that it is possible to predict, fairly accurately, the closing points for velocity valves when the downhole conditions are known. Manufacturer C's poor performance, however, shows that the velocity valve sizing accuracy is heavily dependent on which manufacturer's valve and program are used.

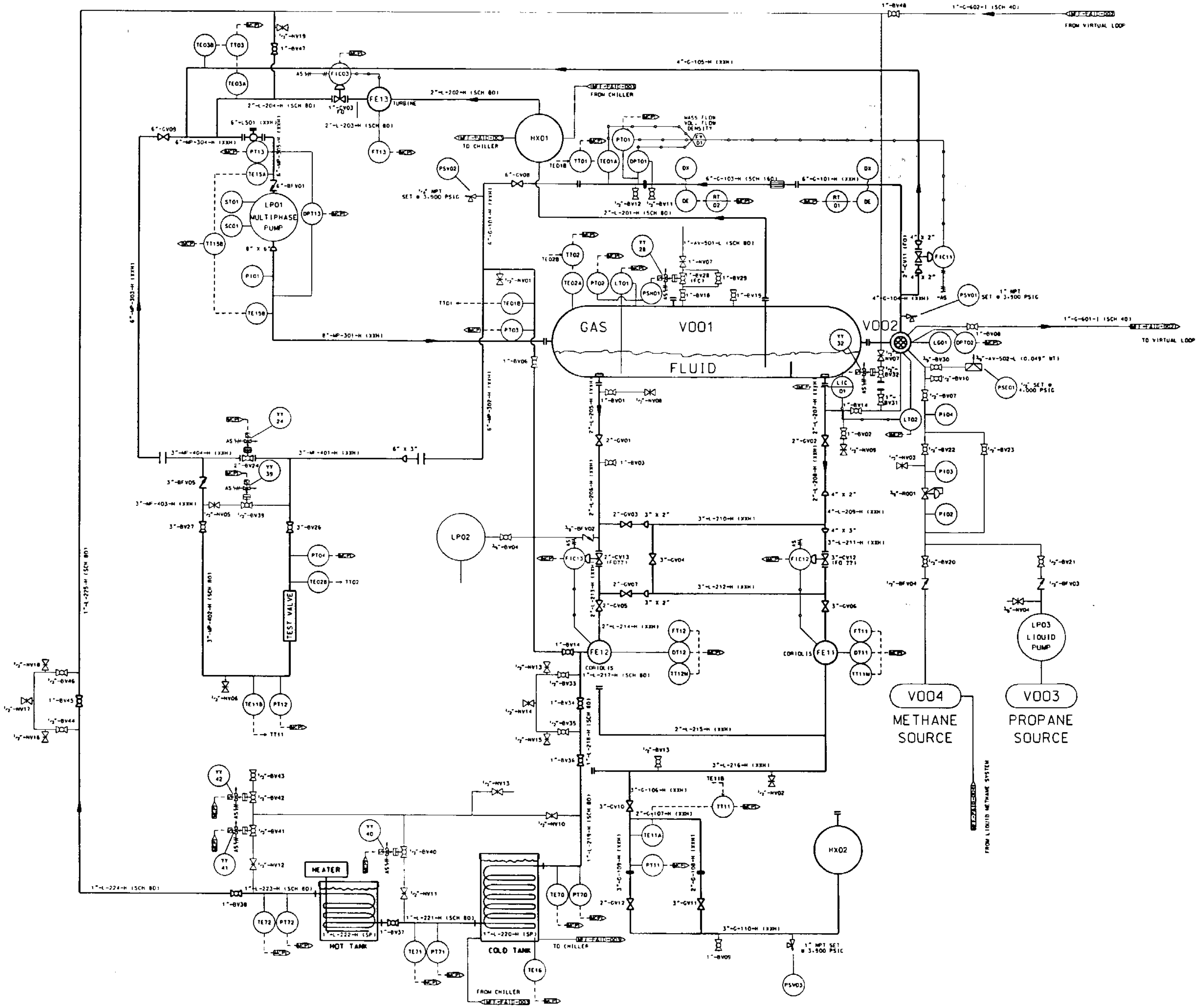
One important note to keep in mind is the fact that the data collected in this project will be provided to the manufacturers, which should enable the manufacturers to enhance the accuracy of their programs. The manufacturers' willingness to participate in the project in order to have access to data provides some indication of the manufacturers' interest in improving their models.

As a final note, simply relying on the manufacturer's sizing program, as shown by the performance of Manufacturer C's program, along with the additional factors mentioned above, provides little certainty that a velocity valve will actually close when required without actually testing the valve after it is installed. The sizing program could be used for preliminary sizing, but field-testing may be the only way to verify, with any real certainty, that it is sized properly. Field testing, especially if done periodically, would also verify the operability of the valve and provide information about how much, if any, it leaks.

Currently, 30 CFR 250.124 states that "[e]ach subsurface-controlled SSSV installed in a well shall be removed, inspected, and repaired or adjusted, as necessary, and reinstalled or replaced at intervals not exceeding 6 months for those valves not installed in a landing nipple and 12 months for those valves installed in a landing nipple." Surface-controlled subsurface safety devices are required to "be tested in place for proper operation when installed or reinstalled and thereafter at intervals not exceeding 6 months." This discrepancy between testing requirements is most likely due to the fact that testing of subsurface-controlled SSSVs is often difficult and in some cases can cause damage to the well or other downhole equipment. However, without the ability to verify the operability of the valves, there is no real certainty that the valves will work when required.

APPENDIX A

PROCESS AND INSTRUMENTATION DIAGRAM OF SwRI MULTIPHASE FLOW FACILITY



SOUTHWEST RESEARCH INSTITUTE

SAN ANTONIO, TEXAS

MULTIPHASE FLOW FACILITY PIPING AND INSTRUMENTATION DIAGRAM

REV. NO.	DESCRIPTION	BY	DATE

DRN	CKD	APPVD	DRAWING NO.
AMB			MFF-P&ID-001
DATE 09-16-02	SCALE N.T.S.		

APPENDIX B

MULTIPHASE FLOW FACILITY OPERATING PROCEDURES

ADDENDUM TO THE STANDARD OPERATING PROCEDURE FOR MULTIPHASE FLOW FACILITY
SwRI PROJECT NO. 04772

DATE: May 9, 2002

SUBJECT: Repeatability and Effectiveness of Subsurface-Controlled Subsurface Safety Valves

CLIENT: MMS

CONTRACT: Government

REFERENCE: Standard Operating Procedures (SOP) for Multiphase Flow Facility, June 2001, Southwest Research Institute®, Mechanical & Materials Engineering Division

APPLICABILITY: This document serves as an addendum to the above-referenced SOP. The safety procedures specified in the Safety Policies and Procedures Manual (SPPM), in the above-referenced SOP, and in this addendum are applicable to all tests conducted under this project.

OPERATING PROCEDURES:
All personnel involved in the test operations will comply with operating procedures specified in the above-referenced SOP and in the attached addendum.

PLANNED START DATE FOR TESTING:
May 15, 2001

PREPARED BY: Andy Barajas, Senior Research Engineer

1. GENERAL OVERVIEW

The purpose of this project is to verify the repeatability and effectiveness of subsurface-controlled subsurface safety valves (velocity valves).

2. SPECIFIC PROCEDURES

These tests will be conducted in the high-pressure loop of the Multiphase Flow Facility. The following steps shall be followed to accomplish the testing (see Appendix A for P&ID):

1. Turn on circulating pump for 40-ton chiller.
2. Turn on 40-ton chiller.
3. Turn on lubrication system for Leistritz pump in accordance with SOP-002, "Leistritz Lubrication System Start-Up."
4. Verify that all valves in the section to be purged are open.
5. Purge flow loop in accordance with SOP-003, "System Purge."
6. Open BV04.
7. Using LP02 (Haskell liquid pump), inject water into separator until the density compensated level is approximately 8".
8. Close BV04.
9. Verify that the following valves are in the OPEN position:
   a) GV01
   b) GV05
   c) GV08
   d) GV09
   e) BV06
   f) BV14
   g) BV26
   h) BV27
   i) NV05
   j) CV03
   k) CV11
   l) CV13
10. Verify that the following valves are in the CLOSED position:
    a) GV02
    b) GV03
    c) GV04
    d) GV06
    e) GV07
    f) GV10
    g) GV11
    h) GV12
    i) BV01
    j) BV02

k) BV03
l) BV04
m) BV07
n) BV08
o) BV09
p) BV10
q) BV11
r) BV12
s) BV13
t) BV24
u) BV25
v) NV01
w) NV02
x) NV03
y) NV04
z) NV06

11. Pressurize system to approximately 1,500 psig in accordance with SOP-004 "System Pressurization."
12. Close CV13 and BV06.
13. Set CV11 to 10% open.
14. Turn on the multiphase pump (@ 600 rpm) in accordance with SOP-005, "Leistritz Multiphase Pump Start-Up."
15. Make sure liquid bypass flow rate is at least 20 gpm (LM13).
16. Slowly increase pump speed until test valve closes; BV24 and CV11 will open automatically.
17. After the multiphase pump has stopped, reset pump.
18. Open test valve by equalizing the pressure across the test valve by opening BV25 (remotely).
19. After test valve has opened, close BV25 (remotely).
20. Close BV24 (remotely).
21. Open BV06.
22. Turn on the multiphase pump (@ 600 rpm) in accordance with SOP-005, "Leistritz Multiphase Pump Start-Up."
23. Make sure liquid bypass flow rate is at least 20 gpm (LM13).
24. Set CV11 to 10% open.
25. Set desired liquid flow rate (LM12) by opening CV13.
26. Slowly increase gas flow rate by increasing the speed of the multiphase pump until the test valve closes, BV24 and CV11 will open automatically.
27. Continue until all test points have been completed.

28. When test points for this particular test valve have been completed, depressurize the test section by closing BV26 and BV27, and slowly opening NV06.
29. Remove test valve from the system
30. Install next test valve.
31. Close NV06.
32. Purge test section by pressurizing the test section to 100 psig three times.
33. Pressurize the test section by slowly opening BV26 and BV27.
34. Repeat test procedure until all valves have been tested.

a. General Safety Requirements

The safety procedures outlined in the referenced SOP will be followed, in particular the required Personal Protection Equipment.

b. Specific Emergency Procedures

In the event of an injury, the emergency operator will be notified at extension 2222.

c. Test Personnel

The test engineers will be Andy Barajas and Robert Hart, and the test technician will be Pete Rivera.

d. Location

The tests will be conducted in the high-pressure flow loop at the Multiphase Flow Facility.

e. Personnel Protection

Personal Protection Equipment described in the referenced SOP will be required.

f. Work Done Outside Normal Working Hours

Testing will be conducted Monday through Friday between the hours of 8:00 a.m. and 5:00 p.m.

g. Clean Up Procedures

The site will be cleaned up during and after the test program to maintain a safe work area.

j. Material Safety Data Sheets (MSDS) & Hazard Classification Information

MSDS sheet for Methane is contained in Appendix B.

APPENDIX C

PREDICTION ERROR CALCULATIONS

Problem Statement:

Calculate the velocity valve prediction errors for the individual and combined phase flow rates.

Input Data:

Prediction Data:

$$P_{gas} := \begin{pmatrix} 1.7 \\ 1.28 \\ 0.95 \\ 0.68 \\ 0.14 \end{pmatrix} \text{mmscfd} \qquad P_{oil} := \begin{pmatrix} 0 \\ 100 \\ 200 \\ 300 \\ 600 \end{pmatrix} \text{BPD}$$

$$P := \text{augment}(P_{gas}, P_{oil})$$

Test Data:

$$D_{gas} := \begin{pmatrix} 1.92 \\ 0.28 \\ 0.42 \\ 0.63 \\ 0.86 \\ 1.02 \end{pmatrix} \text{mmscfd} \qquad D_{oil} := \begin{pmatrix} 0.00001 \\ 577 \\ 474 \\ 342 \\ 246 \\ 194 \end{pmatrix} \text{BPD}$$

$$\text{Data} := \text{augment}(D_{gas}, D_{oil})$$

$$GOR := \overrightarrow{\frac{\text{Data}^{\langle 0 \rangle} \cdot 10^6}{\text{Data}^{\langle 1 \rangle}}} \qquad GOR = \begin{pmatrix} 192000000000 \\ 485 \\ 886 \\ 1842 \\ 3496 \\ 5258 \end{pmatrix}$$

Test Conditions: $\rho_g := 4.94 \dfrac{\text{lbm}}{\text{ft}^3}$ $\qquad \rho_{std} := .042 \dfrac{\text{lbm}}{\text{ft}^3}$

Calculations made using
Mathcad 2000 Professional

Calculations:

Curve Fit of Prediction Data:

Cubic spline fit through prediction data with Oil as a function of Gas

$P := \mathrm{csort}(P, 0)$

$S := \mathrm{cspline}\left(P^{\langle 0 \rangle}, P^{\langle 1 \rangle}\right)$

$Oil_{fit}(x) := \mathrm{interp}\left(S, P^{\langle 0 \rangle}, P^{\langle 1 \rangle}, x\right)$

Cubic spline fit through prediction data with Gas as a function of Oil

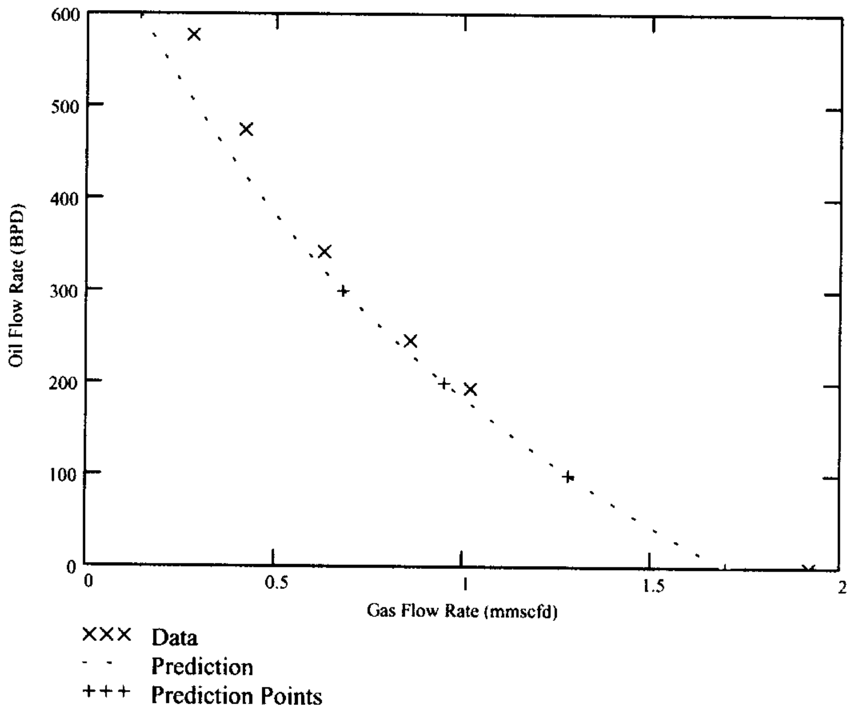
$P := \mathrm{csort}(P, 1)$

$S := \mathrm{cspline}\left(P^{\langle 1 \rangle}, P^{\langle 0 \rangle}\right)$

$Gas_{fit}(x) := \mathrm{interp}\left(S, P^{\langle 1 \rangle}, P^{\langle 0 \rangle}, x\right)$

$gas := \min(P_{gas}), (\min(P_{gas}) + .1) .. \max(P_{gas})$

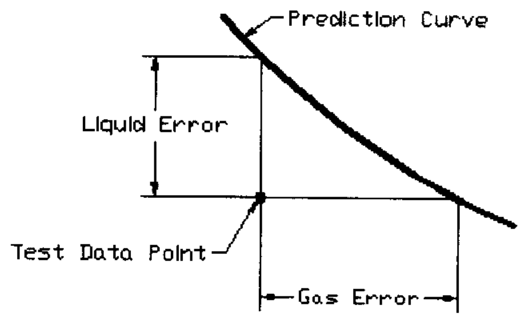
Graph of Prediction Data, Prediction Curve Fit, and Test Data



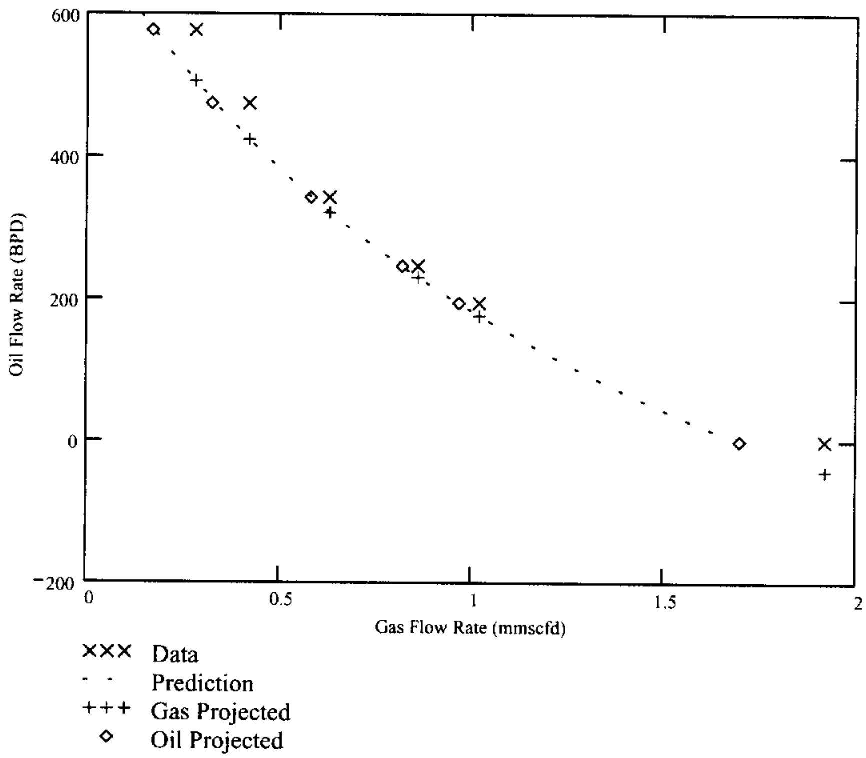
Calculate Individual Gas and Liquid Flow Rate Errors:

Calculate the liquid error by determining the point on the prediction curve at which the gas flow rate matches the gas rate of the test point and subtracting the liquid rate of the test point from the predicted liquid flow rate at that point on the curve.

Calculate the gas error by determining the point on the prediction curve at which the liquid flow rate matches the liquid rate of the test point and subtracting the gas rate of the test point from the predicted gas flow rate at that point on the curve.



Graph of the prediction curve and the test data points with the corresponding liquid and gas projected points.



Calculations made using
Mathcad 2000 Professional

$$Gas_{proj} := \text{augment}\left(Data^{\langle 0 \rangle}, Oil_{fit}\left(Data^{\langle 0 \rangle}\right)\right)$$

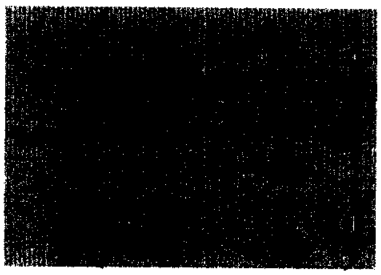
$$Oil_{proj} := \text{augment}\left(Gas_{fit}\left(Data^{\langle 1 \rangle}\right), Data^{\langle 1 \rangle}\right)$$

Projected Points on Prediction Curve:

$$Gas_{proj} = \begin{pmatrix} 1.92 & -41.891 \\ 0.28 & 504.952 \\ 0.42 & 423.206 \\ 0.63 & 321.243 \\ 0.86 & 231.018 \\ 1.02 & 177.058 \end{pmatrix} \qquad Oil_{proj} = \begin{pmatrix} 1.7 & 1 \times 10^{-5} \\ 0.17 & 577 \\ 0.324 & 474 \\ 0.582 & 342 \\ 0.819 & 246 \\ 0.968 & 194 \end{pmatrix}$$

$$\%Err_{oil} := \overrightarrow{\frac{Oil_{fit}\left(Data^{\langle 0 \rangle}\right) - Data^{\langle 1 \rangle}}{Data^{\langle 1 \rangle}} \cdot 100} \qquad \%Err_{gas} := \overrightarrow{\frac{Gas_{fit}\left(Data^{\langle 1 \rangle}\right) - Data^{\langle 0 \rangle}}{Data^{\langle 0 \rangle}} \cdot 100}$$

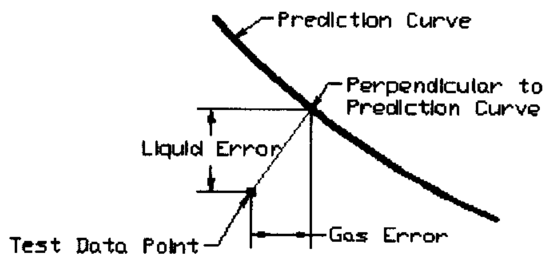
$$\%Err := \text{augment}\left(\%Err_{gas}, \%Err_{oil}\right)$$



Gas Only and Liquid Only Prediction Errors

Calculate the Projected Gas and Liquid Flow Rate Errors:

Calculate the individual phase prediction errors by finding the projected point on the prediction curve that falls on a line which passes through the test point and is perpendicular to the prediction curve. Calculate the errors by subtracting the flow rates at the test point from the flow rates at the projected point on the prediction curve.



Find the projected point:

$$
P(P1, P2, Data, tol, n) := \left|
\begin{array}{l}
step \leftarrow \dfrac{P2_0 - P1_0}{n} \\
x \leftarrow P1_0 + step \\
i \leftarrow 0 \\
\text{while } i \le n - 3 \\
\quad \left|
\begin{array}{l}
m1 \leftarrow \dfrac{Oil_{fit}(x + step) - Oil_{fit}(x - step)}{2step} \\
m2 \leftarrow \dfrac{Oil_{fit}(x) - Data_{0,1}}{x - Data_{0,0}} \\
err \leftarrow \left| \dfrac{m1 - m2}{\left(\dfrac{m1 + m2}{2}\right)} \right| \\
Info_{i,0} \leftarrow x \\
Info_{i,1} \leftarrow Oil_{fit}(x) \\
Info_{i,2} \leftarrow err \\
Info_{i,3} \leftarrow m1 \\
Info_{i,4} \leftarrow m2 \\
Info_{i,5} \leftarrow i \\
x \leftarrow x + step \\
i \leftarrow i + 1
\end{array}
\right. \\
Info \leftarrow csort(Info, 2) \\
\left[P \leftarrow \left(Info_{0,0} \;\; Info_{0,1}\right)\right] \text{ if } Info_{0,2} \le tol \\
P \leftarrow \left(0 \;\; Info_{0,2}\right) \text{ otherwise} \\
P
\end{array}
\right.
$$

$$P1 := \left(Gas_{proj_{0,0}} \;\; Gas_{proj_{0,1}}\right)^T$$

$$P2 := \left(Oil_{proj_{0,0}} \;\; Oil_{proj_{0,1}}\right)^T$$

$$D := \left(Data_{0,0} \;\; Data_{0,1}\right)$$

$$Proj := \left| \begin{array}{l} i \leftarrow 0 \\ n \leftarrow rows(Data) - 1 \\ \text{while } i \le n \\ \quad \left| \begin{array}{l} P1 \leftarrow \left(Gas_{proj_{i,0}} \;\; Gas_{proj_{i,1}}\right)^T \\ P2 \leftarrow \left(Oil_{proj_{i,0}} \;\; Oil_{proj_{i,1}}\right)^T \\ Data \leftarrow \left(Data_{i,0} \;\; Data_{i,1}\right) \\ Info \leftarrow P(P1, P2, Data, .005, 1000) \\ Proj_{i,0} \leftarrow Info_{0,0} \\ Proj_{i,1} \leftarrow Info_{0,1} \\ i \leftarrow i + 1 \end{array} \right. \\ Proj \end{array} \right.$$

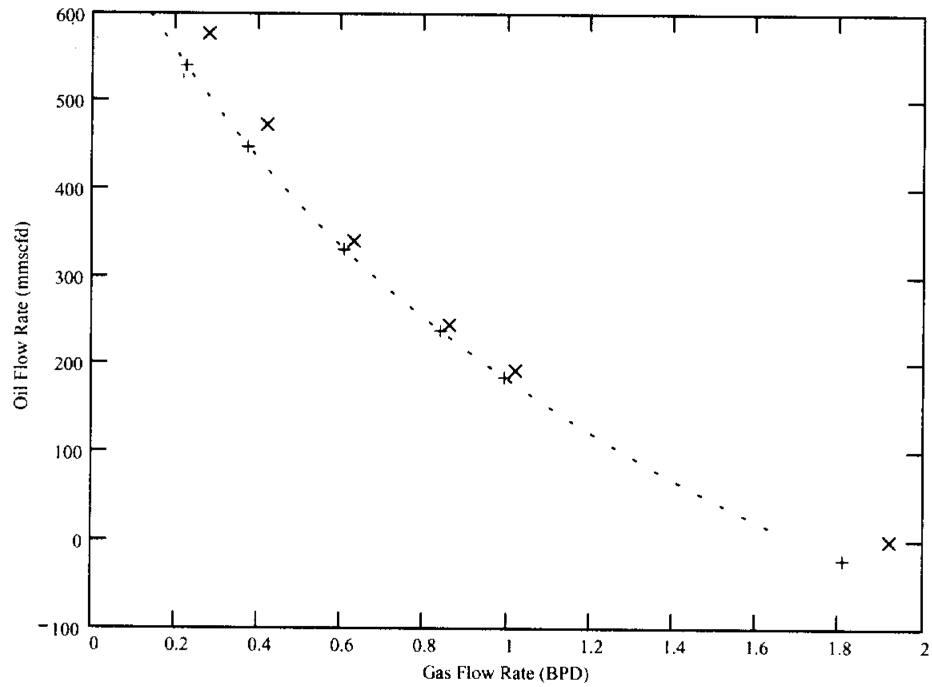
Projected Points

$$Proj = \begin{pmatrix} 1.808 & -21.348 \\ 0.225 & 540.462 \\ 0.375 & 448.321 \\ 0.607 & 331.56 \\ 0.839 & 238.485 \\ 0.994 & 185.5 \end{pmatrix}$$

Test Data

$$Data = \begin{pmatrix} 1.92 & 1 \times 10^{-5} \\ 0.28 & 577 \\ 0.42 & 474 \\ 0.63 & 342 \\ 0.86 & 246 \\ 1.02 & 194 \end{pmatrix}$$

Graph of the prediction curve, test data, and the projected points on the prediction curve.



××× Data
- - Prediction
+++ Projected

Note: The projected points do not appear to be perpendicular to the prediction curve because of the axis scaling.

$$\%Err_{proj} := \overrightarrow{\frac{Proj - Data}{Data}\cdot 100}$$

[redacted]

Projected Prediction Errors Separated By Phases

Calculate the Total Volume Error

Calculate the total volume error by converting the test data and projected prediction points to a volume flow rate and adding the liquid and gas phases to get a total volume flow rate. Calculate the error by subtracting the total volume at the test point from the total volume of the projected point.

$$D_{vol} := \text{augment}\left(\text{Data}^{\langle 0 \rangle} \cdot \frac{\rho_{std}}{\rho_g} \cdot \frac{10^6}{1440}, \text{Data}^{\langle 1 \rangle} \cdot \frac{5.614}{1440}\right)$$ volumetric flow rate for each phase

$$\text{Proj}_{vol} := \text{augment}\left(\text{Proj}^{\langle 0 \rangle} \cdot \frac{\rho_{std}}{\rho_g} \cdot \frac{10^6}{1440}, \text{Proj}^{\langle 1 \rangle} \cdot \frac{5.614}{1440}\right)$$

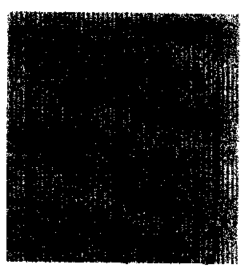
$$D_{vol.t} := D_{vol}^{\langle 0 \rangle} + D_{vol}^{\langle 1 \rangle}$$ total volumetric flow rate

$$D_{vol} = \begin{pmatrix} 11.336 & 3.899 \times 10^{-8} \\ 1.653 & 2.249 \\ 2.48 & 1.848 \\ 3.72 & 1.333 \\ 5.078 & 0.959 \\ 6.022 & 0.756 \end{pmatrix} \frac{t^3}{in} \qquad D_{vol.t} = \begin{pmatrix} 11.336 \\ 3.903 \\ 4.328 \\ 5.053 \\ 6.037 \\ 6.779 \end{pmatrix} \frac{ft^3}{min}$$

$$\text{Proj}_{vol.t} := \text{Proj}_{vol}^{\langle 0 \rangle} + \text{Proj}_{vol}^{\langle 1 \rangle}$$

$$\text{Proj}_{vol} = \begin{pmatrix} 10.674 & -0.083 \\ 1.33 & 2.107 \\ 2.212 & 1.748 \\ 3.581 & 1.293 \\ 4.955 & 0.93 \\ 5.868 & 0.723 \end{pmatrix} \frac{ft^3}{nin} \qquad \text{Proj}_{vol.t} = \begin{pmatrix} 10.59 \\ 3.437 \\ 3.96 \\ 4.874 \\ 5.884 \\ 6.591 \end{pmatrix} \frac{ft^3}{min}$$

$$\%\text{Err}_{vol} := \overrightarrow{\frac{\text{Proj}_{vol.t} - D_{vol.t}}{D_{vol.t}}} \cdot 100$$



Combined Projected Error