DRILL STRING SAFETY VALVE TEST PROGRAM

by

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OBJECTIVE

The objective of this task was to experimentally measure the torque required to close and open drill string safety valves for various flow rates, back pressures, and valve designs.

ABSTRACT

As a primary component of the drillpipe blowout protection system, drill string safety valves should be very reliable. The drill string safety valve's reliability is questionable in its current design configuration. The Petroleum Engineering Research and Technology Transfer Laboratory (PERTTL) under grants from the U.S. Department of the Interior's Minerals Management Service has conducted research to investigate the mechanism of failure associated with the common failure modes. The research also intends to make recommendations for designs that will solve the reliability problems associated with these valves.

INTRODUCTION

A study of blowout preventer pressure test results by the Minerals Management Service (MMS) for the U.S. Outer Continental Shelf during 1993 and 1994 identified drill string safety valves (DSSV's) as one of the least reliable components of the well control system **[Hauser, 1995]**. **Figure 1** details the results. Note that the pressure test failure rate for drill string safety valves and inside blowout preventers was about 25%. This was especially troublesome, since the level of redundant protection for blowouts through the inside of the drill string is much less than for flow through the annulus. Note also the choke manifold had a high pressure test failure rate. A failure in this component is not as serious because these valves are not a primary blowout barrier. Failure of one of these valves generally would not lead to a blowout. Because it is a primary blowout barrier for the drill string, failure of the drill string safety valve could have devastating results.

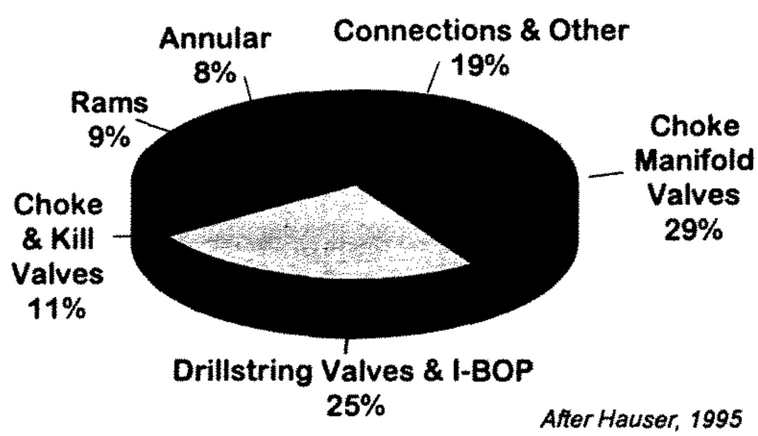


Figure 1: Results compiled from blowout preventer component pressure tests for the U. S. Outer Continental Shelf during 1993 and 1994.

In 1994, Mobil conducted an industry survey which identified 29 safety valve failures during well control operations over an unspecified period. The survey was conducted after Mobil experienced a number of problems in 1993 with stabbing valves leaking after being stripped into a well in a threatened blowout situation. The survey findings, as listed below **[Tarr, 1996]**, identify several common failure modes for safety valves that point to problems inherent to the basic design of the DSSV's.

- Failure to seal against pressure from below
- Failure to open when under pressure due to high torque
- Failure to seal against pressure from above
- Failure to seal against outside pressure when stripped into a well
- Failure to close due to high torque when throttling mud backflow
- Failure to seal due to erosion from abrasive flow

Brian Tarr, one of the authors of the study and a Mobil employee, is also chairing an API Task Group Subcommittee to recommend changes to API Specification 7, Section 2 for Safety Valves. The subcommittee is recommending a new classification scheme for safety valves based on performance testing of valve prototypes. A project jointly sponsored by Mobil and the Gas Research Institute was funding tests of two new prototype valves at the University of Clausthal in Germany. The new prototypes being tested were from German and Canadian manufacturers. The test protocol being followed were the draft procedures being considered by the API Task Group Subcommittee.

In 1995, MMS sponsored a project at LSU to study the failures of DSSV's and recommend improved designs for these valves to help prevent blowouts through drillpipe.

The following topics will be discussed in this report: (1) a review of the basic drill string safety valve terminology and function, (2) common failure modes of DSSV's, (3) identification of alternative devices that can be used with a safety valve to improve reliability, (4) the problems associated with the design of DSSV's that are being addressed by the MMS/LSU project, (5) the experimental test apparatus and procedures, (6) DSSV test results from industry and the results from the experiments at PERTTL, and (7) the recommendations and conclusions drawn from this test data.

DRILL STRING SAFETY VALVES (DSSV'S)

Drill string safety valves are ball valves used to stop flow through the drill string. Shown in **Figure 2** is a photograph of a traditional *TIW* drill string safety valve. The patent has expired on this simple design which is now available from several manufacturers in addition to *Texas Iron Works* (TIW) from which it took its name. The name *TIW Valve* is often used as the generic name for a drill string safety valve. This photograph was taken during a visit to a valve manufacturing facility. The valve has been disassembled here to show the main working components.

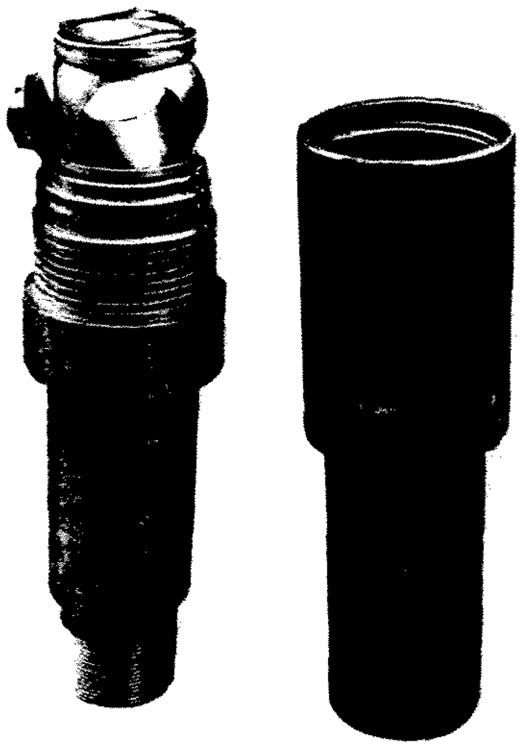


Figure 2: Photograph of the traditional *TIW* drill string safety valve.

Figure 3: Photograph of a safety valve which has been cutaway and made-up on top of a section of drillpipe.

When rotated 180 degrees, the portion of the safety valve shown on the right side of Figure 2 would accept the upper valve seat and spring and screw down over the ball. After assembly, the ball "floats" between the upper and lower seats and seals when pressure is applied against the ball. The spring assists in providing a low pressure seal. The valve stem fits into a circular hole in the valve body. The valve is operated by means of a wrench that is inserted into the valve stem and turned one quarter turn.

Displayed in **Figure 3** is a photograph of a safety valve made-up on top of a section of drillpipe. The valve has been cutaway so that the ball and seats may be observed. This particular safety valve is a one piece valve design that eliminates the need for threads in the valve body area. This not only decreases the number of possible leak paths, but also eliminates the problem of the ball locking due to excessive make-up torque. The basic design remains with a floating ball in a cage which houses the fixed upper and lower seats.

Shown in **Figure 4** are the traditional locations of safety valves. Government regulations require that a safety valve, with an operating wrench, for each size drillpipe be maintained on the rig floor at all times.

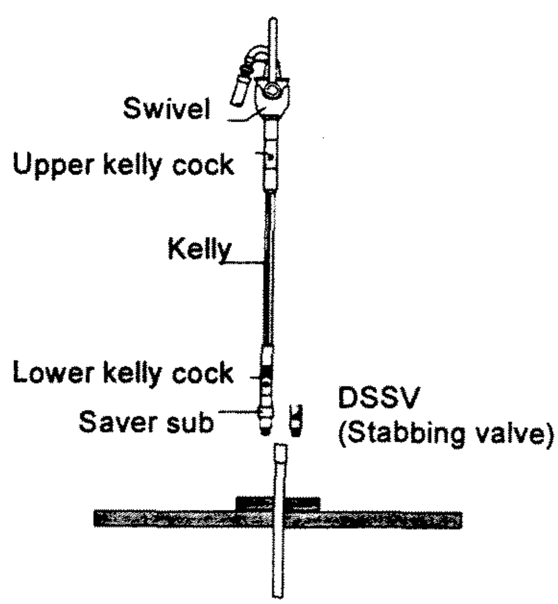


Figure 4: Schematic showing traditional locations of safety valves.

COMMON FAILURE MODES

During fishing operations in the J.W. Goldsby No. 1, observations began to indicate that the 18.0 ppg mud in the hole was insufficient to maintain well control. After backing off the pipe in preparation to sidetrack the well, it began to flow up the drillpipe. The well would not flow with the kelly attached, but flowed when the kelly was removed. It was decided that the kelly saver sub and the DSSV would be left on the drillpipe in the closed position in order to rig up chicksan to the trip tank. After the chicksan was rigged up, the DSSV was opened and it was noted that the well was flowing. The DSSV was closed but failed to seal. In the time it took to ready a second DSSV, the well flowed 25 bbls. Stabbing the valve on a joint of drillpipe to overcome the flow, the second valve would not seal when closed. A third valve was stabbed using the same technique and also would not seal when closed. Attempts to close the valve included rigging the valve wrench to the catline to try to force the valve closed. This resulted in bent and sheared wrenches. **Figure 5** is a photograph of the well taken during the blowout. The well was estimated to be flowing at 1000 BPH with a measured flowing pressure of 3800 psi and a shut in pressure of 7300 psi.

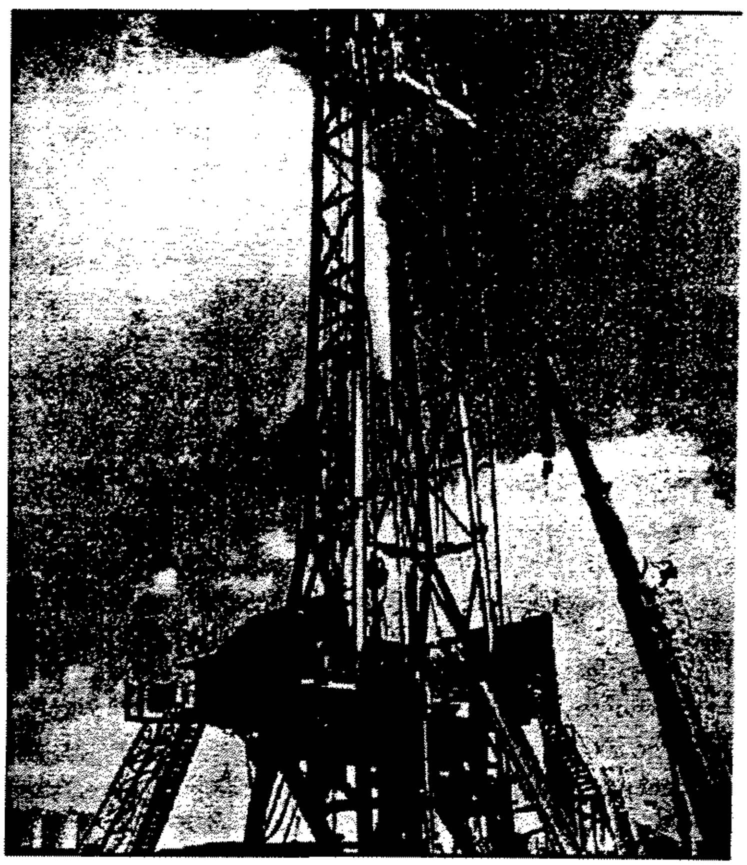


Figure 5: Photograph of Amoco Goldsby Blowout.

Amoco conducted a series of safety valve tests at their research lab after their Goldsby Blowout in 1990. The results of this unpublished study provides information on common failure modes for safety valves. The Goldsby blowout let the high pressure, high flow rate fluid move from below the valve, past the ball and seats, and out of the top. A similar failure occurs when pressure testing equipment is installed on top of a faulty safety valve which allows flow from above the valve, past the ball and seats, and into the drillpipe below. This prevents a valid pressure test from being performed.

Eroded balls, seats and seals are common. The erosion is due to flow of mud solids through the valve as it is being closed. These failures are caused by a partially closed or over rotated valve. If high flow rates are going to be stopped, the valve must be shut completely and quickly. If the valve is not completely closed in one quick motion, a narrow flow path is created between the ball and the seat, eroding the closing side of the seal in a very short time. If the valve is slammed shut there is a possibility of a permanent deformation in the valve stem stop. This deformation allows the ball to be over rotated causing a flow path to erode the seal on the opposite side. However, if the ball is not aligned perfectly in the open position, erosion in an upper or lower kelly valve will also occur during normal drilling operations. In addition, erosion is caused by wireline work done through the valve.

After stripping a stabbing valve into the well, a failed safety valve can let pressure move from the annular space around the valve, in through the valve stem, and into the drillpipe. Surface pressure readings will be irregular or misleading and could cause mistakes to be made during the well control operations. This is caused when the stem is eroded by an unintentional flow path or is damaged by stress cracks. Failed elastomers can also cause this type of failure.

Failure of the valve to close within the available torque limits is another significant failure mode. About 400 ft-lbs is generally regarded as an upper limit of torque that can be applied manually with an operating wrench. If the torque required to completely close the valve is exceeded before the valve is fully closed, the one of the failures associated with partially closed valves can occur. High torque is caused by the build up of pressure in the valve as the valve begins to restrict the flow. The pressure pushes the valve stem further into and against the valve body and the ball is forced against the upper seat. These two actions create friction forces that can not be overcome. If the ball and stem are put under too much pressure, local stress deformations create metal to metal contacts with the associated high friction surfaces. Poor dimensional tolerances also allow metal to metal contact. The ball of a two-piece valve often locks if too much make-up torque is applied across the valve body. Tong placement is critical when tightening across this type of valve.

Failure of the valve to open on a pressure differential or even after pressures are equalized across the ball is also a failure mode. When the torque required to open the valve to start well control operations is too high, the valve has completely failed. It is sometimes necessary to freeze a plug of ice-mud below the safety valve so that the valve can be replaced while there is pressure on the drillpipe. Higher torque values occur during opening yet are caused by the same actions associated with high torque values during closing.

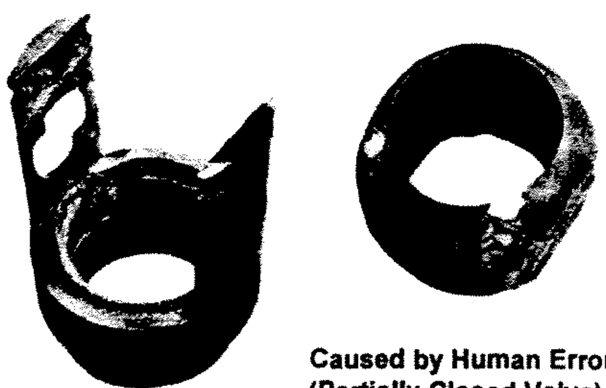


Figure 6: Photograph of ball and seat that has been eroded by mud flowing through a partially closed lower kelly valve.

Shown in **Figure 6** through **Figure 12** are photographs of failed safety valve components. These photographs were taken during a visit to a safety valve manufacturer and at PERTTL. They illustrate some of the types of failures that have been discussed. The backgrounds of the photographs have been cleaned up electronically to better show the components of interest.

Shown in **Figure 6** is a photograph of a ball and seat that has been eroded by mud flowing through a partially closed lower kelly valve. The valve was erroneously left in this position during drilling operations and would not seal during a well control event.

An example of a safety valve ball cut by wireline work being done through the valve is illustrated in **Figure 7**. In order to achieve as large a bore as possible, there is not much extra sealing area on the spherical surface near the ID of the ball. This type of wear can open a leak path that can then be further eroded by flow of mud.

A valve seat cut by fluid erosion due to a slightly over closed valve is depicted in **Figure 8**. Wear on the valve stem stop can sometimes allow too much rotation of the ball. The design of the valve stem stop is very important. A photograph illustrating a failure in the valve stem is shown in **Figure 9**.

Figure 7: Safety valve ball cut by wireline.

Figure 8: Valve seat cut by fluid erosion caused by over-rotation of the ball valve.

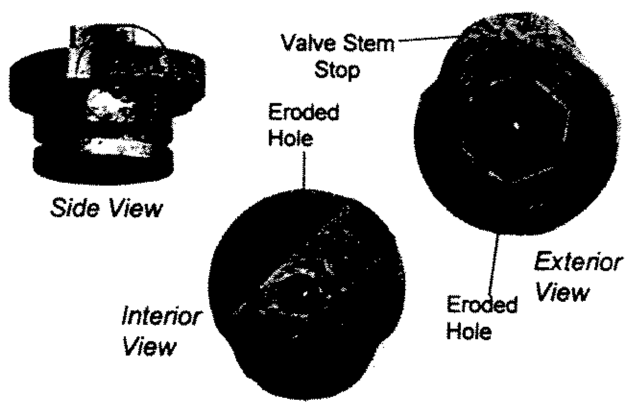


Figure 9: Photograph illustrating valve stem failure.

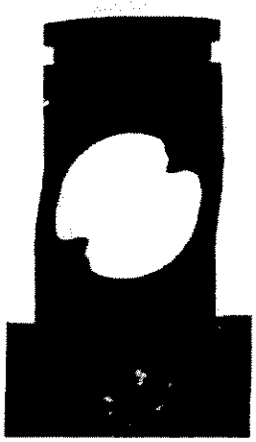


Figure 10: Ball cage deformed around stem opening by excessive torque.

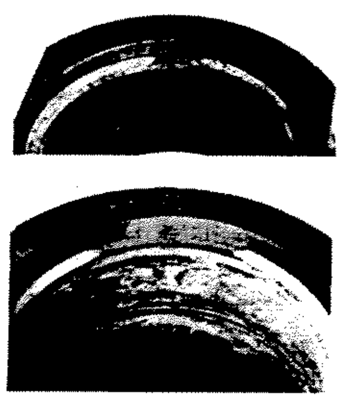


Figure 11: Seal erosion caused by over rotation of the ball.

Figure 12: Valve stem wear due to ball cage deformation.

Figure 10 shows a valve component that has been subject to excessive torque, which caused permanent deformation in the ball cage and valve stem stops. The resulting deformation allowed over rotation of the ball which caused seal erosion (shown in **Figure 11**) and metal to metal contact between the ball cage and the valve stem. This contact is apparent from the wear shown in **Figure 12** on the valve stem.

AUXILIARY DEVICES

Patent searches have supplied good coverage of devices to prevent blowouts through the drillpipe. After 23 patents were reviewed, it was found that a number of alternatives to ball valves have been tried. However, ball valves appear to be best suited to the need for full opening valves with a small outside diameter that can be stripped into the well under pressure. Therefore, auxiliary equipment that compliments the use of safety valves and increases the number of barriers to a blowout through the drill string is preferred. Much of this auxiliary equipment has been identified through discussions with industry experts. The auxiliary equipment identified for added blowout barriers included shear rams, floats or check valve placed in the drill collars near the bottom of the drill string, a drop-in check valve, a velocity triggered check valve, and a double valve assembly.

Shear rams can be used to cut through the drillpipe and close the well on top of the drillpipe if the safety valve fails. The disadvantage of shearing the drillpipe and dropping it to bottom is that it can make it more difficult to eventually circulate kill mud to the bottom of the well.

Floats or drill collars are widely used by some operators to make it easier to stab and close safety valves at the surface. Both flapper and dart type check valves are available. Even if the check valve leaks, the flow rate is generally reduced enough so that the safety valve can be successfully closed without cutting out the valve. Operators may not want to use floats for the following reasons: (1) extra time is needed to fill the inside of the pipe when lowering pipe into the well, (2) higher surge pressures occur when pipe is lowered into the well, and (3) the shut-in drillpipe pressure is more difficult to read after taking a kick.

The drop-in check valve overcomes many of the objections to a float in the drill collars. **Figure 13** is a schematic of a drop-in check valve. A sub that will accept a check valve is run in the drill string near bottom. Just before it becomes necessary to pull the drill string from the well, the check valve assembly is dropped into an open drillpipe connection and pumped to bottom where it latches into the sub. If the well tries to blowout during tripping operations, the check valve will stop the flow and make it easy to stab and close the

Figure 13: Schematic of a drop-in check valve.

surface safety valve as part of the shut-in procedure. In the event wireline work below the check valve becomes necessary, the drop-in check valve is wireline retrievable.

An example of a velocity triggered check valve is shown in **Figure 14**. This valve was designed and tested to a limited extent during the late 70's by Hughes Tool Company for Shell. It was lost in the shuffle of buy-outs during the 80's. Prototype valves are again being built by a new company. Future research will test this valve as part of the MMS project at LSU.

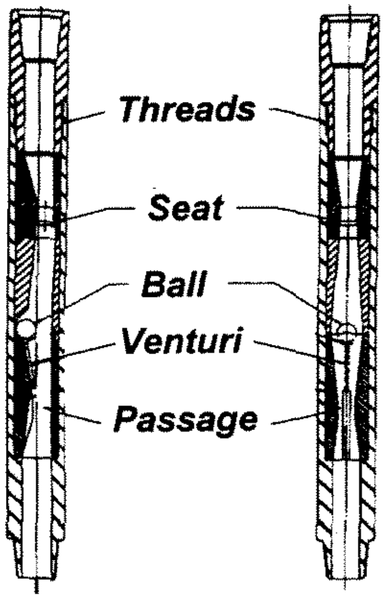


Figure 14: Velocity triggered check valve.

Figure 15: Double ball valve assembly.

In the double valve assembly, as seen in **Figure 15**, we assume that the lower ball may cut out for high flow rates but that the flow rate should be reduced enough to allow the upper valve to be successfully closed if it is closed before the bottom valve totally fails. The bottom valve can also be used as a mud saver valve since a back-up valve is available.

The problem with this approach is that it is not well suited to stabbing valves because of the extra weight that must be handled. A single stabbing valve for 4.5-in. or 5-in. drillpipe weighs more than 100 lbs. To minimize the weight of a double valve, one manufacturer is currently working on a double ball, single body design. This new valve design is currently being field tested by Amoco near Baton Rouge in the Tuscalousa trend.

TEST APPARATUS

The test apparatus designed for the data acquisition associated with testing the DSSV's is shown in **Figure 16** and **Figure 17**. The torque sensor is the primary data generating device used in the testing of the DSSV's. The sensor was chosen over a torque wrench because the information from the sensor is much easier to incorporate with other data taken during the experimental tests. The torque sensor is manufactured in such a way that it is simple to put the apparatus together quickly. A pneumatic actuator is used to open and close the DSSV's with the torque sensor fixed between the valve and the operator. The actuator is designed to be used

Figure 16: Test apparatus with pump in background.

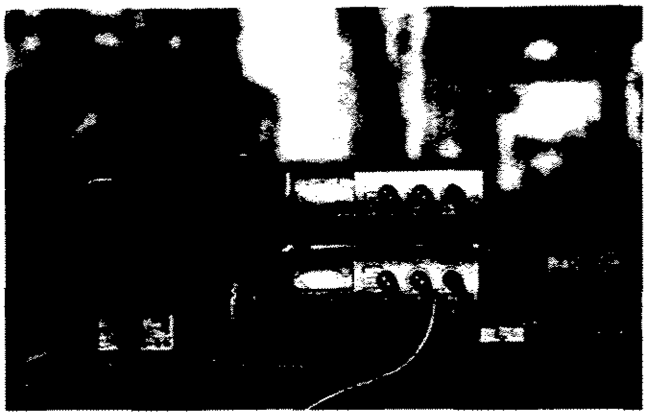


Figure 17: Test apparatus torque sensor, operator, and potentiometer

with valves that open and close through ninety degrees. The force generated by the actuator is supplied by air pressure coming in through a low pressure regulator. The actuator is easily activated using a shuttle valve located downstream from the pressure regulator. The position of the valves is determined from a signal generated by a resistance potentiometer fixed to the actuator. A check system is utilized to tell if the valve is closing completely. A microphone is fixed to the valve and the flow noise is amplified and displayed on an oscilloscope next to the valve. The operator can easily see when the valve has complete closure by looking at the noise generated by the microphone.

The data is acquired through an analog to digital PC board and stored using LabView software. Additional sensors to record pressure in the test string also generate signals recorded by the software during the tests.

TEST PROCEDURES

The testing of the DSSV's was done in two different ways: (1) a static pressure test, and (2) closing on flow. The static pressure test consists of putting the test piping and equipment in the configuration shown in **Figure 18**. When the test string is pressured to the test pressure set at the choke, the drill string safety valve is subjected to static pressure. The valve is then closed on this static pressure and the torque and other data is recorded. The next test point is taken by increasing the set point of the choke to a higher pressure setting.

The flow test configuration is shown in **Figure 19.** To test the valve under flowing conditions, circulation through the test piping is established at the test rate. The valve is closed on the flow and the torque and other data is recorded. To move to the next test point, the flow is increased to the next desirable level.

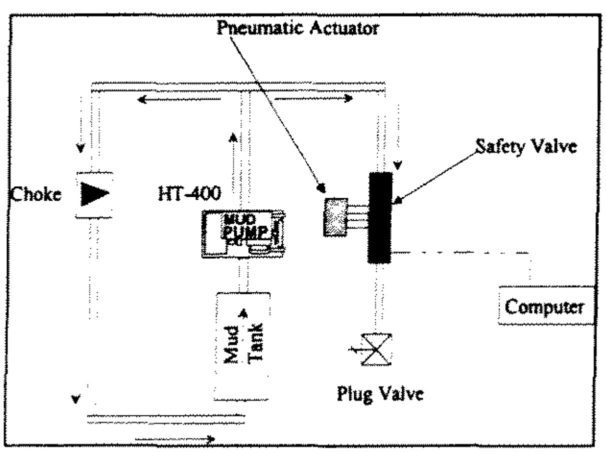


Figure 18: Static test diagram.

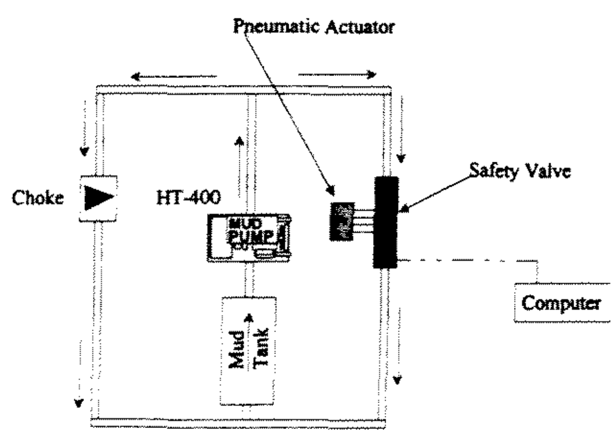


Figure 19: Flow test diagram.

FINDINGS

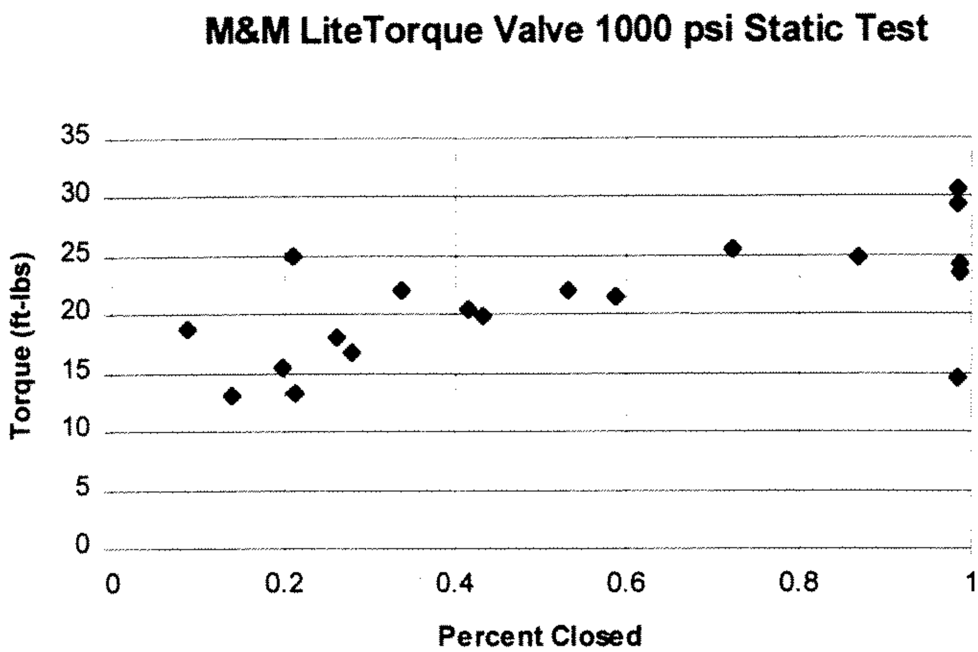
Using the test apparatus and the testing procedures, test results for two commercially available valves were obtained from two different experiments. The static pressure test was performed on a TIW two-piece valve and an M&M LiteTorque valve. The flow test was also performed on these two valves. The static pressure test was performed at 1,000 psi on each of the valves. The collected data for the two valves are shown side by side in **Figure 20** to make a comparison between the two valve designs. Closing values of twenty-five to thirty-five foot-pounds of torque for the Lite- Torque valve are three to four times smaller than the 110 to 115 foot-pounds of torque for the two-piece (TIW) valve. **Figure 21**, the graphs for the 2,000 psi static tests, shows the LiteTorque valve torque values ranging from twenty to forty foot-pounds and the two-piece (TIW) valve torque values exceeding 300 foot-pounds. At 3,000 psi, the LiteTorque valve has torque values that do not exceed fifty-five foot-pounds and the two-piece (TIW) valve exceed 500 foot-pounds. These graphs are shown in **Figure 22**. The static pressure tests of the different valves makes the design differences of the two valves more apparent. The LiteTorque valve contains a bearing between the stem and the valve body. This bearing reduces the frictional forces between the valve stem and the valve casing. The two-piece valve based on a more conventional TIW design does not have the bearing between the stem and the casing and the frictional forces in this area cause increased torque values to be obtained.

The flow test was performed using flow rates that started at 100 gallons per minute (gpm) and increased by 50 gpm up to 350 gpm. Three closing cycles were recorded at each of the flow rates for the M&M LiteTorque valve and the M&M two-piece (TIW) valve. The results for the LiteTorque valve and for the two-piece valve are shown in **Figure 23** and **Figure 24**. Although the flow test data for the two valves differs significantly in value, the condition of the two valves also varies significantly. The LiteTorque valve was flow tested after being used to calibrate the test apparatus in a variety of configurations. This particular valve had been used extensively as the "set up" valve for all of the testing procedures for many months. The two-piece TIW valve was rebuilt with completely new elastomer seals around the stem and new teflon seals in the seats. The past use the LiteTorque valve and the recent rebuild of the two-piece TIW valve make up for the difference in the torque values that were recorded in the data.

CONCLUSION AND RECOMMENDATIONS

The following conclusions can be drawn based on the results obtained in this study to date:

1. Some of the DSSV's tested in this study would not close above 180 gpm with 600 ft-lbs of torque. A significant chance of valve failure has been observed both in this study and in the field. Since valve failure and a lack of redundancy corresponds to a lack of protection for the drillpipe, auxiliary devices should be available in case of safety valve failure.
2. The results observed for each valve proved to be a function not only of its design and condition, but also the closing technique of the operator in the test stand.
3. Preparation of a training tape to instruct personnel on the common causes of valve failure and on the correct valve closing technique is recommended.
4. Additional testing of the current DSSV designs and the refinement of current designs or the development of additional designs is recommended.



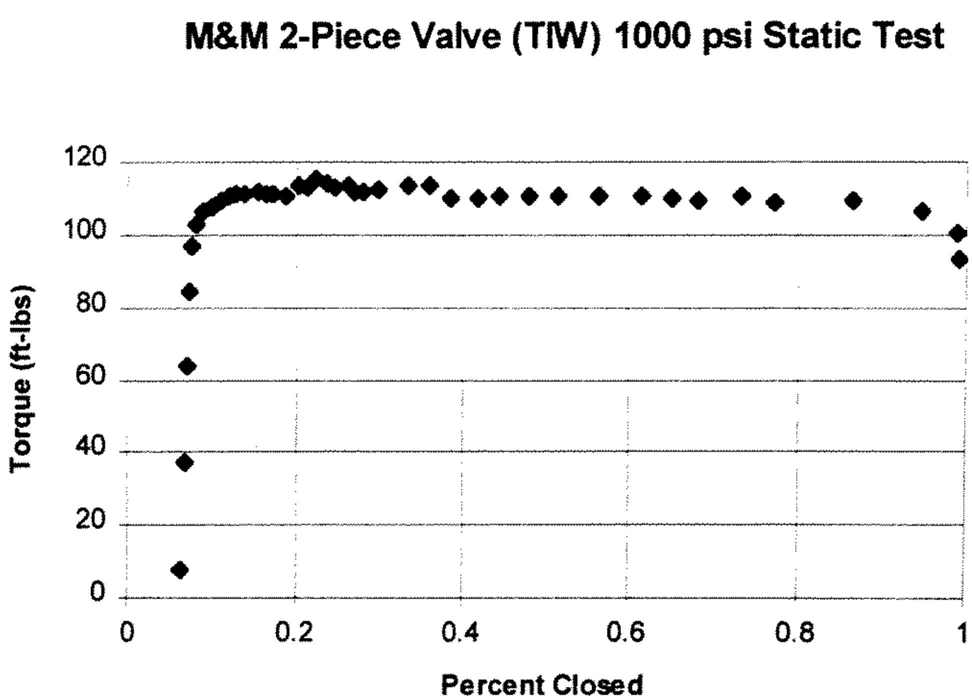
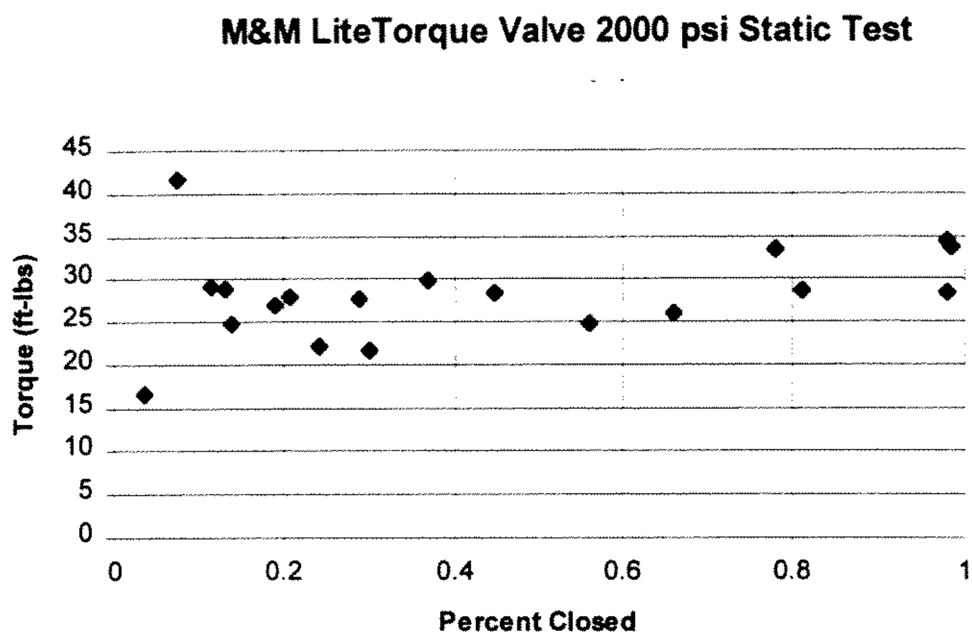


Figure 20: 1000 psi Static test results.



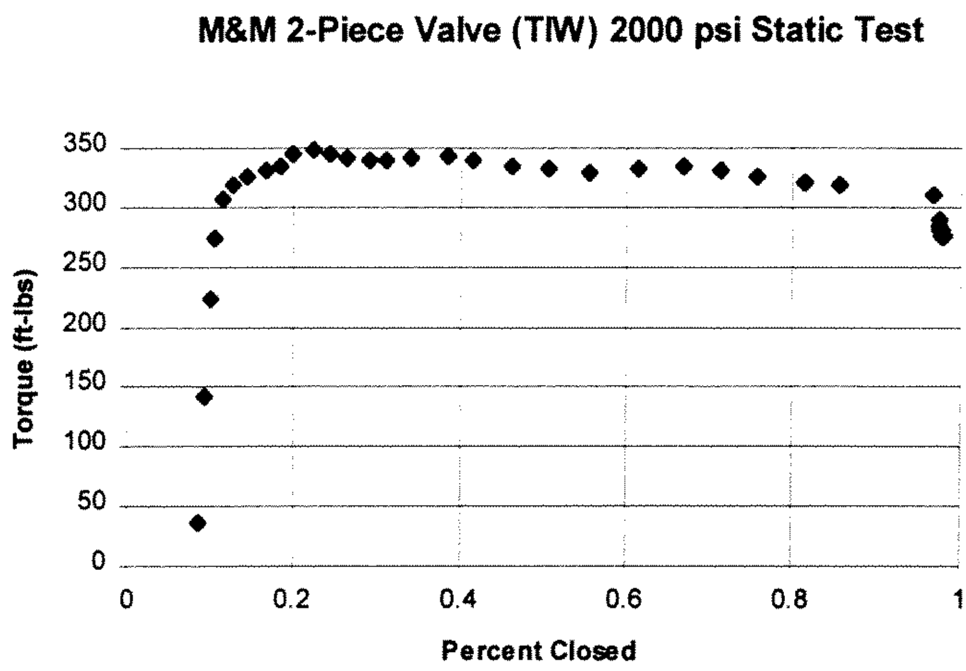
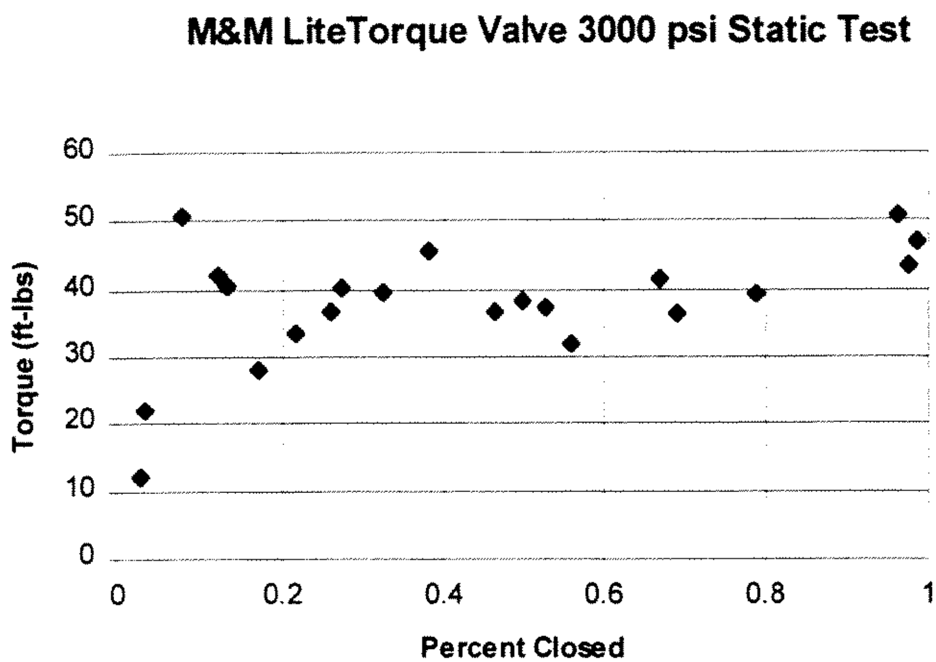


Figure 21:2000 psi Static test results.



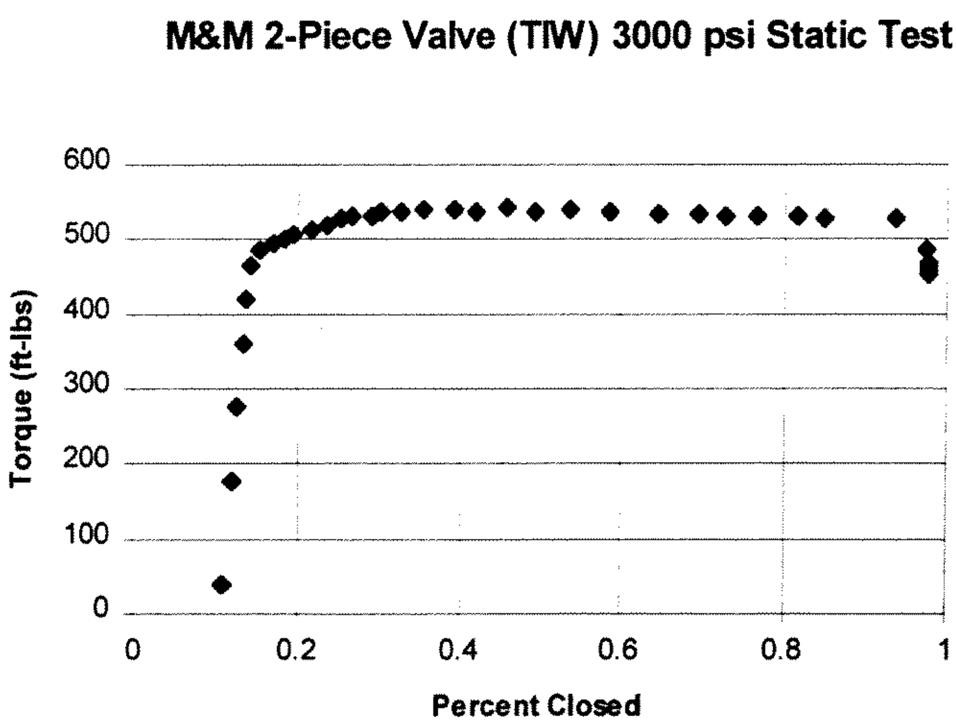


Figure 22: 3000 psi Static test results.

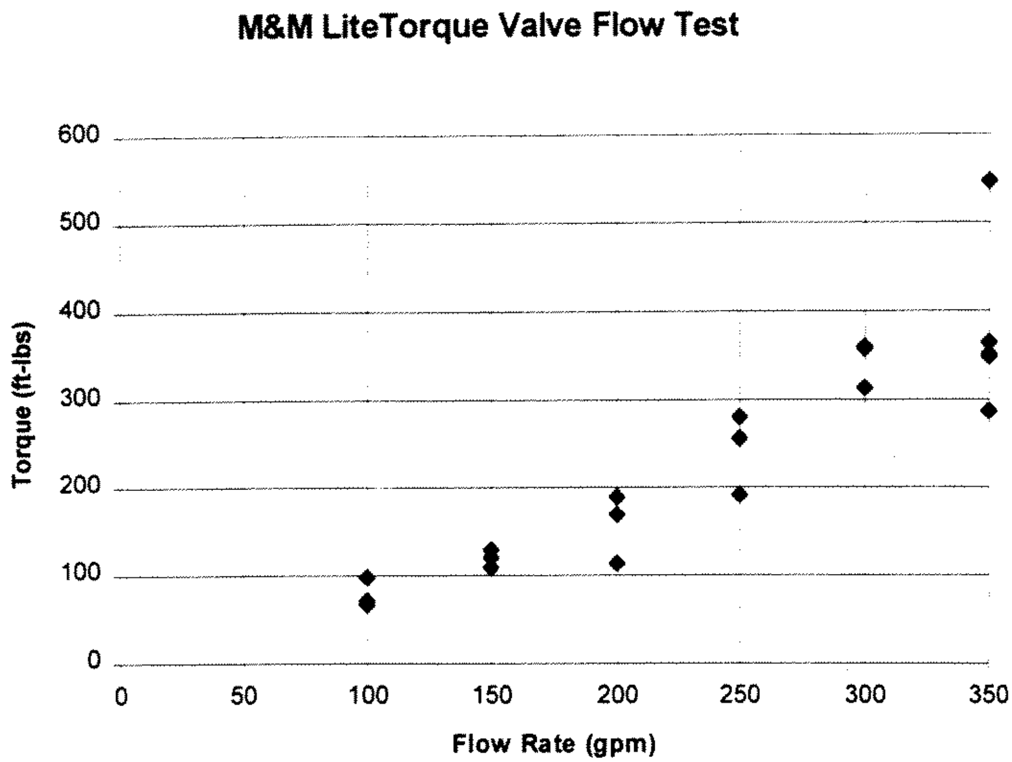


Figure 23: LiteTorque flow test results.

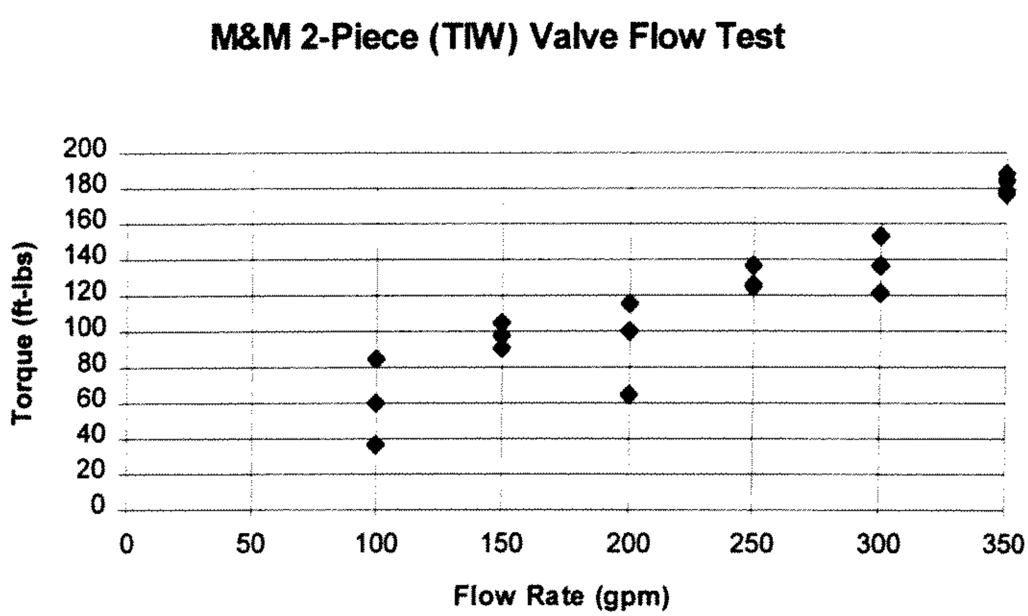


Figure 24: Two-piece flow test results.

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