IMPROVED VALVE DESIGN FOR SUBSURFACE ROD-PUMP ASSEMBLIES AND RELATED IMPROVEMENTS IN OPERATING PROFITS

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A solution now exists for problems attributable to gas interference in down-hole rod-pump assemblies. With the patented Solution Valve (SV), designed and manufactured by Eagle Advanced Oil Field Technologies, gas entering the pump chamber as either free gas or initially as dissolved gas, can be effectively displaced. Positioned on bottom of the conventional plunger, the SV performs in conjunction with conventional standing and travel valves such that the pump chamber is charged with fresh well bore fluids during each pump cycle. Gas locking cannot occur, because all fluids entering the pump are displaced on each stroke, thus eliminating the build up of residual, high-pressure gas bubbles below the plunger or between the SV and an upper travel valve positioned atop the plunger. Improvement in fluid displacement efficiency, with resultant lowering of fluid levels in the tubing-casing annulus, can increase the production of oil and gas.

With the SV it is not necessary for the pump to tag bottom in an attempt to mechanically jar balls off seats and thereby stimulate pump performance. Redistribution of fluids within the SV can often eliminate fluid-pounding topic. Consequently, rod-parts, rod-cut tubing, failures of valve-rods and valve-rod guides can often be eliminated.

Unlike conventional pumps, down-hole debris such as particulate sand, silt, iron sulfide, etc., cannot prevent closing of the SV. Uninterrupted fluid flow through the pump, in conjunction with a constantly rotating seal surface between ball and seat, prevent the accumulation of stagnant fluids and associated settling of debris above and beneath the plunger.

Another ideal application of the SV is in wells where gas cannot be vented up the tubing-casing annulus and where it becomes necessary to pump below a packer. By being able to pump gas as well as liquid, and thus invulnerable to gas-locking, the SV functions quite satisfactorily.

The permanently centered and stationary bail and movable seat of the SV are also well suited for applications in deviated and horizontal well bores where non-vertical orientations can delay ball seating. Similarly, for installations where heavy, viscous crude oils are pumped, the positive and instantaneous opening and closing of the SV eliminate inefficiencies due to ball floating.

INTRODUCTION

Throughout the history of our industry, free gas has been the bane of down-hole pumping devices. To be sure, judicious choices of pump-setting depths in conjunction with the use of dip-tubes and other down-hole separation devices have assisted dramatically by preventing as much gas as possible from entering the pump. But the problem continues to exist. By occupying space that would otherwise be taken up by oil and/or water, gas can significantly reduce the displacement efficiency of the pump stroke. Worse, gas not completely expelled from the pump chamber during the down-stroke must be decompressed during the up-stroke, thus delaying opening of the standing valve. This progression can be cumulative, the end-point of which results in the classic gas-locked pump, a condition wherein the pressure of the gas bubble above the standing valve is <u>greater</u> than the pressure attributable to the hydrostatic head of fluids in the tubing-casing annulus and <u>less</u> than the pressure above the travel valve caused by fluid accumulations in the tubing. Consequently, neither the standing valve or travel valve can open, and the plunger continues ***to*** reciprocate, compressing and decompressing the residual gas bubble. While this extreme condition may not necessarily be permanent, perhaps only lasting from minutes to hours, it can certainly contribute to lost production and/or increased operating costs.

It should be emphasized that high volumes of gas are not required for gas-interference problems to occur. In practice, detrimental effects have been observed in wells producing as little as I5 to 20 Mcf/Day. In contrast, a more reliable indicator of interference seems to be that of producing gas/oil ratio, or perhaps gas/liquid ratio; i.e., the higher the gas/oil ratio, the more likely it seems that gas is detrimentally interfering with down-hole pump performance. To be sure, pump placement and geometry, effectiveness of down-hole gas separation methods, surface venting capacity, as well as the physical properties of the fluids involved and their multiphase relationships, play vital roles in the determination of fluid entry into the pump, pump loading and performance.

It is the purpose of this paper to present a description of the functions and field applications of the Solution Valve. Demonstrated herein are examples of how this simple complement to rod-actuated, down-hole pumps can effectively deal with not only the above-described, deleterious effects of gas interference and the related practice of bottom-tagging, but also how the SV presents a highly acceptable alternative under conditions involving zones isolated below a packer, down-hole debris, deviated or horizontal holes, and heavy, viscous oils.

HISTORY OF DEVELOPMENT

The idea for developing the Solution Valve was conceived by Michael B. Ford in early 1987. In his original model, fluid flowed through the center of the unit and exhausted through milled ports in the stem. Flow resistance and elevated velocities prematurely cut both stem and seat. Various other port designs were tested, from oval-shaped to slotted-flutes to round holes on the stem. In each case, flow cavitations and valve failures resulted.

Ultimately, through many trials and errors, a form of the current design was selected whereby the stem was undercut to allow fluid to equalize in the open chamber of the valve bowl. In this design, problems due to cavitations were eliminated. Additional refinements allowed fluid to exhaust outside the seal stem, thus improving flow dynamics within the valve and further minimizing fluid restrictions. This last change made it possible to drill and tap the seal stem and position a conventional **API** ball on top. **A** hole drilled through the ball permitted it to be anchored in place by a top bolt screwed into the stem.

Tests performed at the Colorado School of Mines revealed the presence of microscopic, hair-line wear patterns on balls extracted from conventional pumps. Wear was particularly pronounced where gas entrapment permitted high-energy releases of gas to violently propel balls against both seats and cages. It was observed that intersections of wear lines were potential leak sites. The stationary ball design of the Solution Valve, with its single, movable wear surface between ball and seat, permits no opportunity for overlapping of wear patterns.

Body components of the first Solution Valve prototype were constructed of 4 140 carbon steel. Valves, stems and seats were made of 440C stainless steel case-hardened to RC58. These metallurgies were satisfactory in some cases, but poor choices in others, particularly in those environments containing hydrogen sulfide or corrosive fluids. Ultimately, following recommendations of the National Association of Corrosion Engineers, **3 16** stainless steel was selected as the alloy of choice for all valve body components, a selection which permitted the SV to be used in both corrosive and non-corrosive environments. An API stellite, nickel-cobalt alloy was chosen for both ball and seat. These metallurgical selections continue to be used in current valve designs.

TOOL DESCRIPTION

Within the SV a permanently positioned ball, centered within the bowl of the valve, is held in place by an undercut top bolt (See Fig. 1). The ball is drilled through to accommodate the bolt and sits atop a ported seal stem. Cross-sectional area and strength of the seal stem are designed to accommodate loads imposed during the pumping cycle. The seal stem is drilled and tapped laterally to accommodate two set screws positioned opposite the undercut segment of the threaded bolt; these function to further secure the bolt in a stable position. Flow area between seal stem and seat plug is sufficiently large that flow resistance is not penalizing and cavitations do not occur.

Riding atop the seat plug is the seat. As with the ball, the seat is maintained in a perfectly centered position within the surrounding valve bowl. The seat plug, screwed onto the bottom of the valve bowl, is in turn screwed onto the bottom of the plunger. Up and down movements of the plunger result in corresponding movements of the seat plug and valve seat in the same direction, thus closing and opening the valve, respectively.

Screwed onto the bottom extension of the ported seal stem is a short drag plunger constructed from **3 I6** stainless steel and coated with standard **API** spray-metal plunger alloy material. Customary clearance between the drag plunger and pump barrel is approximately 0.002". The lower end of the drag plunger is internally tapered to more easily accommodate fluid entry and divert solids and debris away from the plunger-barrel annulus.

When servicing the SV the first time, the two retaining set screws and top bolt can be unscrewed, the ball and seat turned over, and the valve re-run. No other effort or expense is required.

OPERATIONAL ASPECTS

The Solution Valve is positioned at the bottom of the customary pump plunger, while the regular travel valve, usually placed at the bottom of the plunger, is moved to the top. As is normally the case, the standing valve remains positioned at the bottom of the pump barrel.

Frictional drag between the drag plunger and barrel, although small, is sufficient to provide the necessary resistance to affect relative movement of the seat plug on the shaft of the seal stem, and in turn move the valve seat vis-a-vis the ball. As the plunger reverses direction from down to up, this resistance instantaneously forces the seat to close against the centered ball. Almost immediately thereafter, pressure beneath the SV is reduced to near-zero levels, and head pressure imposed by fluid accumulations in the tubing-casing annulus are sufficient to open the standing valve (See Fig. 2, Left Panel). Thereafter, and throughout the remainder of the up-stroke, the pump chamber is charged with new fluids, assuming of course that the well is not pumped off. Positive pressure differential imposed by fluid accumulation in the tubing is sufficient to keep the travel valve closed during this period.

Changing from an up to down direction at the top of the stroke results in reversal of the frictional resistance imposed by the drag plunger. Immediately, the seat is forced away from the ball, thus opening the SV and simultaneously causing the standing valve to close (See Fig 2, Right Panel). At this point the upper travel valve remains closed and prevents fluid loads from being imposed on top of the SV. Throughout the down-stroke the SV remains open, and compression of the volumetric gas fraction between the closed standing valve and upper travel valve eventually become sufficient to open the travel valve and expel fluids into the tubing above.

At the bottom of the stroke a small dead space exists between the SV and the standing valve. In this position, with both the SV and upper travel valves open, pressure within this space is equal to the hydrostatic head imposed by fluids in the tubing. Upon reversal of stroke direction the SV immediately closes, and owing to the small fraction of the pump volume represented, decompression of this space is rapid, and the standing valve open immediately thereafter. This function greatly improves overall pump efficiency and absolutely prohibits the extreme condition of a gas-locked pump. Mechanical jarring or impacting is not required, and certainly not recommended, in order for the SV or travel and standing valves to function efficiently.

It is important to note that to the extent that fractionally-large, high-pressure residual gas bubbles are not allowed to build up above the standing valve, the upper travel valve and standing valve open much more smoothly than with standard assemblies. Violent impacting of balls against cages and seats, and related failures thereof, is greatly reduced.

One simple way to visualize the effectiveness of the SV function is to recall that immediate closing of the SV and corresponding opening of the standing valve at the start of each up-stroke allow the pump to be re-charged with new fluids throughout the upward travel of the plunger. Discharge during the down-stroke of these same fluids through the travel valve and into the tubing therefore must follow. In this manner, the SV displaces gas and/or liquid on every stroke. Functioning as a mini-compressor if required, the SV will actually pump low-pressure gas until such time as more liquid enters the pump intake.

After pumping mostly gas for extended periods, a well may briefly flow, or unload most of the fluid which has accumulated in the tubing. For the period immediately following, particularly in deep wells, it may appear from the surface that the pump has ceased to function. In fact, during this time the SV continues to re-fill the tubing string with new fluids. Cycles of tubing loading followed by rapid unloading may continue for days or weeks until the newly imposed pressure transients, resulting from consistent well-bore withdrawals, are able to establish a more nearly steady-state equilibrium between well-bore and reservoir.

One of the many patented features of the SV is the slightly tapered wall design of the four exhaust ports of the seal stem. During the down-stroke, fluids are displaced upward through the drag plunger, through the four slotted pathways of the seal stem, and around the stationary ball. As these fluids flow along the approximate two-degree bias of the exhaust port walls, centripetal forces imparted against the walls are sufficient to slowly rotate the seal stem and attached drag plunger within the pump barrel. In turn, the ball, being positioned atop and attached to the seal stem, also slowly rotates relative to the seat. To more closely observe this process, laboratory tests were performed with acrylic valves. Here, taper of the port walls was increased stepwise to a maximum of ten degrees; as expected, corresponding increases occurred in the rotational frequency of the seal stem. Resulting pressure drop at the center of the effluent created a vortex sufficiently pronounced that it could be seen through the acrylic wall of the SV.

Thus, the constantly rotating sealing mechanism of the Solution Valve is analogous to the lapping of valves in an engine or compressor where the valves constantly move radially relative to the permanent seats ground into the head(s). The sealing efficiencies of the stationary ball and movable seat continue to improve in the sense that with time and natural wear their surface areas increase. Equally important, debris caught between or tending to adhere to either of the sealing surfaces cannot assume a static, permanent position because of the radial movement of the seat relative to the ball.

BOTTOM-TAGGING NOT REQUIRED

In an effort to help combat the adverse effects of gas interference, many operators resort to the very common practice of "tagging bottom". In this approach the pump is spaced such that at the bottom of the stroke actual contact is made between the plunger and the bottom of the pump. In this manner, standing and/or travel valve balls may be jarred off their seats, and the penalizing effects of delayed valve openings and reduced effective stroke lengths are ameliorated . While an attempt is often made to justify this destructive practice as being "just a light tag", it's a safe bet that at its source, some one or two miles (or more) below the surface of the ground, the actual impact is far from subtle.

"Rod-buckling", "corkscrewing of rods", and "stacking out of rods" are a few of the terms describing the effects that bottom-tagging has on the rod string. The associated cycles of stress reversals induced within the rod string are directly responsible for frequent rod failures, particularly in those rods positioned near the valve-rod and in the upper regions of the rod string. Other direct failures attributable to the compressive and side-loading forces generated during bottom-tagging occur in the valve-rods themselves and in valve-rod bushings (See Fig's. 3-5). Secondary damage caused by the impingement of separated metal fragments can and often does destroy the pump plunger and barrel. Pump shop service professionals commonly describe all such damage as simply due to "pounding".

Rod-cut tubing is frequently another direct result of bottom tagging. And as most operators are aware, the exacerbating effects of corrosion operable under the above-stated conditions further magnify the problem, and vice versa.

ELIMINATION/REDUCTION *OF* **FLUID** POUND

Throughout the upstroke of conventional pump assemblies, entering fluids are able to very quickly segregate within the open barrel beneath the traveling valve. By the time the plunger reaches the top of the up-stroke, a rather stable gas-liquid interface has been established. Upon reversal of stroke direction and throughout the early portion of the down-stroke, the upper free gas phase, which resides between the closed standing valve and the descending traveling valve, is rapidly compressed. During this compression, velocity of the descending plunger is rather constant. However, when the traveling valve abruptly contacts the virtually incompressible liquid phase interface, its velocity abruptly decelerates. This contact, more aptly describable as a high-energy impact, is generally referred to within the industry as "fluid-pound'.

Fluid-pound is always troublesome and can be especially violent when the pressure of the segregated gas phase is very low. Low pump (gas phase) pressures are usually associated with wells having low fluid levels in the tubing-casing annulus, and especially with wells that are pumped off. Typical of wells in this problem category are: 1) Those where fluids are maintained at low levels by pump-off controllers; and 2) Those having pumping units that run continuously (e.g., no time clocks for electrical motors or gas-engine equipped). In these situations, violent fluid-pound can be continuous.

As one might expect, fluid-pound can cause significant damage to the entire pumping assembly. Its effects are directly analogous to the previously described problems associated with bottom-tagging. In each situation rod buckling, or stacking and related stress reversals occur; these, in turn cause failures of rods and pump parts. Moreover, resulting corkscrewed rod configurations wear holes in the tubing. Indeed, these are all very costly consequences of fluid-pound.

With the Solution Valve the above dilemma is usually eliminated, or at worst, greatly reduced in intensity. At the top of the up-stroke, after the pump has been completely recharged with new fluids, pressure trapped between the SV and upper traveling valve is essentially equal to that of the hydrostatic fluid head in the tubing. At the same instant, pressure below the SV is equal to or less than the fluid head in the tubing-casing annulus. That is to say, pressure above the SV is usually much greater than pressure below the SV.

Thus, at the instant the down-stroke begins, and concurrently when the SV opens, high- pressure gas and liquid are suddenly released from above the SV. The jetting action of these entering fluids, spewing through the SV into the pump chamber below, causes atomization of the liquid within the gaseous phase and a temporary redistribution of all fluid phases below the plunger. This more nearly homogenous redistribution provides a rather uniform cushion through which the descending plunger can fall. The previous singular gas-liquid interface is destroyed, and fluid-pound is essentially eliminated.

One final point: When a well is pumped off, the SV continues to pump (compress) gas that is exhausted through the upper travel valve during the down-stroke. However, some residual liquid positioned above the SV will continuously be re-cycled during the down-stroke into the chamber below. In this way, both barrel and plunger remain lubricated. Scored barrels and stuck plungers resulting from dryness and over-heating are eliminated.

PUMPING TRASH AND DEBRIS

Entrained silt, sand, iron sulfide, and other forms of trash can wedge freely-moving balls against cages, occupy space between balls and seats, and perhaps in various other ways, interfere with seating. Even small quantities of debris can hold the ball off its seat. Some liquid not displaced from the pump chamber carries over to the next stroke. This process can continue with progressively more residual oil and/or water accumulating within the pump chamber. With the passing of time gravitational effects become more pronounced, and some of the entrained debris within the stagnant liquid fraction can no longer be held in suspension, but begins to settle out within the pump. This in turn, renders ball seating even less effective, allows for continued growth of the residual liquid fraction, and permits the amount of settled debris to increase still further. Consequently, a greatly accelerated rate of abrasion wear occurs along surfaces of the plunger and barrel. In the extreme, the pump chamber can completely fill with particulate matter, in which case an absence of suitable shut-down controls can lead to violent rod-stacking and potentially damage the entire pumping assembly.

With the Solution Valve, the vertically moving seat always closes around and seals against the stationary and centered ball. The SV closes promptly at the beginning of each up-stroke, thus recharging the entire pump chamber with new fluids until the initiation of the down-stroke. Fluid continues to move through the pump at all times, and the opportunity for settling and accumulation of debris or trash is minimal.

Additionally, and as described previously, the radial movement of the seat effected by the tapered port walls continues to wipe clean the sealing surfaces between ball and seat. In situations where debris is especially concentrated, increasing the taper of the exit port walls imparts greater rotational frequency to the seal stem and seat; this results in an intensification of the swirling forces of the fluid vortex and more effective cleansing of the sealing surfaces.

PRODUCING BELOW A PACKER

Oftentimes the operator is faced with the problem of isolating a zone and producing all fluids, gas included, through the rod-pump. This situation usually occurs when producing multiple zones separately, or when sealing off an upper annular space with casing leaks. Frequently, gas interference effects on conventional pump performance are sufficiently penalizing to render this practice impractical.

In these situations, where the offending gas cannot be separately vented away from pump intake, pumps equipped with the Solution Valve perform efficiently. With the exception of normal losses due to leakage between plunger and barrel, virtually all of the fluids will be displaced from the pump chamber on each down-stroke. Although entering gas will certainly “compete” with oil and water for space, it is not able to accumulate and delay (or restrict) opening and closing of the standing or travel valves. Consequently, the pump continues to function without gas-locking.

HORIZONTAL AND DEVIATED WELL BORES

Non-vertical orientations of down-hole pumps in deviated well bores typically cause uneven wear on balls and seats. Many manufacturers, following API guidelines and using various ball and seat configurations, have had little success in solving this problem. Controlling ball position by tightening tolerances around the ball have resulted in dramatic reductions in pump efficiency and premature failures of balls and seats.

The Solution Valve was designed to perform regardless of pump orientation. Since both ball and seat are always centered within the valve, the SV performs just as efficiently horizontally as it does vertically. An internal guide system maintains perfect alignment of the seating surfaces at all times. Frequently, with conventional pumps functioning in non-vertical holes, 20% or more of the stroke movement occurs before the ball can re-seat itself properly. In these applications the SV immediately opens and closes at the beginning of the down- and up-strokes, respectively, thus assuring high-efficiency performance throughout the pumping cycle.

HEAVY, VISCOUS OILS

Although responsible to different phenomena, difficulties experienced in pumping heavy, viscous crude oils are not dissimilar to those encountered in non-vertical holes. That is, in each case the free-moving ball of the conventional pump is held off its seat for a period of time sufficient to seriously impair volumetric efficiency. In deviated holes gravity pulls the ball to the side of the cage. With heavy crudes, seating of the ball is delayed by viscous drag forces imposed against the surface of the ball. These drag forces counter the opposing forces imposed by gravity and pressure which are required for seating of the ball. Simply stated, the time required for the ball to fall through the viscous oil in route to the seat can be, and often, is a significant fraction of the pumping cycle.

Since resistance to motion imposed by the drag-plunger immediately opens or closes the SV at the initiation of each stroke reversal, seating delays, of the type described above, cannot occur. Greater cross-sectional flow area through the SV and related reduction in pressure drop across the entire valve system further improve fluid dynamics. All valves are able to function more quietly and smoothly. Consequently, the SV performs very favorably when pumping viscous oils. Oftentimes, immediate production increases of 15 to 60% have been achieved.

CASE HISTORIES

During the last seven years, some 3,000 Eagle Solution Valves have been installed in wells located throughout many domestic oil and gas producing regions. Of this number, some 1,600 have been utilized in the Permian Basin. Next appearing are representative examples which have been chosen to illustrate benefits of the tool.

CASE 1: PRIZE OPERATING COMPANY, TAYLOR-SMITH UNIT NO. 1

An SV was installed soon after this San Andres completion was placed on production. Although during the first four months gas production had remained relatively constant at approximately 25 Mcf/Day, oil production rates had fallen steadily from about 25 to 5 Bbl/Day. As may be seen on Fig. *6*, producing GOR's, somewhat high at the outset (>1,000 Scf/Bbl), rapidly climbed to near 5,000 Scf/Bbl, a level well within the range wherein gas interference problems can be expected. On March 21, 2001, an SV was installed. Thereafter, both gas and oil rates significantly increased and then began to stabilize; water production rates also increased from **48** to 58 Bbl/Day. With installation of the SV, bottom tagging was eliminated.

CASE 2: APACHE CORPORATION. LIVINGSTON NO. 17

On Fig. 7 is illustrated the production performance of this Grayburg completion initially equipped with an SV. As typical with solution gas reservoirs, oil rates started high and gradually declined with time. Producing GOR's rapidly climbed as gas saturation, and in turn gas permeability, increased in the near-well-bore region of the reservoir. As observed, at no point were production rates erratic, which would be suggestive of intermittent or permanent residual gas build up within the pump. Rather, a smooth transition occurred for all producing rates and ratios, an observation in keeping with consistent down-hole fluid withdrawals. In this same field the operator initially installed SV's on two additional new Grayburg completions; performance results were comparable.

CASE 3: CHEVRON-TEXACO. G. L. ERWIN A NCT-1 FEDERAL NO. 6

This Blinebry completion exhibits a history of gas interference effects and repetitive pump failures due to tagging bottom. Broken valve-rods and valve-rod bushings and secondary effects of metal fragmentation on plungers and barrels occurred with regular frequency beginning with completion of the well in July 1995. During 1999, and continuing through mid-2000, with GOR's being approximately 4,000 Scf/Bbl, oil rates steadily declined, an indication that even the deleterious effects of pounding bottom were no longer effective in pumping the well down (See Fig. **8).**

On September 11,2000, a 1.25" SV was added to the pump assembly. Immediately, oil rates increased from approximately 20 to in excess of 40 Bbl/Day. Gas also increased from 100 to about 220 Mcf/Day. Since installation of the SV, oil and gas production has averaged approximately 35 Bbl/Day and 230 Mcf/Day, respectively. Throughout this 13-month period bottom tagging has been avoided, and no pump failures have occurred.

CASE 4: CHEVRON-TEXACO, B.F. HARRISON B NO. 17

In this example, similar to the previous one, erratic and declining oil and gas production rates were observable from the Drinkard/Abo zone. A history of pump failures had resulted from tagging bottom. Eventually, in March 2000, even with bottom-tagging, gas interference effects had apparently deteriorated pump efficiency to the point where production began to suffer. One can assume that fluid levels were high. At this time an SV was run into the well, and as may be seen on Fig. 9, production rates of oil and gas were re-established to those levels consistent with pressure depletion projections. Thereafter, as the fluid level was lowered and more gas was able to be vented up the annulus, production rates became more stable, indicating establishment of more nearly steady-state equilibrium between well and reservoir. No further pump failures have occurred during this 20-month period, and bottom tagging was eliminated.

CASE 5: CHEVRON-TEXACO, STATE L NO. 5

This well began producing from the Blinebry zone in July 1995. Initial sustained oil and gas production rates were approximately 35 Bbliday and 250 Mcf/Day (GOR=7,100 Scf/Bbl), respectively, and generally conformed to an expected percentage decline extrapolation over the next five years. By May 1998, oil and gas rates had declined to approximately 8 Bbl/Day and 100 Mcf/Day (GOR=12,500 Scf/Bbl), respectively. At this time an SV was installed, and bottom tagging was terminated. Production continued to decline normally until May 2000, when the pump was pulled and serviced; the ported seal stem, ball and seat of the SV were replaced (cost of SV components: less than $500), and the SV was re-run into the well. The pump assembly continues to perform satisfactorily as of this writing and without tagging bottom.

CASE 6: RAINBOW PETROLEUM MANAGEMENT, INC.. WEATHERRED NO. 1

Since May 1997, oil production rates from this Spraberry well have declined basically in accordance with expected hyperbolic extrapolations, from an initial 15 to 3.5 Bbl/Day by September 2001. During this period gas production increased from about 30 to 70 Mcf/Day, with GOR's climbing from 2,000 to 20,000 Scf/Bbl. Bottom-tagging was a routine production practice, and to be sure, pump function depended upon it. Sustained volumetric pump efficiency averaged no better than 35 to 40%. The well could not be pumped down, and the high incidence of rod parts and broken valve-rods and valve-rod bushings added significantly to operating costs. Pulling frequency averaged about four times per year, and oftentimes sand impaction necessitated stripping of rods and tubing. Intermittent gas and fluid pounding were prevalent.

A Solution Valve was installed on October 5,2001, and bottom-tagging was eliminated. As may be seen on Fig. 10, oil and gas production rates increased and then stabilized during the first eight days following SV installation. Volumetric efficiency of the pump immediately increased to about 71% following SV installation, at which point the well pumped off, then abruptly declined to and remained at approximately 54%. Gas was able to be vented up the tubing-casing annulus more efficiently with the lowered fluid level, and for the first time it became possible to put the well on time clock; an initial off-time component of 25% further contributed to savings in operating costs. Fluid and/or gas pounding disappeared, and the associated uniform and consistent pump loading resulted in a smooth and quiet pumping operation. Prior to installing the SV, about six days had been required to produce back the 30-40 barrels of oil used in hot-oil, paraffin treatments; subsequently, only two days have been required for recovery of the same oil volumes. No subsequent pump repairs or pulling jobs have been required since the SV was installed.

As a matter of further interest, on Fig. 11 are presented the surface and computed down-hole dynamometer cards (Courtesy of Lufkin Automation) as obtained on December 20,2001, at a time near the end of the normal 135-minute on-cycle. As observed, the full-pump signature of the down-hole card corroborates the high volumetric pump efficiency achievable with the SV under these gaseous conditions. A calculated pump intake pressure of 120 psi confirmed the low fluid level existing at this time, and was suggestive that perhaps the fractional on-time could be increased slightly. Also observable from the survey was an absence of fluid pound, an historic contributor to rod-stacking prior to installation of the SV.

CASE 7: TERRACE PETROLEUM, TXL NO. 17-2

This Wolfcamp producer, completed in November 2000, demonstrated from the outset the penalizing effects of gas interference, fluid-pounding and the destructive effects of bottom-tagging. From inception, fluid levels had remained at about 2,500' from surface.

On November 10,2001, a Solution Valve was installed. Eight days later the well tested 50 Bbl/Day oil, 30 Bbl/Day water, and 50 Mcf/Day gas, and on November 21, 2001, the well pumped off. As is often the case, No. 17-2 produces into a common tank-battery with other wells on the lease. However, owing to its large fractional contribution to lease totals, the stabilizing effects of the SV on total production from No. 17-2 are nevertheless apparent, as may be seen on Fig. 12. Production was at least as high, if not slightly higher, after installation of the SV, mechanical operation of the entire pumping assembly was stable and functioning smoothly, fluid-pounding had disappeared, and the damaging and costly effects of bottom-tagging had successfully been eliminated.

No. 17-2 is equipped with the SAM-E pump-off controller provided by Lufkin Automation. It is interesting to note (See Fig. 13) that with the SV, pump-up and shut-down dynagraph signatures are similar to those generated by wells equipped with conventional pumps only. With the well now capable of being pumped off, the pump-off controller could function as designed, thereby reducing pumping time by 20%.

Operator has recently installed SV's on three other wells exhibiting high fluid levels and/or rod-parts and related pump failures due to bottom-tagging.

CASE 8: SHACKELFORD OIL COMPANY, TONTO FERERAL NO. 1 AND 2

This operator installed the SV on each of these Delaware completions in September 2001. Afterwards, production from both wells was maintained at levels equal to or greater than previous levels, and failures associated with bottom-tagging were eliminated.

CASE 9: JACK L. PHILLIPS CO., JOHNS NO. 1

Gas interference effects and extreme gas-blocking had taken their toll on this East Texas well. On July 19, 2001, a Solution Valve was run into the well, and pumping operations were reinstated. During each of the next four days oil and gas production rates soared from approximately 2 Bbl/Day and **34** Mcf/Day, to as high as 65 Bbl/Day and **6**1 Mcf/Day, respectively (See Fig. 14). Thereafter, with the exception of those days where gas engine trouble was experienced, production stabilized at about 4 to 5 Bbl/Day and 30 Mcf/Day until apparently most of the down-hole water accumulations had been depleted. Subsequently, oil rates were stable and averaged about 7 Bbl/Day; gas production was unchanged. Bottom tagging was eliminated.

CASE 10: ANTELOPE ENERGY COMPANY, RATLIFF "F" NO. 1

Extreme swings in production rates were evidenced by this commingled Devonian/Ellenburger completion. Repetitive cycles wherein the pump would be gas-locked and the well totally non-productive would last for 4 to 5 days at a time. Fluid pounding was also common, and down-hole gas separation was inefficient due to sustained high fluid levels in the annulus. Also contributing was the pump being set at 12,300', a position extremely close to the Devonian perforations.

An SV was run into the well on September 22, 2001, and soon thereafter fluid production rates began to stabilize (See Fig. **15).** During the next several months average monthly production increased slightly, fluid pounding disappeared, and as of this writing, the well appears to be pumped off. Of late, gas production rates have begun to decline slightly, indicative perhaps of continuing pressure depletion of this old Devonian field reservoir.

ECONOMIC BENEFITS

As may be concluded from the above examples, installation of the Solution Valve with resultant improvements in pump efficiencies, usually gives rise to increases in oil and gas production rates from those wells which could not be pumped off previously. A more prevalent economic influence however, lies on the operating cost side of the ledger.

By not having to tag bottom, the SV makes possible significant savings in equipment repair costs and related down-time. To illustrate this concept further, data collected by TWS Pump and Supply, was examined. This data, gathered over a four-month time period, represented a group of several hundred wells completed in the troublesome Spraberry zone of the Permian Basin, a producing horizon where gas interference effects, bottom-tagging practices, and down-hole debris contamination are common. On Fig. **16** one may see the various reasons (and frequencies) why wells from this sampling were pulled. In some 15% of occurrences, wells were pulled to either temporarily abandon or work over. However, in the remaining 85%, pulling jobs were prompted by one of three occurrences: rod-parts, holes in the tubing, or pump failures.

Not to overlook or minimize the contributive roles played by time, corrosion (electrolytic as well as chemical), unseated tubing-anchors, etc., it is believed that many of these failures were the direct results of the adverse effects of fluid-pounding or bottom-tagging, no matter how "lightly" this technique may have been administered.

For this same well sampling and time period, Fig. 17 identifies the specific pump components which failed or needed replacing and the number of occurrences thereof. It should come as no surprise, and as may be quickly observed, the most frequently replaced items were those identifiable with the continuous stress-reversals and high-energy impacts resulting from tagging bottom: e.g., failed end-pins, valve-rods, and valve-rod guides. Unlike when the Solution Valve is installed, sudden releases of high-pressure gas within conventional pump assemblies result in high-velocity impacts of balls against seats and cages, and can cause stress failures of the components involved. As is also known, these same energy releases, when occurring in the presence of entrained particulate matter, can rapidly erode both balls and seats. Although not known with certainty, the failure frequencies of travel valve and standing valve cages observed in this data sampling are certainly suggestive, at least in part, of these gas-related phenomena.

Considering current well servicing rates of approximately $150/hour, pump repair costs upward from $500, truck services for pump loading, supervision, etc., a representative cost range of $2,500 to $4,000 can be assumed each time rods and pump are pulled from a well in the 5,000' to 9,000' range. If tubing pulling is also required (tubing failure, stripping job, etc.,), costs can easily climb to above $6,000. Loss of production due to associated down-time contributes further to profit reductions.

By being more efficient, pumps equipped with an SV are able to reduce the fractional on-time component of pump-off controllers and time clocks—yet another way in which operating costs can be lowered. Moreover, owing to the smooth hydraulic loading and unloading of all valves, the SV has repeatedly demonstrated that run times of conventional, down-hole pump assemblies can be extended by 100% or more.

SUMMARY

The Solution Valve has been proven in wells producing throughout the oil industry. A short drag-plunger, acting in conjunction with a centered, stationary ball and movable seat, cause immediate valve opening or closing of the SV at the extreme ends of the stroke, and permits smooth, fluid loading and unloading of all valves. Functioning as a mini-compressor, the SV displaces free gas, as well as oil, water or foam, on each stroke. Due to the SV's higher volumetric efficiency when functioning in the presence of gas, annular fluid levels can be lowered to the seating nipple, thus increasing oil and gas production. The SV will not gas lock and does not require bottom-tagging. Violent impacting of balls against seats and cages due to high-energy release of gas is reduced, if not eliminated. Featured applications include gaseous, heavy-oil and deviated-hole conditions, and zones isolated by packers. The SV is especially effective in pumping fluids with entrained debris which might tend to settle out in conventional pumps. Improvements in operating profit are offered through: Increased production; Elimination of rod-parts and rod-cut tubing caused by fluid-pounding or bottom-tagging and associated stress reversals within the rod string; Higher volumetric efficiencies with resultant increases in off-time for pump-off controllers or timers; and Longer run times for the entire pump assembly.

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VITAE

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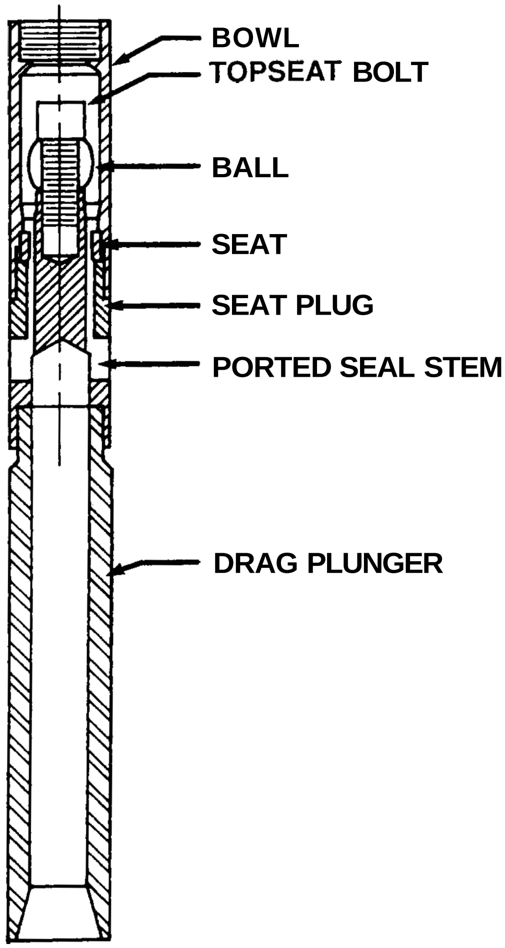

BOWL
TOPSEAT BOLT
BALL
SEAT
SEAT PLUG
PORTED SEAL STEM
DRAG PLUNGER

Figure 1

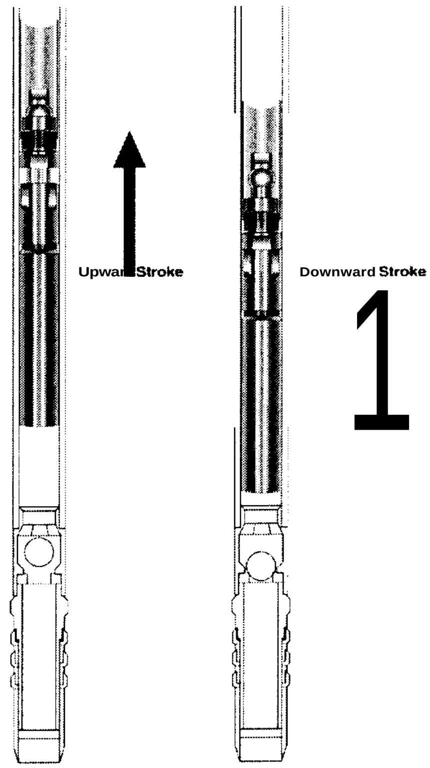


Figure 2

PUMP FAILURE DUE TO TAGGING

Run Time: 207 Days

Finding: Valve Rod Guide and Valve Rod Damaged

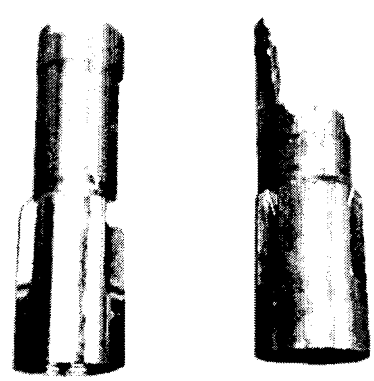


Figure 3

PUMP FAILURE DUE TO TAGGING

<u>Run Time</u>: 135 Days

<u>Finding</u>: Severe Valve Rod and Valve Rod Guide Damage. Plunger Grooved from Broken Pieces of Valve Rod Guide.

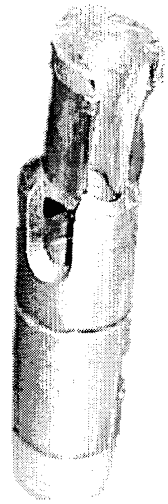


Figure 4

PUMP FAILURE DUE TO TAGGING

<u>Run Time</u>: 29 Days

<u>Finding</u>: Top of Pump Severely Pounded

<u>Result</u>: Total Pump Replaced

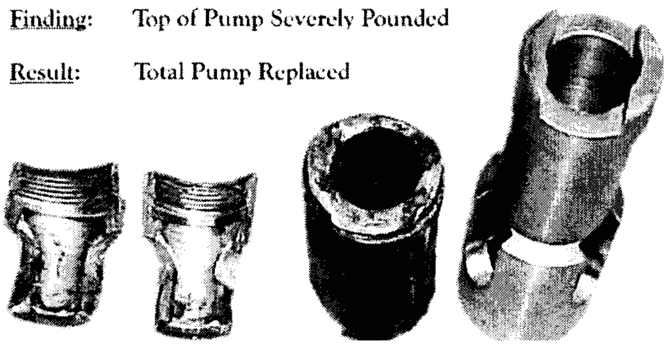
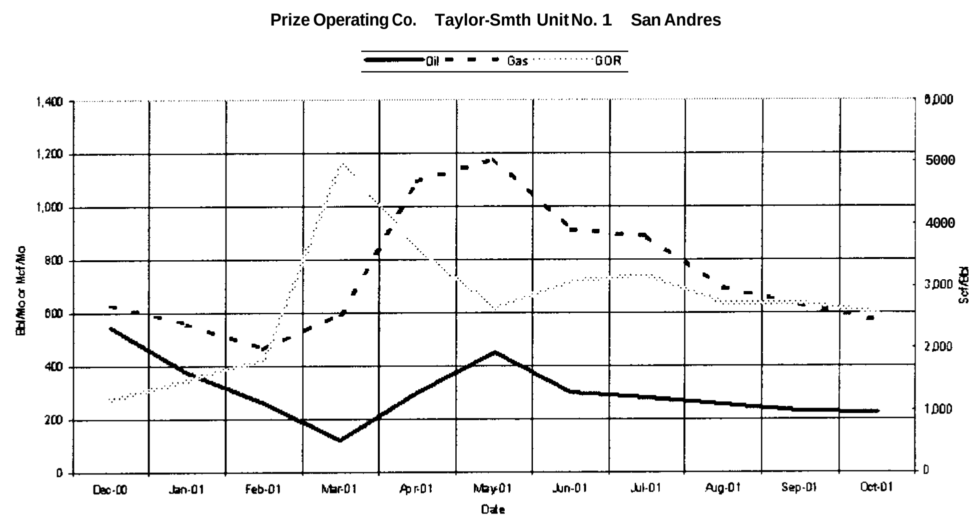
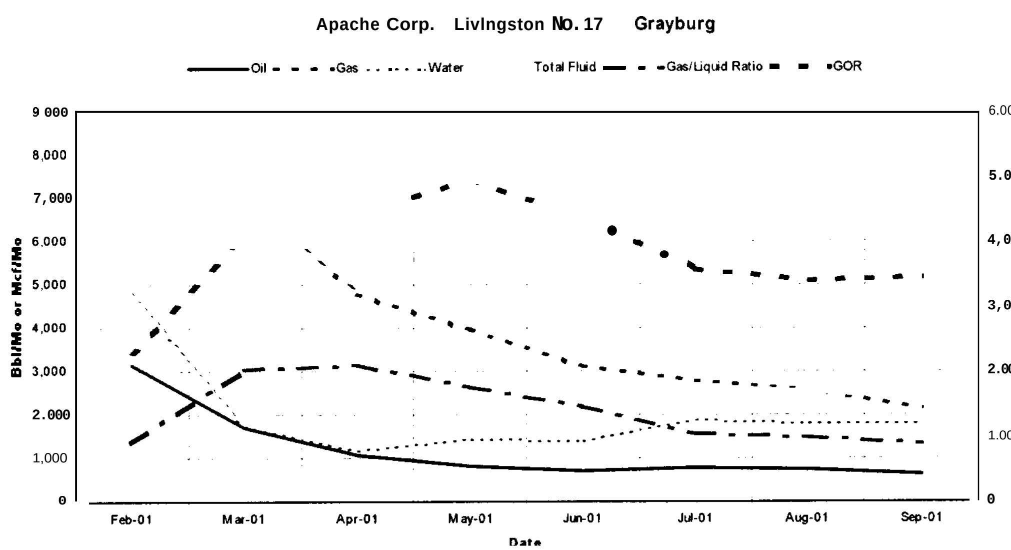


Figure 5



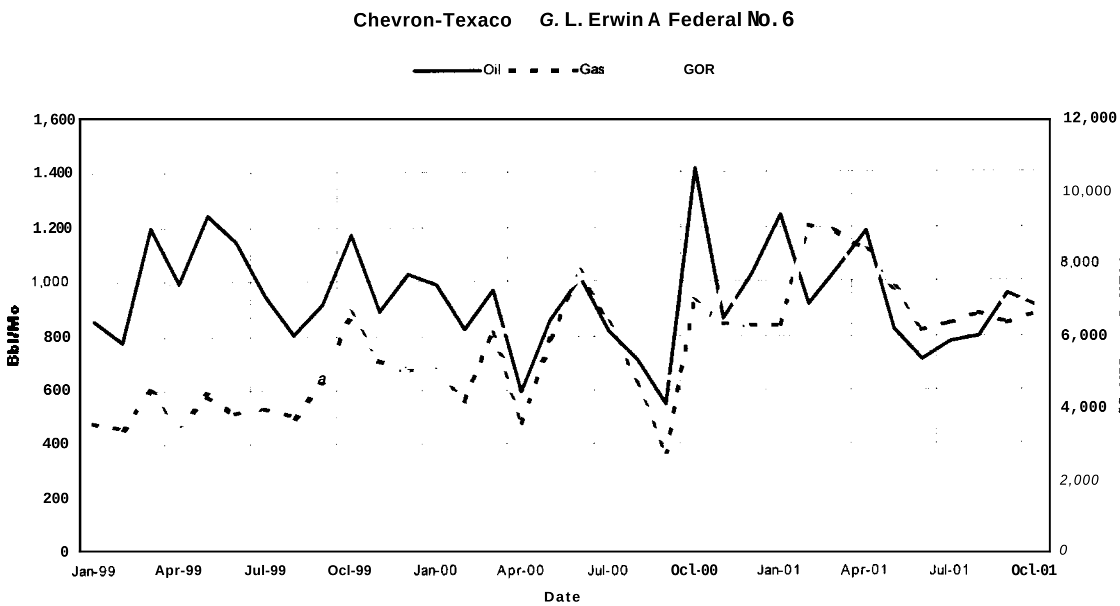
SV Run
3/21/01

Figure *6*



New Well
SV Run 1/26/01

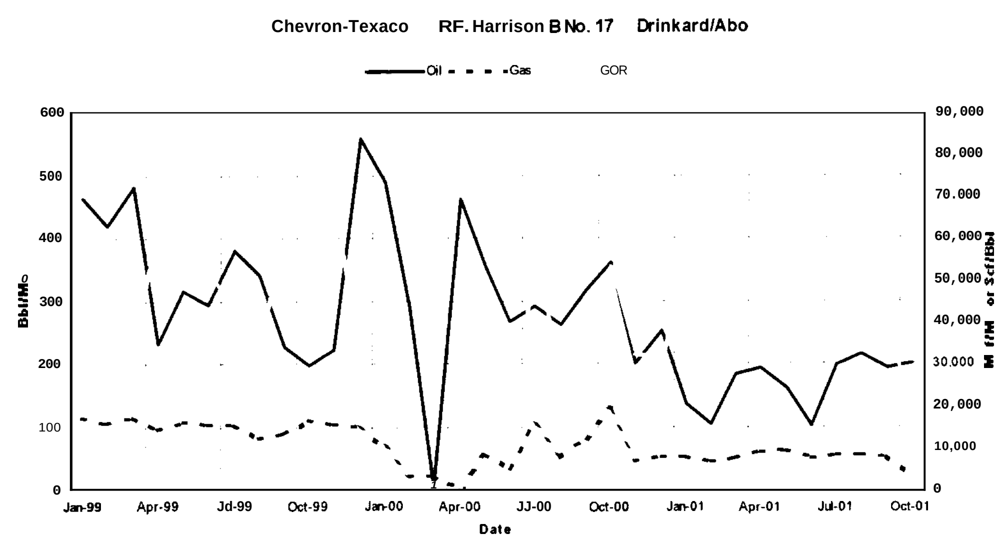
Figure 7



SV Run

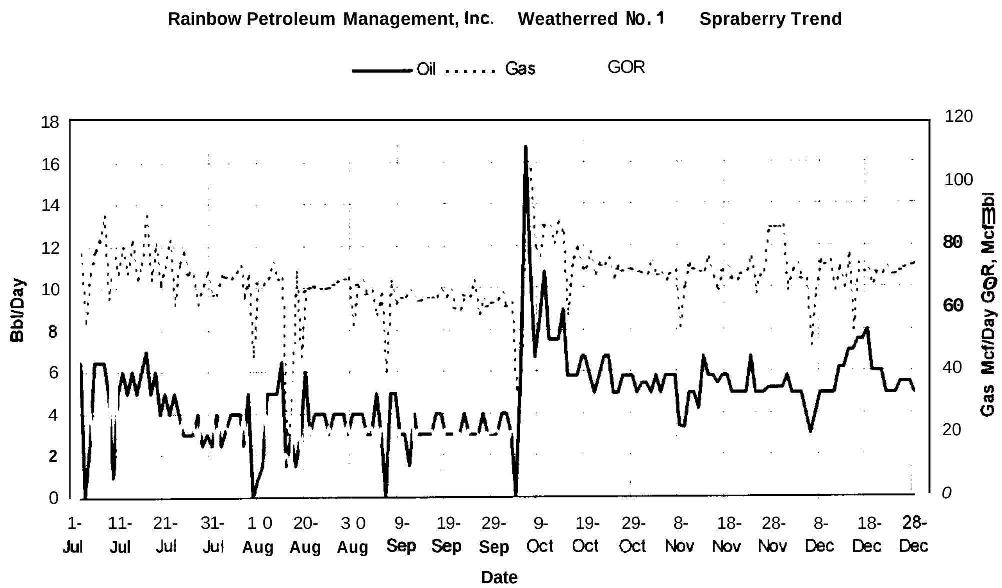
9/11/00

Figure 8

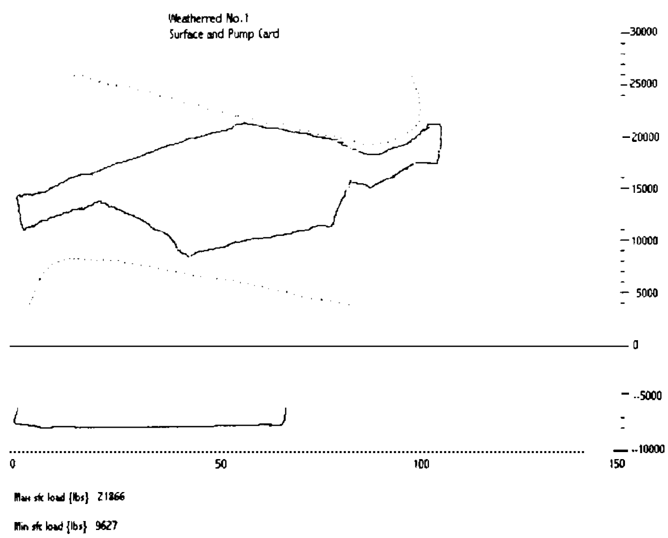


SV Run
3/13/00

Figure 9



SV Run
10/5/01
Figure 10



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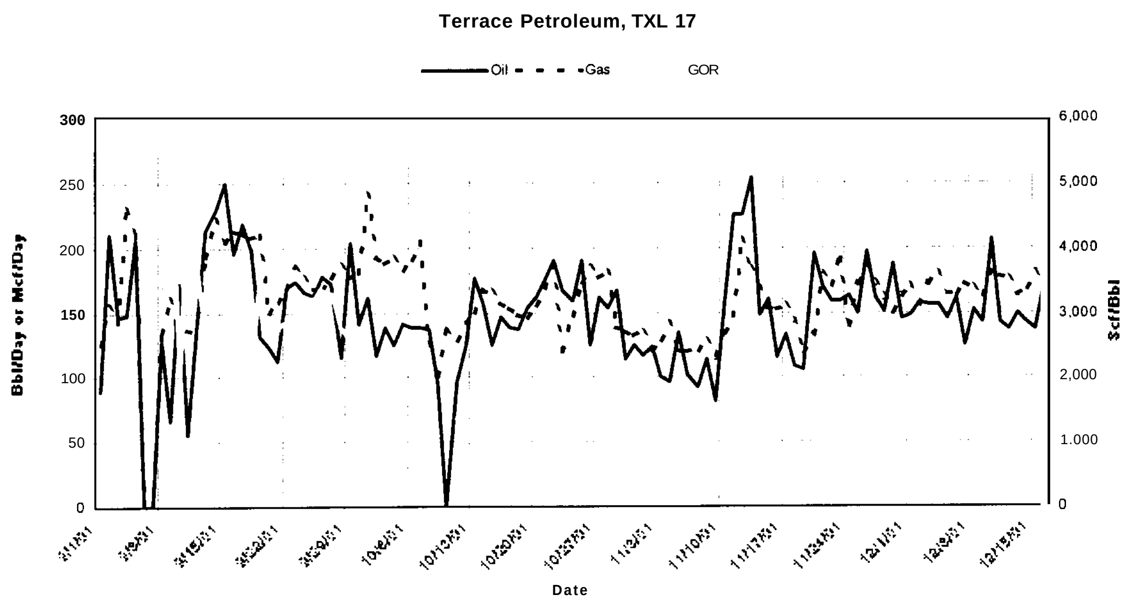
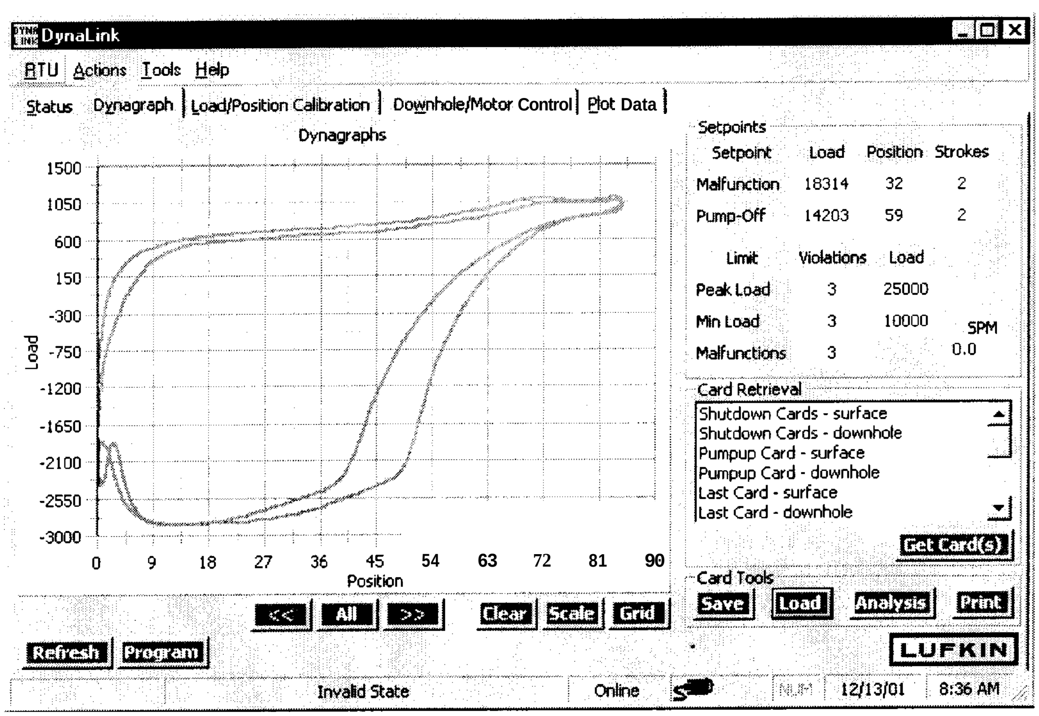


SV Run
11/10/01

Figure 12



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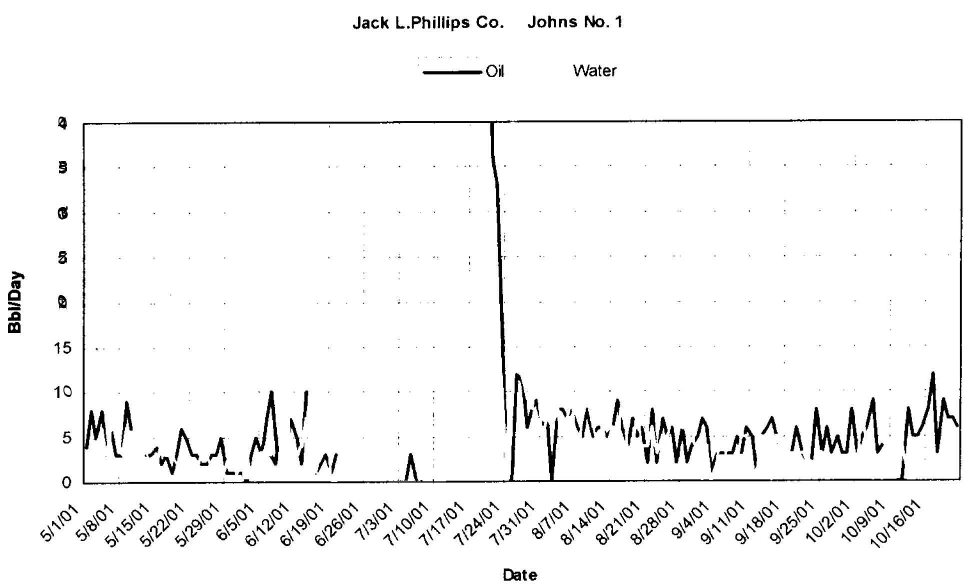
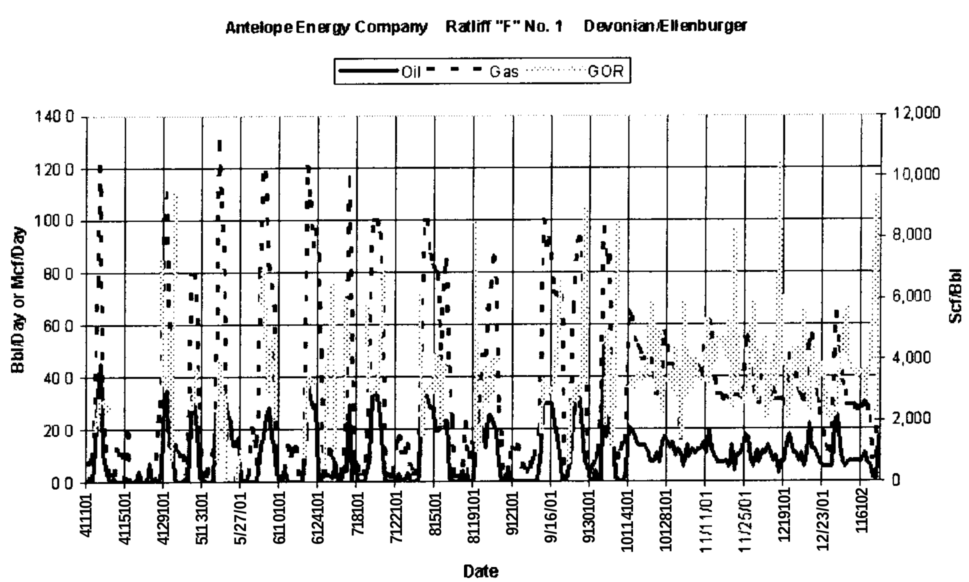


SV Run
7/19/01

Figure 14



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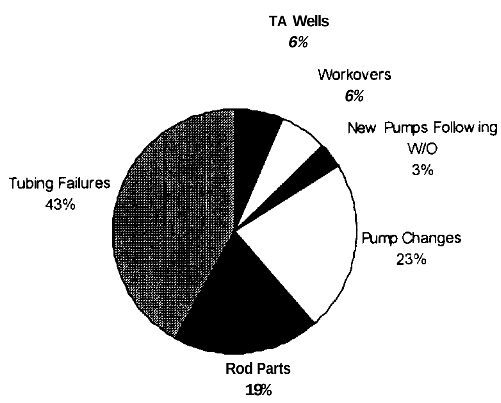

Figure 16

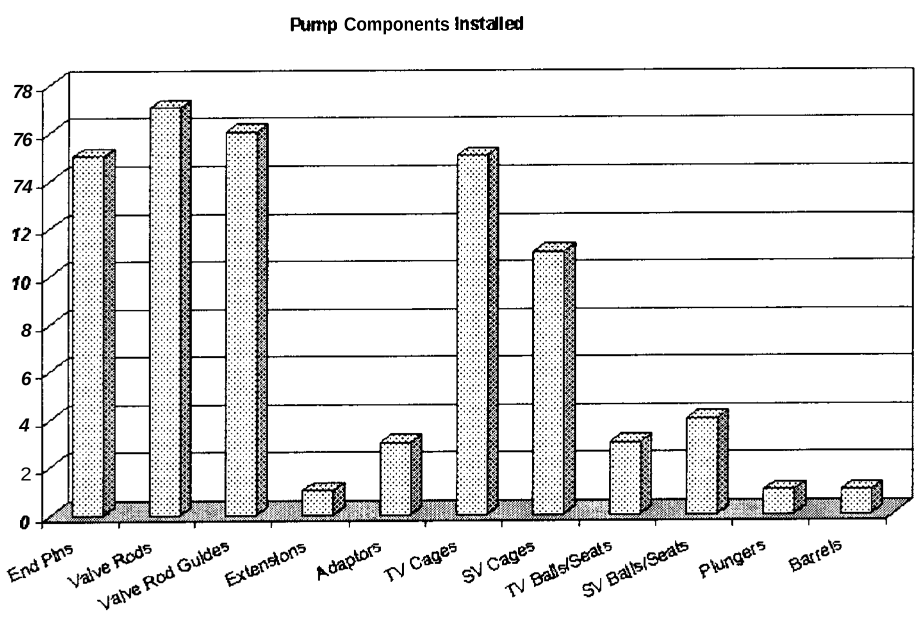

Figure 17