AUTOMATIC CASING SWABS; A FIELD PROVEN PRODUCTION SYSTEM THAT IMPROVES PRODUCTION AND REDUCES OPERATING COSTS

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Introduction

This paper will share the experience and information gathered from the installation and/or operation of over 500 Automatic Casing Swab (ACS) systems. The information provided will assist an operator to determine if a well might benefit from ACS technology .

This paper will review the history of the ACS and its evolution to the present day proven dependable tool. A discussion of the operating principles of the ACS will illustrate the flexibility and wide ranging applications of the ACS system in many types of gas reservoirs.

The economic success of an ACS conversion is largely dependent upon the selection of a well candidate that can benefit from the unique characteristics of the ACS system. This paper will develop a criterion that will allow an operator to evaluate his wells to determine which wells are likely to benefit most from conversion to an ACS production system. Well characteristics known to hinder successful ACS conversions will be discussed.

This paper will compare and contrast the operating principles of the ACS to tubing plungers, pumping unit, swab, and open flow wells. The paper will discuss the application of ACS technology to new wells as an initial production method.

A well must be properly conditioned before an ACS system is installed. The paper will offer a detailed step by step ACS system installation procedure. Safe operating practices, start-up, and production operations will be discussed.

Routine preventative maintenance and trouble shooting will be discussed to assist an operator to minimize remedial services that might be required should the ACS tool cease to operate. Simple preventative maintenance procedures keep the ACS operating at peak performance.

Case histories will illustrate the positive impact that an ACS system can have on well production and operating expenses. The case histories will also highlight the types of wells that might receive the most benefit from ACS technology.

Description of Automatic Casing Swabs

Automatic Casing Swabs combine some of the best features of several commonly used production systems to provide a simple, dependable, economic method of removing fluids from the well. The removal of these well bore fluids will help maximize gas production. An ACS system (Figure 1) consists of a surface lubricator, plunger, and bottom hole stop. The most important component of the ACS system is the ACS plunger (Figure 2). The ACS plunger has a hollow steel mandrel, an external traveling valve and 2 externally mounted elastomer pressure sealing elements. The external traveling valve is manipulated into the open or closed position depending upon the location of the ACS plunger in the well. When the valve is in the closed position, the elastomer sealing elements provide a barrier between the reservoir pressure trapped below the plunger and the well fluids that have accumulated in the wellbore above the bottom hole stop. The ACS plunger is 37 IN long and weighs approximately 65 LBS. The steel portion of the ACS plunger has an maximum OD of 3.75 IN. The elastomer sealing elements of the ACS plunger are manufactured with outside diameters ranging from 4.08 to 4.151 IN to accommodate various weights and inside diameters of casing. The ACS plunger is equipped with multiple flow orifices which can be opened or closed to control the rate which gas and fluid are able to flow through the plunger altering the rate of descent of the ACS plunger as it free falls to bottom.

The ACS system includes a down hole stop that serves as the lowest point that an ACS plunger can travel. The down hole stop establishes the minimum column of fluid that will always remain between the top perforation and the bottom hole stop during ACS operation. The down hole stop may be either a tubing stop or a casing stop (Figure 3). The tubing stop is installed on a length of freestanding centralized tubing that positions the tubing stop immediately above the uppermost perforation. The tubing stop is lowered into the well on a wireline and "J hook". The use of a tubing stop allows the column of fluid remaining above the top perforation to be kept to an absolute minimum. A well that may produce formation fines or frac sand may "sand in" a tubing stop making it very difficult to recover.

The casing stop is installed in the first or second casing collar immediately above the top perforation. The casing stop is designed to mechanically lock in the void of a casing collar between the threaded portions of the upper and lower joints of casing. Placement of the casing stop is determined by the location of the casing collars when the production string is cemented.

The ACS surface lubricator (Figure 4) is used as a flow manifold and to house the ACS plunger between cycles. The ACS surface lubricator is installed on the casing immediately above the master surface control valve. Between cycles, the ACS plunger is held in the surface lubricator in the open position by the lubricator latch mechanism. Continuous gas production is achieved as gas passes through the open valve and hollow steel mandrel of the ACS plunger then out the 3/8 IN flow orifice. The 3/8 IN orifice is installed in the surface lubricator to control the flow of gas and fluids from the well. This orifice is necessary to insure that the plunger is not traveling up the hole with sufficient velocity to cause the lubricator to fail when the 65 LB plunger enters the lubricator. The 3/8 IN orifice also limits the velocity of the gas being produced up the casing so the plunger is able to free fall to bottom in a reasonable period of time.

The ACS surface lubricator utilizes a hammer union so that the surface lubricator can be "broken open" to allow easy access to retrieve the ACS plunger (Figure 5). The ACS surface lubricator has a spring loaded cap in the top of the lubricator to absorb some of the inertia of the 65 LB ACS plunger as it returns to the surface.

History of the Automatic Casing Swab.

The quest for a production system able to effectively remove well bore fluids from a well by free falling to bottom, trapping well bore fluids above the plunger, then using only formation gas pressure to lift the accumulated fluids to the surface began almost as soon as the first producing wells lost the ability to flow fluids to the surface. The concept of the present day ACS system can be traced back as early as 1955 when U. S. Patent #2,714,855 Apparatus for Gas Lift of Liquid in Wells was issued to Mr. N. F. Brown. Since then, numerous U. S. Patents have been awarded which document some of the concepts that have lead to the present day ACS system. The harsh environment of a producing well has stifled some very novel ACS design concepts and ideas. Many different types of valve assemblies have been tested with varying success. The proven systems of today rely upon a simple valve assembly that opens upon entry into the ACS surface lubricator and closes when the bottomhole stop is encountered.

A critical component of any ACS system is the elastomer pressure sealing elements installed on the ACS plunger. Many types of materials have been used in countless configurations in an ongoing search for an improved elastomer pressure sealing element. Elastomer pressure sealing elements strive to balance excellent wear characteristics and superior pressure sealing properties. To be successful, a pressure sealing element must be able to withstand a free fall descent from the ACS surface lubricator to the bottomhole stop, then immediately deliver an effective positive pressure seal against casing that may be 20 or more years old. Once a seal is achieved, the pressure sealing element must maintain an effective seal that separates the accumulated fluids trapped above the ACS plunger from the producing gas below as the plunger and fluid are lifted to the surface. Ongoing research and development seeks to develop a material superior to those presently in use.

Operating Principles

The operating principle of the ACS system utilizes hydraulic principles that can be manipulated in 4 ½ IN casing. The cross sectional area of a typical 4 ½ IN - 10.5 #/FT casing is 12.90 IN^2. This equates to 12.90 LB of "lifting" force for every 1 PSI of differential pressure that acts across the ACS plunger. A typical column of oil field fluid (oil and water) might weigh 8.5 PPG. One barrel of this solution will weigh 357 pounds. That 1 BBL of fluid will require 27.74 PSI to "lift" 1 BBL of fluid in the 4 ½ IN casing. For any given fluid density and casing size, the pressure necessary to "lift" 1 BBL of any fluid can be calculated.

In order to take full advantage of the available "lifting" ability of the formation pressure, an effective pressure sealing element must be used. The seal must be durable to withstand abrasion as the sealing element passes over the casing, and strong enough to lift the weight of the fluid trapped above the ACS plunger. Additionally, the sealing elements must be flexible to maintain an effective seal as the ACS plunger passes through casing collars and it must be compatible with produced fluids. The elastomer sealing elements are installed in pairs with the sealing surfaces being approximately 10 IN apart to span possible casing irregularities and to insure that at least 1 sealing element is always in contact with the casing as the ACS plunger travels through a casing collar.

Advantages of Automatic Casing Swabs

The ACS system has several inherent features that allow an operator to maximize gas production from a well. One way to increase production from a gas or oil well is to lower the wellbore pressure at the producing formation face. Ideally, one wishes to maximize the pressure drop between the reservoir and the wellbore to obtain maximum production. Sales line pressure and flow line friction pressure will always exert some measure of "back pressure" that stifles the maximum deliverability of a well. Short of installing compression equipment, there is no practical way to lower sales line pressure. One way to accomplish a maximum pressure drop is to keep the hydrostatic pressure of the accumulated wellbore fluids to a minimum. The ACS system can help keep the hydrostatic pressure to a minimum by removing the accumulated wellbore fluids on a timely basis.

An ACS system is capable of removing virtually all fluids that have accumulated above the bottomhole stop. Some of the first cycles occurring after the initial ACS conversion may bring larger than expected volumes of fluid to the surface. This is a normal response of the formation adjusting to the lower producing pressure. Fluid production usually returns to at or below the well's original gas to total fluid ratio.

Normally, 1 to 3 BBL of formation fluid are recovered on each complete ACS cycle. Some wells with above average deliverability and pressure have been known to recover more than 66 BBL of fluid in a single cycle. Attempts to consistently recover large volumes of fluid per cycle can cause undue stress and wear on the elastomer sealing elements. Generally speaking, cycle times are normally designed and adjusted to operate the ACS plunger when 1 to 3 BBL of formation fluid has accumulated above the bottom hole stop. This 1 to 3 BBL of accumulated fluid corresponds to a fluid column of approximately 61 to 193 FT and a hydrostatic pressure of 27 to 85 PSI depending upon casing weight and fluid density. By keeping the fluid column to a minimum, the pressure drop between the formation and the sales point can be maximized improving gas production. It is critical that an ACS cycle not begin unless there is at least 1 BBL of fluid covering the bottomhole stop. The fluid column above the bottomhole stop is necessary to slow the descent of the ACS plunger as it free falls to the bottomhole stop. Severe damage may occur if sufficient fluid is not present to arrest the rate of descent of the ACS plunger. By adjusting the ACS cycle time to recover 1 to 3 BBL of total fluid, a compromise is reached which allows the ACS system to operate properly minimizing the hydrostatic pressure remaining on the formation.

Comparison of Automatic Casing Swabs with Other Commonly Used Production Methods

Tubing Plunger or "Rabbit" Wells

A side by side comparison of the ACS system with other production methods can illustrate the advantages and characteristics that make the ACS system a very flexible production tool. One type of well that will normally benefit from conversion to ACS production is a tubing plunger or rabbit well. Rabbit wells are a proven production tool in many areas of the country. Operational and production problems may begin to occur in a rabbit well as production begins to decline. As the well depletes, reservoir pressure and gas deliverability decline requiring longer and longer shut-in times to build the pressure necessary for the rabbit to operate effectively. As the number of cycles decline, production will be affected.

The typical operating cycle of a rabbit well consists of cycling the well on and off using an electronic controller box and motor valve. Initially the well is shut-in, pressure and gas volume is allowed to build in the annulus between the production tubing and the production casing. At a predetermined time or pressure, the electronic controller signals the motor valve to open the sales line valve. The pressure of the gas stored in the annulus overcomes the sales line pressure and chases the rabbit and fluid to the surface. Unfortunately, the stored gas pressure required to operate the rabbit effectively increases the wellbore pressure and hinders the productive potential of the well.

The body of a tubing rabbit has an external diameter slightly smaller than the internal diameter of the production tubing. The smaller diameter of the rabbit allows it to freely travel up and down the tubing. The tubing rabbit does not create a positive pressure seal between the rabbit and the production tubing. The rabbit relies upon turbulence in the fluid immediately above the rabbit to minimize the amount of fluid that can pass through the annular space between the rabbit and the tubing as the rabbit moves up the hole. A rabbit must achieve velocities of 800 to 1000 feet per minute to create sufficient turbulence in the adjacent fluids to minimize fluid leakage or blow by. If for any reason a rabbit is not able to reach the surface, it will stall and fall back to bottom along with any fluids not reaching the surface. This increased fluid volume in the wellbore may require additional stored pressure and volume to lift the increased fluid load on the next cycle. Worn or undersized rabbits, as well as worn or pitted tubing, can increase the amount of fluid that leaks by the rabbit reducing the efficiency of fluid recovery. As a well matures, reservoir pressure and gas deliverability begin to decline. All these factors contribute to a less efficient operation, reduced production, and increased maintenance and operating costs.

Wells utilizing ACS technology have two distinct differences compared to rabbit wells. The first being that ACS systems utilize positive pressure sealing elements to provide a very effective mechanism to lift fluids from the well. The positive pressure sealing elements of the ACS system allow the ACS to operate very effectively to produce gas continuously into the sales line while still recovering virtually all produced fluids. The ACS system does not rely upon stored annular gas pressure and volume or plunger velocity to recover fluids. Fluctuations in sales line pressures that can kill a rabbit cycle are readily absorbed by the ACS system with little or no effect on the production cycle other than to alter the arrival time of the ACS plunger to the surface. In many cases, wells with fluctuating sales line pressures have successfully operated an ACS system after a rabbit system proved ineffective. If sales line pressure increases during an ACS cycle, the ACS plunger effectively shuts the well in, holding the accumulated fluids in place above the ACS plunger. The ACS plunger will remain in place, held by a combination of the pressure trapped below the ACS plunger and the friction occurring between the elastomer sealing elements and the steel casing. The ACS plunger will résumé its upward travel when sufficient gas pressure builds below the ACS plunger to overcome the increased sales line pressure.

Unlike rabbit wells, ACS wells are able to produce gas continuously against sales line pressure. During normal operation, it is not necessary to shut-in a well to allow it to build reservoir pressure so that the ACS plunger will operate. If a well is producing into a sales line with fairly constant pressure, a fairly constant flow of gas and fluid can be expected from an ACS well. This fairly continuous flow of gas provides better sales charts and more accurate chart integration. The nearly steady flow of gas and fluid from the reservoir may help minimize the production of formation fines and the deposition of paraffin.

The principle advantage of the ACS compared to the rabbit is the significantly lower pressure necessary to lift 1 BBL of formation fluid in casing using an ACS versus the pressure necessary to lift 1 BBL of the same fluid in tubing. As before, let us assume that we are working with an 8.5 PPG fluid. One barrel of this fluid will fill up 258 FT of 2 3/8 IN - 4.7 #/FT tubing. Similarly, 1 BBL of fluid will fill 61.7 FT of 4 ½ IN - 10.5 #/FT casing. The hydrostatic pressure required to lift 1 BBL (258 FT column) of 8.5 PPG fluid in tubing is 111 PSI, but only 28 PSI is required to lift 1 BBL in the 4 ½ IN casing because of its 61.7 FT fluid column. The lower pressure to lift a barrel of fluid in casing is a significant factor that can lengthen the economic life of a rabbit well. Compared to a rabbit well, an ACS system requires much less pressure to lift an equal volume of fluid from the well. An ACS system can continue to operate very efficiently in wells with depleted reservoir pressure that are no longer capable of operating a rabbit.

Pumping Unit Wells

Pumping units are an effective production method. Pumping units are normally plagued by high acquisition, installation, operation, and maintenance costs. In addition to the cost of electricity to operate the pumping unit, the cost to install power lines to remote well locations may be a significant expense. Natural gas motors using wellhead gas are costly and difficult to maintain and consume valuable resources that would otherwise be sold. Pump replacements, parted rods, stripping jobs, pumping unit maintenance and pumping unit power costs are significant operating expenses of a pumping unit well.

Normally, as a well's gas production declines, so does its fluid production. The pumping units of some wells must only be operated several hours a week to keep a well pumped off. Gas production in older wells is usually severely reduced when even a small volume of fluid is allowed to accumulate in the wellbore.

An ACS system can overcome many shortfalls of a pumping unit well. Since the ACS plunger is the only moving component of the ACS system, maintenance costs can be significantly lower compared to a pumping unit well. Energy consumption is eliminated. The salvage value of the pumping unit and associated tubular goods may exceed the purchase price of an ACS system.

Wells that have a history of paraffin production can make very good ACS system candidates. The paraffin acts as a lubricant for the elastomer sealing elements and often delivers improved fluid recovery and extended seal life. Since each complete cycle of the ACS plunger wipes the casing, paraffin that might normally deposit on the tubular goods is routinely removed from the wellbore. This repetitive wiping may decrease the incidence of well maintenance attributed to paraffin problems.

Post conversion production increases for a pumping unit well may not be as pronounced as with a rabbit well since the reservoir pressure of a pumping unit well is normally less than that of a rabbit well. A marginal pumping unit well may show increased profitability when converted to an ACS system since the burden of operating and maintenance costs may be less. These reduced costs combined with possible increased production may extend the economic life of these wells. The combined benefits of increased production, lowered operating costs, extended production life, and minimal (if any) expenditure for ACS equipment should convince an operator to investigate installing an ACS system before any pumping unit well is condemned to plugging status.

Open Flow Wells

Open flow wells are a category of wells that are likely to benefit from ACS technology. Open flowing a well in an attempt to create sufficient velocity in the casing string to carry the accumulated fluids from the well is very inefficient. Open flowing a well seldom recovers all the fluid from the wellbore. The fluid that is not recovered will remain in the wellbore exerting hydrostatic pressure on the formation limiting production. Repeated open flowing of a well can create a formation fines problem as well as increasing the potential for paraffin deposition.

An operator must recognize the environmental concerns of fugitive emissions from the resulting mist of formation fluids and chemical additives brought to the surface when a well is open flowed. More importantly, the gas that is open flowed can not be captured for sale.

An ACS system can help improve production by efficiently removing fluids from the wellbore. The well will receive increased revenue since all gas will be produced into the sales line. The ACS system can also eliminate the use of foaming agents often used in open flow wells.

Swab Wells

Swab wells account for a large percentage of stripper well production in many areas. Often times swab wells are in the last stage of their productive life. Normally these wells do not produce enough fluid to justify the expense of a pumping unit. Generally speaking, the wells do not possess the deliverability to remove wellbore fluids by open flowing. A swab well is normally kept in operation because it is capable of acceptable gas production when formation fluids have not accumulated in the wellbore. Production may decrease significantly when even small volumes of fluid accumulate in the wellbore.

Swab wells use a wireline unit to physically swab fluid from the casing. Gas production shows a marked increase immediately following swabbing services. Production begins to decline as fluid begins to accumulate in the casing. Normal weather cycles can make servicing a swab well very difficult during peak demand periods. During winter months, access to wells on remote leases may require dozers or auxiliary equipment to get a swab rig on location further increasing the cost to service the well. An operator is left with a choice of letting production suffer as formation fluids accumulate in the wellbore, or possibly paying increased costs to have a well swabbed.

An ACS system can help deliver maximum production by allowing the ACS to swab the well on a timely consistent basis rather than on a schedule that may be affected by weather related accessability.

New Well Installations

An ACS system is a valid production technique that can be implemented when a well is first turned into the sales line. The expenditure for hardware and installation of an ACS system may be considerably less than the hardware and installation of a rabbit or pumping unit well since both the rabbit and pumping unit systems require tubing to operate. A new well AFE may also be lower when installing an ACS system since no external power source is required at the well location as may be necessary with an electric pumping unit.

When installing an ACS system on a new well, attention must be paid to reservoir pressure maintenance. Lowering the pressure too quickly at the near wellbore region may prematurely lower the formation's natural gas drive and allow large volumes of formation fluids to accumulate in the near wellbore region.

Wells can utilize ACS production methods and manage formation pressures through the use of an electronic controller, motor valve, and pressure sensitive switch gauges. The pressure sensitive switch gauge operates within a preset pressure range causing the motor valve to open the sales line valve when a predetermined maximum pressure is reached. The controller holds the sales line valve open until the wellhead pressure declines reaching the predetermined low pressure point. Once the low pressure point is reached, the controller signals the motor valve to close the sales line valve allowing the formation pressure to recover. When the well is shut-in, the ACS plunger stops, maintaining the accumulated fluid above the plunger. Increasing formation pressure below the ACS plunger is transmitted to the gas column above the plunger to the pressure switch. The well will remain shut-in with the fluid held in place above the plunger by the elastomer pressure sealing elements of the ACS plunger. When the preset upper pressure limit is reached, the sales line valve will again open allowing the ACS plunger and the accumulated fluid to move toward the surface. This method of operation allows the well to "cycle"somewhat similar to a rabbit well. The significant differences being that the ACS is not storing energy in the annulus. Also, the elastomer pressure sealing elements allow the ACS plunger to stop in mid-cycle and maintain its position and fluid column until the well is again cycled.

Candidate Selection

There are three primary characteristics to consider when determining if a well might benefit from ACS technology. The most important information to be gathered is the amount of reservoir pressure available to lift the ACS plunger and fluids to the surface. The available pressure determines the theoretical height of a column of fluid that could be lifted from the well. Although the well is physically capable of lifting a maximum theoretical column of fluid, it is normally not practical to try to operate an ACS with such a large load. Production will be slowed by the increased hydrostatic pressure exerted on the formation. Larger loads can also cause unnecessary stress and wear on the elastomer sealing elements.

If reservoir pressure is unknown, a 48 to 72 hour shut-in test will provide an estimate of remaining reservoir pressure. A total estimated reservoir pressure can be obtained by adding the recorded surface shut-in pressure to the hydrostatic pressure of the wellbore fluids and gas present in the well.

Extensive field tests have been conducted using an ACS plunger equipped with an electronic data recorder and 2 pressure transducers. One pressure transducer recorded the producing gas pressure below the ACS plunger. The other pressure transducer recorded the pressure above the ACS plunger consisting of the sum of the sales line pressure and the hydrostatic pressure of the column of fluid and gas being lifted by the ACS plunger. The difference between those values consistently averaged approximately 6 PSI. The 6 PSI represents the pressure necessary to lift the weight of the ACS plunger and overcome the friction of the elastomer sealing elements with the casing.

The pressure that is actually available to remove fluid from the well is the available reservoir pressure less the sum of the sales line pressure and 6 PSI necessary to lift the ACS plunger. The maximum differential pressure ($P_{diff}max$) is critical in determining if an ACS system is appropriate for a well. For any fluid density, the column of fluid that can be lifted by 1 PSI of pressure can be easily calculated. The volume of fluid occupying 1 linear foot of any size and weight casing is easily found in most service company handbooks. The theoretical maximum volume (Vmax) of formation fluid that can be lifted by the available lifting pressure can be calculated using the following formula:

$$\text{Vmax} = P_{diff}\text{max} * \text{F P G} * \text{Casing Capacity}$$

Where: $P_{diff}max$ (PSI) = Reservoir Pressure (PSI) - Sales Line Pressure (PSI) - 6 PSI

F P G (FT/PSI) is the Fluid Pressure Gradient

$$\text{F P G} = \frac{1}{\text{Fluid density (PPG)} * 0.052 \text{ PSI/PPG-FT}}$$

Casing capacity (BBL/FT)

By example:

Reservoir pressure:	:	560 PSI
Producing line pressure:		120 PSI
Pressure to lift ACS plunger:		6 PSI
Fluid density:		8.5 PPG
Production casing:		4 ½ IN - 10.5 #/FT

$$P_{diff}\text{max} = 560 \text{ PSI} - 120 \text{ PSI} - 6 \text{ PSI} = 434 \text{ PSI}$$

$$\text{F P G} = \frac{1}{8.5 \text{ PPG} * 0.052 \text{ PSI/PPG-FT}} = 2.26 \text{ FT/PSI}$$

Casing capacity = 0.0159 BBL / FT

Vmax = 434 PSI * 2.26 FT/PSI * 0.0159 BBL / FT

<u>Vmax = 15.6 BBL</u>

For this example, the available reservoir pressure is theoretically capable of lifting up to 15.6 BBL of 8.5 PPG fluid. This calculation ignores the back pressure created by the hydrostatic pressure of the gas column.

Next, one should consider the well's historic gas to total liquid ratio. Although there may be sufficient pressure available to lift a large column of fluid from the well, one must determine if the ACS system will be able to remove the fluid on a timely basis to make the conversion practical. Generally speaking, a well with sales line pressure of less than 100 PSI should have a minimum gas to total fluid ratio of 3 - 5 MCF / BBL of total fluid produced to be practical. A well with a gas to total fluid ratio of less than 3 - 5 MCF / BBL will normally have cycle times so long as not to be practical.

The third category of information to be researched is the well's production decline curve. A well that is not producing up to expectations but has the shape of a typical decline curve for wells in the area is probably not an ideal candidate for ACS conversion if the object of conversion is improved production. The well may receive an economic benefit from reduced operating expenses following an ACS conversion but may see little improvement in production. A well that shows a sudden or unexplained decrease in production may be a very good candidate for conversion. An unusual production decline curve normally indicates the presence of a physical or mechanical problem somewhere between the perforations and the sales point. It is possible that a hole has developed in the tubing, a rabbit may be worn, or a down hole pump may require repairs. The perforations may be plugged with paraffin or sanded off. Regardless of the cause of the problem, a service rig is likely to be used to diagnose and solve the problem. Most remedial service work to diagnose any production problem will include swabbing fluid from the well, establishing the correct total depth of the well, and a shut-in test to establish reservoir pressure. The data collected may be used to determine if the well might benefit from an ACS conversion.

In some cases, wells with steeper than projected production decline curves are found to have production equipment problems. When converted to ACS production, some wells are able to recover the "lost" production volumes and return to at or near the original projected production rates.

Physical Concerns

When considering a possible ACS conversion, time should be allocated to research the physical properties of the well. The condition of the production casing is the individual component of the well that has the greatest impact upon the successful conversion to an ACS production system. It is important to evaluate the overall condition of the production casing. A uniform weight and style of casing should be present throughout the entire string of casing. The presence of any internal casing equipment installed for cementing or stimulation services could hinder the free travel of the ACS plunger into or out of the well and must be considered.

Standard well head equipment may not be compatible with an ACS system. Conventional gate or frac valves may have internal guides or shoulders that may not allow the elastomer sealing elements to pass freely through the valve. A full opening ball valve should be used as the master surface control valve for ACS conversions.

Any area of the casing where salt rings or buildups, paraffin deposits or unusual corrosion have occurred must be studied to determine if the casing is sufficiently smooth to allow the elastomer sealing elements to function properly. Surface irregularities in the casing may cause premature wear to the sealing elements. Rough casing can cause an incomplete pressure seal between the casing and the sealing elements causing poor ACS performance and decreased production.

Although obvious, it is worth mentioning that copies of the original casing tally and all perforating logs should be consulted to confirm the length and weight of the original casing installed and to locate the correct placement of the bottom hole stop.

Wellbore Preparation

Once a decision to convert a well to ACS production is made, the wellbore should be conditioned to provide an optimum operating environment for the ACS plunger. After all production equipment (rods, tubing, wellhead, pumping unit, etc.) is removed from the well , the current effective well depth must be measured and compared to the original well records. This offers another check of wellbore integrity before any ACS equipment is installed. This step may reveal that most perforations are covered with sand or formation fines. Regardless of the production method employed, a well could not produce to its' potential if any perforations are covered.

Total depth should be measured and compared to the original casing tally, driller's log, and perf logs. Any accumulated fill-up should be removed. The next step is to scrape or broach the production casing. The casing scraper may be run on tubing or wireline. When run on wireline, the scraper must be run beneath a heavy set of stem and jars to provide sufficient weight to overcome the friction and drag created by the scraper as it cleans the inner surface of the casing. Standard practice with wireline scraping is to operate the casing scraper up and down the casing from surface to the top perforation at least 3 times. Any history of salt, paraffin, or scale buildup requires that additional scraping should concentrate on the areas of known problems.

Any tight spots or areas exhibiting unusual drag when scraping should be noted and researched. The areas of increased drag may indicate a joint or joints of heavier weight casing or an area of possible corrosion. Additional scraping may provide additional assurance of properly conditioned casing.

Equipment Installation

When installing an ACS system, the order of component installation may vary depending upon individual circumstances of the well. Conceptually, ACS equipment installation will begin by attaching a safety nipple on the upper-most joint of production casing. This safety nipple provides a standard 2 IN threaded connection allowing an access point below the surface master control valve. In the event the ACS plunger or other service tools become stuck in the lubricator, or if the stem of the surface master control valve twists off, the safety nipple allows for pressure control to either release wellhead pressure or to provide access to kill the well. Once under control, the defective equipment can be safely removed and replaced.

A full opening ball valve is installed immediately above the safety nipple. In addition to being full opening, the surface master control valve should have chamfered edges on the ball to allow the elastomer sealing elements to easily pass through the valve. The chamfered shoulder is especially helpful in the event that the flow channel of the ball is not exactly aligned with the flow channel of the valve body.

Normally the bottom hole stop will be installed next. The bottom hole stop may be either a tubing stop or a casing stop. The tubing stop is installed on the top of centralized free standing tubing cut to a length to position the tubing stop immediately above the top most perforation. The casing stop is normally installed in the first or second casing collar immediately above the top most perforation. The casing stop is installed in the space of the casing collar not filled by the threaded portion of the upper and lower joints of casing.

If a bottom hole stop is inadvertently placed below the top perforation, it is possible that sufficient gas production may occur through the perforations above the bottom hole stop so that the plunger is never able to develop a sufficient seal to lift the ACS plunger out of the perforations. An original casing tally and all perforating logs should be used to determine the correct placement of the bottomhole stop in the well.

The next step in preparing the well for ACS production is to swab the accumulated fluid from the wellbore. Once swabbed down, the well can be turned back into the sales line at give an operator an estimate of the well's current production capabilities. The gas and fluid production can be used to estimate the initial cycle frequency for the ACS and to estimate the ACS plunger cycle time.

The final step in equipment installation is to install the surface lubricator on top of the surface master control valve. Once in place, the sales line is connected to the lubricator and the well is ready for production.

Startup

Once all ACS equipment is installed and sales and flow lines are secure, the well is ready to begin production. The gas sales line can be opened to begin continuous gas sales. Before the ACS plunger is released from the surface lubricator, it should be confirmed that there is at least 1 BBL of fluid covering the bottom hole stop to slow the descent of the plunger before the stop is reached. If sufficient fluid is not present to slow the decent, significant damage could occur when the free falling ACS plunger strikes the bottom hole stop.

To start an ACS production cycle, the lubricator latching mechanism is manipulated to release the ACS plunger allowing it to begin its free fall toward the bottom hole stop. The latch mechanism should be re-engaged to catch the ACS plunger when it returns to the surface lubricator at the completion of the cycle.

Gas production will continue as the ACS plunger free falls toward the bottom hole stop at rates of up to 1000 feet per minute(Figure 6). Gas present in the casing will enter the ACS plunger through the open valve passing through the plunger as it falls. When the ACS plunger reaches fluid, the rate of descent will decrease. The ACS plunger will continue falling as the accumulated well bore fluids pass through the open valve and the plunger. When the ACS plunger reaches the bottom hole stop, the weight of the plunger will cause the external valve to close. The closed valve and the elastomer sealing elements effectively isolate the reservoir pressure trapped below the ACS plunger from the fluids above the plunger. As reservoir pressure increases approximately 6 PSI (the pressure necessary to lift the ACS plunger), the ACS plunger and the trapped fluids will begin to move up the hole(Figure 7).

Produced gas exits the surface lubricator through a 3/8 IN flow orifice at the same rate gas is produced from the formation. As fluid reaches the surface, the plunger's upward travel may slow as fluid is throttled through the 3/8 IN production orifice. The upward travel of the ACS plunger must be slowed before it enters the surface lubricator to avoid possible damage that could occur if the ACS plunger enters the surface lubricator at too high a velocity.

As the last fluid is produced through the flow orifice, the ACS plunger simultaneously enters the lubricator engaging the latch assembly and opening the valve of the ACS plunger. As the valve opens, "tail" gas or the gas immediately below the ACS plunger is able to immediately enter the sales line allowing continuous uninterrupted gas sales.

Attention should be given to the well's new ACS "signature" on the sales chart. An ACS that is operating properly will develop an individual pattern that can help diagnose operational problems should they arise. A return time for the ACS plunger can be calculated using an estimated production rate at sales line pressure . If the ACS plunger has not returned within twice the calculated return time, the position of the fluid level trapped above the ACS plunger should be measured using an acoustic or similar depth measuring device. It is suggested that the location of the fluid level be measured again after 4 hours of gas sales to determine the rate the ACS plunger is ascending.

If the ACS plunger is traveling at a rate significantly different than originally estimated, review the calculations giving special attention to sales line pressures and estimated gas sales rate. Remember that the gas below the ACS plunger must be measured in absolute gas volumes (gas under pressure), where gas sales are reported in standard gas volumes (gas at atmospheric conditions).

It is not uncommon for an ACS to lift an unusually large fluid volume during the well's first few cycles following ACS conversion. A larger load will cause longer cycle times. As long as the ACS plunger is traveling toward the surface, the system is functioning as designed and is responding to the well's individual properties at that given time. No adjustments are required.

If the ACS plunger is not returning toward surface and the operator is certain that gas sales are occurring, a service technician or sales representative should be contacted.

Producing a Well with an Automatic Casing Swab

When producing a well with an ACS, care must be taken to maintain the ACS plunger and other components of the system so that optimum production can be sustained. It is recommended that the ACS plunger be removed from the surface lubricator and inspected after each of the first 10 cycles, then at least once every 30 days or cycles which ever comes first. The ACS plunger should be visually inspected from top to bottom noting any debris that has accumulated on the plunger or any unusual discoloration. Any solids found on the plunger should be analyzed to determine the composition and probable source. Sand and formation fines found on the plunger may indicate an accumulation of solids in the wellbore and may signal a need to raise the bottom hole stop. The presence of salt or paraffin crystals should alert an operator of a possible need to perform preventative maintenance before the problem causes the ACS plunger to stop running. Discoloration of any component of the ACS system may be a sign of corrosion and should be investigated.

Care should be taken to insure that any chemicals used to treat a well are compatible with the ACS plunger and the elastomer sealing elements. Some paraffin solvents and methanol solutions can have detrimental effects on the elastomer compounds used in the O-rings and pressure sealing elements. A manufacturer's representative should be consulted before introducing anything other than fresh or brine water into a well containing an ACS system.

The elastomer sealing elements should be carefully inspected anytime the ACS plunger is removed from the surface lubricator. Any tears or cuts in the sealing elements should be noted and investigated. Each well will exhibit a unique wear pattern on the sealing elements. Shallow scratches in the sealing elements are normal and are evidence of surface imperfections present in the casing. The elastomer sealing elements seem to wear until an equilibrium point is reached where the sealing elements have worn to "custom fit" the casing present in that well.

An ACS that is running properly will develop a pattern of travel time and fluid removal that is fairly constant if sales line pressures do not fluctuate. Any significant deviation from this pattern may be an indication that the elastomer sealing elements are about to fail. The ACS plunger should be retrieved for inspection and repaired if necessary.

To maintain peak production, some operators review maintenance records of each ACS well to determine if the elastomer sealing elements require replacement on a regular basis. If a pattern of replacement can be established, future maintenance for the ACS plunger will be scheduled to replace the sealing elements when 90% of predicted service life of the sealing element has elapsed.

If the ACS plunger does not return to the surface, the elastomer sealing elements may have lost a portion of their sealing ability. It is imperative that an acoustic depth measuring device be used to determine the position of the ACS plunger in the well, and to confirm if the plunger is truly stuck or if it is simply traveling slowly. If the ACS plunger is moving slowly to the surface, it is normally best to allow it to surface normally. The plunger should be caught in the surface lubricator for removal, inspection, and repairs, if necessary.

If stuck, the ACS plunger can often be bypassed to the surface for inspection and repair. When bypassing a well, it is critical that all gas pass through only the 3/8 IN flow orifice in the surface lubricator. If the ACS plunger can not be bypassed to the surface, a service rig will be required to retrieve the ACS plunger from the well. In the case of a stuck plunger, it is important to not only determine the location of the ACS plunger, but to also determine if the well is selling gas, or is dead. Extreme care must be taken when servicing a well with a stuck ACS plunger. Remember that 12.90 LBS of upward force is created for every 1 PSI of pressure trapped below a stuck ACS plunger. Tremendous amounts of energy is stored in the compressed gas trapped below a stuck ACS plunger. The safest method of retrieving a stuck ACS plunger is to first eliminate any differential pressure acting across a plunger.

Any threaded connections which attach the various components of the ACS plunger should be thoroughly inspected and secured anytime the ACS plunger is removed from the surface lubricator. The valve should be shifted to the open position then stood vertically on the ground to see if the valve will close under the weight of the ACS plunger. If the valve will not close under its' own weight in the atmosphere, it will certainly not close when its' weight is reduced because of the buoyant effect of the accumulated wellbore fluids. If the ACS plunger does not close under its' own weight, the plunger should be dismantled according to the manufacturers instructions and inspected for accumulation of foreign debris in the internal workings of the ACS plunger, reassembled, and tested.

As with any production system operating at elevated pressure, common sense and standard safe work practices should always be observed.

Chart Integration

The ACS system has the unique characteristic of allowing almost any well to produce at near steady state conditions at all times. This continuous near steady state production of gas and fluids from the reservoir can help deliver the maximum production at any sales line pressure. In addition to delivering maximum production rates, the gas that is produced can be measured with greater accuracy. If the standard orifice differential pressure recording device is used, an orifice plate can be installed that allows virtually all flow to be recorded on the pressure chart. Since the flow rates and pressures are nearly steady state, pressure spikes and surges normally associated with rabbit wells can be all but eliminated .

Another factor allowing better chart integration is the near continuous production of gas from an ACS well. Continuous production allows more accurate chart integration since production time can be accurately measured.

Restricted or Regulated Sales Lines

It can be very difficult to maximize gas production in a well services by a restricted or regulated sales line. Often times, it is virtually impossible to operate a rabbit well efficiently into a restricted sales line. A rabbit well relies on gas velocity to chase the rabbit and fluids to surface. Since the velocity of the rabbit may decrease as the sales line pressure increases and becomes packed with gas, the rabbit will often stall returning to bottom before it can surface removing the load of fluid from the well.

Because of the positive sealing elements of the ACS, the upward travel can slow or even stop without losing the load of fluid being lifted from the well. When sales line pressure decreases, the ACS will begin moving toward the surface.

Economic Impact

Since 1992, one company has installed over 200 ACSs on various types of producing wells. These conversions have been performed in large groups of up to 55 wells per year. Due to the historical data available, the 1992 program was analyzed to determine the long term economic effects of ACS.

The 1992 program consisted of converting 32 Ohio Clinton Sandstone producers from tubing plungers and swab wells to ACS production. For six months prior to the conversion year, the average per well producing rate of 19 MCFD, 1.4 BOPW and 1.6 BWPW. Average direct well expense was $102 per well. Total conversion costs for the 32 wells were $176,000 ($5,500 per well), which includes a capital cost of $112,000 ($3,500 per well) for ACS systems and a direct expense of $64,000 ($2,000 per well) for labor and rig costs. Although not included in this analysis, a significant portion of the capital costs of the ACS system could be offset by any salvageable equipment removed as a result of the conversions (tubing, wellheads, rods, etc.).

As can be seen from Figure 8, total production following the conversions improved significantly. By the end of 1992, the average well producing rate had increased to 26 MCFD, 1.9 BOPW and 2.7 BWPW. This translates to more than a 35% improvement in both gas and oil production. Production has remained above pre-conversion projected levels for more than three years, with the wells recovering over 142,000 MCF of additional gas compared to pre-conversion expectations. By the end of 1994, these wells were averaging over 16 MCFD, even though several wells were struggling to overcome significant increases in line pressure.

This improvement in production has had a direct effect on the total net revenue (Figure 9). Since the wells were converted, an additional $450,000 has been realized due to production improvements resulting from the ACS. After two years of production, total net revenues is still above levels that were predicted in 1992. Through 1994, net revenue has been increased by 45% over previously projected rates. This is higher than the 35% production increase due to improved product prices.

In addition to net revenue, significant improvements in net operating income (revenue less expense) have also been realized (Figure 10). Through the end of 1994, operating income for the 32 converted wells was $335,000 greater than the values projected in 1992. This is a result of not only improved production but also of reduced operating costs (Figure 11). As previously mentioned, direct well expenses for the 32 wells averaged $102 per well per month during the year before conversions. Since the beginning of 1993, direct well expense has averaged $93 per well per month, which is an 8.8% reduction. Although this reduction is not as significant as the production improvement, it does demonstrate that the ACS has a positive effect on operating costs.

In summary, the 32 well conversion program performed in 1992 increased production rates while decreasing direct well expenses, which should ultimately result in additional reserve recovery. As a result of the successful program, additional programs have been performed in subsequent years with varying degrees of success. An ACS production system offers an economic alternative to other production methods when applied to the proper candidate.

Instrumented Automatic Casing Swabs

In an attempt to better understand the intricate workings of the ACS, a working ACS was outfitted with 2 electronic pressure transducers and a data gathering board. The transducers were positioned to measure the pressure above and below the elastomer sealing elements of the ACS plunger. The synchronized collection of accurate pressure data offered a near continuous record the pressures that affected the ACS plunger through the complete production cycle. By analyzing the pressures and calculating the resulting forces acting on the ACS plunger, a clearer understanding of the operation of the ACS plunger can be obtained.

Raw pressure data was gathered in the field and adjusted to compensate for temperature drift caused by the natural thermal gradients present in the well. A higher pressure is recorded by the transducer below the elastomer sealing elements because additional pressure is necessary to overcome the weight of the ACS plunger and the friction between the sealing elements and the casing. On average, a 6 PSI pressure differential is measured by the transducers on either side of the sealing elements. The actual differential pressure necessary to operate the ACS plunger may vary within an individual well as a reflection of the physical condition of the casing at any given location in the casing string.

Figure 12 depicts data gathered for analysis. The rapid increase in pressure between points 1 and 2 are a result of pressure being applied to the surface lubricator as the master surface control valve is opened. A slight decrease in pressure is noted in the region between points 2 and 3 when the sales line valve is opened and gas begins to produce. The pressure increase measured between points 3 and 4 are a result of the ACS plunger being exposed to increasing hydrostatic pressure from the gas column as the plunger is released and allowed to free fall to the bottom hole stop. The information recorded between points 4 and 5 represents the pressure measured above and below the elastomer sealing elements of the ACS as the plunger and accumulated fluids are lifted toward the surface. The differential pressure across the plunger is fairly constant at 6 PSI. Pressure variations are evidence that the relative roughness of the casing varies at different points throughout the well. The increased pressure measured between points 5 and 6 are a result of fluid being throttled through the 3/8 IN flow orifice in the surface lubricator. The sudden decrease of pressure occurring between points 6 and 7 is a result of the well being bypassed to purge the surface lubricator and flow lines of fluids. The region between point 7 and 8 correspond to gas being directed into the sales line and allowing gas sales to continue.

Case Histories

It is estimated that at least 900 ACS systems have been installed since 1990. Generally speaking, wells converted to ACS production techniques have shown considerable production improvements.

Figure 13 is a production curve from the Ohio Mining #31D well in Dover Township of Athens Co., OH. The decline curve is typical of a Clinton Sandstone reservoir. Prior to conversion, the well was operated as a swab well. Production showed the characteristic surges in production resulting from the removal of accumulated wellbore fluids by the swab rig. These peaks in production are normally a positive indication that a well may benefit from ACS technology. Since an ACS production system consistently removes the accumulated fluids from the wellbore, post conversion production rates for swab well conversions are normally near the peak values achieved immediately following swabbing operations. Prior to ACS conversion, the Ohio Mining #31D struggled to produce an average 7 MCFD. Following conversion to ACS production methods, the well consistently produces approximately 50 MCFD.

Figure 14 is a production curve from the Clinton Petroleum #2 well in Randolph Township of Portage Co., OH. The Clinton Petroleum #2 produces from the Rose Run Formation. Initially, the Clinton Petroleum #2 was produced using a tubing plunger. As production declined, the rabbit struggled to run and the well was converted to a pumping unit well. As production continued to decline, the pumping unit become uneconomical to operate. Immediately before ACS conversion, the Clinton Petroleum #2 well was producing approximately 20 MCFD with a very steep production decline curve. Following the installation of ACS equipment, the well produced between 40 and 60 MCFD with a shallower production decline. It should also be noted that a significant increase in oil production was obtained following ACS conversion.

Summary

The ACS production system has been around in one form or another since 1955. The ACS is a simple dependable production system that utilizes formation pressure to efficiently remove formation fluids from the wellbore. The most favorable characteristics of several commonly used production methods have been incorporated into the design of the ACS. Some of these features include: effective timely removal of formation fluids, simple dependable operation, reduced operating and maintenance costs, and improved gas production. An ACS can improve gas production and reduce operating costs. The ACS system should be considered for any new well installation or anytime present production techniques require repair or become uneconomical to operate. The use of ACS technology can add years of productive life to a well.

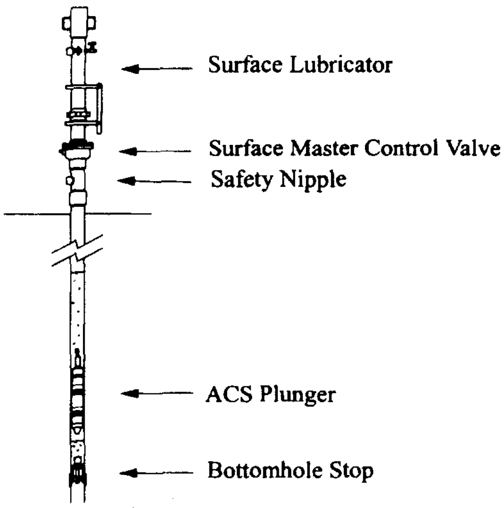

Figure 1 - Automatic Casing Swab Components

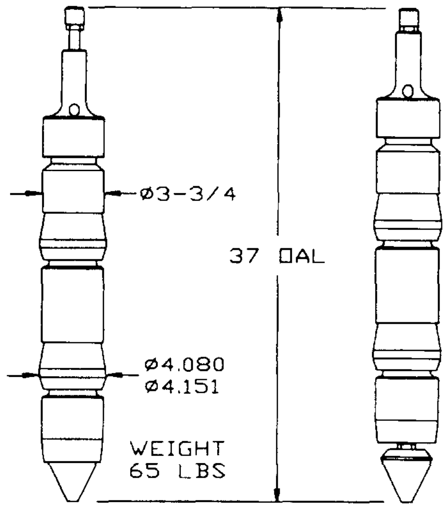

Figure 2
ACS Plunger - Closed ACS Plunger - Open

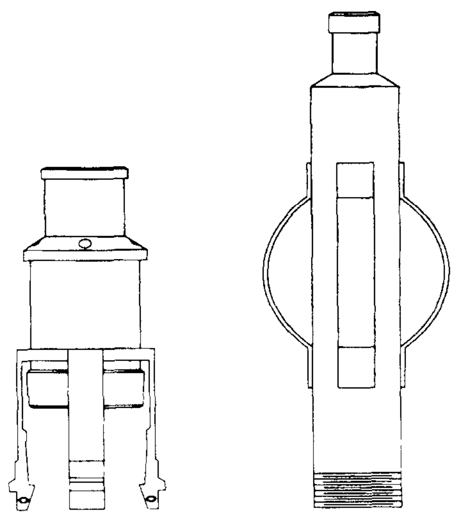

Figure 3
Casing Stop Tubing Stop

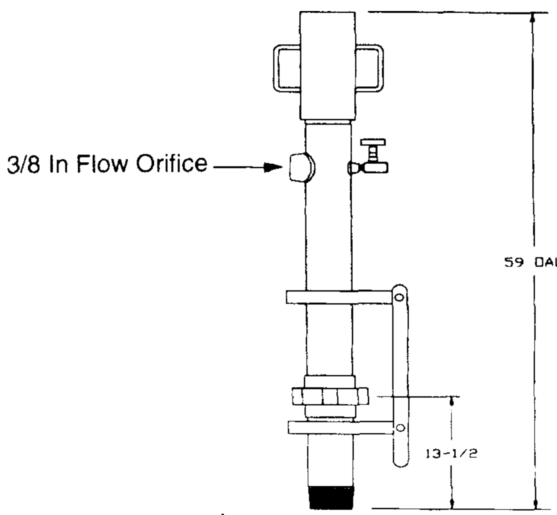

Figure 4 - ACS Surface Lubricator

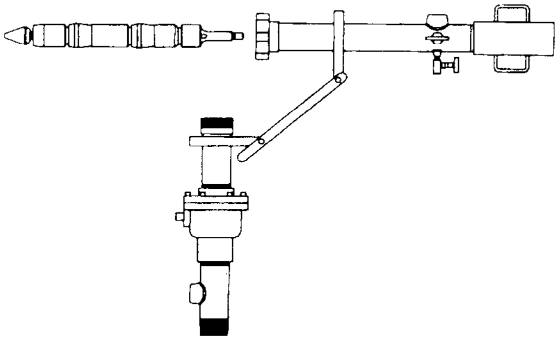

Figure 5 - ACS Plunger & Lubricator

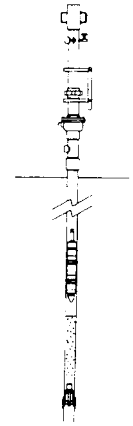

Figure 6 - ACS Plunger freefalling to the bottom hole stop. Gas and fluid are able to enter the open valve, traveling through the hollow body of the plunger. Gas production continues.

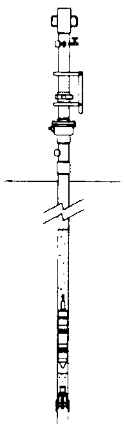

Figure 7 - ACS Plunger has traveled to the bottomhole stop and closed. All fluid accumulated above the bottom hole stand are trapped by the elastomer seals. The ACS Plunger and fluids are being lifted to the surface by gas being produced by the formation.

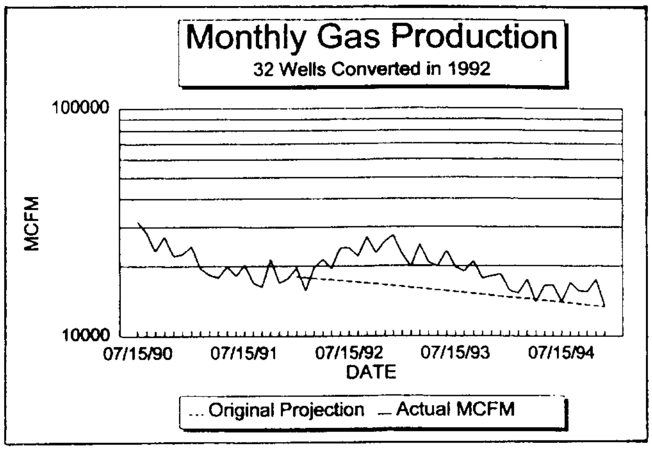

Figure 8

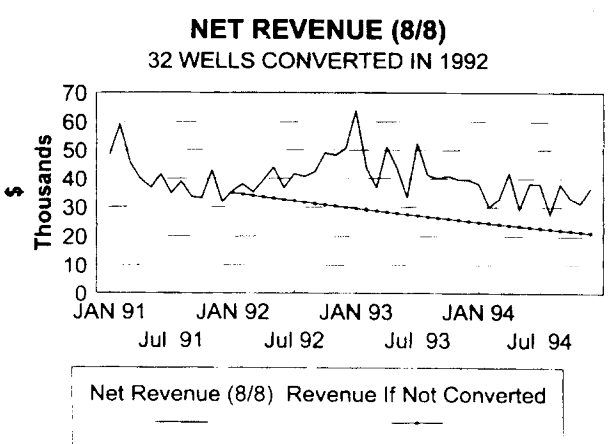

Figure 9

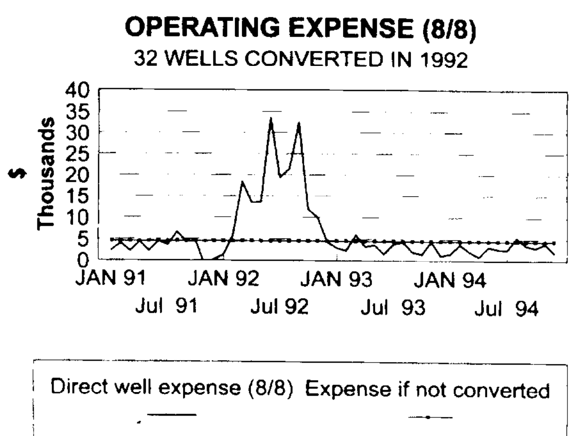

Figure 10

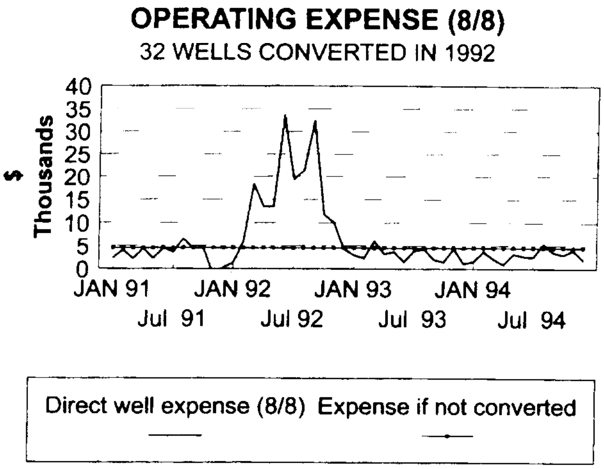

Figure 11

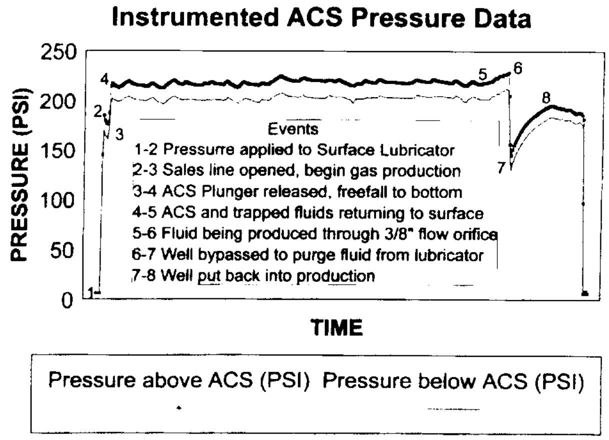

Figure 12

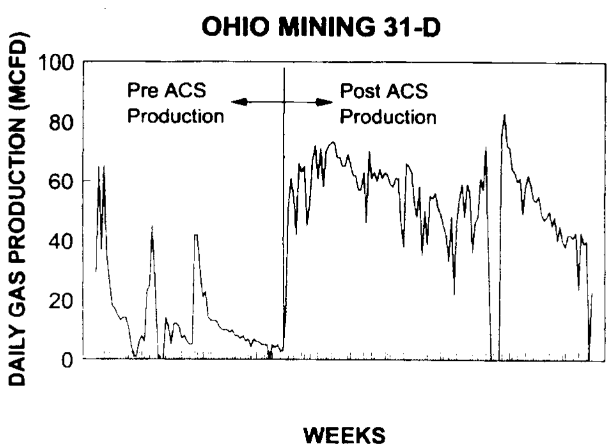

Figure 13

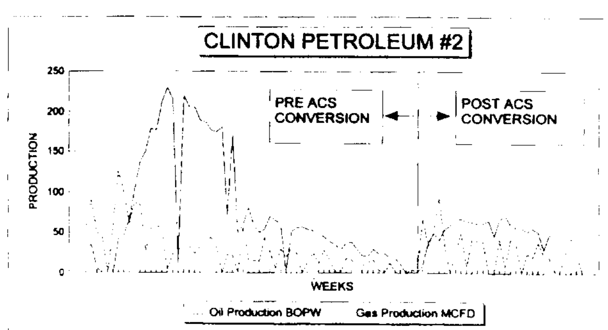

Figure 14