

THE AMERICAN OIL & GAS REPORTER

MAY 2005

The "Better Business" Publication Serving the Exploration / Drilling / Production Industry

GAS INDUSTRY STRATEGIES page 48 COMPRESSION TECHNOLOGY page 78



Douglas Reynolds Jr.
President IOPA
Tri-State
"There are lots of places in the Illinois Basin that have been drilled heavily where you still have the potential of finding excellent production."
Page 121



Robert G. Alley
President KOGA
"Both oil and gas producers and KOGA are enjoying today's market conditions."
Page 125



J.R. Hurd
President TIPO
"All the independents I talk to have their 'pedal to the metal' and are exploring to the maximum extent allowed by their personnel, equipment and supplies."
Page 131



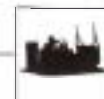
Rod Eson
Chairman CIPA
"I think we have seen a shift to more people looking to add reserves through drilling instead of acquisitions."
Page 136



David House
Chairman OIPA
"We continue to explain to policy-makers how important our issues are. It is a mistake for people to focus on commodity prices and fail to see anything else."
Page 140



Logan Magruder
President IPAMS
"Breaking regulatory impasses is critical to getting more natural gas into the marketplace today."
Page 148



Systems Reduce Casinghead Pressure

By Larry Richards
and James Sidebottom

MIDLAND, TX.—Seeking to wrench additional dollars from existing production, more and more producers are turning to low-horsepower compression to enhance production from mature wells.

Casinghead pressure can have a dramatic negative impact on the production curves of many mature formations. Couple this existing pressure with the trend of increasing pipeline pressures across the country, and the impact is substantial.

Using compression on mature basins is growing exponentially across the United States, driven by high commodity prices and the speed with which the technology can be implemented. The technology does not work on every formation, but the results can be dramatic on those formations that respond. Backpressure is exerted on an oil or gas well from several sources. It may be the backpressure required to operate the separator or lease equipment, or the pipeline pressure. Backpressure at the wellhead results in elevated downhole formation pressure and often a significant reduction in the amount of hydrocarbons that effectively migrate into the well bore.

The primary source of backpressure in

many mature wells is casinghead gas. Historically, much of this gas was simply vented

casing pressure and thereby backpressure on the well, increasing production. Today's regulatory environment severely curtails an operator's ability to vent this gas stream. In addition, wellhead prices of \$5 an Mcf make wasting this valuable natural gas commodity an economic and environmental issue. Casinghead pressure reduction units capture this gas, but the real payoff often comes in dramatic increases in oil and gas production.

Casinghead gas usually consists of flash gas off the oil reservoir, resulting in a fairly wet gas stream (typically 0.85 spec gravity/16 gallons of liquid per thousand cubic feet of gas (gpm)). This gas fills the annulus between the casing and tubing from the producing zone to the wellhead. The weight of this extremely tall column of wet gas sitting on the formation has an incremental effect on bottom-hole pressure. The multiple of the pressure exerted on the formation is dictated by oil-specific gravity and well depth. When wellhead pressure is added, usually in the form of a flowline or first-stage separator, the pressure on the formation is significantly increased. The equation is further complicated by fluctuating

wellhead pressure from the pipeline, which can literally shut in mature wells.

Relieving this pressure reduces the weight (pressure) on the formation, allowing hydrocarbons to more easily flow from the formation into the well bore. In addition, reducing wellhead pressure reduces the amount of gas entrained in the produced oil, which often eliminates gas locking in downhole pumps, increasing pump efficiency. The goal is to maintain casinghead pressure as close to zero as possible. In areas of the country where it is allowed, these systems are often configured to pull a vacuum.

Compelling Economics

Using compression to minimize downhole pressure has strong commercial success in a wide range of formations and applications. It is most commonly used in conjunction with downhole pumps and most successfully in waterflood or carbon dioxide flood projects. Other successful applications include gas wells on plunger lift, coalbed gas wells, and standard wellhead compression on flowing gas wells. Formations that respond can produce some very compelling economics, as demonstrated in actual case studies (for comparative purposes, all four case studies are based on an oil price of \$50 a barrel and a gas price of \$5 an Mcf).

In the first case study, a major oil and gas producer in Southeast New Mexico began implementing a staged testing of its wells in 2004. Casinghead reduction units have now been added to 10 wells, resulting in daily gas sales increasing from 1,280 Mcf to 1,726 Mcf—an average of 44.6 Mcf per well, per day. In addition, oil sales have increased by nine barrels of oil a day. The increase in the gas stream is worth \$2,230 a day, while the increased oil generates an additional \$450. Together, the addition of compression added \$80,400 a month in incremental revenue to these 10 wells.

In Southeast Oklahoma, a mid-sized independent placed a casinghead reduction unit pulling four wells in mid-2004, reducing wellhead pressure from 100 to 1 psi. Gas sales increased 90 Mcf (\$450) a day and oil sales increased 3 barrels (\$150) a day for a total \$18,000 monthly revenue increase.

In another application last year in Coleman County, Tx., a large independent reduced casinghead pressure from 25 to 1



Implementing low-horsepower compression to reduce wellhead pressures can result in dramatic oil and gas production increases. In West Texas, a small independent realized an additional \$167,250 in monthly oil and gas revenues by increasing production using four compressors pulling multiple wells to reduce casinghead pressure by 44 psi.



Casinghead gas is usually flash gas off the reservoir, which results in a relatively wet gas stream. Liquid handling equipment and compressor selection are critical in designing equipment packages for reducing casinghead pressure.

psi. The project resulted in increasing daily gas production by 79 Mcf (from 31 Mcf to 110 Mcf) and daily oil production by 96 barrels (from 21 to 117 barrels). As a result of reducing pressure by 24 psi, monthly revenues increased \$155,850.

A small independent in Ector County, Tx., reduced casinghead pressure from 45 to 1 psi in 2004 utilizing four separate compressors pulling multiple wells. This project resulted in a 45-Mcf/day increase in gas and a 107-barrel/day increase in oil production, boosting revenues by \$167,250 a month.

Testing Potential Wells

As these case studies illustrate, the payback economics can be substantial. Fortunately, the majority of wells tested in mature basins have responded favorably to reducing casinghead pressure. In fact, in our experience, 65 percent of mature basins respond favorably. Many wells show dramatic increases in oil and/or gas production, particularly in waterflood or CO₂ flood projects. In addition, casinghead pressure reduction allows subsurface pumps to operate more efficiently, often eliminating “gas locking” problems, and eliminates the impact of fluctuating or rising pipeline pressures on production.

However, not all formations respond favorably, and even individual adjacent wells producing from the same formation may respond differently. While some

entire formations have been identified that do not respond within areas that do respond, it is necessary to either conduct well-by-well testing or link the wells into a common gas gathering system. Also, some formations may respond with increased produced water, and in some cases, wells may respond strongly for 7-10 days and then drop to previous levels. Oil production gains after 30 days generally remain constant, but gains in gas production often follow a less predictable curve.

Based on these strengths and weaknesses, it is recommended that a forma-

tion be tested before compression equipment is purchased or a long-term lease is signed. A Merla tester or similar orifice device can determine the approximate volume of casinghead gas produced. A gas analysis is also recommended to determine the specific gravity of the gas (for best compressor selection) and measure hydrogen sulfide and CO₂ content.

With this information in hand, a temporary trailer- or skid-mounted package is moved to location for a 30-45 day test. When backpressure is first relieved, the well often releases a significant amount of “flush” production during the first two or three days and then decreases to a sustainable production curve. A full 30-day test will produce the data necessary to run accurate economics at the new level of production. Initial test units are typically fitted with natural gas engines to minimize installation costs during the testing phase. The units can be fitted with an automated programmable logic controller restart function that minimizes downtime and callouts for field personnel.

If the well responds appropriately, an electric-drive unit can be moved to location to replace the test unit. Electric-drive packages have dramatically less maintenance issues and do not consume \$5/Mcf gas. If wells are located in close proximity to one another, opportunities may exist to link multiple wells to the same compressor. The key is distance, keeping in mind that the goal is to maintain each wellhead to as close to 0 psi as possible. Linking distant wells may save some money on compressor costs, but could cost twice the amount saved in lost potential revenue by not pulling the farthest wells closer to



A structured test approach is used to evaluate the estimated production curve of the well or formation following the reduction of casinghead pressure. This includes determining the volume of casinghead gas produced, analyzing the gas, and conducting a 30-45 day test using a portable trailer- or skid-mounted package.



If multiple wells are located in close proximity, clusters of wells can often be linked to a single compressor package. The key is distance. Linking wells located far apart may save on compressor costs, but could cost much more in lost potential revenue by not pulling the farthest wells closer to 0 psi.

0 psi. When logistically feasible, a cluster of 10-20 wells can be linked to a single compressor package.

Design Considerations

As discussed, casinghead gas is typically a wet gas stream. In addition, it is not unusual for liquids to be produced by the casing during certain oil field operations. As a result, it is recommended that specific liquid handling equipment be considered in the design of any casinghead gas gathering system. This can be accomplished with drip pots positioned along the low spots of the gathering system or adding a separator in front of the compressor package.

Utilizing an experienced packager of casinghead gas reduction units can save hours of frustration and downtime on field installations. Each application requires special design considerations, often learned the hard way through years of experience. For example, packages on plunger lift wells require oversized scrubbers and liquid transfer pumps to handle the large volumes of liquids produced at the timed lift of the plunger. All applications require customer-installed bypass lines and feed gas lines to other lease equipment, both of which are critical to the long-term proper functioning of the equipment. Produced gas can be sent down the flowline or separate gas line, and polypipe is often used to reduce costs.

Proper system design is critical to maximize production and eliminate downtime. The heart of the system is a low-horsepower

compressor package designed according to the gas volume from the well, pressure of the discharge line required, and the specific gravity of the gas stream. These units typically range from five to 400 horsepower and can be driven with either electric or natural gas engines.

Four types of compressors are commonly used for this application: rotary vane, rotary screw, reciprocating, and liquid ring compressors. Each type of compressor has relative strengths and weaknesses, and each has its own optimum application range, which help determine

which type is most effective for a specific application. However, compressor selection and sizing is the most critical element in overall system design, and should incorporate some flexibility for changing well conditions and pipeline pressures. Spending the time and money to ensure that the optimum compressor type is selected based on the requirements of the application pays large returns after installation, which, after all, is the reason for installing the equipment in the first place.

Compressor Types

Rotary vane compressors are generally the most cost-effective technical solution for handling wet casinghead gas streams for volumes ranging between 25 Mcf and 4 million cubic feet a day, but they are limited to 50-60 psi discharge pressures. While rotary vanes can handle wet gas streams very effectively, they cannot tolerate slugs of liquid into the compressor. It is important to design these systems to minimize the possibility of liquids reaching a rotary vane compressor.

Rotary screw compressors are generally the most versatile technical solution for capturing wet or dry gas streams on daily volumes of 300 Mcf to 5 MMcf. Rotary screws can pull a significant vacuum and can handle discharge pressures up to 350 psi. In addition to handling wet gas, they also can handle the liquid slugs that often accompany casinghead gas. Versatility comes with a cost, however, as these packages are generally the most expensive of the four compressor types.



Rotary vane, rotary screw, reciprocating and liquid ring compressors can all be used in casinghead pressure reduction applications. Each has relative advantages and drawbacks. Small reciprocating compressors like the one shown here can be cost-effective alternatives for remote wells, but are only recommended for dry gas streams.

Reciprocating compressors work well in casinghead applications, but are recommended only for dry gas applications. These units are especially cost-effective on dry gas volumes to 500 Mcf/d and pressures to 500 psi. Larger reciprocating compressors can be used on dry gas applications when multiple wells are manifolded into a single unit.

Finally, liquid ring compressors can be effective in areas where a deep vacuum is required. While very efficient at pulling a deep vacuum, liquid rings are extremely limited on discharge pressure and are able to handle up to only 20-25 psi discharge.

Package design is extremely important to effectively maintain pressures as low as 1 psi on the wellhead. It is accomplished using a bypass system with a recycling/throttling valve, whereby a bypass pilot control maintains a constant pressure, and the gas is recycled on the skid below the set point. This design allows steady pressure to be maintained on the well bore. Inlet scrubbers with automated liquid transfer pumps (or blow cases) are recommended for handling liquids. Control systems can range from the most basic system shutdowns to incredibly sophisticated automation and remote monitoring.

As more operators evaluate the economic returns of using compression to increase production, this technology should continue to see dramatic growth. Properly designing and installing the equipment is critical to optimal performance and peak financial return. Few production alternatives for increasing revenue offer an operator a greater potential return with a lower level of risk, helping unlock the profitability of many mature fields. □

LARRY S. RICHARDS joined Hy-Bon Engineering in March 2003 as president. He previously served as vice president, operations support, for Key Energy. Before that, Richards served at Continental Emsco Co. as vice president of operations for the engineered products group and as vice president of marketing. He is a graduate of Texas A&M University.

JAMES SIDEBOTTOM is senior vice president and general manager of Midland, Tx.-based Hy-Bon Engineering Co. Inc., which designs and manufactures casinghead pressure reduction units utilizing a variety of compressor types. Sidebottom has eight years of experience in the gas compression business. He holds a B.S. in civil engineering from the University of Kentucky.

EVERY™ DRIVER.



Whether you are gathering gas at the wellhead, boosting pressure for pipeline transmission or driving an artificial lift pump, you need a power source you can depend on. Every time. One that keeps production up and maintenance costs down. That's why Cummins is everyone's power of choice for the oil and gas industry. And with over 5,500 distributor, branch and dealer locations worldwide, Cummins support is everywhere you need it. Contact your local Cummins distributor, call us at 1-800-DIESELS (1-800-343-7357) or visit our web site at www.everytime.cummins.com.



©2005 Cummins Inc., Box 3005, Columbus, IN 47202-3005 U.S.A.