# PACEMAKER TWO-PIECE PLUNGER LIFT SYSTEM A NEW INVENTION FOR AN OLD TECHNOLOGY

Preston G. Abbott
BP America Production Company

ABSTRACT

Plunger lifts are used widely to remove liquids from gas wells. The Pacemaker plunger is a new approach to this traditional method of artificial lift. Traditional plunger lifts require shut-in time for the plunger to fall and to build pressure to drive the plunger to surface. Shut-in time equates to lost production and forces liquids back into the formation. The Paccmakcr normally only rcquircs 5-10 seconds of shut-in timc per cyclc, and little or no prcssurc build-up timc. The plunger operates as two interdependent pieces. Each fall separately and can do so against significant gas rates. Once on bottom, the ball seals off in a cavity in the piston. Gas velocity then drives both to surface. At the surface a rod in the lubricator separates the ball from the piston, and the next cycle begins. The end result is that the well produces continuously and liquids arc not forced hack into the formation.

OVERVIEW

Plunger lift systems have been and continue to be used as an effective and economical means of removing liquids from gas wells. Numerous modifications have been made to the plungers, controllers, and surface equipment over the years. The Pacemaker two-piccc plunger is yet another modification, but with differences significant enough lo earn U S. patent protection.

Traditional plunger lift systems continue to he tremendously successful, but have a few inherent drawbacks. It is necessary to shut the well in for a pzriod of time, usually 30-60 minutes, in order for the plunger to fall to the bottom of the tubing. The amount of time depends on tubing depth, type of plunger, and the clearance fit between the plunger and the tubing. Additional shut-in time, usually in the range of 1-6 hours, is then required for the well to build enough pressure to force the plunger and its liquid load hack to surface. This shut-in time equates to a certain amount of lost production.

In contrast, the Pacemaker system generally requires less than 1 minute of shut-in time per cycle. This is possible due to the patented design of thc plunger. The complete plunger assembly is two separate hut interdependent pieces, a ball and a hollow piston. Both pieces fall separately and are able to fall against flow rate, reducing or eliminating the shut-in period for the plunger to fall.

Traditional plunger lift systems count on stored pressure to drive the plunger back to surface. Because of the time required to build pressure, a traditional plunger will commonly make 3-12 complete cycles per day. The Pacemaker utilizes gas velocity to drive the plunger back to surface. This reduces the requirement for a shut-in period to build pressure and allows for more frequent plunger trips It is not uncommon for a Pacemaker to make 50-100 cycles per day. Consequently, the Pacemaker provides longer flow times and more consistent gas rates.

MECHANICAL COMPONENTS

The downhole equipment consists of a hottomhole spring assembly, the hall, and the hollow piston. The hottomhole spring assembly is usually landed on a collar stop, a tubing stop, or a pump seat nipple. If landing on a pump seat nipple, the nipple must be undersized. The assembly is generally a free-floating spring and is very similar to a traditional hottomhole spring assembly, with one major exccption. The upper portion or fishing neck is made of titanium rather than carbon or stainless steel. The titanium is a tougher metal with somewhat better memory than steel. This is important iu that the Pacemaker ball and piston trip at significantly higher speeds than traditional plungers. When the spring assembly is made of steel the impact of the hall and piston tends to flare out and/or break the fishing neck. During each cycle, the ball drops to the bottom of the tubing first and rests on the bottom-hole spring assembly. At a predetermined time later, the piston falls to bottom. When the two meet, the hall seats in a cavity in the bottom of the piston. This creates the seal necessary to drive the plunger assembly hack to surface.

The surface equipment looks very similar in outward appearance *to* the traditional plunger lift lubricator. However, its internal parts have been redzsigncd to acconunodate the Pacemaker plunger. An anvil and its bumper spring serve to cushion the arrival impact of the piston A shifting rod or separator rod is hung-off through the anvil inside the lubricator. It has a separate spring that cushions the arrival impact of the ball. The purpose of the rod is to separate the ball and piston when they arrive at the surface. This causes the ball to fall back to the bottom of the tubing. In the original design, a gas-operated cylinder physically caught and held the piston at the surface. The shifting rod has been redesigned with a knob that has a somewhat larger outside diameter on the bottom end. The reduced clearance between this knob and the internal diameter of the piston acts like a self-adjusting choke. Any reasonable amouut of gas rate will hold the piston in the lubricator. The flow valve must be closed for approximately 5-10 seconds to allow the plunger lo slip off the rod and fall back to bottom.

A standard magnetic sensor is attached to the outside of the lubricator to record the arrival of the plunger. All of the control methods for this system are dependent upon the sensing of the plunger arrival. There are various methods of controlling the flow valve. Some companies use their own automation equipment. However, most companies use the stand-alone control box that was specially designed for the Pacemaker plunger. It monitors the arrival sensor, operates the flow valve based on adjustable parameters, and records previous trip times.

## APPLICATIONS

The Pacemaker was originally designed to plunger lift slimhole, tubingless completions in South Texas. Traditional plungers tend to work best when the tubinglcasing annulus is available to act as a volume chamber to store gas, as the well is shut-in to build pressure. Aslimhole, tubingless completion does not have a tubinglcasing annulus. It is therefore very difficult to plunger lift this type of wellbore completion. The Pacemaker was the solution lo this problem since gas velocity trips the plunger to surface rather than stored pressure. Wells that have been configured with a packer on the end of the tubing are effectively the same as a slimhole completion, since the packer isolates the tubinglcasing annulus from the gas zone. The use of a Pacemaker on wells with the tubing/packer configuration often eliminates the need for rig work to remove the packer when installing a plunger lift system on the well.

The Paccmakcr has also proven itself to be a viable solution to plunger lifting wells that are characterized as high rate/low bottomhole pressure. There are numerous wells in the United Slates that have ultra-low bottomhole pressures, in the range of 100-200 psi, yet are capable of gas rates upwards of 200 mcpfd if the wellbore fluid can be removed. Even in the absence of bottomhole pressure, the gas velocities are sufficient to drive the Pacemaker plunger to surface. With traditional plungers, the fluid in these low-pressure wells is quickly pushed down past the plunger and back into the formation during the shut-in time. This results in the plunger tripping to surface dry and the fluid is not effectively removed from the wellbore. Conversely, the Pacemaker falls against flowrate and gets under the fluid while it is still moving up the tubing. Due to the faster-than-noruial speed at which the plunger roundtrips from the surface and the elimination of shut-in time, the fluid does not have time to fall back down the tubing. Fluid is effectively removed and the gas production is optimized.

Another advantage of the Pacemaker plunger is that it works extremely well in tandem with a wellhead conipressor. Traditional plungers have been used behind wellhead compressors hut often make the operation of the compressor difficult. If the shut-in time required by the plunger becomes too long, the compressor will be starved of fuel gas and die. Even when shut-in times are short, there is a certain amount of wasted fuel gas and horsepower as the compressor recycles gas to stay on line. The Pacemaker and the wellhead compressor complement each other. The compressor lowers the line pressure, which in turn increases the gas velocity up the tubing. The Pacemaker provides a more constant flow of gas to the suction of the compressor, allowing it to deliver longer mn times. The Pacemaker also tends to make more plunger trips, removing the wellbore fluid in smaller quantities. This generally prevents the carryover of fluids from the surface separation equipment. Increases in daily gas production have been achieved by minimizing the recycle times and by keeping the compressor operating efficiently.

Over the years the gas industry has developed correlations to predict the minimum gas velocity required to flow liquids out of a gas well. However, increases in gas rates have been achieved with some Pacemaker installations on wells that were previously deemed to be producing above the critical velocity required to remove wellbore fluids. One of the contributing factors to this performance may be that once the fluid enters the tubing this plunger lift system will carry it to surface. With a traditional plunger lift system, some of the fluid that enters the tubing will be pushed down past the plunger and back into the formation during the shut-in time to build pressure. It appears that the Pacemaker not only removes fluid from the wellbore, but also provides a means of cleaning up fluids from the near-wellbore region of the producing formation. The installation of Pacemakers on strong gas wells has proved to be a very profitable use of this technology. This is especially hue for those wells that currently do not have any type of artificial lift installed. These types of wells have been identified by field personnel observations of slug flow at the well, sweeping gas rates through meters, signs of loading on daily production curves, favorable responses to soap treatments, and swab tests resulting in short-term gas rate increases. Do not assume that a high gas rate well does not have a liquid-loading problem.

Pacemakers have been run in sandy wells with marginal success, but this application is not recommended at this time. The theory for the pilot tests was two-fold. The Pacemaker allows the well to produce without the large swings in gas rates that are inherent to traditional plungers. This should help prevent the surging of sand into the wellbore and up the tubing. The Pacemaker plunger also stays in constant motion while making its trip to bottom and back. This should provide enough turbulence to keep sand from settling out on top of the plunger and sticking it. This second part of the theory has not proved to be the case, as some plungers have become stuck with sand. It will probably be necessary to place some sort of a sand screen at the end of the tubing for this to become a reliable use of the Pacemaker.

## INSTALLATION CONSIDERATIONS

A detailed instruction sheet for the installation of the Pacemaker is available from the supplier. In particular, it is important to plumb in the surface equipment so that the ball is not able to enter a wing valve or a bypass flow beam. The wellhead should be stripped down to one master valve if possible. The lower end of the shifting rod must be below any flow beam piping. When this is not done, the ball can exit the tubing into the cavity. It then re-enters the tubing after the piston has been released and falls on top of the piston. The plunger assembly then becomes inoperable. Some wellheads have also been found to have a similar cavity just above the tubing hanger. **A** sleeve can be installed to prevent the entry of the ball into this cavity. The wellhead tree and tubing must be the same size.

Full-opening control valves are preferred, especially for wells that have low bottomhole pressures or high water rates. This helps minimize the amount of backpressure on the well as the fluid moves through the wellhead equipment. The Pacemaker MEGA 1000 stand-alone control box appears to be the simplest method of controlling the system. Programmed to be self-adjusting, it increases and decreases the amount of afterflow to match the actual plunger trip time to a pre-selected target time. Its only drawback is that a person must periodically visit the well location in order to monitor the system and adjust the settings for optimum performance. Telemetry is not yet available for this control box.

Attempts to use an existing carbon steel or stainless steel downhole spring will not result in a cost savings. The impact of the ball and piston will flare out and/or break the fishing neck in a very short time. It is permissible, and even desirable, to drop the titanium spring assembly on top of an existing spring. In the event that the plunger assembly falls against a dry column of gas, the additional spring will further cushion the impact. If the spring is to be landed on a pump seat nipple instead of a collar or tubing stop, the seat nipple must be undersized. Specify a 1.780” I.D. for a 2-3/8” seat nipple and a 2.250’ I.D. for a 2-7/8” seat nipple. Be aware that the Pacemaker spring assembly can become wedged into or knocked through standard pump seat nipples and standard profile nipples.

## PLUNGER COMBINATIONS AND SELECTION

The piston and ball come in a variety of materials and sizes, but are matched for a specific piston-to-ball weight ratio. The pistons are made of either titanium or steel. They are currently manufactured for standard 2-3/8” and 2-7/8” tubing. **A** prototype system for 3-1/2” tubing has been field-tested and a system for 2-1/16” tubing is currently being developed. The lengths of the pistons range from 6” to 12”. The balls, from lightest to heaviest, are made of silica nitrite, titanium, zircon ceramic, steel, and cobalt.

The shorter titanium piston with a silica nitrite ball is recommended for wells with low gas and fluid rates. The medium length titanium piston with a titanium ball is the most durable combination. It is recommended when the gas velocities range from 15-45 ft/sec and when the fluid/gas ratio ranges from 8-10 bbl/100 mcf of gas. The longer titanium pistons with a zircon ceramic hall or the shorter steel pistons with a zircon ceramic hall are used when the plunger trip time in minutes is greater than 3 times the well depth in 1000‘s of feet. For example, this combination would he recommended when the average roundtrip plunger time on an 8000’ well is greater than 24 minutes. The steel pistons with either a steel hall or cobalt ball are used to shorten long plunger trip times in wells that have high gas and/or fluid rates.

Each well with a Pacemaker installed should be monitored for changes in gas or fluid rates. Changes in either of these rates should be responded to with adjustments to the control settings and/or the use of a different piston/ball combination.

## EQUIPMENT DAMAGE

The Pacemaker plunger has the ability to trip at extremely high speeds. It therefore has the potential to damage both the downhole and surface equipment, if not operated properly. **As** with most artificial lift systems, it does require attention and maintenance.

The damage most often results from frequent dry tripping of the plunger assembly. The plunger impact on surface equipment tends to be cushioned when controllers are adjusted so the plunger brings with it a minimum of 3 seconds of fluid. This should he checked routinely by a visit to the location to ohscrve **a** plunger arrival. The plunger delay setting can he adjusted to achieve this amount of fluid. l h e running of the lightest plunger possible for a particular well will also help to achieve a soft or cushioned arrival.

## MAINTENANCE

The internal lubricator parts should be removed and inspected every 90 days. The two springs should he checked for cracks or collapse. The anvil and separator rod should he checked for cracks and swelling.

The piston and hall should he caught and inspected every 90 days. The plunger and ball wear are anticipated to be similar to that of traditional plungers. The piston should he replaced when its outside diameter has been worn by 0.030" below its original diameter or if it has cracks or chips. The ball should he replaced when it has been worn by 0.015" below its original diameter or if it has cracks or chips.

**It** is recommended that the bottomhole spring assembly be inspected after 10,000 plunger trips. It should be checked for cracks, swelling, and spring collapse.

In the event that it is necessary to fish the piston, ball, or bottombole spring, each has been designed to be retrieved with standard slickline tools. The piston has an inside fishing neck machined into it. The ball and spring may he retrieved simultaneously with a 3-prong grab or separately with a standard sized overshot.

## CANDIDATE SELECTION

The Pacemaker plunger lift system is not the solution to all artificial lift problems However, it has proven itself to he very effective in certain types of wells. The following types of wells should definitely be considered for a Pacemaker installation.

1) Consider strong gas wells that currently do not have artificial lift, as they have the potential to yield some of the largest increases in gas rates. Many are likely to be producing above minimum critical velocity, hut have undetected loading problems.
2) Consider wells with a decline curve analysis indicating that there is a reasonable chance of exceeding 200 mcpfd if the well were to be unloaded. **A** minimum gas velocity of 16 ft/sec, using surface pressures and rates, is a similar yet more rigorous estimate for selecting better candidates.
3) Consider all wells that produce into wellhead compressors. The compressor lowers the line pressure, and the Pacemaker provides a physical means of removing the wellhore fluids. The two systems work well in tandem.
4) Consider wells that are configured with a packer on the end of the tubing. The Pacemaker often functions better when the casingiiubing annulus is isolated from the producing zone.

Unless the plan is to intentionally test the limits of this plunger lift system, one should he cautious about installing the Pacemaker on the following types of wells.

1) Wells that will produce less than 150 mcfpd or less than 16 ft/sec, when completely unloaded
2) Wells that have water/gas ratios greater than 100 bbls/mmcf.
3) Wells that produce less than **5** hfpd, especially those with gas rates above critical velocity
4) Wells that show minimal gas rate increases when swab tested.
5) Wells that tend to make sand.

## ACKNOWLEDGEMENTS

The Pacemaker plunger lift system was invented and patented by Edward (Mike) Wells. He and his brother, Mark Wells, are the co-owners of MGM Well Service in Corpus Christi, Texas. The owners and employees of MGM have provided excellent customer service with regard to the delivery and installation of this system and have made exceptional efforts to continuously improve the technology.
The Lower 48 Onshore Business Unit leadership team of BP America is to he commeiided for its general business practice of graniing its employees the time and resources to explore new technologies. The BP Deliquification Network, headed by Howard Gee, provided the vehicle for the rapid sharing of this technology across all of the company's assets in North America. Gordon Gates, David Lewis, James (Carey) Dilbeck, and Carl Sisk are to be particularly commended for piloting initial tests of the Pacemaker, identifying potential applications, and promoting its widespread use within the company. BP's field personnel, too numerous to name, ultimately deserve the credit for the success of this system.

THE AUTHOR

Preston Abbott holds a BS in petroleum engineering from Texas A&M University. After serving four years in the United States Marine Corps, he began his oil and gas career in 1989 working for HCM in Dallas, Texas. He joined BP America in 2001 and is currently assigned as a production engineer for the Carthage Field in East Texas.