Clean out existing well perforations by surging the formation

Surging the formation with a wireline retrievable tool can remove debris from perforations and increase flow channel area, thereby potentially increasing production from the existing wells

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ONE IMPORTANT advantage of the now popular tubing conveyed perforating system (TCP) is believed to be its ability to dislodge debris from perforations and to flush out all or part of the surrounding compacted area. This is accomplished by perforating with a differential pressure toward the wellbore. This differential can be very high, approaching formation shut-in pressure.

A new service tool provides a means to surge existing wells that were perforated without high underbalance, in which perforation damage (debris and compaction) is thought to exist. This can be accomplished by suddenly subjecting the existing perforations to high differential pressure much as in the tubing conveyed perforating method.

The basic procedure for surging the formation with the backsurge tool is:

- Set "plug" type valve (backsurge tool) in the tubing.
- Create a differential pressure across this valve.
- Suddenly open the valve, dumping fluid from the casing below the packer into the low pressure section of tubing.

This creates a high differential pressure across the perforations to backsurge and flush the flow channels. The plug is retrieved with a slick wireline. Since it is not necessary to kill the well to unseat the packer and to pull the tubing, the cost is substantially less than reperforating with large guns. The process can be repeated as often as desired.

TCP BACKGROUND

The perforating phase of well completions has undergone scrutiny and change in recent years. It is well documented1 that shaped charge guns leave the perforations (within the formation stone) filled with gun debris and surrounded with a compacted area of reduced permeability. A finite differential pressure (a variable depending on many factors) is required to dislodge the debris and start flow. Therefore, it is conceivable that perforations that are not subjected to sufficient differential pressure, such as could occur when swabbing, can remain plugged and may never produce.

Downhole flowmeter tests2 have shown that many wells only produce from 10% to 20% of the existing perforations. Therefore, it is suspected that many perforations in some wells are indeed still plugged from the original perforating operation. Further, it is also documented3 that the compacted stone surrounding the wellbore can restrict flow. TCP is now being performed on many newly completed wells to ensure ample flow area through perforations.

POST COMPLETION OPERATION

A great number of wells completed in past years did not use TCP methods, some of which are suffering from reduced production rates due possibly to plugged or partially plugged perforations. A slick wireline tool has been designed (and tested) to dislodge the perforation debris and open additional flow area. The wireline tool uses the same principle of differential pressure as TCP to remove the debris from the perforations.

Tool design. The initial tool design took into consideration current downhole wireline tools connected to locking mandrels and set in tubing landing nipples. It was desirable to design a back surge tool that would fit into this family of downhole

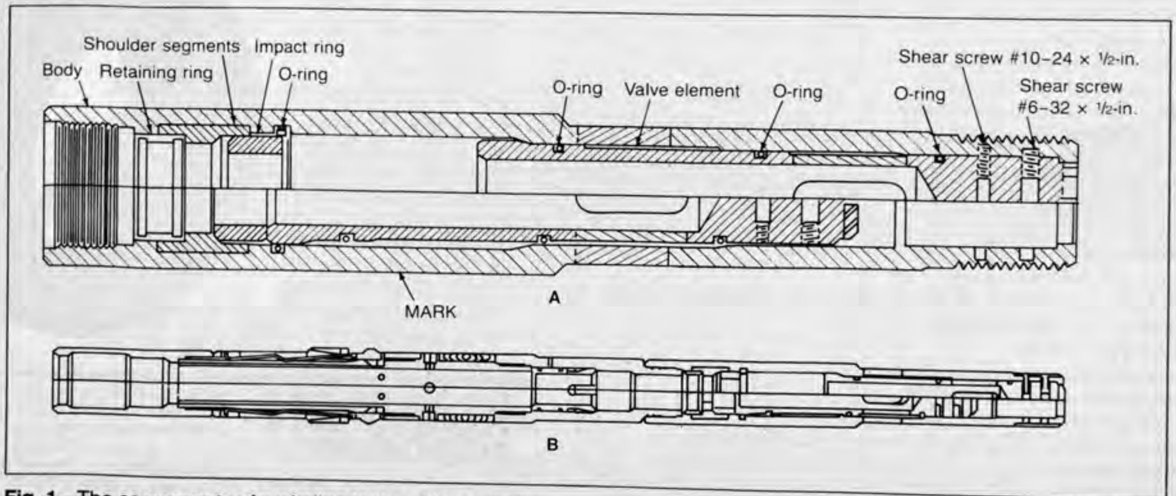

Fig. 1—The components of a wireline tool and its operation.

tools. Fig. 1a illustrates the components of a $2^3/_8$-in. backsurge tool.

Tool operation. The tool is run on a slick wireline connected to a locking mandrel and equalizing valve (Fig. 1b) and landed in a landing nipple close to the bottom of the tubing string. When pressure across the tool reaches a predetermined value, shear screws will permit a valve in the tool to open instantaneously. The rapid valve opening causes the well to suddenly produce its fluid, thereby flushing out the debris lodged in the perforations. Then the tool is retrieved by wireline and the well placed back on production.

Curves in Fig. 2 illustrate a pressure profile of the pressure surge due to the backsurge tool operation as compared to flowing a well through the tubing string. A much greater instantaneous differential pressure can occur downhole using the surge tool.

Features of the design. The operator determines the pressure at which the valve opens and installs the desired number of shear screws. Up to six #6 and six #10 brass shear screws are normally used in the $2^3/_8$-in. tool, while eighteen #10 brass screws can be used in the $4^1/_2$-in. tool. This permits a maximum of 6,800 psi and 4,900 psi differential pressure for the $2^3/_8$-in. and $4^1/_2$-in. tools, respectively. The sheared screws are retained within the tool and are retrieved with it.

To minimize damage due to the active parts of the tool, a replaceable brass insert is used as a shock-absorbing element. It is designed to be replaced after each use, if damage is significant.

The internal shoulder that stops the motion of the valve element is a three-piece segmented part. It is held in position by a retainer ring, which, in turn, is kept in its position by an equalizing sub. Disassembly is quick and easy, requiring a minimum of tools.

The O-ring glands are sized successively smaller toward the bottom end of the tool. This feature minimizes frictional drag on the valve element. As the valve element moves upward, all three O-rings leave their respective honed bores and face internal diameters that are larger than their free outside diameters. Thus, there is no further O-ring drag on the valve element and it is free to move as rapidly to the open position as possible.

The uppermost O-ring is not used for sealing. It provides a rest for the brass insert to keep it in position. This O-ring also serves as a "catcher" to retain the valve element in place after it shifts to the open position. This feature allows more rapid retrieval of the tool than if the valve were to return to the closed position and prevent hydraulic bypass.

APPLICATION OF BACK SURGE TOOL

Backsurging the perforations can be accomplished on existing wells. Good candidates are:

- Wells that could produce more as indicated by well tests
- Wells completed before TCP was in widespread use
- Wells in which scale problems are known
- Water injection wells.

To relieve pressure above the tool, surface pressure is lowered by opening a wing valve. For many wells, especially oil wells that have a significant hydrostatic head, relieving surface pressure will not establish the desired pressure across the tool. In such cases, fluid above the tool must be removed. A common method for accomplishing this is to run coil tubing into the well and displace the crude oil with pressurized

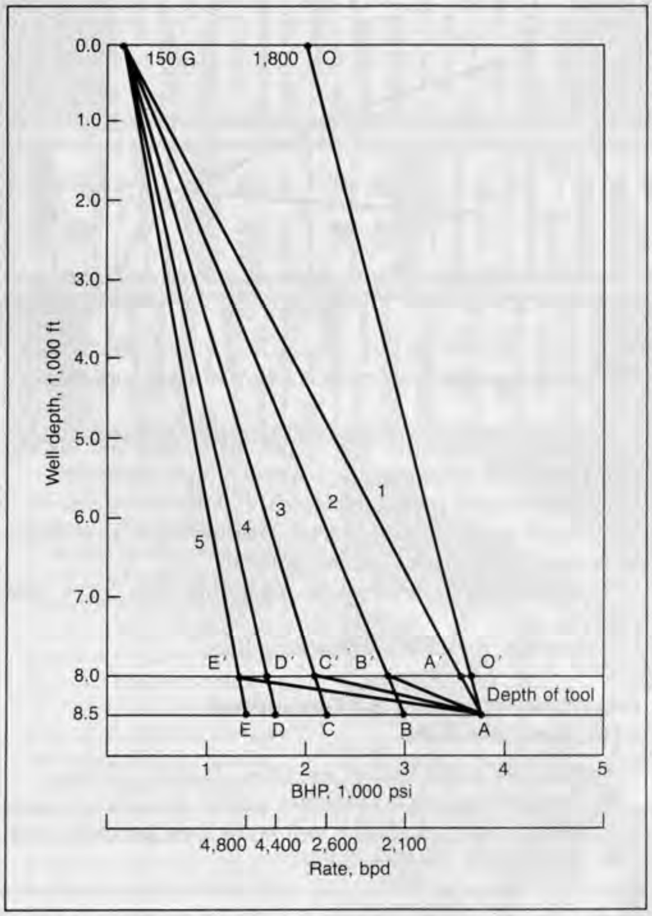

Fig. 2—Pressure profile indicated a much greater instantaneous differential pressure caused by using backsurge tool

nitrogen. Another method would be to run the tool into the well to just above its landing nipple and stop. Fluid above the tool is then pumped back into the formation by injecting pressurized nitrogen into the tubing at the wellhead. Once a sufficient column of crude oil has been displaced, nitrogen injection would stop and the tool would be landed and the job carried out as outlined previously. Although it is not normal practice to pump well fluids back into the formation, the procedure does save the expense of a coil tubing unit.

Procedure for using the backsurge tool varies with the type of the formation:

Formations with Sufficient Pressure.

- Allow formation to build approaching maximum practical shut-in pressure.
- Run tool in the well and lock in landing nipple, remove wireline.
- Open wing valve and bleed down pressure at surface—back surge tool opens at preset pressure differential.
- Allow well to produce at maximum rate for a short interval.
- Retrieve tool, put well back on line.

Formations with Lower Pressure.

- Allow formation to build to maximum practical shut-in pressure.
- Run tool in the well and lock in landing nipple.

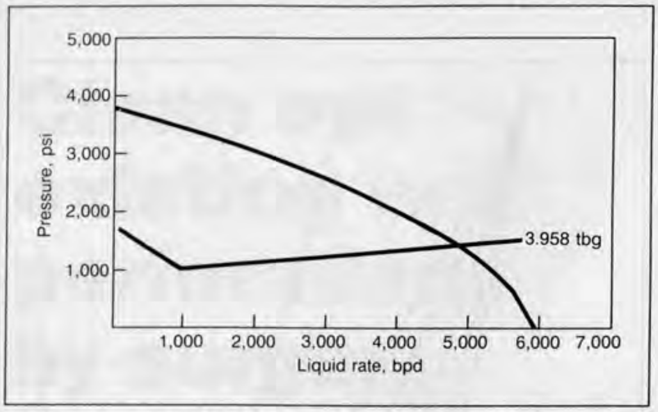

Fig. 3—Inflow performance curve and a 4 1/2-in. tubing outflow curve.

- Run coil tubing in well to just above tool and displace well fluids with nitrogen.
- Remove coil tubing from well.
- Open wing valve and bleed down pressure at surface—back surge tool opens at preset pressure.
- Allow well to produce at maximum rate for a short interval.
- Retrieve tool, put well back on line.

Alternate Procedure for Formations with lower pressure.

- Run tool in the well to just above landing nipple.
- Connect pressurized nitrogen source to wellhead, pump nitrogen into well, displacing well fluids back into formation.
- Lock tool in landing nipple.

TABLE 1—Well input data

Liquid rate (oil + water), bpd	QL	=	4800
Gas liquid ratio, scf/bbl	GLR	=	1000
API oil gravity	API	=	25
Specific gravity of gas (air = 1.0)	SGG	=	0.7
Specific gravity of water	SGW	=	1.0
Percent water cut	WCUT	=	0
Flowing wellhead temperature, °F	TSUR	=	125
Flowing bottomhole temperature, °F	TBOT	=	195
Measured depth of the well, ft	DEPTH	=	8500
Flowing pressure (wellhead or bottomhole), psi	PREF	=	150
Tubing ID, in. (for casing flow use tubing OD)	DIA	=	3.958
Casing ID, in. (for tubing flow use zero)	DICAS	=	0
Kinetic energy term multiplier (use 1)	XKEN	=	1.0
Elevation term multiplier (ratio of tvd/md)	ELEV	=	1.0
Friction term multiplier (use 1)	FRICT	=	1.0
Sign (+1. for gas wells, HIGAS = 0 for oil wells)	SIGN	=	1.0
(HIGAS = 1 for gas wells, HIGAS = 0 for oil wells)	HIGAS	=	0

- Allow formation to build to maximum practical shut-in pressure.
- Open wing valve and bleed down pressure at surface.
- Tool opens at preset pressure differential.
- Allow well to produce at maximum rate for a short interval.
- Retrieve tool, put well back on-line.

If the backsurging is performed, the operator will be able to get maximum potential from each well. And the method is quick and relatively inexpensive, providing good potential for early payout.

TABLE 2—Flowing bottomhole pressure (fbhp) vs. depth

Flowing pressure psig	Depth ft	Slug velocity ft/s
160	82	58.7
300	1,175	31.7
450	2,272	20.8
550	2,977	16.8
700	4,005	12.9
850	5,004	10.4
1,000	5,980	8.7
1,100	6,618	7.8
1,300	7,851	6.4
1,325	8,000	6.3
1,412	8,500	–
		*29.2

*Average from all points.

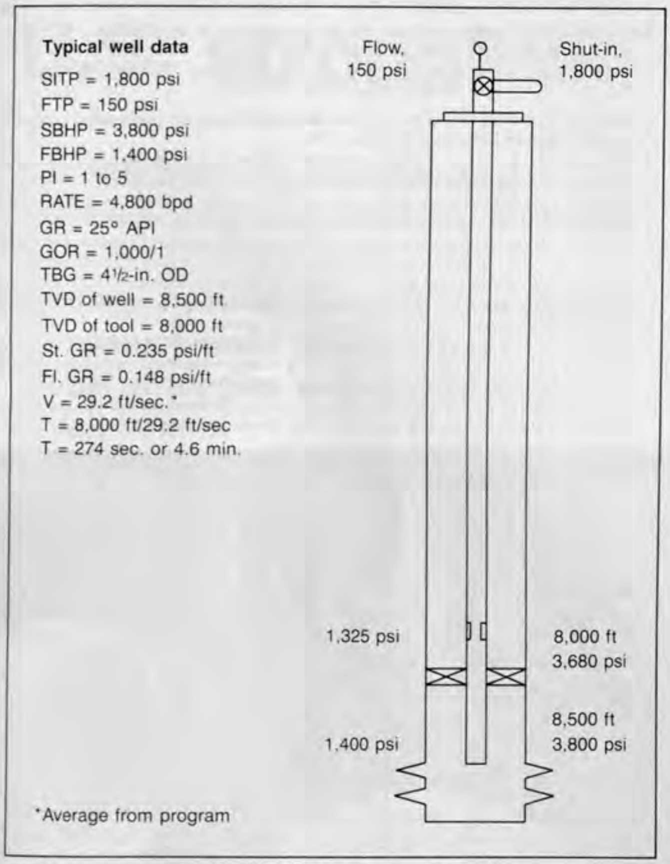

Fig. 4—Typical well data of the example well and surging procedure: Build well pressure to static condition. Run in backsurge tool and land with a 2,355-psi differential pressure. Bleed down tubing pressure above back-surge tool. Backsurge tool will shear when tubing pressure above is reduced (3,680 – 2,355) = 1,235 psi.

COMPUTER ANALYSIS

To illustrate the possible effect of "surge pressure" using the back surge tool as compared to the pressure differential generated by flowing the well at a high rate, the following data were used for an example:

Static bottomhole pressure, psi	3,800
Test liquid rate (oil and water), bpd	4,000
Flowing bottomhole pressure at test liquid rate, psi	2,000
Tubing OD, in.	4½

Reservoir inflow performance was calculated using Vogel's equation and the flowing bottomhole pressure required for various production rates through 4½-in. OD tubing was calculated using the generalized correlation of Hagedorn and

Brown. Inflow and outflow curves were plotted as in Fig. 3, from which it can be seen that the maximum production rate through 4½-in. OD tubing (the intersection of the inflow and outflow curves) is 4,800 bpd.

With Table 1 input data, a pressure versus depth traverse was computed using the generalized correlation of Hagedorn and Brown. Flowing pressures and depths, shown in Table 2, were selected from the printout and plotted (E, E′, G) as in Fig. 2 . The well diagram, Fig. 4, also illustrates the wellbore with the backsurge tool installed at 8,000 ft. The tool is shear pinned to surge the formation with a differential pressure of 2,355 psi.

Therefore, when the tubing pressure above the backsurge tool is reduced to 1,325 psi, the valve in the tool moves rapidly, imposing a 2,335-psi differential to the formation, causing an instantaneous surging action shown as curve 5 (points A, E′, G). Flowing curves were also plotted in Fig. 2 as curves 1 through 4. The difference between the flowing curves 1,2,3 and 4 is a time factor(s). By using the backsurge tool, the differential pressure surge to the formation is instantaneous. By opening up the tubing and flowing the well, curve 1 will progress to curve 4 and impose a differential pressure to the formation, but it may require minutes, hours, days or weeks for this to occur depending on the flow characteristics of formation.

To determine maximum drawdown using the backsurge tool most effectively for flowing wells, the following is recommended:

- Determine maximum production from well, Fig. 4.
- Use a flowing gradient program and plot depth vs. pressure.
- Select the fbhp at maximum production at proposed location of the back surge tool.
- Set shear pin value in back surge tool to shear at a differential pressure to give the selected fbhp.

FIELD TEST DATA

A field test of the 4½-in. backsurge tool was performed on a well that had similar data to the above computer model. The well was producing 1,300 bpd. The backsurge tool was set to operate at approximately 1,500 psi, which is illustrated in Fig. 2 as flowing curve A, C′, G. After surging the well one time, production increased to 1,780 bpd, a 37% improvement.

ACKNOWLEDGMENT

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