Jars, Jarring and Jar Placement

A jar is an impact tool installed in the drillstring to free stuck pipe. Essentially unchanged for 30 years, jars are among the least glamorous devices in the oil field. But some rules of thumb about jarring dynamics can lead to improper application. This introduction covers the latest on the technology, use and placement of jars.

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Oilfield professionals have long recognized that preventing stuck pipe is always less expensive than unsticking pipe. Successful prevention lies in understanding the mechanisms of pipe sticking. These mechanisms have long been known, but only in the past few years have some operators converted this knowledge into a usable form, reducing fishing time and hole costs.

Despite these improvements, there is consensus, although no statistical proof, that the incidence of stuck pipe across the industry has remained relatively unchanged. This is a "technical fix": the smarter we become at preventing stuck pipe, the more risks we take. We drill high-angle and horizontal wells, multiple targets or formations considered too risky in the past, or use topdrive to make hole faster than cuttings can be cleared. The incidence of stuck pipe therefore remains stable. The means of lowering this figure, according to experience at British Petroleum (BP), lie as much in technique as in technology. Teach drillers to drill smarter, BP found, and less pipe will become stuck in the first place.

But because no prevention program is guaranteed, research has continued into jars and jarring physics. Because jar location in the drillstring can mean the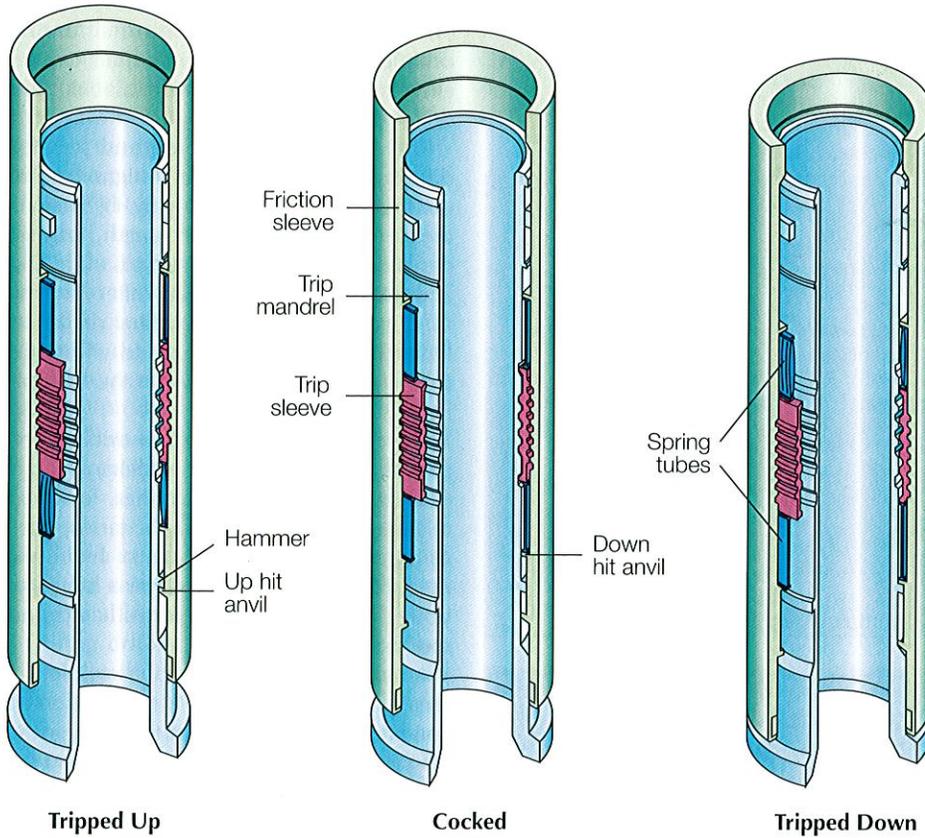 difference between success and failure, work is under way to streamline jar placement programs, making them faster, more powerful and easier to use. Jars themselves have been submitted to objective testing[1] and the limits of their performance are being extended.
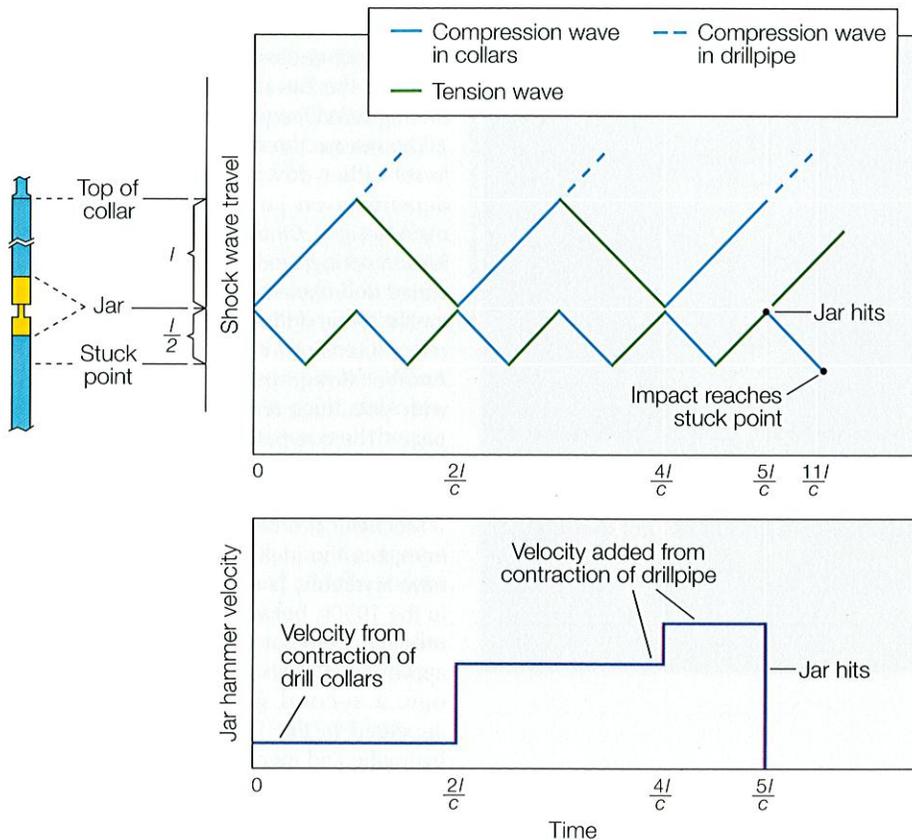
What are Jars?

From the outside, a drilling jar looks about the same as a drill collar, having the same outside diameter (OD) and being hollow to permit the passage of mud. Inside, a jar is basically a sliding mandrel that allows a brief and sudden axial acceleration of the drillstring above the jar (*next page, above*). Travel of this mandrel is limited by a stop (the hammer) that strikes a stop on the outer sleeve (the anvil).

Most jars release—called a trip, hit or lick—both up and down; a few work in one direction only. Between the end of upstroke and end of downstroke is the cocked position. In jarring up, for example, the driller pulls and stretches the drillpipe. When the jar releases, the drillpipe contracts and the mass of drillstring above the jar accelerates up the length of the trip mandrel for 5 to 9 in. [13 to 23 centimeters (cm)], depending on jar design and diameter. When the hammer hits the anvil, the mass stops and transmits a shock wave that travels up and down the drillstring several times (*next page, below*). The intention is to break the drillstring loose from the stuck point.

A properly designed jarring up assembly usually exerts more force than jarring down.

Tripped Up

Cocked

Tripped Down

Friction sleeve

Trip mandrel

Trip sleeve

Spring tubes

Hammer

Up hit anvil

Down hit anvil

□ **Cross section of Anadrill's mechanical EARTHQUAKER jar, showing the tripped up, cocked (or neutral) and tripped down positions.**

Compression wave in collars — — Compression wave in drillpipe

Tension wave

Top of collar

l

Jar

$\frac{l}{2}$

Stuck point

Shock wave travel

Jar hits

Impact reaches stuck point

0 $\frac{2l}{c}$ $\frac{4l}{c}$ $\frac{5l}{c}$ $\frac{11l}{c}$
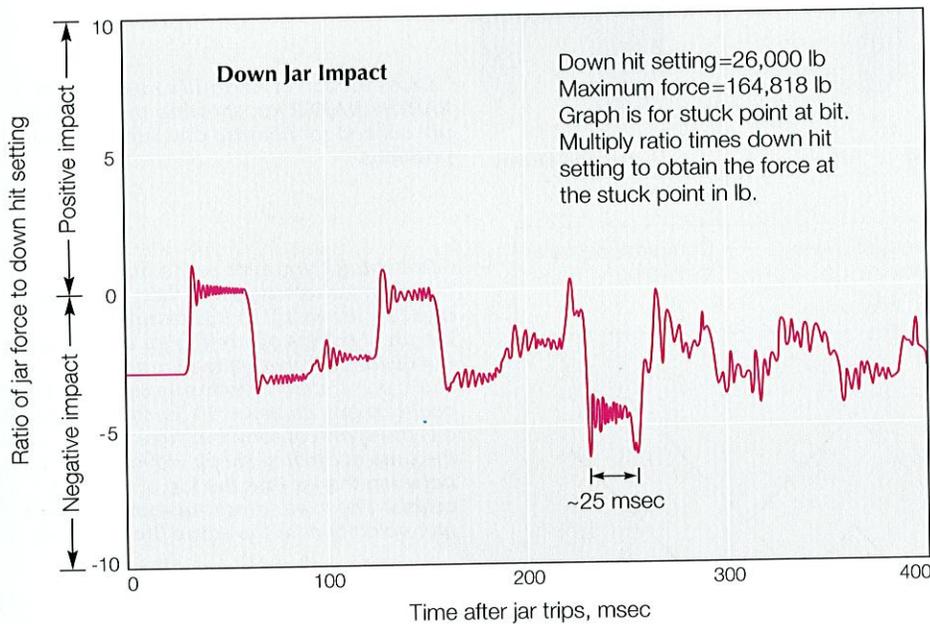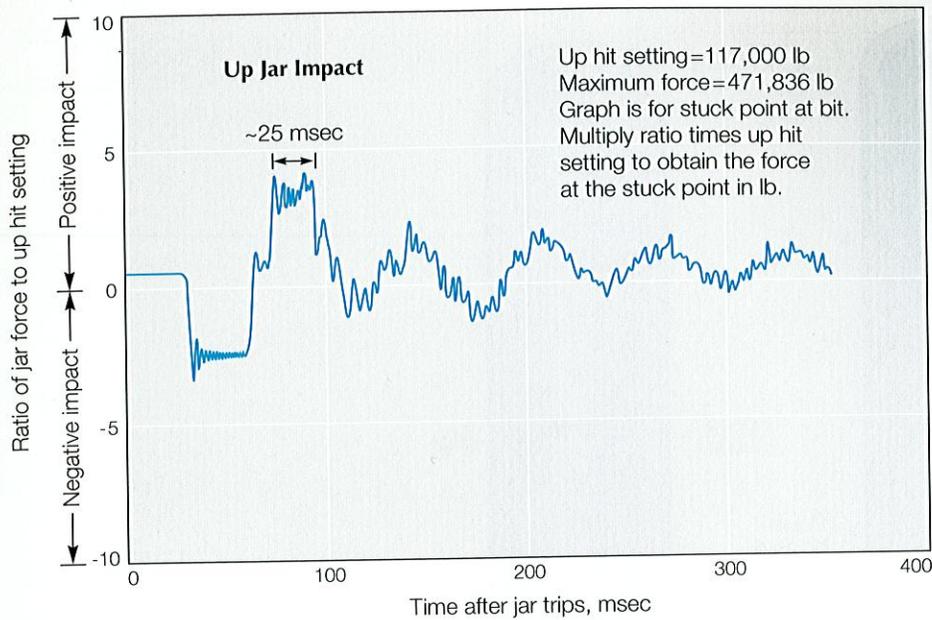
□ **Drillstring dynamics in the time between jar release and when the hammer hits the anvil. In this example, l is length of collars above the jar and $l/2$ is the distance between the jar and the stuck point, taken arbitrarily as $l/2$, but it could be any distance. In the top diagram, c is the speed of sound in steel, and $2l/c$ is the time of the first shock wave round-trip between the jar and the top of the drill collars. The lower diagram shows jar hammer velocity over the same time interval.**

Velocity added from contraction of drillpipe

Velocity from contraction of drill collars

Jar hits

Jar hammer velocity

0 $\frac{2l}{c}$ $\frac{4l}{c}$ $\frac{5l}{c}$

Time

1. Kyllingstad A and Halsey GW: "Performance Testing of Jars," paper IADC/SPE 20001, presented at the 1990 IADC/SPE Drilling Conference, Houston, Texas, USA, February 27-March 2, 1990.

Up Jar Impact

~25 msec

Up hit setting = 117,000 lb
Maximum force = 471,836 lb
Graph is for stuck point at bit.
Multiply ratio times up hit
setting to obtain the force
at the stuck point in lb.

Ratio of jar force to up hit setting
Negative impact — | — Positive impact

Time after jar trips, msec

Down Jar Impact

Down hit setting = 26,000 lb
Maximum force = 164,818 lb
Graph is for stuck point at bit.
Multiply ratio times down hit
setting to obtain the force at
the stuck point in lb.

~25 msec

Ratio of jar force to down hit setting
Negative impact — | — Positive impact

Time after jar trips, msec

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☐ *Jarring force at the stuck point, chosen as the bit, showing an example in which the up jarring force (top) is about three times that of down jarring (bottom). Note that the productive jarring force lasts about 25 milliseconds, which is directly related to the length of collars moving above the jar. Jarring magnitude changes between up and down jarring but not duration. (From Askew, reference 8.)*

This is because the driller can pull on the drillpipe with a greater force than can be exerted by compression from slacking off drillpipe weight (*left*).

There are jars for fishing and jars for drilling; these have similar designs but are constructed and used differently. Fishing jars are not standard drillpipe length, are not designed to withstand the stresses of drilling and are run in the hole only after backing off. Drilling jars are standard drillpipe lengths, are durable enough to withstand drilling stresses and are run in the bottom-hole assembly (BHA).

There are two main types of drilling jars, mechanical and hydraulic. Mechanical jars operate using a series of springs, lock and release mechanisms. Hydraulic jars operate using the controlled passage of hydraulic fluid. Hydromechanical jars are a hybrid of both designs, usually hydraulic up and mechanical down.

A mechanical jar trips up at a preselected tensile force, and down at a preselected compressional force. The jar trips only at the set threshold, which is normally beyond the forces reached while drilling. The position of the mechanical jar during drilling is either cocked or extended (tripped up); it's a matter of driller preference. Drilling is never conducted with the jar tripped down because unnecessary down jarring might damage the bit and measurement-while-drilling (MWD) equipment.

The release threshold of a mechanical jar is set either downhole or at the surface, depending on jar design. There are two main designs. One uses the principle of the torsion spring, and its release force can be varied downhole by 10 to 15% by applying torque to the drillpipe. Left torque decreases release tension; right torque increases it. Another design uses an expanding sleeve with slots, lugs and ancillary springs (*next page*). The overpull necessary to trip the jar can be reduced downhole by increasing mud flow rate.

Mechanical drilling jars predate hydraulic ones, but the idea of a hydraulic jar is not new. Hydraulic jars for fishing first appeared in the 1950s, but were troubled by seal failures and were not sturdy enough for drilling applications. With advances in seal technology, a second generation for drilling appeared in the 1970s and 1980s. Today, hydraulic and mechanical jars have comparable life expectancies (see "Comparison of Mechanical and Hydraulic Drilling Jars," *next page*).

The main difference between the two jars is that the hydraulic jar does not trip at a

preselected threshold. When, and how forcefully, the jar trips is determined by the magnitude of the applied tension or compression. In tripping up, for example, the force of the blow is proportional to "overpull," the pull on the moving pipe in excess of its weight in air or fluid.[2] The greater the overpull, up to the tool's maximum, the sooner the jar trips and the harder the blow. This gives the hydraulic jar the advantage of having a continuously variable jarring force within its design limits. In tripping up, for example, overpull of 100,000 lb [45,360 kg] may produce a large blow in 20 seconds, whereas overpull of 10,000 lb [4536 kg] may produce a small blow in 200 seconds. A second advantage is that a hydraulic jar of OD less than 6.25 in. [16 cm] has a larger inside diameter (ID) and can more easily admit a wireline cable than a comparable mechanical jar.

During drilling, it is recommended that the hydraulic jar that fires both up and down be run in the extended position. If run in the cocked position, there is a risk of unintended firing, unless tension and compression at the jar are exactly balanced—an unlikely condition. If drilling is conducted with the jar in the cocked position, upward movement when picking up off bottom must be slow to bleed the jar open and avoid a forceful trip. As with a mechanical jar, drilling with a hydraulic jar in the tripped down position is usually avoided.

A hydraulic jar consists of two reservoirs of hydraulic fluid separated by a valve (next page). When tension or compression is applied to the tool in the cocked position, fluid from one chamber is compressed and passes through the valve at high flow resistance into the second chamber. This allows the tool to extend or contract. The distance traveled is called the metering stroke. When the stroke reaches a certain point, the compressed fluid is allowed to suddenly bypass the valve. The jar trips as the fluid rushes into the second chamber, instantly equalizing pressure between the two chambers. The greater the force on the jar, the greater the compression of the fluid and the sooner and more forceful the release.

Once a hydraulic jar is cocked, it will fire if given enough time to complete the meter-

2. *Stuck Pipe Prevention Manual.* Sugar Land, Texas, USA: Anadrill (1991): 42.

   Overpull is a measure of sticking force. Overpull is typically monitored while drilling to detect sticking. It equals hook load while moving the drillstring up minus total string weight.

Comparison of Mechanical and Hydraulic Drilling Jars		
Capabilities	**Mechanical**	**Hydraulic**
Overpull setting variability	One setting made at surface of 10,000 to 180,000 lb, depending on jar size.	Continuously variable downhole, between 10,000 and 135,000 lb.
Ease of admitting wireline cable for surveying equipment and string shots	Easier passage with larger OD tools. Passage difficult or impossible in high inclination wells.	Typically has a larger ID than mechanical jar with same OD, which is an advantage up to an OD of about 6 1/4 in.
Ability to increase or decrease tension setting from the surface	No—Anadrill Yes—Dailey and similar designs can change by 10–15%.	Yes
Temperature sensitivity	Negligible. Will function in wells >500°F [260°C]. Have been used in geothermal wells.	400°F [204°C] bottomhole static is approximate limit. As temperature increases, tool may release sooner and without reaching full tension. With high-temperature packing, oils and greases, some jars have operated successfully at 550°F [288°C].

Ed Freeman photo.

☐ Trip sleeve for the 4 1/8 -in. [10-cm] diameter EARTH-QUAKER mechanical jar. Note that the sleeve acts as a radial spring along its length (inset). At the preset tension or compression, the outside teeth of the trip sleeve spring out into matching grooves on the friction sleeve ID. When this happens, the trip sleeve releases the trip mandrel that is inside the trip sleeve, with similar teeth and grooves, and trips the jar.

ing stroke. This gives hydraulic jars an advantage in directional, high-angle and horizontal wells. In these conditions, excess drag may prevent the driller from applying sufficient tension or compression to trip a mechanical jar. A cocked hydraulic jar, however, will eventually fire, even with minimal tension or compression.

A characteristic drawback of the hydraulic design is that repeated jarring can overheat the fluid. This reduces its viscosity, which shortens the metering time and trips the jar before the desired tension can be applied. As a result, jarring force declines over time. To cope with this problem, some jars are designed to compensate for heating of hydraulic fluid. Evidence on the success of these designs is equivocal. Experience at BP in North America indicates that problems associated with heating have been solved in the past few years. A 1990 study at the Rogaland Research Institute in Stavanger, Norway, however, found that heat-compensating designs are ineffective in all but one of the jars tested.[1]
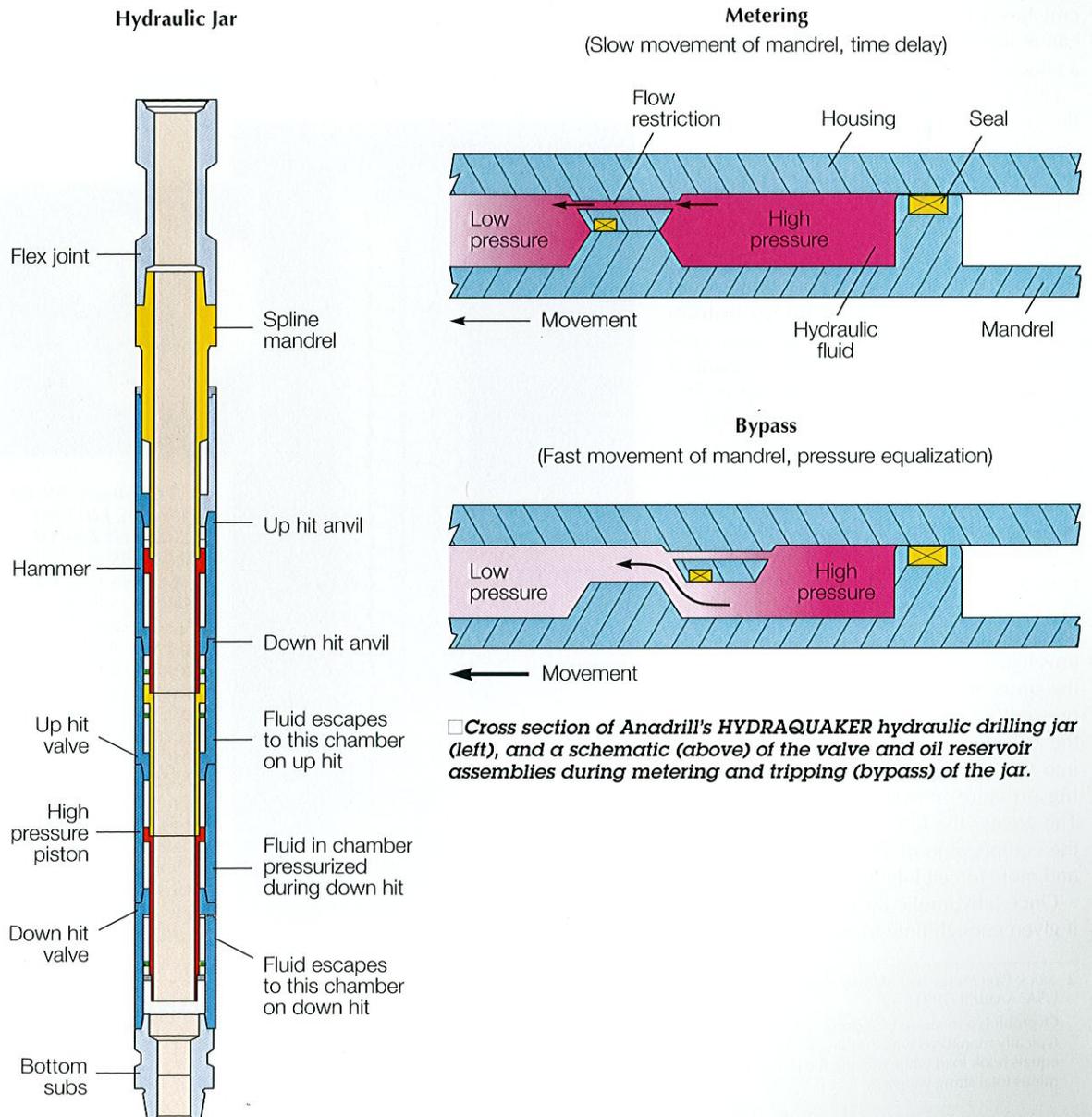
Vices and virtues aside, the choice between a mechanical and hydraulic jar is usually made based on the drilling manager's familiarity. Sometimes preferences vary by hydrocarbon province; other times they are uniform throughout a company. For example, in Oryx Energy Company, 60 to 70% of jars are hydraulic, and in areas known for high hole drag, at least 70% of jars are hydraulic. In BP Alaska, mechanical jars are run most of the time and particularly when the driller anticipates a milling operation. Mechanical jars are thought to be immune to damage from metal cuttings, which may damage seals of a hydraulic jar. One major prefers mechanical jars for drilling because of the perception of higher durability and the certainty that the jar will not fire until the threshold is reached.

Jar Operation

Incorrect jar installation and usage may sometimes contribute more to the problem than to the solution. Here are a few caveats.
• BHA components. The risk of sticking the jar itself and drillstring above the jar is

Hydraulic Jar

Flex joint
Spline mandrel
Up hit anvil
Hammer
Down hit anvil
Up hit valve
Fluid escapes to this chamber on up hit
High pressure piston
Fluid in chamber pressurized during down hit
Down hit valve
Fluid escapes to this chamber on down hit
Bottom subs

Metering
(Slow movement of mandrel, time delay)

Flow restriction
Housing
Seal
Low pressure
High pressure
Movement
Hydraulic fluid
Mandrel

Bypass
(Fast movement of mandrel, pressure equalization)

Low pressure
High pressure
Movement

☐ *Cross section of Anadrill's HYDRAQUAKER hydraulic drilling jar (left), and a schematic (above) of the valve and oil reservoir assemblies during metering and tripping (bypass) of the jar.*

reduced if drillstring components above the jar do not exceed jar diameter.[3] Risk of damaging the jar mandrel is reduced if a flex joint is run next to the jar mandrel. This limits flexion stress at the mandrel. Small BHAs (4³/₄-in. collars, 3¹/₂-in. drillpipe), because of their low weight, can sometimes produce insufficient jarring peak force.

- Jarring direction. Improper jarring direction can be counterproductive (see "Recommended Jarring Direction," *right*). As a rule, jarring is most effective when it is opposite the direction the drillpipe was traveling when the pipe got stuck: jar down if sticking occurs while tripping out and jar up if sticking occurs while tripping in. Key seating, for example, can be a problem in deviated wells (see "Techniques for Breaking Free," *page 30*). If the pipe lodges in a key seat while tripping out, jarring down may force it free, whereas jarring up may work the pipe farther into the key seat.

- Peak jarring force. Maximum jarring force is based on allowable overpull. Impact damage to the drillstring is not a concern. Although one major oil company reports buying dozens of MWD tools damaged by jarring, this cost is found to be negligible compared to that of sidetracking.

- Initial jarring force. Choice of initial jarring force varies. Starting with peak jarring force is often preferred when sticking progresses quickly, such as in differential sticking. Some operators nearly always start at the maximum to move the pipe as soon as possible. Others, such as Elf, will start lower and work up as needed. The premise is that more force than needed endangers pipe joints, and fishing for parted pipe is far more expensive than the rig time needed to increase jarring force over several hits. Elf also advocates jarring lightly in both directions at first to see which is more successful. Violent jarring in the wrong direction can convert a minor problem into a major one.

- Drag and extension force. These two factors can make a jar appear to trip with insufficient or excessive tension and must be accounted for when relating surface load to tension at the jar. Drag on drillpipe increases overpull. In vertical wells, drag can be negligible, but in directional wells drag is taken, by rule of thumb, to increase overpull needed to fire the jar by 10% (see "Effect of Drag on Tension at Jar," *above, right*).

Recommended Jarring Direction		
	Jarring Direction	
Type of Sticking	Up	Down
Key seating		X, with torque
Differential sticking	X	X
Swelling shales Mechanical sticking (on slips, arm of underreamer, stabilizer blade) Poor hole cleaning Sloughing shales	X, when tripping down	X, when tripping out
Unconsolidated formations at connections	X	
Mobile formations (salt, some shales)	X	

Effect of Drag on Tension at Jar

Calculation of tension at the jar, while accounting for the effect of drag, might be:

Total string weight in mud:	200,000 lb
Weight below jar:	50,000 lb
Weight above jar:	150,000 lb
Maximum overpull value:	100,000 lb
	(minus 10,000 lb for safety)
Maximum safe overpull at surface:	290,000 lb

In this scenario, the driller cannot safely pull more than 290,000 lb at the surface. Drag affects the string above the jar only, effectively increasing its weight by 10%, to 165,000 lb. The maximum pull available at the jar is 290,000 - 165,000 = 125,000 lb. The mechanical jar release is therefore set near this value. If the release is set too low, the jar may fire from movement of the pipe alone; if set higher, it may not fire at all.

Extension force, created by pressure inside the drillstring exerted by circulating mud, can also make a jar appear to trip prematurely or late. Extension force is determined by the internal cross-sectional seal area of the jar times the pressure drop across the tool. If mud pressure is high enough, extension force will open the jar, literally lifting the drillstring. When jarring up, this force must be added to the surface overpull to obtain actual tension at the jar. Jarring down while circulating requires overcoming extension force before the jar can be fired.

Jarring up can sometimes be achieved or assisted by extension force. In cases of severe sticking or drag, overpull can't trip a mechanical jar or induce a large enough blow from a hydraulic jar. In either case, a jar can sometimes be tripped by increasing the mud pump rate or by a combination of increasing mud pressure and pulling. This is a safe procedure with a mechanical jar, but involves some risk with a hydraulic jar. Jar manufacturers provide information on calculation of safe extension force.

- Accidental jarring.[4] A virtue of the hydraulic jar—that once cocked, it will eventually fire—can also be a liability. During drilling, the jar is normally extended (tripped up). If the driller slacks off enough weight, the jar will cock. When the driller next picks up off bottom, the jar will start metering and may fire. In

3. Schmid JT Jr: "Designing BHAs for Better Drilling Jar Performance," *World Oil* 195, no. 5 (October 1982): 100-104.
4. For recommendations for jar placement to avoid accidental tripping during drilling, see reference 3.

vertical wells, this has been known to knock pipe out of the slips and result in requiring a fishing job. In directional wells, such accidental jarring is usually not a concern because pull on the pipe is not sufficient to induce a large shock, and because the shock is damped by the pipe lying on the low side of the hole.

Jar Placement

Many operators, particularly in North America, obtain satisfactory jarring from empirically determined jar placement. Oryx runs mainly hydraulic jars in tension (above the neutral point[5]) high enough in the string to permit sufficient weight on bit and to have enough weight on top to cock them easily from the tripped up position. In most cases this means the jar is between the fourth and sixth drill collars from the top of the BHA.

A continuing debate in jar placement is whether the jar should be positioned in tension or compression. Widespread practice has been to always place the jar in tension, a policy maintained by many companies. There are two main reasons for this:
• To achieve a greater peak force. Higher jar position (in tension) also means less accelerated mass above the jar, and therefore greater velocity of pipe above the jar and greater peak force.
• To minimize the possibility of getting stuck above the jar. The higher the jar, the smaller the chance of being stuck above it.
There is a perception that jars may buckle under compression, or that flexion of the jar will affect deviation control. Jar stiffness, however, exceeds that of drillpipe, and well trajectory is usually controlled in the BHA significantly below the jar.

About the only point of agreement is that a hydraulic jar that is less affected by extension force should never be run at or near the neutral point. At this location, it is prone to repeated cocking and firing as the neutral point travels up and down when the driller pulls up and slacks off. This not only produces unnecessary jarring, it also wears the jar prematurely. This problem does not

affect mechanical jars because travel of the neutral point does not produce enough force to cock or fire the jar. It also does not affect jars that are easily opened by extension force, since they require more slack off weight to cock.

There are different jar philosophies for different geographic areas within BP. BP Alaska, for instance, places its jars in tension between heavyweight drillpipe and collars to reduce the risk of sticking. The advantage of this location is a low risk of becoming stuck above the jar. The disadvantages are that the jar may be farther from the stuck points, usually low in the BHA, and jarring down is less forceful. Bowen Tools, Inc. has addressed this concern by offering an up jar that goes in the upper part of the string and a down jar in the lower part, where a lot of weight can be stacked.

Although many operators still prefer to run jars in tension, studies at Anadrill have shown that its jars will endure drilling in compression, and that running a jar too high above the neutral point can result in a short impulse and ineffective jarring. This is especially true in directional wells with heavyweight drillpipe and few drill collars in the BHA. In these wells, the neutral point is often up in heavyweight drillpipe, far from the stuck point. If the jar is placed above this neutral point, jarring force at the stuck point may be greatly reduced because of wall drag above the jar and damping from heavyweight drillpipe and drill collars. Anadrill has also found that the stuck point is often closer to the bit than is usually thought. Placing the jar near the top of the BHA, at the fourth or fifth heavyweight joint, may prevent sufficient force from reaching the stuck point.

The frontier of jar development, as with so much in drilling today, lies in high-angle and horizontal wells. Operators are still experimenting with optimal jar placement and selection. Use of multiple jars is also under investigation. A decade ago, use of multiple jars was not recommended because of the uncertainty of drillstring behavior, which reduces control of the jarring operation.[3] Today, using finite-element code to model wave propagation along the

drillstring, more operators are attempting the technique. An operator in the Middle East has had success with two jars in a horizontal well: a hydraulic jar 50 to 100 ft [15 to 30 m] above the final kickoff and a mechanical jar in the horizontal section atop the BHA. The upper jar was used to free stuck pipe at the kickoff, the most common point of sticking in horizontal wells, and the horizontal jar for a stuck BHA. The mechanical jar was placed in the horizontal section for fear that firing of the upper jar would damage a hydraulic jar if it was below.

In the USA, one of the most active drillers of horizontal wells in the Austin chalk has been Oryx, which drilled approximately 100 horizontal wells between early 1989 and early 1991. Horizontal sections averaged 3000 ft [915 m] early in the project, but have increased to an average of 4000 ft [1220 m].

Earlier this year, Oryx polled approximately 20 drilling foremen working in horizontal wells in the chalk about their preferred jar type and use. Hydraulic jars were the clear choice, always placed above the kickoff to avoid tripping difficulty associated with hole drag. Oryx has found that in horizontal wells, jarring is not useful for freeing key-seated pipe or stabilizers stuck by cuttings. A jar above the kickoff is useful for overcoming sticking associated with friction developed while making connections. Oryx runs jars in all its horizontal wells but needs them only 5 to 10% of the time, usually to jar down and urge bits and stabilizers through bends. When rotating out fails to free pipe stuck from a cuttings bed or key seat, Oryx backs off as low as possible and lowers the jar position so it is nearer the stuck point.

In Oryx's experience, the main consideration in jar placement in horizontal wells is having sufficient weight above the jar to cock it from the tripped up position. Weight below the final kickoff isn't a concern because the pipe is lying on the low side of the hole.
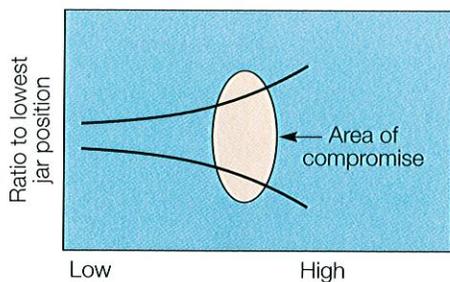
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5. The neutral point in the drillstring is where the axial force is zero. Pipe above the neutral point is in axial tension, below it, in axial compression.

6. Skeem MR, Friedman MB and Walker BH: "Drillstring Dynamics During Jar Operation," *Journal of Petroleum Technology* (November 1979): 1381-1386.

Jar Placement Programs

Although many operators place jars based on empirical evidence, use of jar placement computer programs, either proprietary or from a service company, has expanded in the past few years. These programs analyze wave propagation along the drillstring during jarring to model jarring force for different jar positions, BHA configurations and well trajectories. The goal is to find the jar position that maximizes the peak force and the impulse, which is the integral of force with respect to time (*below*). To do this, placement programs optimize two variables:

- velocity of BHA above the jar just before the hammer hits the anvil, which determines peak force
- length of BHA above the jar that contributes the most momentum to jarring, which determines impulse.

Peak force increases with the velocity of BHA above the jar—the faster it travels, the higher the peak force produced. Impulse increases with the length of BHA above the jar—the longer the moving pipe, the longer it takes to stop moving and longer the impulse. Peak force and impulse are generally inversely related: the higher the jar is in the BHA, the less mass is moving, so the greater the acceleration and peak force, but the smaller the impulse. Conversely, the lower the jar is in the BHA, the more mass and the greater the impulse but the smaller the peak force. Somewhere in the BHA, therefore, is a point at which a jar can be placed to achieve the optimum combination of peak force (velocity) and impulse (mass). Where is this point?

This problem was first addressed by Skeem and colleagues in 1979.[6] They did one-dimensional modeling of wave propa-

gation along the drillstring to derive the timing, duration and qualitative value of peak jarring force at a known stuck point. From this, they verified the inverse relationship between peak force and impulse. They also showed that lengthening jar stroke from 4 to 8 to 12 inches [10, 20 and 30 cm] increases both peak and impulse for a given jar position in the BHA. They concluded, however, that the optimum position depends on the often unknown sticking mechanism. Differential pipe sticking, for example, occurs along a length, not at a point. The jarring peak force must therefore not only exceed the sticking force, but must be maintained long enough to move the length of the stuck BHA. This may take a few blows or tens of blows. They also assumed that the stuck point is known, which it often is not.

The need for a more powerful predictor of jar placement prompted Kalsi and col-

□ *The jarring trade-off (above)—finding the jar location that optimizes both peak force (impact) and duration (impulse). A force of long duration will not move the fish if the peak force does not exceed sticking force. On the other hand, a peak force that exceeds the sticking force but lasts only a short time will not cause much fish movement, resulting in inefficient jarring. Many hits will be required to free the fish. The stair-step figure (right) illustrates selection of jar location, based on input from the Kalsi program, used by BP Exploration in Alaska. Impact force and impulse are plotted for each 30-ft [9-m] joint of pipe. For a given length of pipe, impact value is flat, but impulse is increasing. The optimum combination of impulse and impact is taken at the right end of the impact step, just before it drops off to the next level. For example, jar location at point A gives high impact but low impulse; B gives good impact and a little higher impulse; C is the optimum choice, giving the same impact as B, but a higher impulse. D gives the highest impulse, but the lowest impact. (From Askew, reference 8 and courtesy of BP Exploration.)*
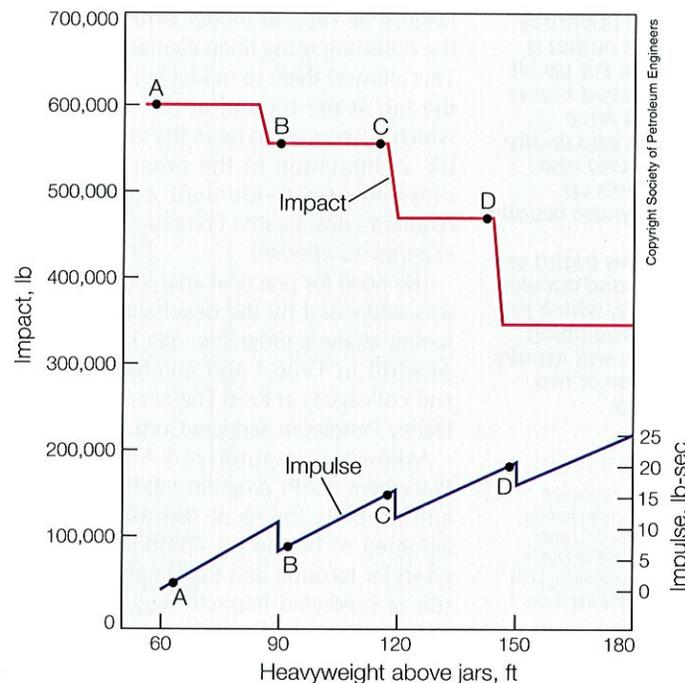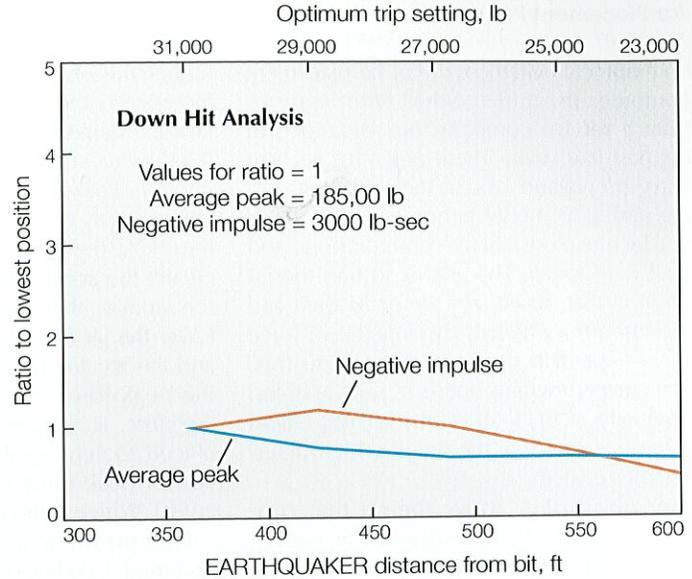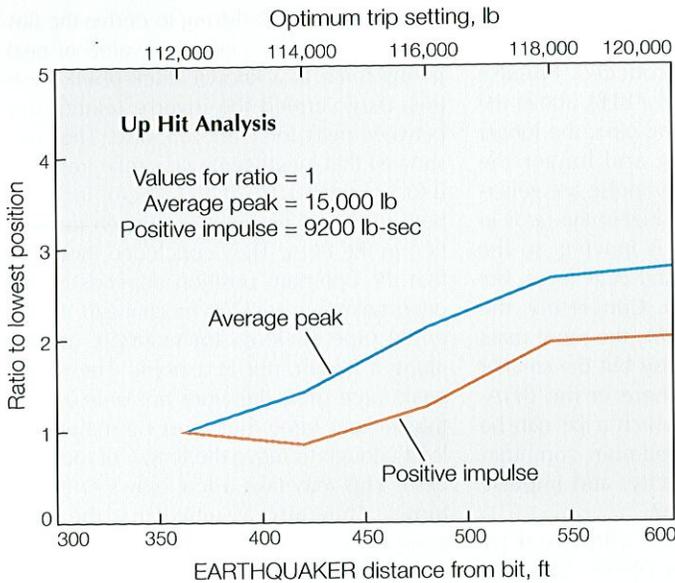
Optimum trip setting, lb

112,000   114,000   116,000   118,000   120,000

Up Hit Analysis

Values for ratio = 1
Average peak = 15,000 lb
Positive impulse = 9200 lb-sec

Average peak

Positive impulse

Ratio to lowest position

EARTHQUAKER distance from bit, ft

Optimum trip setting, lb

31,000   29,000   27,000   25,000   23,000

Down Hit Analysis

Values for ratio = 1
Average peak = 185,00 lb
Negative impulse = 3000 lb-sec

Negative impulse

Average peak

Ratio to lowest position

EARTHQUAKER distance from bit, ft

□ *Finding the jar position that optimizes peak force and duration. This output is the heart of the CAP program. For up hit analysis (left), as the jar is moved higher in the BHA, the average peak force increases sharply, then slows and finally levels off. The impulse (duration) also increases, then slows and levels off. Although not shown here, impulse usually declines after leveling off.*
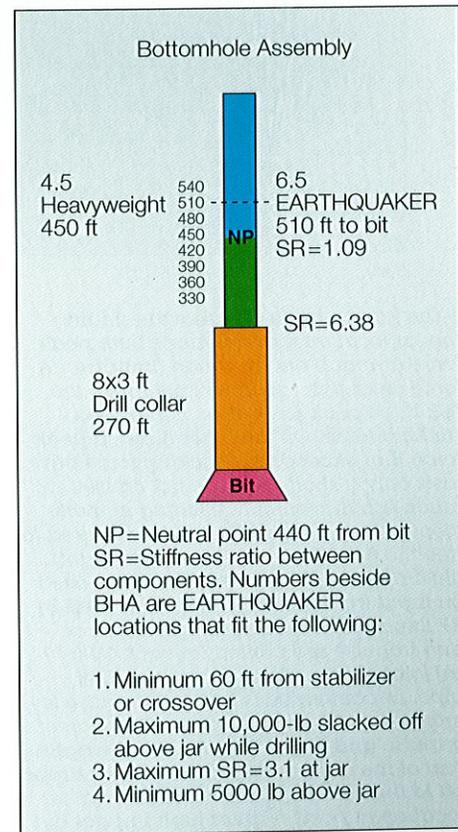
The down hit analysis curves (right) are flatter because pipe velocity and acceleration are governed by gravity, which produces less energy than pipe stretching used in up jarring. This graph will usually recommend jar placement one or two joints below that for up jarring.

7. Kalsi MS, Wang J-K and Chandra U: "Transient Dynamic Analysis of the Drillstring Under Jarring Operation Using Finite Element Method," paper SPE/IADC 13446, presented at the 1985 SPE/IADC Drilling Conference, New Orleans, Louisiana, USA, March 6–8, 1985; *SPE Drilling Engineering* 2, no. 1 (March 1987): 47–55.

8. Askew WE: "Computerized Drilling Jar Placement," paper IADC/SPE 14746, presented at the 1986 IADC/SPE Drilling Conference, Dallas, Texas, USA, February 10–12, 1986.

9. Wang J-K, Kalsi MS, Chapelle RA and Beasley TR: "A Practical Approach to Jarring Analysis," paper SPE/IADC 16155, presented at the 1987 SPE/IADC Drilling Conference, New Orleans, Louisiana, USA, March 15–18, 1987; *SPE Drilling Engineering* 5, no. 1 (March 1990): 86–92.

leagues in 1985 to model jarring forces on the drillstring using finite-element methods.[7] This allowed them to model jarring forces at the jar, at the bit and at the stuck point, which is assumed to be in the vicinity of the bit. A limitation of the program was its unwieldy finite-element code, which required considerable computer power and expertise to operate.

The need for practical analysis in the field was addressed by the development of two jarring analysis programs, one by Askew of Anadrill in 1986,[8] and another by Wang and colleagues at Kalsi Engineering Inc. and Dailey Petroleum Services Corp. in 1987.[9]

Askew's Computerized Analysis and Placement (CAP) program models the BHA and predicts forces at the stuck point—assumed to be the bit—produced for any given jar location and trip setting. Comparison of predicted impacts shows which jar position gives the best response at the stuck point. In addition to recommending jar placement, the program also suggests optimal trip setting and BHA design for effective jarring. Program inputs are weight on bit, mud weight and a description of the BHA, including pipe ID and OD, pipe lengths, inclination angle and overpull allowance.

From a computed plot of peak force vs. impulse for jar positions chosen (*above*), the user selects a position that optimizes peak force and impulse. The program gives both up and down hit responses, enabling the user to choose a jar placement best suited to the predominant jarring direction, if known.

Bottomhole Assembly

4.5 Heavyweight 450 ft

540
510
480
450   NP
420
390
360
330

6.5 EARTHQUAKER 510 ft to bit SR=1.09

SR=6.38

8x3 ft Drill collar 270 ft

Bit

NP=Neutral point 440 ft from bit
SR=Stiffness ratio between components. Numbers beside BHA are EARTHQUAKER locations that fit the following:

1. Minimum 60 ft from stabilizer or crossover
2. Maximum 10,000-lb slacked off above jar while drilling
3. Maximum SR=3.1 at jar
4. Minimum 5000 lb above jar

□ *A scale schematic of the BHA is part of the final output of the CAP program. Stiffness ratio is the ratio of the section moduli, where the pipe size changes. The stiffness ratio at the jar is limited to 3.1 or less to avoid placements where larger and stiffer components above and below the jar will concentrate bending stress at the jar. (From Askew, reference 8.)*

With regard to BHA design, the program gives a scale graphic representation of the BHA, neutral point location, and changing stiffness of BHA components. These data are used to revise jar position, BHA design, or both (*previous page, bottom*). Jar operation loads are also predicted. This tells the driller how much pick up or slack off from the free rotating string weight is needed to jar up, cock or jar down, with mud pumps on or off.

The jar placement program by Wang and colleagues improved on Skeem's work mainly by accounting for drill collar movement below the jar and the use of a nonuniform BHA, including heavyweight drillpipe. Heavyweight drillpipe, which was not so common at the time of Skeem's study, is a concern because transmission of jarring force is significantly altered at the interface of heavyweight and standard drillpipe or drill collars.

The program produces a two-dimensional or three-dimensional plot of the jarring impulse for a set of selected jar and BHA variables (*below*). The program takes into account jar stroke, overpull, length of pipe above the jar, length of pipe from the jar to an assumed stuck point, and stuck force and frictional loses in the BHA above and below the jar. It improves on previous programs by modeling jarring dynamics for various positions of the stuck point. It can be run in 15 seconds on a personal computer.

At Anadrill, the latest advance in jar placement is a revision of the Askew program, which had two limitations that could introduce error into jar placement: It did not account for localized wall drag (a big factor in directional wells), and it included the influence of collar movement below the jar (discovered to be a source of measurement noise). The new program uses the well plan trajectory to predict the magnitude and location of drag at 500 nodes, which are distributed evenly over the length of the modeled pipe. Accounting for drag is important because it influences jarring effectiveness. For example, a jar placed just below an interval of high drag will be less effective in up jarring than one placed above such an interval. The new program is designed to run in a few minutes on a personal computer.

Jar placement programs are relatively new. Their evolution has necessarily followed developments in drillstring and BHA design and in understanding of wave propagation along the drillstring. The programs have evolved from a research tool to the first generation field application. Now it is up to the drilling engineer to determine what unanswered questions the next generation of programs can address.   —JMK
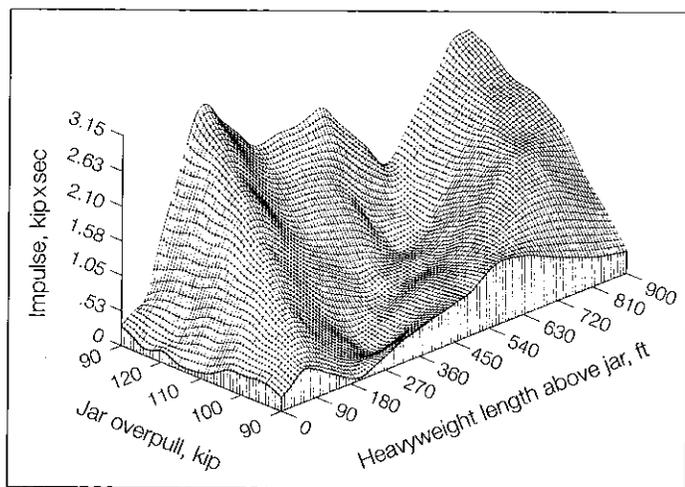
A 3D surface showing the effect of length of heavyweight drill pipe above the jar on jar overpull and impulse, used to optimize jar placement. Effective jarring depends on jar placement, overpull, stuck force and stuck point location. The program of Wang et al can be run with any set of jarring variables. They report that the peaks and valleys indicate some jar placements with heavyweight drillpipe can result in "negligibly small" impulses. As length of pipe above the jar is increased, the first peak results from an increase in impact duration, owing to the greater mass of pipe. But continued increase in the pipe length above the jar results in a lower hammer velocity. This works in combination with downward pipe movement and stress-wave reflections to create a valley in the impulse curve. The peaks and troughs in this graph show that jar placement in a heavyweight drillpipe BHA is trickier than in a BHA with a uniform drill collar design, in which the impulse curve plot has only one peak. (From Wang et al, reference 9.)