WellServ

DST TOOLS CATALOGUE

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table of contents

Test Tools

Purpose of Well Tests

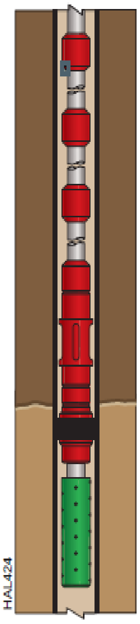
A properly conducted well test is a temporary completion of a well to acquire dynamic rate through time, pressure, and fluid property data. The well test often indicates how the well will perform when it is subjected to various flow conditions. An analysis is usually performed on the data to determine reservoir parameters and characteristics. Production decline maybe predicted using these parameters and characteristics. The production decline can be used to predict cash flow. Once cash flow is known, improved drilling, completion, and production decisions can be made on this well and other wells in the field. Well test objectives can be classified as short term or long term.

- Short-term well test objectives typically involve gathering and analyzing sufficient well data to obtain a description of the reservoir system in the vicinity of the wellbore.
- Long-term well test objectives focus on gathering and analyzing data to obtain a complete description of the reservoir. The test time required to satisfy the test objectives varies for each reservoir. These test times are directly related to the testing costs and data needed. Therefore, testing times are a principal concern for the company conducting the test.

Downhole Testing Equipment

The well testing and sampling operation is typically accomplished with an assortment of test tools. The basic downhole test tools required for a well test include:

- Reversing valve
- Tester valve
- Samplers
- Gauges (pressure and temperature recorders)
- Packer
- Tubing conveyed perforating guns



Typical APR® Annulus Pressure Response Cased Hole Testing String

To determine the makeup of a test string, a test objective must be established and well defined. If the objective of the test is to perforate underbalanced and then test, only tools with a full opening should be used. A rule of thumb to observe when selecting the components of a test string is to keep the string as simple as possible. Avoid redundancy unless there is a real benefit to be gained. A variety of techniques and arrangements of our test tools are used to handle diverse types of tests—from openhole to high-pressure/high temperature(HPHT) and underbalanced to name a few.

APR® Annulus Pressure Response Test Tools

The full-opening APR® annulus pressure response system of testing tools allows for a well test to be conducted with the blowout preventer (BOP) rams closed and without pipe manipulation or rotation to control the test. The APR tools are operated by simply applying and releasing annulus pressure. If there is a need to close the tester valve in an emergency, bleeding the annulus pressure off will close the tool, permitting corrective measures to be taken. If a leak in the workstring should develop during the test to such an extent that annulus pressure cannot be bled off quickly enough to close the tester valve, the operator can then control the well by increasing the annulus pressure to the predetermined operating pressure of the APR rupture disk (RD) safety circulating valve.

This will lock the RD safety circulating valve ball in the closed position while opening the reversing ports to the annulus fluid. At this point, reversing out the string contents and conditioning mud can take place.

Two major applications for APR® test tools are for wells drilled:

• In directional holes where pipe manipulation is difficult.
• From floating vessels.

Since these test tools are full opening, other tools can be run on wireline or coiled tubing to perforate, test, sample, treat the formation, and retest all in a single trip. In high-volume wells, the full-opening feature permits flow rates high enough to obtain more definitive test data, so test results are more reliable. The APR well testing method is safer, faster, and provides more reliable information than conventional methods used in the past.

Pre-Job Planning

Like all other operations required for drilling a well, pre-job planning is essential to ensure a safe and successful well test. The Management System (HMS) serves as a pre-job planning and execution guide to ensure that work is conducted in a professional, safe, and effective manner. All personnel involved with the test must be informed of the different procedures needed to perform the test and must be prepared to react to changing well conditions during the job. Planning for a safe well test can be divided into two main events:

• Pre-job meeting
• Wellsite preparation

Pre-Job Meeting

The following information should be discussed prior tothe job.


Pre-Job Meeting Discussion

Test Objectives

• Pressure and temperature data
• Flow rates
• Downhole samples
• Test duration
• Test multiple zones
• Type of data collection—surface readout, memory gauges
• Analysis of collected data

Well Information


HAL6736
Real-Time Surface Readout and Data Communication Reduce Test Time

• Expected bottomhole temperature
  - Elastomers required
  - Data collection required
  - Weight of annular fluid
• Surface pressure
  - Pressure rating required for the surface equipment
• Downhole pressure
  - Pressure rating required for the downhole tools
  - Packer required
  - Type of cushion required

- Data collection system required
- Tubulars required

- Type of Production—crude, dry gas, H2S, CO2, etc.
  - Elastomers required
  - Tools required
  - Surface equipment required
  - Test duration
- Type of mud system—water based, oil based, brine
  - Elastomers required
  - Tools required
- Casing or liner
- Size and weight—to determine size of tools
  - Pressure rating
  - Location of liner lap
  - Pressure rating of liner lap
- Hole conditions
  - Total Measured Depth (MD)
  - True Vertical Depth (TVD)
  - Maximum deviation—can have an effect on what tools are used and if wireline is practical
  - Type of formation—will sand be produced?
- Perforating
  - Tubing conveyed perforating—pressure activated, bar job
  - Perforating before test
  - Wireline guns through downhole tools
- Type of workstring
  - Tubing—recommended for high pressure gas, HPHT
  - Drill collars—drift needed for wireline passage
  - Landing string—for floating vessel
- Drill pipe
- Cushion
  - Type of cushion—determines type of elastomers required
  - Weight of cushion—determines pressure differential across test tools and workstring
  - Method of cushion placement—spot, self-fill, fill at surface

Wellsite Preparation

Prior to testing, the following preparations need to be completed.

Equipment Preparation

- Pressure test blowout preventers(BOP)

- Pressure test subsea equipment
- Pressure test surface equipment
- Function test downhole tools
- Pressure test downhole tools
- Drift all equipment
- Obtain work permits for pressure Testing

Note: All non-essential personnel should be restricted from area when pressure testing.

Personnel Preparation

- Hold safety meeting before test
  - Know location of firefighting equipment
  - Know evacuation procedures
  - Stress no smoking rule during test
  - No welding or open flames during testing
  - No lifting over surface well test area
  - Use correct personal safety equipment
- Instruct all essential personnel what procedures will be followed during testing.
  - Running in hole (RIH)
  - Firing tubing conveyed perforating (TCP) guns
  - Flowing well
  - Shut-ins
  - Wireline procedures
  - Sampling
  - Killing well
  - Reversing out
  - Pulling out of hole (POOH)
- Know when to abort test.
  - H2S detected over flowing limit—equipment not rated forH2S service
  - Downhole tool malfunction
  - Subsea tool malfunction
  - Surface leak that cannot be bypassed or repaired quickly
  - Deteriorating weather conditions
  - Leak in string, casing, tubing, etc.
- Establish methods of communication.
  - Voice
  - Hand signals
  - Hand radios

Conducting a Safe Well Test

During a test, there are numerous factors to be considered to help ensure a safe well test.

Picking Up Tools

- Only qualified personnel to sling and direct crane operator
- Use a guide rope line for long assemblies
- Always use handling subs

Making Up Tools

- All tools to be measured and drifted prior to running in well
- Tool operator to direct the make up of the tools and advise driller on proper torque requirements
- Use safety clamp or dog collar anytime the elevators are released from the tool
- Always use a hole cover
- Do not use iron rough neck on tools

Running in Well

- Ensure the hole is filled before running in
- Ensure the hole is stable before running in
- Monitor well fluid while running in
- Slow down at liner laps
- Avoid sudden stops while running in
- Tool operator must be on rig floor at all times

Beginning Test

- Set packer
- Test packer seal by pressuring up on annulus
- Ensure surface equipment is lined up correctly for inflow and light burners
- With annulus pressure applied and tester valve open, pressure up on tubing and fire TCP guns
- Observe surface pressure and monitor for leaks
- Open surface choke manifold on flow well
- Check production for presence of H_2S—abort test if surface equipment is not rated for H_2S or H_2S is over the low level ppm requirement
- Observe annulus pressure and maintain it at a predetermined pressure
- If annulus pressure suddenly increases or decreases, shut in downhole

Note: It is normal to see gradual pressure changes caused by temperature effects.

- If surface leak occurs, shut in downhole
- To shut in well for a "build up," release annulus pressure
- Observe annulus pressure for changes during the "buildup" period
- Observe tubing pressure for changes during the "buildup" period

Note: It is normal to see an increase in tubing pressure immediately after shut in when flowing gas. If tubing pressure is bled down during the "build up," enough pressure must be maintained to prevent collapse of the tubulars.

- Follow same procedure for additional flow and build up Periods

Terminating Test

- Reverse out all recovery with one of the following tools:
  - Annulus pressure operated
  - Tubing pressure operated
  - Bar drop operated
  - Mechanical operated
- If producing gas, fill the tubing prior to opening the reversing valve to help prevent U-tubing
- Reverse circulate until returns are free of hydrocarbons
- Unseat packer
- Observe annulus fluid for stability

Pulling Out of Hole

- Observe annulus fluid for stability
- Pull out of hole
- Stop periodically for flow check of well stability
  - Fill hole if necessary
- Use caution when breaking out tools for any pressure trapped between connections
- Use safety clamps or dog collars on tools
- Do not use iron rough neck on tools

Metallurgy

Service Environment

Immerse in various well fluids including hydrocarbons, dilute HC1, sour gas, salt water, and CO2 for the normal exposure time for drillstem testing.

Design Basis

This design meets or exceeds material requirements for sour gas service above 175°F set forth in NACEpublicationMR0175-90.Design calculations and safety factors are per Specification 615.41861.

Specification

- Heat Treat, Fabrication, Material Test Requirements, AISI 4140 Components for Sour Gas Service at temperatures of 175°F or greater.

Heat Treatment - AISI 4140 - 271-301 Hb (Rc 28-32) – Sour Gas Service at temperatures of 175°F or greater.

Short-Term Seal Selection Guide: O-rings

	ASTM D1418Design	NBR-Peroxide Cure	FKM	FKM	FEPM
	Specification	599.33001	600.33001	600.33001	601.30000
	Min. Temp °F (°C)	-40（-40）	-10（-23）	-10（-23）	40（4）[3]
	Max. Temp °F (°C) Exposure δ 24 hours	400（204）	500（260）	500（260）	500（260）
	Max. Temp °F (°C) Exposure δ 5 days	350（177）[4]	400（204）[5]	400（204）[5]	400（204）
	Max. Temp °F (°C) Exposure δ 5 days	275（135）	325（163）	325（163）	400（204）
	Max. Pressure at 500°F		10000psi(68940kPa)[6]	10000psi(68940kPa)[6]	10000psi(68940kPa)[6]
	Max. Pressure at 350°F	10000psi(68940kPa)	10000psi(68940kPa)	10000psi(68940kPa)[6]	10000psi(68940kPa)
	Max. Pressure at 275°F	15000psi(103410kPa)	10000psi(68940kPa)	10000psi(68940kPa)	8000psi(55152kPa)
	Max. Pressure at 150°F	20000psi(137880kPa)	15000psi(103410kPa)	15000psi(103410kPa)	8000psi(55152kPa)
Gases	H_2S		8	8	8
	CO_2	8	8	8	8
	CH_4(**Methane**)	8	8	8	8
	N_2	8	8	8	8
Oil-Based Fluids	**Sweet Crude**				
	Diesel				
	Aromatic Hydrocarbons and Solvents (Xylene and Toluene)	7			7
	Oil-Based Muds/Fluids	9	9	9	9
	Ester-Based Drilling Mud				
	Amine/Oil Inhibitors	7			
Water-Based Fluids	**Water-Based Inhibitors**				
	Steam				
	Salt Water				
	Zn Bromide				
	Ca Bromide (<14.2 ppg)				
	Na Bromide (<12.4 ppg)				
	Formates				
	High pH Fluids (>9)				
Other Fluids	**Alcohols**				
	Methanol				
	HCl and HCF Acid Mixture				
	Weak Acid (HCL<15%)				
	Strong Acid (HCL>15%)	7			
	Acetic and Formic Acids				

	Excellent – Recommended
	Good - Slightly affected, but no significant chemical change
	Conditional - Time and/or temperature limitations
	Conditional – Operational considerations for running
	Not recommended
	No information available

Short-Term Guidelines: Packer Elements

	ASTMD1418Design	NBR - Sulfur Cure
	Trade Name	Nitrile
	Temperature Range °F (°C)	5
	Element Package Max. Pressure psi (MPa)	5
Gases	H2S	3
	CO2	4
	CH4（Methane）	4
	N2	4
Oil-Based Fluids	Sweet Crude	
	Diesel	
	Aromatic Hydrocarbons and Solvents (Xylene and Toluene)	1
	Oil-Based Muds/Fluids	6
	Ester-Based Drilling Mud	
	Amine/Oil Inhibitors	1
Water-Based Fluids	Water-Based Inhibitors	
	Steam	
	Salt Water	
	Zn Bromide	2
	Ca Bromide (<14.2 ppg)	2
	Na Bromide (<12.4 ppg)	2
	Formates	
	High pH Fluids (>9)	
Other Fluids	Alcohols	
	Methanol	
	HCl and HCF Acid Mixture	
	Weak Acid (HCL<15%)	
	Strong Acid (HCL>15%)	3
	Acetic and Formic Acids	

(green)	Excellent – Recommended
(yellow)	Good - Slightly affected, but no significant chemical change
(purple)	Conditional - Time and/or temperature limitations
(blue)	Conditional – Operational considerations for running
(red)	Not recommended
(white)	No information available

Notes

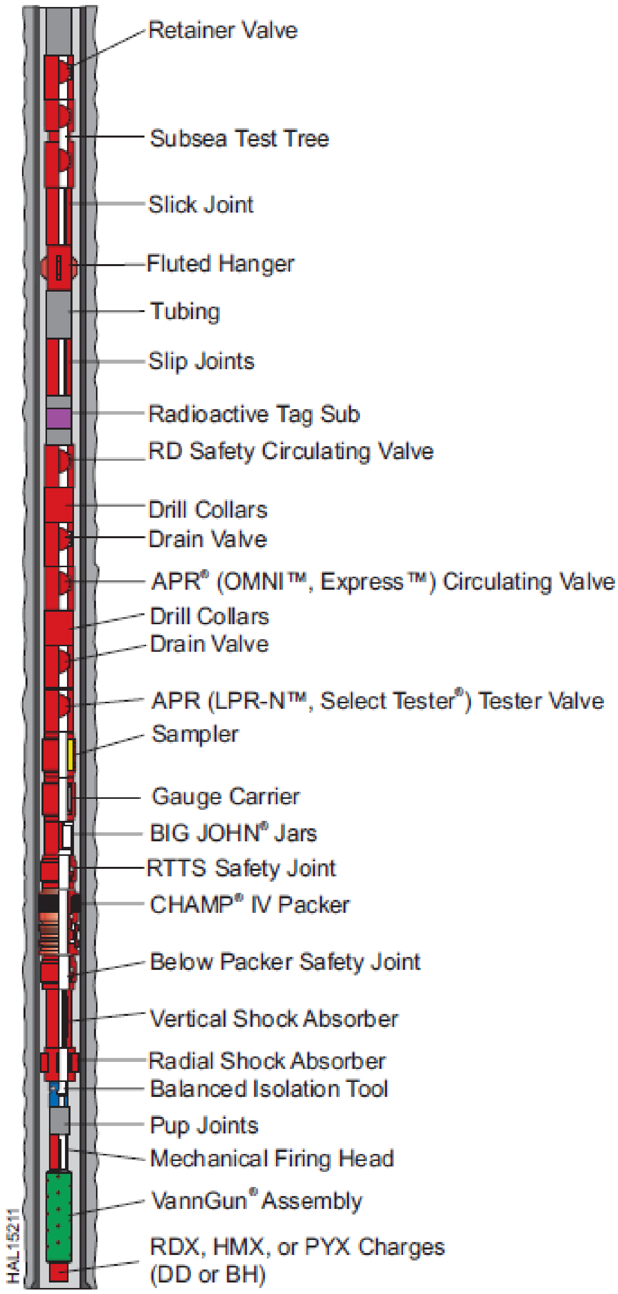
1. Some chemicals and environments cause certain rubber types to lose elasticity, which can affect setting or resetting packer elements. Usually, no other physical degradation of the rubber is apparent. Service tools can be run in these environments if the packer or bridge plug is set within 8hours of starting in the hole. The packer or plug cannot be reset after initial operations have begun.
2. Some chemicals can cause physical degradation of certain rubber types. To keep these chemicals from prolonged contact with the rubber, pump them into the workstring and the wellbore. Do not allow them in the drilling or completion fluids. If fluids are spotted, do not spot these chemicals across the packer seat (over displacement). Run a pup joint below a retrievable packer to provide a fluid barrier for packer elements. Place sand above a retrievable bridge plug to provide a physical barrier to pumped chemicals.
3. Incompatibilities that previously existed with chemicals that are produced from an oil or gas well may not exist in certain service operations if the well has been properly killed, and those chemicals do not exist in the wellbore. Further, pumping operations will keep produced chemicals from entering the wellbore during the service operation.
4. Chemical incompatibilities may not be severe enough to cause concern, but explosive decompression can damage seals or packer elements. Explosive decompression occurs when a sudden pressure loss occurs after prolonged exposure to this chemical. Explosive decompression is compound dependent and could damage seals or elements.
5. Temperature and pressure ratings are dependent on tool design and application.
6. Testing is recommended due to variability of proprietary ingredients in “Oil-Based Muds.”

Cased Hole

String Examples

This section provides a brief discussion on some of the various tools used in cased hole testing including:

- Packers
- Circulating valves
- Tester valves
- Accessory tools



String Example

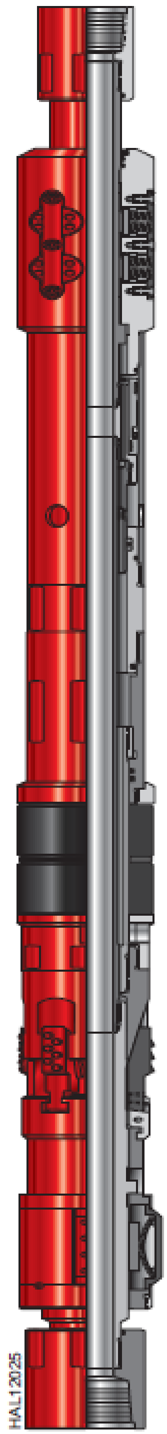
CHAMP Ⅳ Packer

The CHAMP® IV packer is a hook wall-retrievable packer with a concentric bypass. As the tool is lowered into the hole, a J-slot holds the bypass open and controls the setting of the packer. When the packer is set, a balancing piston activated by tubing pressure holds the bypass closed.

Each tool assembly includes a J-slot mechanism, mechanical slips, packer elements, hydraulic slips, and a bypass. Round, piston-like slips used in the hydraulic hold down mechanism prevent the tool from being pumped up the hole. The bypass allows fluids to pass around the bottom of the tool when it is removed from the hole. This design eliminates accidentally opening a conventional bypass during circulation around the bottom of the packer.

Circulation around the CHAMP IV packer is not interrupted if the packer element temporarily seals unintentionally as when it passes through points of interference in the casing.

The CHAMP IV packer is well suited to tubing conveyed perforating applications where the firing head assembly is easily incorporated into the CHAMP IV packer. The CHAMP IV packer is ideally suited for horizontal applications due to its limited rotational requirements and integrated circulating valve. Just a quarter-turn is required, at the tool, to set the packer and close the circulating valve. A straight upward pull opens the circulating valve and unseats the packer.



CHAMP® IV Packer

Features and Benefits

- The packer is used in highly deviated wells or where pipe manipulation is difficult.
- Picking the packer straight up (no torque required) opens the bypass.
- The tool is easily relocated in multiple zones during a single trip for treating, testing, or squeezing.
- The concentric bypass valve allows a larger bypass flow area.
- The CHAMP IV packer is used with a retrievable bridge plug for straddling zones during various operations.
- A CHAMP IV packer would be the tool of choice where positive circulation below the packer is required such as in drillstem testing, TCP applications, using tailpipe, for shallow service, and as liner tools.

Operation

The tool is run slightly below the necessary setting position. If the packer is to be set, it must be picked up, and right-hand rotation must be applied so that a half-turn can be obtained at the tool. In deep or deviated holes, several turns with the rotary may be necessary. For the position to be maintained, the right-hand torque must be held until the mechanical slips on the tool are set and can begin taking weight.

Pressure applied below the packer forces the hydraulic hold down slips against the casing to prevent the packer from being pumped up the hole.

The concentric bypass valve is balanced to the tubing surface pressure, which prevents the bypass from being pumped open with tubing pressure. Straight, upward pull on the tubing string opens the bypass and unsets the packer.

CHAMP Ⅳ Packer

Casing Size in.	Packer ODin. (cm)	Packer IDin. (cm)	End Connections	NominalCasing Weightlb/ft	Minimum Casing Drift IDin. (cm)	Maximum Casing ID in. (cm)	Length in. (cm)	Tensile Rating** lb (kg)	Working Pressure ***psi (kPa)
4 1/2	3.87 (9.83) 3.75 (9.52)	1.80 (4.57)	2 3/8EUE	9.5-10.5 11.6-13.5	3.927-3.795 (9.975-9.639)	4.090-4.000 (10.389-10.16)	92.49 (234.92)	71200 (32296)	8400 (57916)
5	4.18 (10.62)	1.80 (4.57)	2 3/8 8Rd EUE	18-20.8 11.5-15.0	4.032-4.366 (10.241—11.089)	4.276 (10.861)	93.63 (237.82)	71200 (32296)	8400 (57916)
5 1/2	4.57(11.61) 4.40(11.81)	2.00(5.08) 1.80(4.57)	2 3/8EUE	13-20 20-23	4.653-4.545 (11.819-11.544)	5.044-4.778 (12.812-12.136)	90.46 (229.77)	88900 (40325)	8400 (57916)
6 5/8 或 7	5.25 （13.34）	2.00 （5.08）	2 7/8 8RD EUE	6 5/8: 23-32 7:41-49.5	5.318 (13.508)	5.791 (14.709)	91.42 (232.21)	88800 (40279)	10000 (68900)
7	5.65 (14.35)	2.37 (6.02)	2 3/8 EUE 2 7/8EUE 3 1/2IF 3 7/8CAS	17-38	5.795 (14.719)	6.538 (16.607)	98.85 (251.08)	148600 (67404)	10000 (68900)
7 5/8	6.35 (16.13)	2.37 (6.02)	2 7/8 8RD EUE(Optional Adapters： 3 7/8CAS, 2 7/8PH6, 3 1/2IF)	20-39	6.477(16.452)	7.125 (18.098)	96.75 (245.75)	148600 (67404)	10000 (68900)
8 5/8	7.04(17.88)	2.62(6.65)	3 7/8CAS	44-56	7.313 (18.575)	7.625 (19.367)	123.80 (314.45)	215640 (97814)	10000 (68900)
	6.75(17.15)	2.37 （6.02）	3 7/8CAS	58.7-68.1	7.126 (18.100)	7.001 (17.783)	123.80 (314.45)	313600 (142249)	10000 (68900)
9 5/8	8.15(20.70) 7.80(19.81)	2.87(7.29)	4 1/2IF	29.3-53.5 40-71.8	8.379-7.969 (21.283-20.241)	9.063-8.835 (23.020-22.441)	125.22-117.23 318.06-297.76)	341900 (155086)	10000 (68900)
13 3/8	11.94 (30.33) 11.50 (29.21)	3.75 (9.53)	4 1/2IF	48-72 72-98	12.191-11.781 (30.965-29.924)	12.715-12.347 (32.296-31.361)	141.84 (360.27)	651300 (295429)	5000 (34474)

RTTS Packer

The RTTS packer is a full-opening, hook wall packer used for testing, treating, and squeeze cementing operations. In most cases, the tool runs with a circulating valve assembly.

The packer body includes a J-slot mechanism, mechanical slips, packer elements, and hydraulic slips. Large, heavy-duty slips in the hydraulic hold down mechanism help prevent the tool from being pumped up the hole. Drag springs operate the J-slot mechanism on ≤ 3 1/2-in. (88.9-mm) packer bodies, while larger packer sizes ≥ 4-in. (101.6 mm) use drag blocks. Automatic J-slot sleeves are standard equipment on all packer bodies.

The circulating valve, if used, is a locked-open/locked-closed type that serves as both a circulating valve and bypass. The valve automatically locks in the closed position when the packer sets. During testing or squeezing operations, the lock prevents the valve from being pumped open. A straight J-slot in the locked-open position matches with a straight J-slot (optional) in the packer body. This combination eliminates the need to turn the tubing to close the circulating valve or reset the packer after the tubing has been displaced with cement.

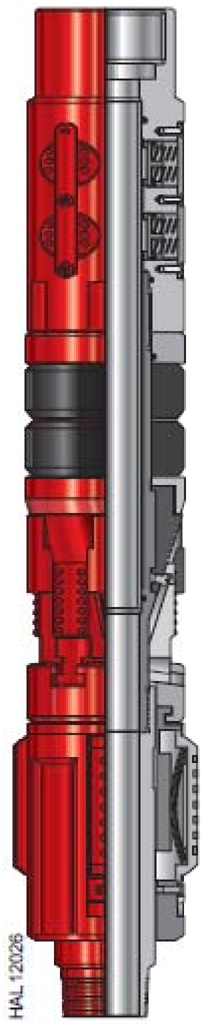
Features and Benefits

- The full-opening design of the packer mandrel bore allows large volumes of fluid to pump through the tool. Tubing-type guns and other wireline tools can be run through the packer.
- The packer can be set and relocated as many times as necessary with simple tubing manipulation.
- Tungsten carbide slips provide greater holding ability and improved wear resistance in high-strength casing. Pressure through the tubing activates the slips in the hydraulic holddown mechanism.
- An optional integral circulating valve locks into open or closed position during squeezing or treating operations, and opens easily to allow circulation above the packer.

Operation

The tool is run slightly below the desired setting position to set the packer and is then picked up and rotated several turns. If the tool is on the bottom, only a half-turn is actually required. However, in deep or deviated holes, several turns with the rotary may be necessary. To maintain position, the right-hand torque must be held until the mechanical slips on the tool are set and can start taking weight.

The pressure must be equalized across the packer to unset it. As the tubing is picked up, the circulating valve remains closed, establishing reverse circulation around the lower end of the packer. The circulating valve is opened for coming out of the hole when the tubing is lowered, rotated to the right, and picked up.



RTTS Packer

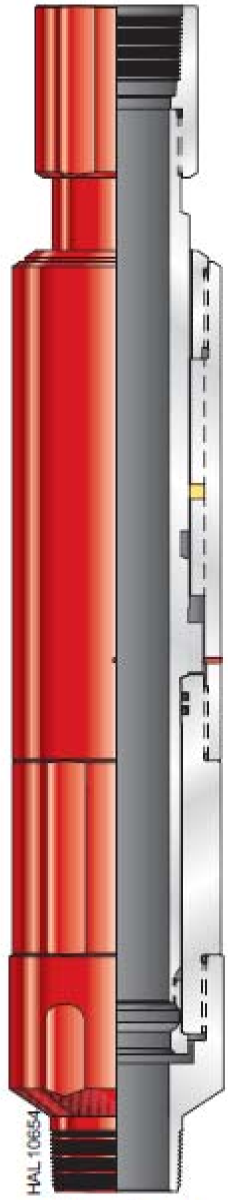
RTTS Packer

Casing Size in	Casing Weight Range lb/ft	Nominal Tool OD in. (cm)	Minimum ID in. (cm)	Top Thread Connection (female)	Lower Thread Connection (male)
2 3/8	4.6	1.81（4.60）	0.60（1.52）	1.050in.OD 10RD EUE	1.050in OD 10RD EUE
2 7/8	6.4	2.22(5.64)	0.75(1.91)	1 7/8in OD 10RD EUE	1.315in OD
	7.9-8.7	2.10(5.33)	0.60（1.52）	1.050in OD 10RD EUE	1.050in OD 10RD EUE
3 1/2	5.7	2.93(7.44)	0.62(1.57)	1 7/8in OD 12 UNS EUE	1.315in 10RD
	9.2-10.2	2.70(6.86)	0.62(1.57)	1 7/8in OD 12 UNS EUE	1.315 in 10RD
	13.3	2.50(6.35)	0.62(1.57)	1 7/8in OD 12 UNS EUE	1.315 in 10RD
4	9.5-11.6	3.18(8.08)	1.12(2.84)	2 11/16 in 10 UNS	2 3/8in 8RD EUE
	12.5-15.7	3.06(7.77)	0.865(2.20)	2 11/16 in 10 UNS	1 7/8in 8RD Drill Pipe (male)
4 1/2	9.5	3.79(9.63)	1.80(4.57)	3 3/32in 10 UNS	2 3/8in 8RD EUE
	15.1-18.1	3.55(9.02)	1.51(3.84)	2 11/16in 10 UNS	2 3/8in 8RD EUE
	11.6-13.5	3.75(9.53)	1.80(4.57)	3 3/32in 10 UNS	2 3/8in 8RD EUE
5	23	3.75(9.53)	1.80(4.57)	3 3/32in 10 UNS	2 3/8in 8RD EUE
	15-18	4.06(10.31)	1.80(4.57)	3 3/32in 10 UNS	2 7/8in 8RD EUE
	11.5-13	4.25(10.79)	1.80(4.57)	3 3/32in 10 UNS	2 7/8in 8RD EUE
5 1/2	23-26	4.25(10.79)	1.90(4.83)	3 1/2in 8 UNS	2 7/8in 8RD EUE
	20-23	4.38(11.13)	1.80(4.57)	3 3/32in 10 UNS	2 7/8in 8RD EUE
	13-20	4.55(11.56)	1.80(4.57)	3 1/2in 8 UNS	2 3/8in 8RD EUE
6	15-23	5.06(2.85)	1.90(4.83)	3 1/2in 8 UNS	2 7/8in 8RD EUE
6 5/8	24-32	5.43(13.79)	1.90(4.83)	3 1/2in 8 UNS	2 7/8in 8RD EUE
7	17-38	5.65(14.35)	2.40(6.10)	3 7/8in CAS 4 5/32in 8 UNS	2 7/8in IF 3 1/2in CAS 2 7/8in 8RD EUE
	49.5	5.25(13.34)	2.00(5.08)	3 1/2in 8 UNS	2 7/8in 8RD EUE
7 5/8	20-39	6.35(16.13)	2.40(6.10)	4 5/32in 8UNS	2 7/8in 8RD EUE 3 1/2in IF 3 7/8 in CAS
8 5/8	24-49	7.31(18.57)	3.00(7.62)	4 1/2in API IF T.J.	4 1/2in API IF T.J.
9 5/8	40-71.8	7.80(19.81)	3.00(7.62)	4 1/2in API IF T.J.	4 1/2in API IF T.J.
	29.3-53.5	8.15(20.70)	3.75(9.53)	4 1/2in API IF T.J.	4 1/2in API IF T.J.
10 3/4	32.75-51	9.30(23.62)	3.75(9.53)	4 1/2in API IF T.J.	4 1/2in API IF T.J.
	55.5-81	8.85(22.48)	3.75(9.53)	4 1/2in API IF T.J.	4 1/2in API IF T.J.
11 3/4	38-54	10.20(25.91)	3.75(9.53)	4 1/2in API IF T.J.	4 1/2in API IF T.J.
	60-71	10.10(25.65)	3.75(9.53)	4 1/2in API IF T.J.	4 1/2in API IF T.J.
13 3/8	48-72	11.94(30.33)	3.75(9.53)	4 1/2in API IF T.J.	4 1/2in API IF T.J.
	72-98	11.50(29.21)	3.75(9.53)	4 1/2in API IF T.J.	4 1/2in API IF T.J.
16	75-109	14.18(36.02)	3.75(9.53)	4 1/2in API IF T.J.	4 1/2in API IF T.J.
	109-146	13.62(34.59)	3.75(9.53)	4 1/2in API IF T.J.	4 1/2in API IF T.J.
18 5/8	78-118	16.87(42.85)	3.75(9.53)	4 1/2in API IF T.J.	4 1/2in API IF T.J.
20	94-133	17.87(45.39)	3.75(9.53)	4 1/2in API IF T.J.	4 1/2in API IF T.J.
	169-204	17.25(43.82)	3.75(9.53)	4 1/2in API IF T.J.	4 1/2in API IF T.J.

RTTS Safety Joint

The RTTS safety joint is an optional emergency back off device. The safety joint releases the workstring and tools above the packer if the packer becomes stuck during operations.

The design of the RTTS safety joint makes unintentional operation difficult.



RTTS Safety Joint

Features and Benefits

- Positive sequence of operation helps prevent premature release.
- Tools above it can be retrieved when string is stuck.

Operation

The RTTS safety joint is run immediately above the RTTS packer so that the greatest number of tools above the packer can be removed.

Before the safety joint can be used, a tension sleeve located on the bottom of the lug mandrel must first be parted by pulling up on the workstring.

After the tension sleeve has parted, the safety joint is released by right-hand torque while the workstring is rotated a specified number of cycles.

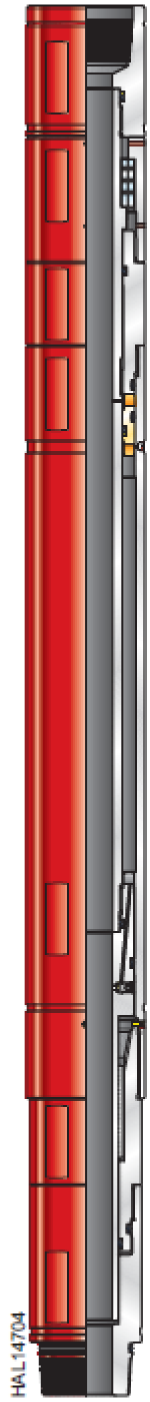
RTTS Safety Joint

Casing Size	OD in. (cm)	ID in. (cm)	End Connections	Length in. (cm)	Tensile Rating** lb (kg)	Burst Rating** psi (kPa)	CollapseRating**psi (kPa)
2 3/8	1.81 (4.60)	0.68 (1.73)	1.05 10RD	24.3 (61.7)	36000 (16330)	9600 (66190)	23200 (159959)
4 1/2-5	3.68 (9.35)	1.90 (4.83)	2 3/8 EUE	38.5 (97.8)	95000 (43092)	11500 (79290)	11500 (79290)
7-7 5/8	5.00 (12.70)	2.44(6.20)	2 7/8EUE	39.9 (101.4)	164000 (74390)	12000 (82738)	10900 (75153)
8 5/8-13 3/8	6.12 (15.54)	3.12(7.92)	4 1/2IF	42.7 (108.5)	301000 (136533)	13700 (94459)	10400 (71706)

Below Packer Hydraulic Safety Joint

The below packer hydraulic safety joint is designed for use in test strings or shoot and pulls to allow a packer to be unset and disconnected from tubing conveyed perforating guns if the guns become stuck following perforation and testing.

This tool is operated by pulling a preset amount on the workstring until the tool is actuated to provide 36 in. of travel to unset the packer. Rotating the safety joint to the right 30 turns releases the tool from the perforating guns and leaves a 4 3/4-in. OD nipple facing up. Inside the nipple is a 3 1/2-in. IF tool joint box facing up. This allows the guns to be picked up with a standard overshot or a 3 1/2-in. IF pin thread.



Below Packer Hydraulic Safety Joint

Operation

Before the safety joint is activated, splines on the operating piston and the lower nipple lock the tool against rotation. A hydraulic rupture disk in the tool can be selected for release forces up to 100,000 lb. When an axial load is applied to the tool, the load is transmitted through the top adapter to the operating mandrel and into the operating piston. As the piston starts to move up inside the oil case, it begins to compress the oil inside the casing, causing the oil pressure inside the case to rise. Greater axial loads create greater pressures inside the case.

When the load and pressure become great enough, the rupture disk will burst, allowing the oil to dump into the ID of the tool. This lets the top adapter, operating mandrel, and operating piston slide up inside the oil case. As the operating piston moves up out of the lower nipple, the splines on both pieces disengage, freeing the operating assembly to rotate. The operating assembly can stroke up 36 in., which should unset the packer. Lugs on the bottom of the lugged adapter match lugs on the top of the lugged floating piston, and lugs on the top of the operating piston match lugs on the bottom of the lugged floating piston .

When the tool is pulled apart into the fully extended position, the lugs on all of these parts lock the operating assembly to the rest of the tool. At this point, an axial load of up to 250,000 lb may be applied if desired. If right-hand rotation is now applied, the left-hand thread on the bottom of the oil case will back off, shearing the brass locking screws located at the bottom of the case at approximately 1,000 ft/lb of torque. After 30 turns of right-hand rotation, the case will be backed completely off the bottom nipple.

The packer and rest of the workstring can then be retrieved. The bottom nipple and bottom adapter, which have a4 3/4-in. OD and 3 1/2-in. IF tool joint box, will be left in the well, looking up on top of the gun assembly. Fishing may be performed with a standard overshot or 3 1/2-in. IF tool joint pin thread.

The below packer hydraulic safety joint may also be set for a predetermined release force by pinning the shear set at the top of the tool. Depending on the number of pins used(approximately 2,100 lb per pin), the release force may be set at up to 125,000 lb using the shear set, which may be used with the rupture disk to provide two different releases in the tool. The shear set can be pinned for relatively small axial load if the intent is to eliminate any bounce or extension in the tool which may be present due to the weight of the perforating guns below the tool. In this case, the shear set will support the weight of the guns without movement while allowing the rupture disk to control the activation force for extending the tool if it is necessary to back the tool off. The shear set may also be set to a release value which is almost as high (80%) as the rupture disk release setting. Setting the tool in this way can provide protection from accidentally releasing the tool by rupturing the disk at the time of perforation. When the guns produce a hard downward kick, the shear set might possibly shear, but this will help protect the disk from rupturing. Since the disk remains intact, the tool will not extend, and there will be no risk of accidentally releasing the tool. This tool is pressure-balanced when it is in a bull-plugged condition and below the packer as it will be when used on the TCP job.

Below Packer Hydraulic Safety Joint

Nominal Tool Size in.	ODin. (mm)	IDin. (cm)	End Connections	ServiceTemperature*°F (°C)	Makeup Length in. (cm)	Tensile Rating**lb (kg)	Working Pressure**Psi(bar)	Maximum ReleaseSettinglb (kg)
3 7/8	3.90 (99.06)	1.80 (45.72)	2 7/8CAS	400 (204)	122.65 (311.531)	131000 (59422)	15000 (1034.21)	65000 29484) Mechanical
								100000 （45360） Hydraulic
								55000 （24948） Hydraulic
5.00	5.03 （127.76）	2.25 （57.15）	3 7/8CAS	400 (204)	112.40 (285.496)	250000 (113400)	15000 (1034.21)	125000 (56700) Mechanical

Express™ Circulating Valve

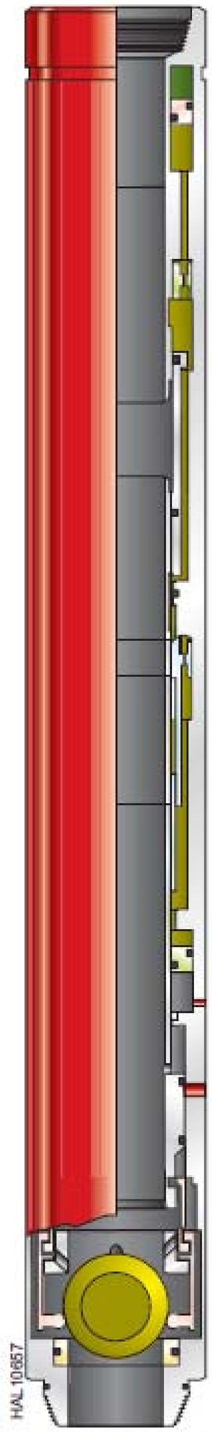
The Express™ circulating valve is a full-opening, annulus pressure-operated, recloseable circulating valve for use incased holes. This tool is operated by repeatedly cycling annulus pressure up to a predetermined value and then releasing this pressure. A specific annulus pressure sequence moves the tool from the well testing position to the circulating position when necessary. The Express circulating valve consists of several major systems. The nitrogen section includes a gas-charged accumulator that stores the operating pressure used to shift the tool. The amount of nitrogen in the tool depends on well hydrostatic pressure (fluid weight and depth) and downhole temperature. This information is necessary to properly prepare the tool for operation.

The upper hydraulic section controls the transition of the tool from the welltesting position to the circulating position. The operating and control mechanisms are contained in a closed oil system that is used to isolate these mechanisms from well fluids and to transmit applied annulus pressure to the nitrogen section.

The circulating ports and ball valve work together to isolate the formation while spotting or reversing out fluid through the circulating valve . The circulating ports cannot open until the ball valve closes. A blank position is interposed between the well testing and circulating positions.

Features and Benefits

- Permits fluid circulation and pressure testing of the string in conjunction with testing tools
- Allows an unlimited number of pressure cycles on the annulus without shifting out of the well test position (unless a specific annulus pressure sequence is applied)
- Allows additional annulus pressure operated tools to be operated without interfering with the position of the Express circulating valve
- Imposes no cycle limitation on the well test program
- Decreases the time required to move from the well testing position to the circulating position and return to the test position
- Allows an unlimited number of pressure cycles



Express™ Circulating Valve

Operation

The Express™ circulating valve is operated by cycling the annulus pressure whereby a pressure increase to a specified value is followed by a pressure decrease of that same value. While the Express circulating valve is in the well test position, application of annulus pressure at intervals of time greater than a specified period will not move the tool out of the well test position. Moving out of the well test position is accomplished by applying annulus pressure twice within a specified period. Once the tool has shifted out of the well test position, it requires only a minimum waiting period between annulus pressure cycles until it returns to the test position. The sequence can be repeated as often as desired.

Express™ Circulating Valve

Nominal Tool Size in.	OD in.(cm)	ID in.(cm)	Thread connections	Service Temperature * °F(℃)	Length in.(cm)	Tensile Rating** lb.(kg)	Working Pressure*** psi(bar)	Circulating Flow Area in.^{2} (cm^2)	Number of Ports
3 7/8	3.90 (9.91)	1.80 (4.57)	27/8 CAS	450 (204)	438.66 (114.20)	175,000 (79380)	15,000 (1034)	3.61 (23.29)	4
5.00	5.00 (12.7)	2.28 (5.79)	37/8 CAS	450 (204)	371.65 (944.00)	371.458 (168 493)	15,000 (1034)	3.61 (23.29)	6

FUL-FLO® Hydraulic Circulating Valve

The FUL-FLO® hydraulic circulating valve serves as a bypass around the packer or as a circulating valve to circulate a well after testing.

When run below a closed valve, the tool serves as a bypass around the packer and helps relieve pressure buildup below the closed valve when it is stung into a production packer.

When run above a closed valve, the tool can be used as a circulating valve when the workstring is picked up.

Features and Benefits

- Permits passage of wireline tools through its full-opening bore
- Requires no pipe rotation to operate

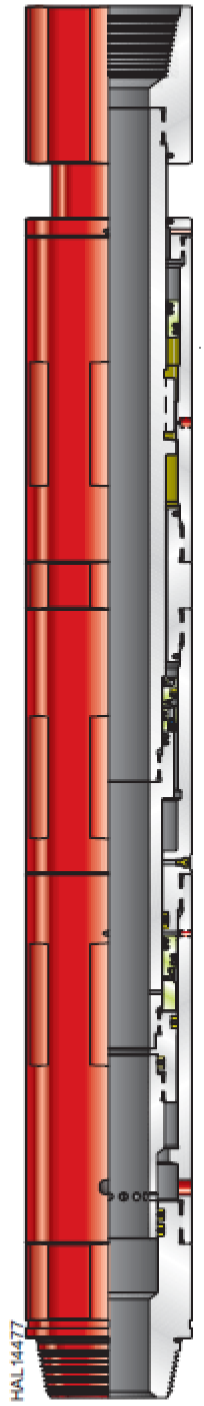
Operation

Bypass ports close when weight is set down and reopen when weight is lifted.

A hydraulic metering system provides a 2 to 3-minute delay in closing after weight is applied. This delay allows either the RTTS packer to be set or the test string to be stung into a permanent packer before the bypass ports close. The ports reopen without a time delay.

During stimulation work, the latching piston adds a downward force on the circulating sleeve to help keep the valve closed.

Operation of the valve is the same whether it is used as a circulating valve or as a bypass. No torque is required. Weight is applied to close the tool, and the workstring is picked up to reopen it.



FUL-FLO® Hydraulic Circulating Valve

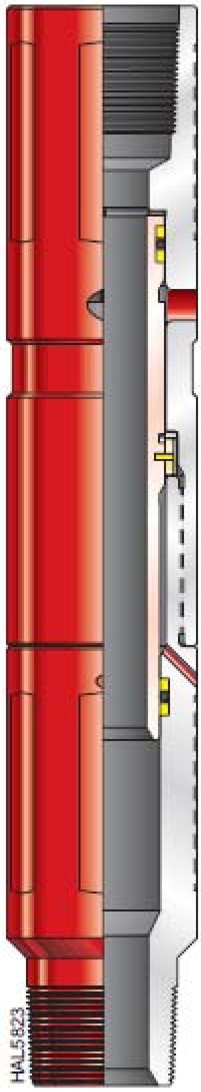
FUL-FLO® Hydraulic Circulating Valve

Nominal Tool Size in.	OD in.(cm)	ID in.(cm)	Thread connections	Service Temperature * °F(℃)	Length* in.(cm)	Stroke Length in.(cm)	Tensile Rating** lb.(kg)	Working Pressure*** psi(bar)	FlowArea in.^{2}(cm^2)	Number of Ports
3.00	3.06 (77.72)	1.25 (31.75)	21/4 CAS	450 (204)	79.80 (202.69)	3.00 (7.62)	134,000 (60 782)	15,000 (1034)	1.27 (8.19)	4
3 7/8	3.90 (99.06)	1.80 (45.72)	27/8 CAS	450 (204)	82.69 (210.03)	3.00 (7.62)	164,000 (74 390)	10,000 (689)	1.17 (7.55)	6
4 5/8	4.68 (118.87)	2.25 (57.15)	31/2 IF 37/8 CAS	450 (204)	83.76 (212.75)	3.00 (7.62)	261,000 (118.389)	Burst 15,000 (1034)	1.28 (8.26)	4
5.00	5.03 (127.76)	2.03 (51.56)	37/8 CAS	450 (204)	83.76 (212.75)	3.00 (7.62)	261,000 (118.389)	15,000 (1034)	1.28 (8.26)	4

Internal Pressure-Operated (IPO) Circulating Valve

The internal pressure-operated (IPO) circulating valve is a single-shot circulating valve which allows circulation through the workstring before trip-out and serves as a drain valve during trip-out. It can be run in cased holes or openholes and maintains a full bore through the tool. The IPO circulating valve is used in the following situations:

- When a full-opening string is needed
- When redundant backup to annulus pressure-operated circulating valves is needed
- When a limited amount of annulus pump pressure is available to operate annulus pressure tools



Internal Pressure-Operated (IPO) Circulating Valve

Features and Benefits

- Requires no string manipulation to operate tool
- Permits passage of wireline tools through full-opening bore

Operation

The IPO circulating valve is operated by internal pressure (500 to 10,000 psi above hydrostatic). Pressure required to operate the tool is determined by shear pins, which hold the sliding valve in the closed position. To open the valve, tubing pressure is increased to a pressure above annulus hydrostatic equal to the shear value of the shear pins. Once operated, the IPO circulating valve is locked open.

Internal Pressure Operated (IPO) Circulating Valve

Nominal Tool Size in.	OD in.(cm)	ID in.(cm)	Thread connections	Service Temperature* °F(℃)	Length in.(cm)	Tensile Rating** lb.(kg)	Working Pressure*** psi(bar)	Flow Area in.^{2} (cm^2)	Number of Ports
3	3.06 (7.77)	1.00 (2.54)	23/8 EUE	450 (204)	19.74 (50.14)	165,000 (74 844)	15,000 (1034)	0.75 (4.84)	4
3 7/8	3.90 (9.91)	1.80 (4.57)	27/8 EUE	450 (204)	23.52 (59.74)	220,000 (99 792)	15,000 (1034)	1.23 (7.94)	4
5.00	5.03 (12.78)	2.25 (5.72)	37/8 CAS 31/2 IF	450 (204)	22.18 (56.34)	391,000 (177 358)	15,000 (1034)	1.55 (10.00)	4

OMNI™ Circulating Valve

The OMNI™ circulating valve is an annulus pressure operated, recloseable circulating valve. Throughout the operation, the tool is repeatedly cycled up to a predetermined annulus pressure and then released.

The OMNI valve consists of a nitrogen section, an oil system, a circulating valve, and a ball valve. The nitrogen section contains the nitrogen gas that counterbalances the hydrostatic and annulus pressures. The amount of nitrogen in the tool depends on well hydrostatic (mud weight and depth) and downhole temperature. This information must be known to properly prepare the tool for running in.

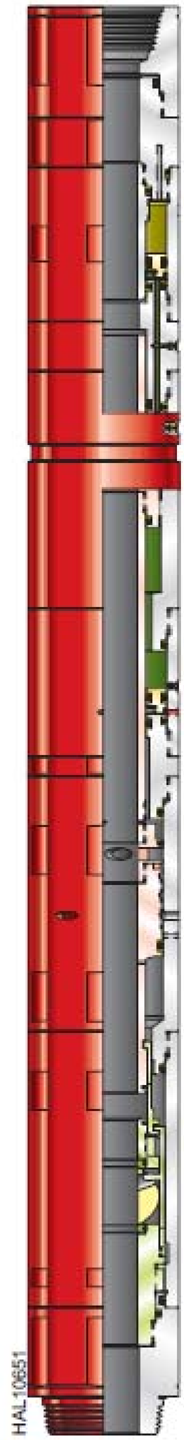
Note: With certain completion fluids, the mud weight at the surface can be significantly different from the actual mud weight downhole.

The operating and control mechanisms are contained in a closed oil system activated by annulus pressure acting on the nitrogen chamber, allowing an unlimited number of pressure cycles.

The circulating valve and the ball valve work together to keep circulating pressure off the formation. The ball valve will close before the circulating valve opens. The ball valve closes off the workstring.

Features and Benefits

- Permits well testing, pressure testing, and fluid circulation
- Allows unlimited number of pressure cycles



OMNI™ Circulating Valve

Operation

The well can be flow tested when the valve is in the well test position. When in this position, the circulating ports are closed and the ball valve is opened. During a downhole closure drillstem test, the OMNI valve is in the well test position during flow and shut-in periods. The workstring can be pressure-tested in the blank position because the ball valve closes before the circulating valve opens. Fluid can be pumped in either direction through the tool in the circulating position. In this position, the circulating ports are open and the ball valve is closed.

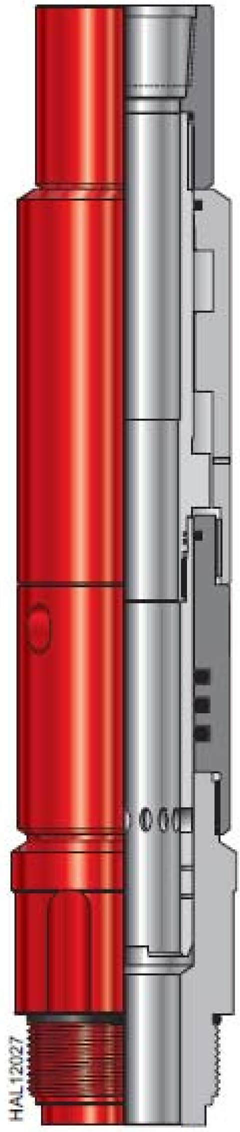
Note: Before the tool is run, the hydrostatic pressure at the specified tool depth must be known. This information is required to obtain the proper nitrogen charging pressure.

OMNI™ Circulating Valve

Nominal Tool Size in.	OD in.(cm)	ID in.(cm)	Thread connections	Service Temperature* °F(℃)	Length in.(cm)	Tensile Rating** lb.(kg)	Working Pressure*** psi(bar)	Flow Area in.^{2} (cm^2)	Number of Ports
3 7/8	3.90 (9.91)	1.80 (4.57)	2 7/8 CAS	450 (204)	278.79 (708.13)	175,000 (79 380)	15,000 (1034)	3.61 (23.29)	6
5	5.03 (12.78)	2.28 (5.79)	3 7/8 CAS	450 (204)	253.78 (644.60)	371,458 (168 493)	15,000 (1034)	3.61 (23.29)	6
7	7.00 (17.78)	3.50 (8.89)	5 1/4 CAS	450 (204)	333.21 (846.35)	470,191 (213 279)	15,000 (1034)	8.91 (57.48)	6

RTTS Circulating Valve

The RTTS circulating valve is a locked-open/locked-closed valve that serves as both a circulating valve and bypass. The clearance between the RTTS packer (or any hook wall packer) and the casing ID is relatively small. To reduce the effect of fluid-swabbing action when the tool is run in or pulled out of the hole, a packer bypass is generally used.



RTTS Circulating Valve

Features and Benefits

- The valve can be locked closed when the packer is unset to reverse fluid around the bottom of the packer.
- The tool's full opening allows tubing-type guns and other wireline equipment to pass.

Operation

The RTTS circulating valve is automatically locked in the closed position when the packer is set. During testing and squeezing operations, the lock helps prevent the valve from being pumped open. A straight J-slot in the locked-open position can be used with the straight J-slot (optional) in the packer body. This combination eliminates the need to turn the tubing to close the circulating valve or reset the packer after the tubing has been displaced with cement.

The RTTS circulating valve can be run directly above the packer body or further up the workstring.

When placed in the hole, the valve must be in the locked-open position. The J-slot in the packer-body drag block (or drag sleeve) must also be placed in the unset position.

When the circulating valve is opened to come out of the hole, the tubing is lowered, turned to the right, and picked up.

RTTS Circulating Valve

Size in.	OD in.(cm)	ID in.(cm)	End connections	Length in.(cm)	Tensile Rating** lb.(kg)	Burst Rating** psi (kPa)	CollapseRating** psi (kPa)
23/8	1.68 (4.271)	0.68 (1.73)	1.05 10 RD	18.42 (46.79)	31,900 (14 470)	11,600 (79 979)	9,900 (68 259)
41/2 to 5	3.60 (9.14)	1.80 (4.57)	23/8 EUE	32.2 (81.8)	85,000 (38 556)	10,100 (69 637)	10,700 (73 774)
5.1/2 to 65/8	4.18 (10.62)	1.99 (5.05)	23/8 EUE 27/8 EUE	31.9 (81.03)	150,700 (68 358)	10,000 (68 900)	14,200 (97 906)
7 to 75/8	4.87 (12.37)	2.44 (6.19)	27/8 EUE 31/2 IF 37/8 CAS	32.9 (83.57)	148,800 (67 496)	10,000 (68 900)	10,100 (69 637)
85/8 to 133/8	6.12 (15.54)	3.00 (7.62)	41/2 IF T.J.	38.4 (97.54)	311,400 (141 251)	10,500 (72 395)	10,100 (69 637)

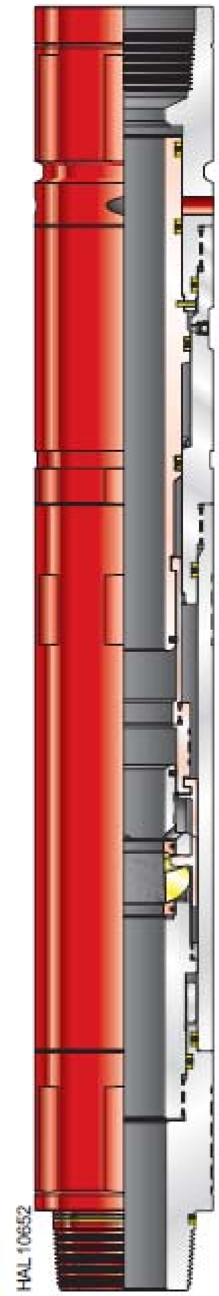
Rupture Disk (RD) Safety Circulating Valve

The rupture disk (RD) safety circulating valve functions as both a safety valve and circulating valve. The tool functions as a safety valve when the annulus pressure reaches a predetermined value. At that pressure, the valve isolates the workstring below the tool and establishes communication between the annulus and the workstring above the tool. This tool converts into a circulating valve when the ball valve section is removed.

Features and Benefits

The tool is composed of three major sections:

- The power section consists of a power mandrel case and rupture disk that is available for a wide range of pressure applications. The rupture disk bursts at a predetermined pressure, allowing annulus pressure to be applied to a differential area on the power mandrel. The power mandrel moves down, first pushing the ball valve closed, and then opening a set of circulating ports.
- The circulating section consists of a set of ports that are initially sealed by the power mandrel. When the rupture disk bursts, the power mandrel moves down, exposing the ports that allow communication between the annulus and workstring.
- The safety valve consists of a ball valve, operating pins, and collet fingers. As the power mandrel moves down, the operating arms close the ball valve. The collet fingers expand, allowing the power mandrel to continue traveling down to open the circulating ports.



Rupture Disk (RD) Safety Circulating Valve

Operation

Before the RD safety circulating valve is used, the operating pressure is calculated for selecting the proper rupture disk pressure rating. Required information includes mud weight, testing depth, bottomhole temperature, and maximum annulus pressure. When the rupture disk safety circulating valve is run with an annulus pressure-operated valve, the safety valve operating pressure should be kept1,000 psi above the operating pressure of the tester valve.

Rupture Disk (RD) Safety Circulating Valve

Nominal Tool Size in.	OD in.(cm)	ID in.(cm)	Thread connections	Service Temperature* °F(℃)	Length in.(cm)	Tensile Rating** lb.(kg)	Working Pressure*** psi(bar)	Flow Area in.^{2} (cm^2)	Number of Ports
3.00	3.06 (7.77)	1.00 (2.54)	21/4 CAS	450 (204)	60.00 (152.4)	114,000 (51 710)	15,000 (1034)	1.23 (7.94)	4
3 7/8	3.90 (9.91)	1.80 (4.57)	27/8 CAS	450 (204)	70.90 (180.09)	187.366 (84 989)	15,000 (1034)	3.14 (20.26)	4
5.00	5.03 (12.78)	2.28 (5.79)	37/8 CAS	450 (204)	68.02 (172.77)	328,000 (148 781)	15,000 (1034)	3.14 (20.26)	4
5.00 SG[1]	5.03 (12.78)	2.28 (5.79)	37/8 CAS	450 (204)	68.02 (172.77)	405,000 (183 708)	15,000 (1034)	3.14 (20.26)	4

VIPR Circulating Valve

The VIPR circulating valve is a full-opening, recloseable circulating valve operated by applying internal pressure to create a differential between the tubing and annulus. It can be run in either cased or openhole.

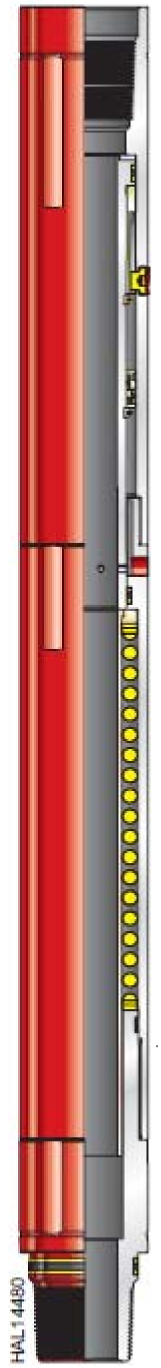
Features and Benefits

This tool can be used to perform the following functions:

- Fill the workstring while running in
- Spot a fluid cushion
- Reverse the workstring

Operation

When the tool is open, ports in the OD allow fluid communication between the tubing and annulus. When fluid flows from the tubing to the annulus, a pressure drop is generated due to the relatively small circulating ports in the mandrel. When the circulating rate from the tubing to annulus reaches a value sufficient to create approximately200 psi higher pressure in the tubing than in the annulus at the tool, the circulating ports will close. To open the VIPR circulating valve, tubing pressure must be cycled three times to return to the circulating position. This is accomplished by increasing the tubing pressure to 500 psi above the annulus pressure, then releasing the tubing pressure. When pressure is released on the third cycle, the circulating ports open.



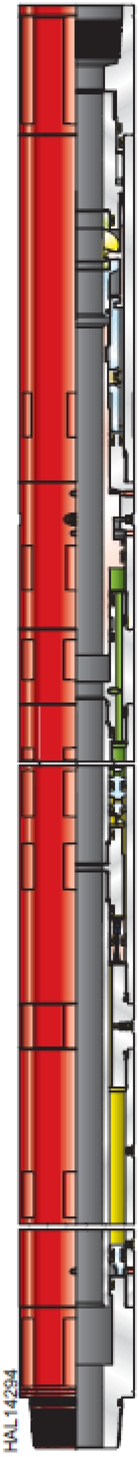
VIPR Circulating Valve

VIPR Circulating Valve

Nominal Tool Size in.	OD in.(cm)	ID in.(cm)	Thread connections	Service Temperature* °F(℃)	Length in.(cm)	Tensile Rating** lb.(kg)	Working Pressure *psi(bar)	Opening pressure	Closing ressure	Flow Area in.^{2} **(cm^2)**
3	3.06 (7.77)	1.03 (2.62)	21/4 CAS	450 (232)	66.76 (169.57)	130,000 (58 968)	15,000 (1034)	500 psi (35 bar) tubing pressure above annulus	Sufficient flow rate to create 200 psi (13.78 bar) tubing pressure above	0.2209 (1.4252)
63/4	6.75 (17.15)	3.50 (8.89)	51/4CAS	450 (232)	66.04 (167.74)	590,389 (267 800)	10,000 (689)	500 psi (35 bar) tubing pressure above annulus	Sufficient flow rate to create 200 psi (13.78 bar) tubing pressure above	0.6627 (4.275)

LPR-N Tester Valve

The LPR-N™ tester valve is a full-opening, annulus pressure-operated valve. It measures multiple closed-in pressures in cased holes where pipe manipulation is restricted and a full-opening string is required. The nitrogen chamber is charged at the surface to a selected pressure determined by surface temperature, bottomhole temperature, and bottomhole pressure. If the intended test requires a permanent packer that uses a stinger mandrel or seal nipple, a variety of bypass tools are available, depending on field application, to help ensure that the formations and downhole equipment are protected from excessive pressure buildup.



LPR-N™ Tester Valve

Features and Benefits

- The ball valve operates independently of internal pressure changes, such as with acidizing or fracturing operations.
- Advanced materials and processes provide a unique metal-to-metal seat for exceptional gas-holding capabilities.
- The LPR-N tester valve has been through an extensive five-day qualification testing at 400°F and15,000 psi burst and collapse pressures.
- An open-in feature allows the operator to run the LPR-N tester in the hole with the ball valve opened or closed.
- Fluids can be spotted or circulated through the LPR-N tester with the packer unseated.

A double nitrogen chamber can be added to the LPR-N tester for use in deep, hot, high-pressure wells to reduce the operating pressure.

Operation

The LPR-N tester valve is composed of a ball valve section, a power section, and a metering section.

The ball valve section provides multiple downhole closures. It is turned by operating arms. The power section has a floating piston that is exposed to the hydrostatic pressure on one side and pressurized nitrogen on the other side. With the packer set, pump pressure applied to the annulus moves the piston downward, activates the operating arms, and opens the ball valve. When the annulus pressure is released, pressurized nitrogen returns the piston upward, closing the ball.

After the surface equipment is properly installed, the packer is set, and the rams are closed, pressure is applied to the annulus, using rig pumps to operate the LPR-N tester.

To begin testing, quickly apply pump pressure to the annulus to a predetermined pressure, and hold for 10 minutes to pressurize the nitrogen chamber. After pressure has been metered through the metering cartridge, pressure in the nitrogen chamber will be slightly less than combined hydrostatic and pump pressure in the annulus. This helps ensure that the ball valve stays open during testing or treating operations.

The closing force may be increased on wells with an extremely high flow rate and wells producing a large amount of sand. Before the tool is closed, the annulus pressure is increased to a predetermined safe pressure below the operating pressure of the circulating valve and held for 10minutes. This procedure creates additional closing force when the annulus pressure is released.

Releasing the annulus pressure as quickly as possible closes the ball valve. A minimum of 10 minutes is needed to allow excess closing pressure in the nitrogen chamber to equalize before annulus pressure is reapplied. It is best to use the highest safe operating pressure to obtain maximum closing force.

LPR-N Tester Valve

Nominal Tool Size in.	OD in. (mm)	ID in. (cm)	Thread Connections	Service Temperature* °F (°C)	Length in. (cm)	Tensile Rating** lb (kg)	Working Pressure*** Psi(bar)
3.00	3.06 （7.77）	1.12 (2.84)	2 1/4 CAS	450 (232)	167.76 (426.11)	160000 (72576)	10000 (689)
3 7/8	3.90 (9.91)	1.80 (4.57)	2 7/8CAS	450 (232)	199.88 (507.7)	219000 (99338)	10000 (689)
5.00	5.03 (12.78)	2.25 (5.72)	3 7/8CAS	450 (232)	191.30 （485.90）	367,448 (166 674)	15000 (1034)
5.00 （SG）	5.03 (12.78)	2.28 (5.79)	3 7/8CAS	450 (232)	208.46 （529.49）	405581 (183971)	15000 (1034)
7.00	7.00 (17.78)	3.50 (8.89)	5 1/4 CAS	450 (232)	194.16 （493.17）	417709 （189473）	10000 (689)

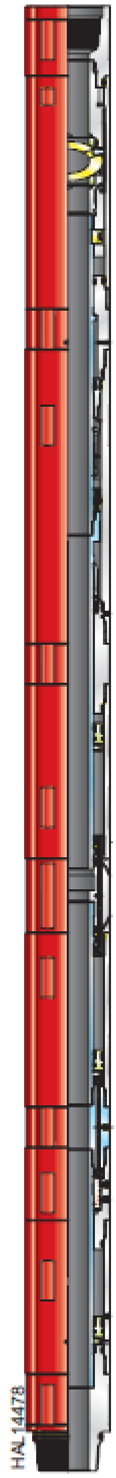
Select Tester® Valve

The Select Tester® valve is a full-opening, annulus pressure Operated tool. With applied pressure, the tool can be locked open and then returned to the normal operating sequence at any time. The ball valve operates independently of pressure changes from operations such as acidizing and fracturing. This gives the Select Tester valve greater compatibility and flexibility with other tools in the string.

Features and Benefits

- Incorporates advanced materials and processes providing a unique metal-to-metal seal for exceptional gas-holding capabilities
- Has undergone extensive five-day qualification testing at400°F and 15,000 psi including a 16,500 psi burst and collapse test
- Allows operator to reverse out/circulate to the lowest point of circulation below the Select Tester valve. This facilitates well kill operations, saving both time and money.
- Allows operator to run in or come out of a hole in the open position, enhancing safety and maximizing well control options.
- Allows operator to spot cushion to the lowest point of circulation below the Select Tester valve. This improves control of drawdown pressure and reduces recovery of mud and other rathole fluids.
- Simplifies string design by eliminating the need for a bypass when stinging into or out of a production packer.
- Maximizes flexibility during well kill operations since the Select Tester valve can be operated with the packer unset.

Note: When annulus pressure is applied or bled off to zero, it is recommended operating procedure to wait 10 minutes before operating the Select Tester valve again.



Select Tester® Valve

Operation

Once the packer is set, pressure is quickly applied to the annulus to operate the Select Tester® valve. This creates the differential pressure that acts across the operating section to move the mandrel down, causing the ball to rotate to the open position. To close the ball, annulus pressure is released to zero. The nitrogen section acts to move the operating mandrel up. This upward travel of the mandrel rotates the ball valve back to the closed position. To activate the lockout feature, the normal operating pressure is increased by 1,300 psi.

This higher level of pressure prevents the operating mandrel from moving up. In this position, the ball valve will remain open when the annulus pressure is released. To reactivate the tool, annulus pressure is once again increased to 1,300 psi above normal operating pressure. This will reactivate the operating section and return the tool to normal operating mode. The lockout feature can be reactivated as many times as desired without having to remove the tool from the well.

Select Tester® Valve

Nominal Tool Size in.	OD in. (mm)	ID in. (cm)	Thread Connections	Length in. (cm)	Tensile Rating** lb (kg)	Working Pressure*** Psi(bar)
5.00	5.03 (12.78)	2.25 (5.72)	3 7/8CAS	286.10 （726.69）	357000 (161935)	15000 (1034)
7.00	7.00 (17.78)	3.50 (8.89)	5 1/4 CAS	282.00 （716.28）	501538 （227498）	10000 (689)

Tubing String Testing (TST) Valve

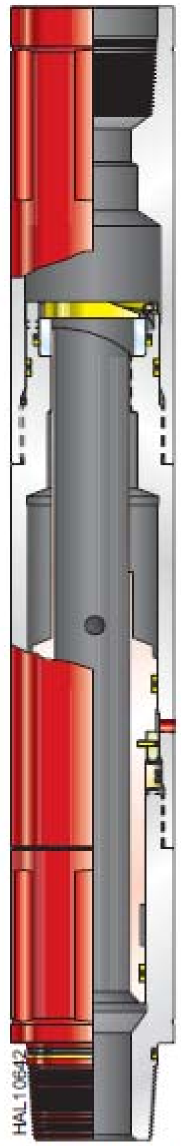
The tubing string testing (TST) valve is a full-opening valve used to pressure-test the workstring while running in the hole. The valve is operated after it is stung into a permanent packer or after a retrievable packer is set. The TST valve requires a differential pressure between the annulus and the tubing to shear. The TST valve can also be used for pipe flexing if it is run below an annulus pressure-responsive circulating valve.

The TST valve consists of:

- flapper valve and spring
- shear pin section
- locking dogs

Features and Benefits

- Flapper valve requires only 4 psi to open.
- Testing string can be pressure-tested as many times as required as it is run in the hole.
- Valve shear rating can be pre-determined at 500 psi increments.
- Valve can also be used for pipe flexing.



Tubing String Testing (TST) Valve

Operation

When the TST flapper valve opens, it allows the workstring to fill up. The shear pins hold the mandrel in place. The workstring can be pressure-tested as many times as required as it is run in the hole. While the workstring is stationary, a spring keeps the flapper valve closed. After the workstring pressure test is complete, the tool is sheared when annulus pressure is applied to the predetermined shear pin rating.(The shear rating can be adjusted in 500 psi increments to shear from 500 to 6,000 psi differential.) When the pins shear, the mandrel moves up and pushes the flapper open, allowing the locking dogs to engage. The tool is then fully open. The tool works on differential pressure between annulus and tubing. Failure to shear initially on application of annulus pressure is not critical. The process of drawing the well down also creates a pressure differential that helps the tool shear. When used for pipe flexing, the TST valve is run below an annulus pressure-responsive circulating valve, such as the RD circulating valve. The string is pressured up against the flapper valve as many times as required. The circulating valve is sheared after flexing operations are complete, and the workstring is pulled out dry.

Tubing String Testing (TST) Valve

Nominal Tool Size in.	OD in. (mm)	ID in. (cm)	Thread Connections	Length in. (cm)	Tensile Rating** lb (kg)	Working Pressure*** Psi(bar)
3.00	3.06 (7.77)	1.00 (2.54)	2 1/4 CAS	54.00 (137.16)	153000 (69400)	15000 (1034)
3 7/8	3.90 (9.91)	1.80 (4.57)	2 7/8CAS	44.67 (113.46)	249000 (112946)	15000 (1034)
5.00	5.03 (12.78)	2.28 (5.79)	3 7/8CAS	48.00 (121.92)	415957 (188678)	15000 (1034)
5.00 (SG)	5.03 (12.78)	2.28 (5.79)	3 7/8 CAS	51.20 (130.05)	369100 (167424)	15000 (1034)

Rupture Disk (RD) Tubing String Testing (TST) Valve

The rupture disk (RD) tubing string testing (TST) valve is a full-opening valve used to pressure test the workstring while running in the hole. The valve is operated after it is stung into a permanent packer or after a retrievable packer is set. To operate the tool, annulus pressure is applied, rupturing the disk moving the mandrel up and pushing the flapper open.

The TST valve consists of:

- flapper valve and spring
- shear pin section
- locking dogs

Features and Benefits

- Flapper valve requires only 4 psi to open.
- Workstring can be pressure tested as many times as required as it is run in the hole.
- Valve shear rating can be predetermined by the rupture disk.
- Valve can also be used for pipe flexing.

Operation

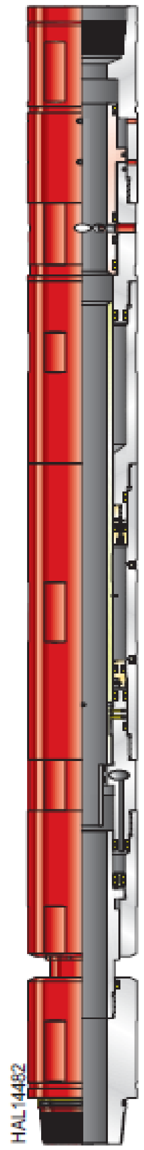
The RD TST valve is normally set to operate at a pressure around1000 psi (69 bar) above well hydrostatic at the tool. This allows the tool to be run in and operated when pressuring up on the first annulus cycle. When the TST flapper valve opens, it allows the workstring to fill up. The shear pins hold the mandrel in place. The workstring can be pressure tested as many times as required as it is run in the hole. While the workstring is stationary, a spring keeps the flapper valve closed. After the workstring pressure test is complete, the tool is sheared open when annulus pressure is applied to rupture the disk moving the mandrel up and pushing the flapper open, allowing the locking dogs to engage. The tool is then fully open.

Rupture Disk (RD) Tubing String Testing (TST) Valve

Rupture Disk (RD) Tubing String Testing (TST) Valve

Nominal Tool Size in.	OD in. (mm)	ID in. (cm)	Thread Connections	Service Temperature* °F (°C)	Length in. (cm)	Tensile Rating** lb (kg)	Working Pressure*** Psi(bar)
5.00	5.03 (12.78)	2.28 (5.79)	3 7/8CAS	450 （232）	76.25 （193.68）	416000 (188698)	15000 (1034)

Rupture Disk (RD) Tubing String Testing (TST) Bypass Valve



The rupture disk (RD) tubing string testing (TST) bypass valve is a weight activated, normally open valve. It is run in the workstring to prevent pressure buildup below the tester valve while stinging into a production type packer or while setting a retrievable packer during a well test. It is a “one shot” type tool that must be removed from the well to re-open it.

Features and Benefits

The tool is composed of three major sections:

- The bypass port section consists of an upper adapter, ported mandrel, and ported nipple. The upper adapter contains two 1/4 NPT ports. Pressure applied to the lower port shifts the ported mandrel up. Pressure applied to the upper port shifts the ported mandrel down. This allows the tool to be pressure tested at the surface prior to going in the well.
- The metering section contains an air chamber and an oil chamber separated by a metering cartridge. Once the tool has been triggered, the operating mandrel in the section moves up, closing the bypass ports. This section provides a 10 to20-minute delay, depending upon the hydrostatic pressure, in the closure of the ports.
- The trigger section is composed of a rupture disk nipple, splined housing, floating piston, splined mandrel, and lower adapter. The splined mandrel, floating piston, and splined housing form a hydraulic ram whenever weight is applied. The resultant pressure is transmitted to a rupture disk in the rupture disk nipple. This prevents any upward movement of the splined mandrel until the correct weight is applied to shear the rupture disk.

Operation

While running in the well, the metering section is isolated from annulus and tubing hydrostatic pressure. Please note that this section is at atmospheric pressure, and the maximum pressure ratings of the outer cases and the operating mandrel should be considered during the pre-job planning. With the tool in the open position, the bypass ports provide a pressure equalization path while stinging into a production packer or setting a retrievable packer.

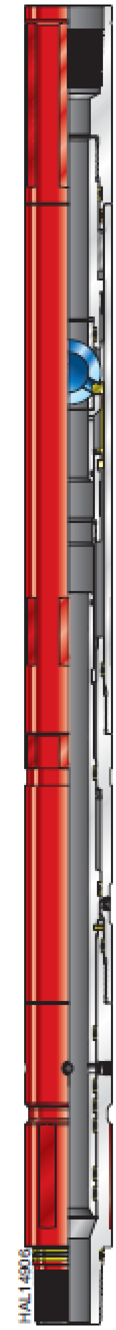
To operate this tool, weight must be applied to shear the rupture disk. Depending on customer requirements, the amount of weight to trigger the tool can be varied by changing the rupture disk.

Rupture Disk (RD) Tubing String Testing (TST) Bypass Valve

Nominal Tool Size in.	OD in. (mm)	ID in. (cm)	Thread Connections	Service Temperature *°F (°C)	Length in. (cm)	Collapsed Length in. (cm)	Tensile Rating** lb (kg)	Working Pressure*** Psi(bar)	Flow area in.2 (cm2)	Number ofPorts
5.00	5.03 (12.78)	2.28 (5.79)	3 7/8CAS	450 （232）	108.22 (274.88)	106.17 (269.67)	195000 (88452)	15000 (1034)	2.14 （13.806）	4

Rupture Disk (RD) Bypass Pressure Test Valve

The rupture disk (RD) bypass pressure test valve is a full-opening, single-shot annulus operated valve. The tool functions as a pressure testing and a bypass valve. The tool is commonly used at the start of a drillstem test to allow the tool string to be pressure tested against the closed ball valve. This tool also has a bypass below the ball that allows the tool string to be "stung in" to a production packer. To operate the tool, annulus pressure is applied, rupturing the disk, closing the bypass ports, and opening the ball valve.



Rupture Disk (RD) Bypass Pressure Test Valve

Features and Benefits

The tool is composed of three sections:

- The ball valve section is at the top of the tool and consists of a ball valve, operating pins, and collet fingers. The collet fingers expand, allowing the power mandrel to continue traveling up to open the ball valve and close the circulating ports.
- The power section consists of a power mandrel case and rupture disk available for a wide range of pressure applications. The rupture disk bursts at a predetermined pressure, allowing annulus pressure to be applied to a differential area on the power mandrel. The power mandrel moves up, first pushing the ball valve open, and then closing a set of circulating ports.
- The bypass section is at the bottom of the tool and consists of a set of ports and a power mandrel. When the rupture disk bursts, the power mandrel moves up, closing off the ports and communication between the annulus and the tool string.

Operation

The rupture disk bypass pressure test valve is normally set to operate at a pressure around 1000 psi (69 bar) above well hydrostatic at the tool. This allows the tool to be run in and then operated when pressuring up on the first annulus pressure cycle.

Another method of running the tool is to use it for pressure testing the tool string and then use well hydrostatic while running in to operate the tool automatically. When running the tool in this mode, it is acceptable to use shear pins to determine the operating pressure. If an accurate operating pressure is required, the rupture disk must be used.

Note: This tool should have the only closed ball valve while running in. If any other closed ball tools are run in the string, a bypass must be run to avoid an air chamber between the closed balls. The air chamber trapped between the balls could cause the tool to not operate, operate a very high pressure, or cause damage to the tool

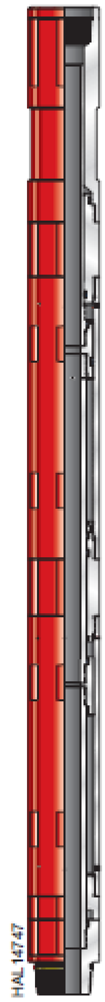
Rupture Disk (RD) Bypass Pressure Test Valve

Nominal Tool Size in.	OD in. (mm)	ID in. (cm)	Thread Connections	Service Temperature*° F (°C)	Length in. (cm)	Tensile Rating** lb (kg)	Working Pressure*** Psi(bar)	Flow area in.2 (cm2)	Number of Ports
5.00	5.03 (12.78)	2.28 (5.79)	3 7/8CAS	450 (232)	72.44 (184.00)	313813 (142352)	15000 (1034)	3.14 （(20.26)）	4

AccessoryTools

Slip Joints

A slip joint compensates for the movement associated with ocean heave or temperature change without allowing the movement to disturb the placement of downhole tools. A slip joint operates by balancing its volume. As the slip joint stretches and increases its internal volume, a differential piston within the slip joint allows the same volume of fluid into the pipe. The net result is no change in internal volume. Each slip joint has 5 ft of travel but can be combined with other slip joints to provide additional travel. Slip joints are designed to transmit the torque or rotation required to operate tools such as packers or safety joints. When multiple slip joints are run, they are normally connected together rather than located throughout the pipe string. The number of slip joints required depends on ocean heave and the amount of expected contraction and expansion.



Slip Joint (Retrofit)

Features and Benefits

- Provides a variable-length joint to allow expansion and contraction of pipe during testing or stimulation
- Helps space out the workstring when the subsea tree is landed
- Keeps vertical movement of drilling vessel from disturbing tool placement
- Provides free travel in workstring to reciprocate tools

Operation

The weight of the workstring(excluding tools, anchor, and traveling blocks) is used to determine the location of the slip joint. The slip joint(s) are placed above the necessary packer setting weight.

When multiple slip joints are used, the top joint makes its complete travel, then the next joint down makes its travel, and so on. The weight indicator may show a slight bump as each slip joint reaches the end of its travel.

Slip Joint

Nominal Tool Size in.	OD in. (mm)	ID in. (cm)	Thread Connections	Length in. (cm)	Stroke Length in. (cm)	Tensile Rating** lb (kg)	Working Pressure*** Psi(bar)
3 Hex	3.06 (7.77)	1.00 (2.54)	2 3/8 EUE	117.59 ((298.68))	42.00 (106.68)	146308 (66365)	10000 (689)
5 Retrofit (SG)	5.03 （12.78）	2.31 (5.87)	3 7/8CAS	244.30 (620.52)	60.00 (152.4)	184122 (83517)	15000 (1034)

Round Mandrel Slip Joint

The round mandrel slip joint, like other slip joints, accepts the movement associated with ocean heave or temperature change without allowing the movement to disturb the placement of downhole tools.

The round mandrel slip joint has the following characteristics:

- Top of the mandrel slip joint has4 3/4-in. (120.65-mm) drill collar profile for easy handling with the rig elevators and slips
- Maintains its full tensile rating when collapsed and locked
- Can be locked in the closed position for handling, reducing the risk of damage to the lifting/sealing mandrel
- Internally pressure and volume balanced
- String can be picked up with the slip joint locked; the slip joint can then be unlocked before it is run into the hole
- Provides free travel in the string to reciprocate tools without unseating the packer

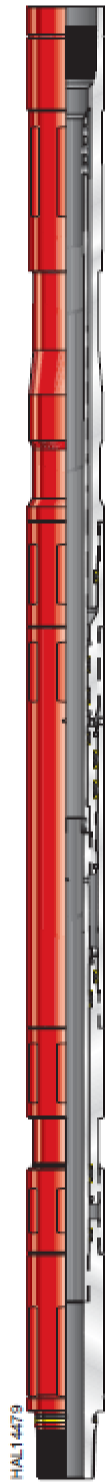
A slip joint operates by balancing its volume. As the slip joint stretches and increases its internal volume, a differential piston within the slip joint allows the same volume of fluid into the pipe. The net result is no change in internal volume.

Each slip joint has 5 ft (1.52 m) of travel but can be combined with other slip joints to provide additional travel.

When multiple slip joints are run, they are normally connected to one another rather than located throughout the pipe string. The number of slip joints required depends on ocean heave and the amount of expected contraction and expansion.

Features and Benefits

- Provides a variable-length joint to allow the pipe to expand and contract during testing or stimulation
- Keeps vertical movement of the drilling vessel from disturbing tool placement
- Helps space out the testing string when the subsea tree is landed
- Provides a constant weight on the packer during testing or stimulation



Round Mandrel Slip Joint

Operation

The weight of the tool string (excluding tools, anchor, and traveling blocks) is used to determine the location of the slip joint. Once the necessary packer-setting weight is shown on the weight indicator, the slip joint is placed into the string.

When multiple slip joints are used, the top joint makes its complete travel, then the next joint down makes its travel, and so on. The weight indicator may show a slight bump as each slip joint reaches the end of its travel.

A pressure test can be performed on the entire 5-ft (1.52-m) length of the sealing mandrel OD.

Round Mandrel Slip Joint

Nominal Tool Size in.	OD in. (mm)	ID in. (cm)	Thread Connections	Service Temperature* °F (°C)	Length in. (cm)	Stroke Length in. (cm)	Tensile Rating** lb (kg)	Working Pressure*** Psi(bar)
3 7/8	3.90 (9.91)	1.80 (4.57)	2 7/8 CAS	450 （232）	180.00 （457.2）	60.00 (152.4)	150000 (68 040)	10000 (689)
5.00	5.03 （12.78）	2.31 (5.87)	3 7/8CAS	450 （232）	180.00 （457.2）	60.00 (152.4)	225000 (102 060)	15000 (1034)

BIG JOHN® Hydraulic Jar

The BIG JOHN® hydraulic jar is included as part of a toolstring to help remove stuck tools.

The jar helps free a stuck tool or toolstring by resisting a pull on the workstring. When the workstring is stretched by the pull, tension in the jar is released and an upward impact is delivered to the stuck tool.

Features and Benefits

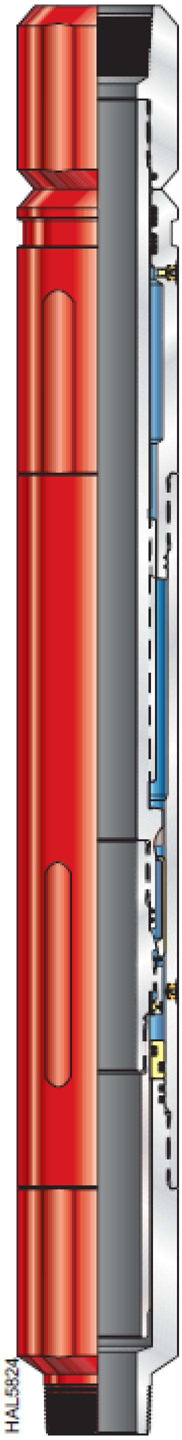
- Design of the hydraulic system ensures long life with little maintenance.
- Rig time is reduced.

- Jar can be recocked rapidly.
- Jar time delay is adjustable.
- Amount of pull to trip the jar can be varied within the limits of the time-delay system.

Operation

The temporary resistance that powers the jar is provided by a hydraulic time-delay system. Resistance is released when the metering sleeve inside the jar moves into a bypass section of the outer case. This action allows the special hydraulic oil to bypass rapidly.

The time delay required to release the temporary resistance varies in relation to the weight of the pull. For example, alight pull requires more time for release than a hard pull. When tools below the jar are stuck, a steady pull applied to the jar creates an upward impact blow to the string. The jar can be recocked when the string is set down.



BIG JOHN® Hydraulic Jar

BIG JOHN® Hydraulic Jar

Nominal Tool Size in.	OD in. (mm)	ID in. (cm)	Thread Connections	Service Temperature*°F (°C)	Length in. (cm)	Stroke Length in. (cm)	Maximum Pull to Trip² lb (kg)	Maximum Pull³ lb (kg)	Tensile Rating** lb (kg)	Working Pressure** *psi (bar)
3.00	3.06 (7.77)	1.03 (2.62)	2 1/4 CAS	450 (232)	57.98 （147.27）	4.43 (11.25)	7000 (3175)	100000 (45360)	120000 (54432)	15000 (1034)
3 5/8	3.63 (9.22)	1.80 (4.57)	2 3/8 EUE	450 (232)	58.73 (149.17)	10 (25.40)	30000 (13608)	109000 (49442)	151000 (68494)	Burst 13000 （896） Collapse 9500 （655）
3 7/8	3.90 (9.91)	1.25 (3.18)	3 1/8 8N	450 (232)	60.00 （152.4）	10 (25.40)	60000 (27216)	111000 (50349)	190000 (86184)	15000 (1034)
4 5/8	4.63 (11.76)	2.25 (5.72)	3 2/1 IF 3 7/8 CAS 2 7/8 EUE	450 (232)	60.00 （152.4）	10 (25.40)	50000 (22680)	139000 (63050)	229000 (103874)	Burst 15000 （1034） Collapse 13000 （896）
5	5.03 (12.78)	2.30 (5.84)	3 2/1 IF 3 7/8CAS	450 (232)	62.62 (159.05)	10 (25.40)	75000 (34020)	124000 (56246)	227000 (102967)	15000 (1034)
5SG	5.03 （12.78）	2.30 (5.84)	3 7/8CAS	450 (232)	62.98 (159.96)	10 (25.40)	75000 (34020)	124000 (56246)	231000 (104782)	15000 (1034)

Drain Valve

The drain valve consists of a ported body, sliding sleeve, and rotating nut, which controls the position of the sliding sleeve. The sleeve either covers or exposes the ports in the body of the valve. The drain valve is suitable for sour service at all temperatures. A drain collar and associated components are required when relieving pressure.

Features and Benefits

• Allows pressure trapped between two closed valves to be relieved in a controlled manner

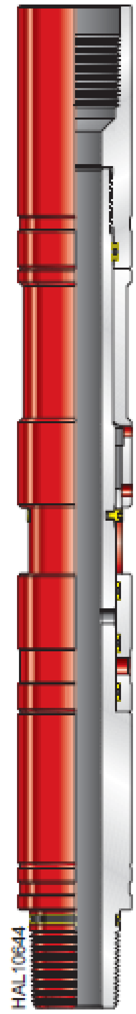
• Used to recover large volume fluid samples

Operation

The drain valve is installed between any two valves that may come out of the hole with pressure or fluid trapped between them. Pressure is relieved by installing the drain collar and drain nipples on the drain valve. Valves, lines, or sample bottles may be attached to the drain nipples depending on the desired disposition of the fluid in the string. After the drain collar assembly is attached, the ports in the tool are exposed by using a chain wrench or pipe wrench to rotate the drain nut, which moves the sliding sleeve.

When the ports in the sleeve are aligned with the ports in the body of the tool, the fluid may be drained.

It is also possible to trap a large volume fluid sample between two valves if a sample chamber of some kind (tubing, drill collar, etc.) is placed between the valves. In most cases, the drain valve would be run at the bottom of the sample chamber to facilitate transfer. This will not be a PVT sample.



Drain Valve

Drain Valve

Nominal Tool Size in.	OD in. (mm)	ID in. (cm)	Thread Connections	Length in. (cm)	Tensile Rating** lb (kg)	Working Pressure***psi (bar)
3.00	3.06 （7.77）	1.00 （2.54）	2 1/4 CAS	42.00 (106.68)	81000 (36742)	15000 (1034)
3 7/8	3.90 (9.91)	2.00 (5.08)	2 7/8 CAS	30.01 （76.53）	160000 (72576)	15000 (1034)
5.00 (SG)	5.03 （12.78）	2.28 (5.79)	3 7/8CAS	41.28 （104.85）	247000 (112039)	15000 (1034)
7.00	7.00 (17.78)	3.50 (8.89)	5 1/4 CAS	52.20 (132.59)	751462 (34863)	15000 (1034)

Rupture Disk (RD) FUL-FLO® Sampler

The rupture disk (RD) FUL-FLO® sampler is a full-open, full bore sleeve sampler for use on drillstem tests. The sampler is controlled by a rupture disk that is operated by annulus pressure.

Features and Benefits

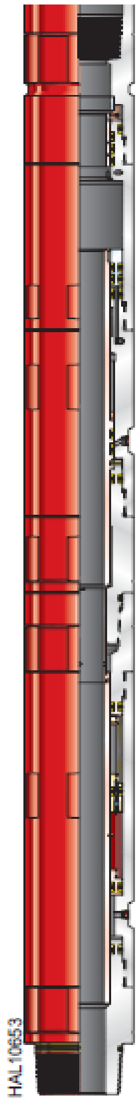
- Time-delay feature allows the sample to be trapped after a preset time. Different metering cartridges can be used to vary the closing time.
- Full-open capabilities are retained after the tool has trapped its sample.
- Several samplers can be run on a test to allow sampling at different times.

Operation

The FUL-FLO sampler is controlled by a pressure-operated rupture disk and has a sample mandrel with a built-in differential area. To catch a sample, annulus pressure is increased to a predetermined level, the rupture disk in the sampler breaks, and the mandrel traps the sample.

When the rupture disk breaks, the differential area of the sample mandrel is exposed to an air chamber on one side and hydrostatic pressure and applied annulus pressure on the other. This condition results in the sample mandrel moving up and trapping the sample. When the sample mandrel reaches the top of its stroke, it is locked in place by a set of locking dogs.

The 1,200-cc sample chamber allows a sufficient sample for two 500-cc non-monophasic (bulk) samples.



Rupture Disk (RD) FUL-FLO® Sampler

Rupture Disk (RD) FUL-FLO® Sampler

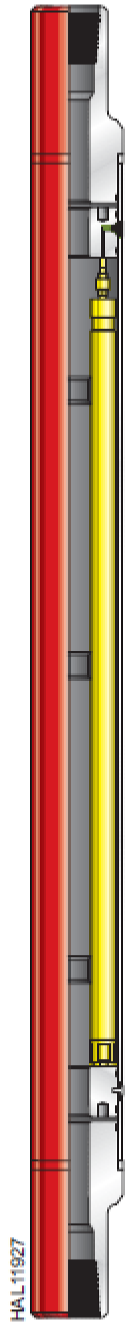
Nominal Tool Size in.	OD in. (mm)	ID in. (cm)	Thread Connections	Length in. (cm)	Tensile Rating** lb (kg)	Working Pressure***psi (bar)	Sample Volume CC
3 7/8	3.90 (9.91)	1.80 (4.57)	2 7/8 CAS	131.00 (332.74)	202000 (91627)	15000 (1034)	1200
5.00	5.03 (12.78)	2.28 (5.79)	3 7/8CAS	82.00 (208.28)	342000 (155131)	15000 (1034)	1200

SIMBA®–Tubing-Mounted Single-Phase Fluid Sample Carrier

We has developed the SIMBA® tubing-mounted single-phase fluid sample carrier for running on standard drillstem tests (DST), shoot and pulls, or anytime a tubing conveyed fluid sampling system is needed.

The SIMBA carrier is able to retain a 2.25-in. ID and fishability specifications in 7-in. and above casing even when carrying two of the Westport T-FAS® SPS 15 full-size 600-cc 1.69-in.single-phase fluid samplers. These advantages along with real-time capability with the APT™ annular pressure trigger technology and INSITE Anywhere® service make the SIMBA carrier unmatched in versatility.

The main objective on any DST is to gather data, including reservoir fluid data. Pipe conveyed downhole sampling systems provide a cost effective solution for drillstem tests where running wire maybe an issue including deepwater, horizontal, high-pressure/high-temperature (HPHT), and H2S applications. Not only does this result in a safer rig operation, but since wireline sampling runs can now be eliminated, it can translate into substantial cost savings. Other applications can include shoot and pull jobs where data acquisition is often compromised for the sake of speed. By including pipe-conveyed sampler carriers in the shoot and pull string, downhole fluid samples can be easily obtained without complicating the test string design and without running wireline. Pipe-conveyed sampling systems also play an important role in the new generation of reduced emission testing using the FasTest™ system.



SIMBA®–Tubing-Mounted Single-Phase Fluid Sample Carrier

Features and Benefits

- Sampling initiation using APT technology
- Carries two T-FAS® SPS 15 single-phase samplers
- Full flow 2.25-in. ID for wireline applications
- Future developments include multiple firing devices interchangeable to achieve acoustic, annular pressure, pressure pulse, mechanical, and wireline-fired systems
- Mercury-free sampling

This tool complements the full line of downhole reservoir evaluation tools.

SIMBA®–Tubing-Mounted Single-Phase Fluid Sample Carrier

Nominal Tool Size in.	OD in. (mm)	ID in. (cm)	Thread Connectio ns	Top Centralizing Subin. (cm)	MainBody Length in. (cm)	Bottom Centralizing Subin. (cm)	Tensile Rating** lb (kg)	Working Pressure** *psi (bar)	Sample Capacity (600 CC each)
5.30	5.30 (13.46)	2.25 (5.72)	3 7/8CAS	11500 (292.1)	325 (825.5)	116.00 (294.64)	344600 (156310)	12500 (862)	2

Shock Absorber

We offers two types of shock absorbers:

- Vertical
- Radial

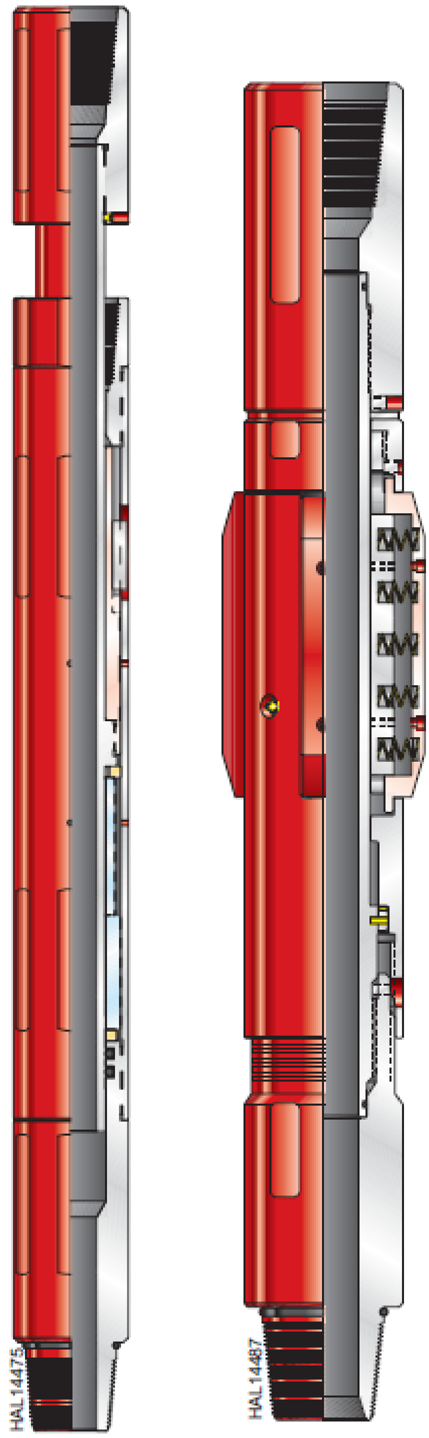
Shock absorbers protect pressure-measuring equipment or other sensitive components in the workstring for shock loads transmitted through the workstring by firing of TCP guns.

Operation

The vertical shock absorber is designed to protect pressure measuring components from vertical shock loads and is normally run below the packer. It is always run between the gauge carrier and perforating guns. It is recommended that the vertical shock absorber be run in conjunction with a drag block assembly for effective shock absorption.

A 3 3/8 in. OD vertical shock absorber is available with a blank ID. When run in the workstring, this absorber is located below the TCP guns and above the gauges.

In radial shock absorbers, spring-loaded drag blocks absorb radial shock waves transmitted through the workstring. The drag block assembly is located below the packer and between the gauges and TCP guns.



Vertical Shock Absorber *Radial Shock Absorber*

Vertical Shock Absorber

Nominal Tool Size in.	OD in. (mm)	ID in. (cm)	Thread Connections	Service Temperature**°F (°C)	Length in. (cm)	Tensile Rating** lb (kg)	Working Pressure***psi (bar)
3 3/8	3.375 (8.57)	N/A	2 3/8 EUE	450 (232)	48.30 (122.68)	79,000 (35843)	N/A
3 7/8	3.90 (9.91)	1.80 (4.572)	2 7/8 EUE	450 (232)	49.00 (124.46)	130,000 (58968)	10,000 (689)
5.00	5.03 ((12.78))	2.25 (5.72)	3 1/2IF	450 (232)	58.42 (148.39)	300,000 (136080)	15,000 (1034)

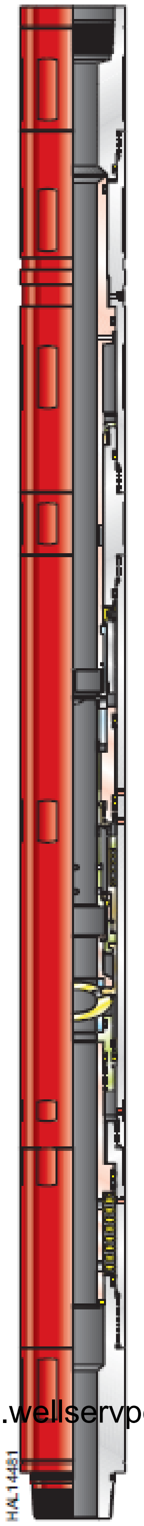
Radical Shock Absorber

Nominal ToolSize in.	OD in. (mm)	ID in. (cm)	Thread Connections	Length in. (cm)	Tensile Rating** lb (kg)
7-9 5/8	5.00 (12.7)	2.25 (5.72)	3 1/2 IF	42.00 ((106.68)	370,000 (167832)

MPV Pressure Test Bypass Valve

The MPV pressure test bypass valve is a full-opening, differential pressure operated bypass and pressure testing valve for use in cased holes. This tool has the capability of allowing multiple pressure tests of the workstring. It also includes a valve to automatically fill the workstring with annular fluid while running in the hole.

Features and Benefits



MPV Pressure Test Bypass Valve

This tool has the same basic features as the TST valve plus these adlditional features:

- Pressure testing is performed while running in the hole against a closed ball valve. Sealing on a valve that is always closed is a highly reliable method.
- The tool includes an internal bypass that allows the seal assembly to be stung in and out of a production packer as many times as required.
- The tool can be set to automatically operate at a specific predetermined hydrostatic pressure by using a rupture disk.

The MPV valve can be used downhole for:

- Pressure testing workstring while running in the hole.
- Pressure testing workstring after setting a retrievable packer or stinging into production packer.
- Flexing tubing or drillpipe.

Operation

The MPV valve is composed of four sections: operating, autofill, ball valve, and bypass operating sections.

The operating section is activated by applying higher pressure above the ball valve section than below. The higher pressure above the ball valve section deactivates the autofill and bypass sections, allowing annulus pressure to be applied. (If a rupture disk is used, when communication through the rupture disk is established, annulus pressure must be higher than workstring pressure by approximately500 to 600 psi.) Next, a differential pressure of approximately 250 to300 psi disengages the primary locking mechanism, rolling the ball open and locking it in the open position.

The autofill section allows annular fluid to enter the workstring when annular pressure is 10 psi greater than the workstring pressure. The autofill section is closed when pressure testing. To reopen the autofill section, the pressure above and below the ball valve section must be equalized. The autofill section can be disabled by plugging three 1/4-in. NPT ports and using a rupture disk.

The ball valve section provides a highly reliable positive seal when pressure testing. This positive seal is maintained by a proven ball and seat configuration.

The bypass section is closed at the same time as the autofill section by applying higher pressure above the ball valve section than below. When the pressures above and below the ball valve section are equalized, the lower compression spring returns the bypass section to the open position.

Note: Do not run a closed valve below the MPV valve. The trapped volume will interfere with successful tool operation.

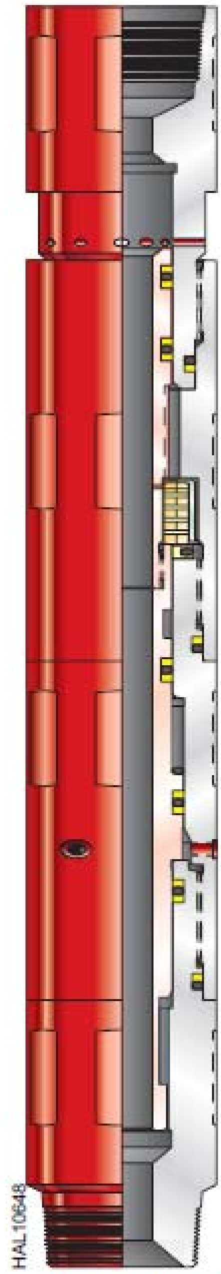
MPV Pressure Test Bypass Valve

Nominal Tool Size in.	OD in. (mm)	ID in. (cm)	Thread Connections	Length in. (cm)	Tensile Rating** lb (kg)	Working Pressure***psi (bar)	Operating Pressure
5.00	5.03 (12.78)	2.258 (5.79)	3 7/8CAS	141.24 ((358.75))	389,500 (176677)	15,000 (1034)	Rupture disk rating and/or 500to 600 psi (34-41 bar) annulus pressure above workstring pressure at the tool
7.00	7.00 (17.78)	3.50 ((8.89))	5 1/4CAS	163.86 (416.20)	501,538 (227498)	10,000 (689)	Rupture disk rating and/or 500to 600 psi (34-41 bar) annulus pressure above workstring pressure at the tool

Pressure-Responsive (PR) FAS-FIL™ Valve

The pressure-responsive (PR) FAS-FIL™ valve runs in the workstring with its ports open to allow the drillpipe to fill up above a closed valve. Atypical workstring for formation surging with the PR FAS-FIL valve consists of the following (from top to bottom):

1. Drill pipe to surface
2. PR FAS-FIL valve
3. PR multi-service valve (top)
4. Surge chamber
5. PR multi-service valve (lower)
6. CHAMP® IV packer



Pressure-Responsive (PR) FAS-FIL™ Valve

Features and Benefits

- Operates without pipe manipulation
- Saves rig time compared to conventional methods of filling workstring
- Permits through-tubing operations through full-opening ID

Operation

As the toolstring is run in the hole, the open ports in the PR FAS-FIL valve allow annulus fluid to fill the drill pipe. The valve is set to close at a predetermined hydrostatic pressure just before the packer reaches the required setting depth. This operating pressure can be varied depending on conditions and customer requirements.

The proper number of pins are installed in the shear set for the required operating pressure of the valve. The shear pins resist the force generated by annulus pressure acting across a differential area in the power section of the tool. When the resistant force is overcome, the pins shear, and the sealing mandrel moves upward across the ports in the ported adapter. The ports are straddled by seals on the sealing mandrel, blocking fluid communication from the annulus to the drill pipe. As the mandrel completes its upward travel, a set of locking dogs falls into position. Once the ports are closed, they cannot be opened until the tool has been redressed.

Pressure-Responsive (PR) FAS-FIL™ Valve

Nominal Tool Size in.	OD in. (mm)	ID in. (cm)	Thread Connections	Length in. (cm)	Tensile Rating** lb (kg)	Burst Rating** psi (bar)	Collapse Rating** psi (bar)
3	3.06 (7.77)	1.00 (2.54)	2 3/8 EUE	39.2 (99.57)	160,500 (72800)	11,700 (806.13)	15,200 (1047.28)
3 7/8	3.90 (9.91)	1.80 (4.57)	2 7/8 EUE	39.5 (100.33)	225,100 (10200)	8,500 (585.65)	11,900 (819.91)
4 5/8	4.68 (11.89)	2.25 (5.72)	3 1/2IF	42.7 (108.5)	284,000 (128822)	7,600 (524.64)	13,300 (916.37)
6 1/8	6.12 (15.54)	3.00 (7.62)	4 IF	43.1 (109.5)	567,000 (257191)	16,500 (1136.85)	13,300 (916.37)

Pressure-Responsive (PR) Multi-Service Valve

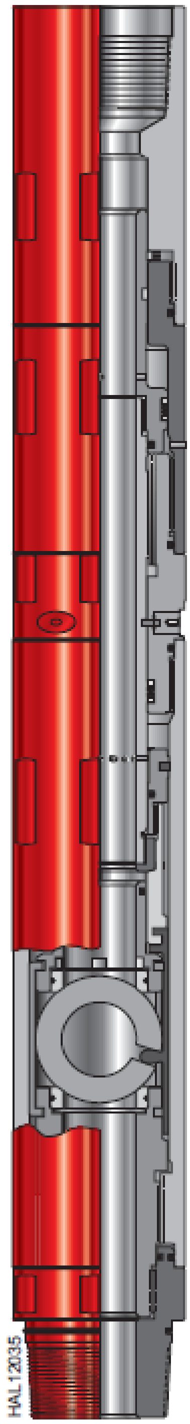
The pressure-responsive (PR) multi-service valve is a fullopening, annulus pressure-operated valve for use in cased holes. This tool can be run as a surge valve or backpressure valve.

Top and bottom PR multi-service valves are run at the same time to form a surge chamber. This surge helps clean debris from the perforations before a stimulation treatment, sand control treatment, or flow test.

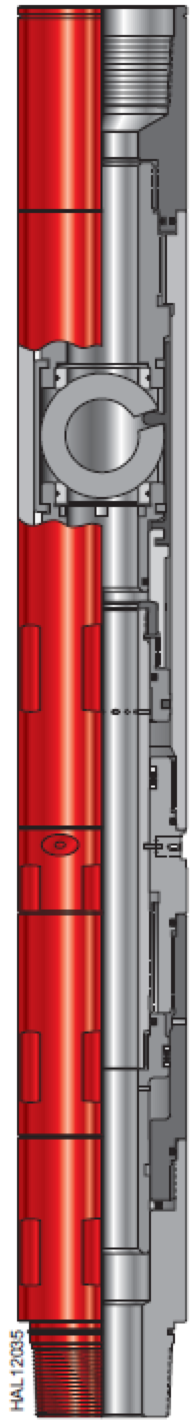
Potential for sudden pressure surge is provided when two multi-service valves are spaced apart in the tubing string to form an atmospheric air chamber. When the bottom ball valve is opened, solids forced into the perforations are swept into the air chamber by the fluid stage.

Features and Benefits

- Requires no pipe manipulation to operate
- Achieves more effective surge because of the instant ball opening
- Creates the required air chamber volume by spacing valves
- Allows circulating or spotting of well fluid when surging is complete
- Permits through-tubing operation through full-opening ID



Top Pressure-Responsive (PR) Multi-Service Valves



Bottom Pressure-Responsive (PR) Multi-Service Valves

Operation

As PR multi-service valves are run into a well, the ball valves are in a closed position, and atmospheric air is trapped between the valves. The bottom valve is opened by the operating piston, which has one side exposed to the annulus pressure above the packer and the other side exposed to pressure below the packer.

After the packer has been set, pressure applied to the annulus moves the piston downward to pull the ball into the open position. The locking dogs drop into a groove, keeping the ball in the fully open position.

As long as the tubing pressure is equal to or greater than the annulus pressure, the top valve is kept closed when the lower valve is operated.

Before the top valve can be opened, tubing pressure must be relieved while the annulus pressure is maintained. The top PR multi-service valve also contains locking dogs that lock the ball in the fully open position. After the valves have been opened, circulation can occur with the packer unseated.

Opening pressure is controlled by the shear pins. The number and type of shear pins can be adjusted to raise or lower the operating pressure.

Pressure-Responsive (PR) Multi-Service Valve

Nominal Tool Size in.	OD in. (mm)	ID in. (cm)	Thread Connections	Length in. (cm)	Tensile Rating** lb (kg)	Burst Rating** psi (bar)	Collapse Rating** psi (bar)
3 7/8	3.90 (9.91)	1.80 (4.57)	2 7/8 EUE	49.96 （(126.14)）	229600 (104147)	8500 (58606)	7900 （(54469)）
4 5/8	4.68 (11.89)	2.00 (5.08)	3 1/2IFT.J. 3 7/8 CAS	60.25 (153.04)	354100 (160620)	9800 (67569)	11300 (77911)
5	5.03 （12.78）	2.25 (5.72)	3 1/2IFT.J. 3 7/8 CAS	59.37 （(150.80)）	341800 (155040)	8700 (59985)	8600 (59295)

Super Safety™ Valve

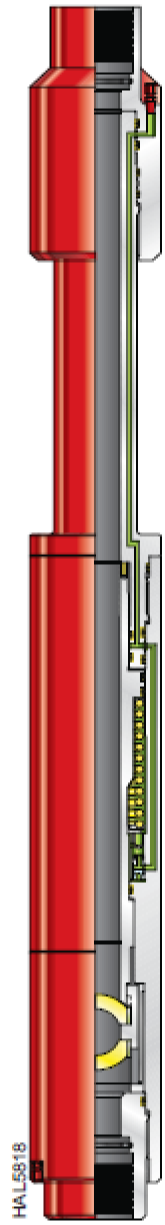
The Super Safety™ valve (SSV) is a master valve used for testing operations from jack-up or land rigs. The SSV is installed in the test string so that a BOP ram can be closed on the ramlock sub located in the top section of the valve. The annulus is then protected by the BOP rams, and the test string is protected by the safety valve. The Super Safety valve is capable of cutting wireline and 1.5-in. coiled tubing. If equipped with a cutter ball, it is capable of cutting 2-in. OD, .125-in. wall coiled tubing using a nitrogen dome charge or by applying balance line pressure.

Features and Benefits

The Super Safety valve is controlled by two hydraulic lines and contains a chemical injection port for injecting chemicals at the valve body further downhole to an injection sub or to actuate a subsurface safety valve. The valve is held open by maintaining hydraulic pressure on the control line.

The valve is designed to close by spring force but incorporates a nitrogen dome charge chamber to provide increased closing force and to lessen the time required for closing. This feature gives the valve the ability to cut wireline and coiled tubing without adding balance line pressure.

- Normally closed/fail-safe
- Maintains pump-through capabilities at all times
- Nitrogen dome charge for fast response
- Capable of cutting 1.5-in. coiled tubing, or if equipped with a cutter ball 2-in. OD, .125 in. wall thickness coiled tubing
- Small 8-in. OD fits inside 9 5/8-in.casing



Super Safety™ Valve

Super Safety™ Valve

OD in. (mm)	ID in. (cm)	End Connections	Valve Length in. (cm)	Total Length in. (cm)	Tensile Rating** lb(kg)	Working Pressure*** lb(kg)	Temperature Range °F (°C)
8.0 (20.32)	3.0 (7.62)	5-4ACME Box x Box	50.00 (127.0)	79.6 (202.2)	400,000 (181440)	15,000 (6804)	32-325 (0-163)