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June 17 2015

Tenaris

Size: 5.500 in.
Wall: 0.361 in.
Weight: 20.00 lbs/ft
Grade: P110-IC
Min. Wall Thickness: 87.5 %

Connection: TenarisXP™ BTC
Casing/Tubing: CAS
Coupling Option: REGULAR

PIPE BODY DATA

GEOMETRY

Nominal OD	**5.500** in.	Nominal Weight	**20.00** lbs/ft	Standard Drift Diameter	**4.653** in.
Nominal ID	**4.778** in.	Wall Thickness	**0.361** in.	Special Drift Diameter	**N/A**
Plain End Weight	**19.83** lbs/ft				

PERFORMANCE

Body Yield Strength	**641** x 1000 lbs	Internal Yield	**12630** psi	SMYS	**110000** psi
Collapse	**12100** psi				

TENARISXP™ BTC CONNECTION DATA

GEOMETRY

Connection OD	**6.100** in.	Coupling Length	**9.450** in.	Connection ID	**4.766** in.
Critical Section Area	**5.828** sq. in.	Threads per in.	**5.00**	Make-Up Loss	**4.204** in.

PERFORMANCE

Tension Efficiency	**100** %	Joint Yield Strength	**641** x 1000 lbs	Internal Pressure Capacity(1)	**12630** psi
Structural Compression Efficiency	**100** %	Structural Compression Strength	**641** x 1000 lbs	Structural Bending(2)	**92** °/100 ft
External Pressure Capacity	**12100** psi				

ESTIMATED MAKE-UP TORQUES(3)

Minimum	**11270** ft-lbs	Optimum	**12520** ft-lbs	Maximum	**13770** ft-lbs

OPERATIONAL LIMIT TORQUES

Operating Torque	**21500** ft-lbs	Yield Torque	**23900** ft-lbs		

BLANKING DIMENSIONS

Blanking Dimensions

(1) Internal Pressure Capacity related to structural resistance only. Internal pressure leak resistance as per section 10.3 API 5C3 / ISO 10400 - 2007.

(2) Structural rating, pure bending to yield (i.e no other loads applied)

(3) Torque values calculated for API Modified thread compounds with Friction Factor=1. For other thread compounds please contact us at licensees@oilfield.tenaris.com. Torque values may be further reviewed. For additional information, please contact us at contact-tenarishydril@tenaris.com

BLOWOUT PREVENTOR SCHEMATIC

Minimum Requirements

OPERATION : Intermediate and Production Hole Sections

Minimum System Pressure Rating : **5,000 psi**

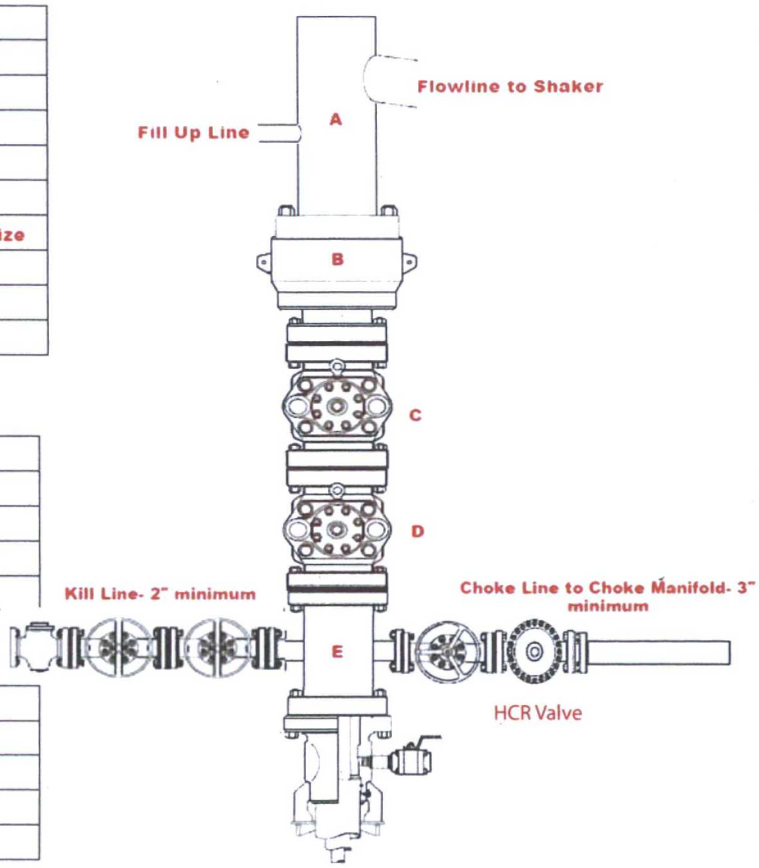
	SIZE	PRESSURE	DESCRIPTION
A		N/A	Bell Nipple
B	13 5/8"	5,000 psi	Annular
C	13 5/8"	5,000 psi	Pipe Ram
D	13 5/8"	5,000 psi	Blind Ram
E	13 5/8"	5,000 psi	Mud Cross
F			
DSA	As required for each hole size		
C-Sec			
B-Sec	13-5/8" 5K x 11" 5K		
A-Sec	13-3/8" SOW x 13-5/8" 5K		

Kill Line

SIZE	PRESSURE	DESCRIPTION
2"	5,000 psi	Gate Valve
2"	5,000 psi	Gate Valve
2"	5,000 psi	Check Valve

Choke Line

SIZE	PRESSURE	DESCRIPTION
3"	5,000 psi	Gate Valve
3"	5,000 psi	HCR Valve



Installation Checklist

The following item must be verified and checked off prior to pressure testing of BOP equipment.

- ☐ **The installed BOP equipment meets at least the minimum requirements (rating, type, size, configuration) as shown on this schematic. Components may be substituted for equivalent equipment rated to higher pressures. Additional components may be put into place as long as they meet or exceed the minimum pressure rating of the system.**
- ☐ **All valves on the kill line and choke line will be full opening and will allow straight though flow.**
- ☐ **The kill line and choke line will be straight unless turns use tee blocks or are targeted with running tess, and will be anchored to prevent whip and reduce vibration.**
- ☐ **Manual (hand wheels) or automatic locking devices will be installed on all ram preventers. Hand wheels will also be installed on all manual valves on the choke line and kill line.**
- ☐ **A valve will be installed in the closing line as close as possible to the annular preventer to act as a locking device. This valve will remain open unless accumulator is inoperative.**
- ☐ **Upper kelly cock valve with handle will be available on rig floor along with safety valve and subs to fit all drill string connections in use.**

After Installation Checklist is complete, fill out the information below and email to Superintendent and Drilling Engineer

Wellname: ______________________________

Representative: ______________________________

Date: ______________________________

CHOKE MANIFOLD SCHEMATIC

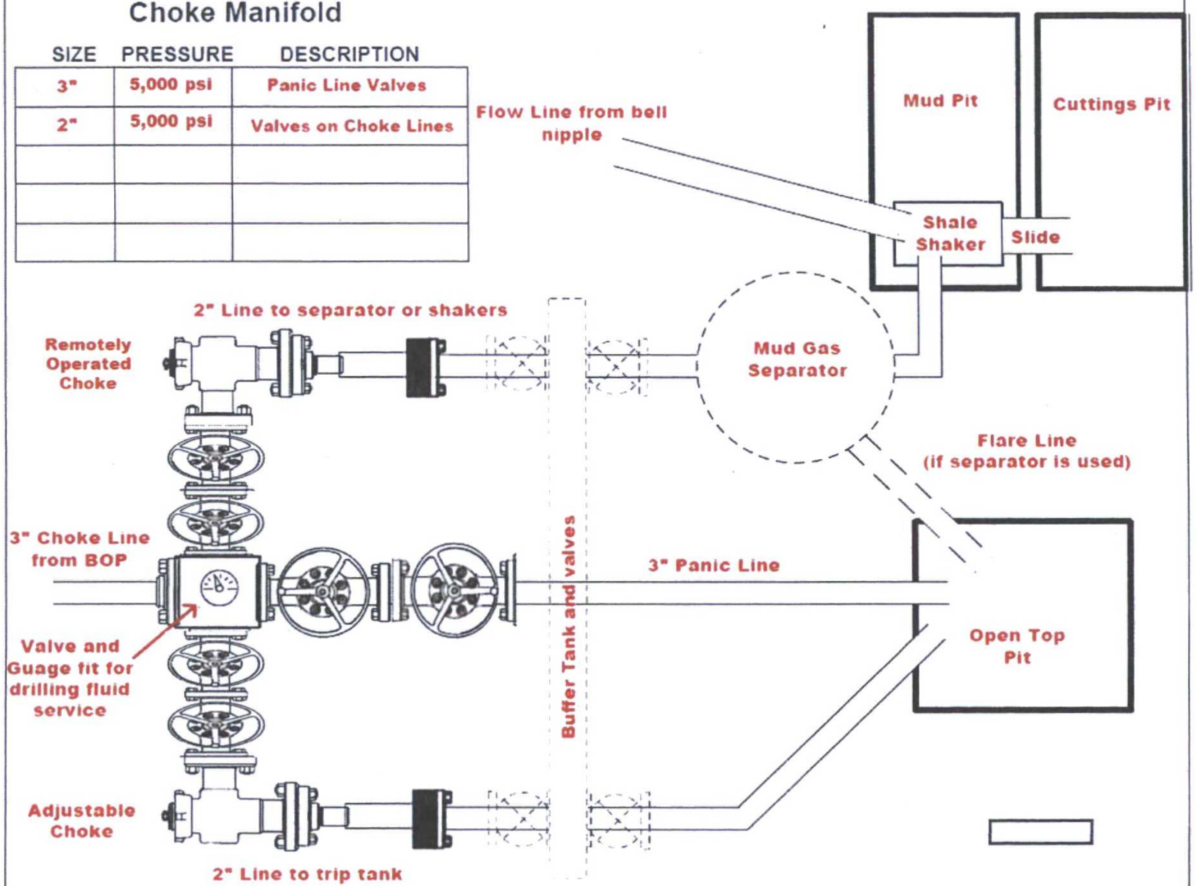
Minimum Requirements

OPERATION : Intermediate and Production Hole Sections

Minimum System Pressure Rating : **5,000 psi**

Choke Manifold

SIZE	PRESSURE	DESCRIPTION
3"	5,000 psi	Panic Line Valves
2"	5,000 psi	Valves on Choke Lines



Installation Checklist

The following item must be verified and checked off prior to pressure testing of BOP equipment.

- ☐ The installed BOP equipment meets at least the minimum requirements (rating, type, size, configuration) as shown on this schematic. Components may be substituted for equivalent equipment rated to higher pressures. Additional components may be put into place as long as they meet or exceed the minimum pressure rating of the system.
- ☐ Adjustable Chokes may be Remotely Operated but will have backup hand pump for hydraulic actuation in case of loss of rig air pressure or power.
- ☐ Flare and Panic lines will terminate a minimum of 150' from the wellhead. These lines will terminate at a location as per approved APD.
- ☐ The choke line, kill line, and choke manifold lines will be straight unless turns use tee blocks or are targeted with running tess, and will be anchored to prevent whip and reduce vibration. This excludes the line between mud gas separator and shale shaker.
- ☐ All valves (except chokes) on choke line, kill line, and choke manifold will be full opening and will allow straight through flow. This excludes any valves between mud gas separator and shale shakers.
- ☐ All manual valves will have hand wheels installed.
- ☐ If used, flare system will have effective method for ignition
- ☐ All connections will be flanged, welded, or clamped (no threaded connections like hammer unions)
- ☐ If buffer tank is used, a valve will be used on all lines at any entry or exit point to or from the buffer tank.

After Installation Checklist is complete, fill out the information below and email to Superintendent and Drilling Engineer

Wellname: ____________________

Representative: ____________________

Date: ____________________

BOPE Testing

Minimum Requirements

Closing Unit and Accumulator Checklist

The following item must be performed, verified, and checked off at least once per well prior to low/high pressure testing of BOP equipment. This must be repeated after 6 months on the same well.

☐ Precharge pressure for each accumulator bottle must fall within the range below. Bottles may be further charged with nitrogen gas only. Tested precharge pressures must be recorded for each individual bottle and kept on location through the end of the well. Test will be conducted prior to connecting unit to BOP stack.

Check one that applies	Accumulator working pressure rating	Minimum acceptable operating pressure	Desired precharge pressure	Maximum acceptable precharge pressure	Minimum acceptable precharge pressure
☐	1500 psi	1500 psi	750 psi	800 psi	700 psi
☐	2000 psi	2000 psi	1000 psi	1100 psi	900 psi
☐	3000 psi	3000 psi	1000 psi	1100 psi	900 psi

☐ Accumulator will have sufficient capacity to open the hydraulically-controlled choke line valve (if used), close all rams, close the annular preventer, and retain a minimum of 200 psi above the maximum acceptable precharge pressure (see table above) on the closing manifold without the use of the closing pumps. This test will be performed with test pressure recorded and kept on location through the end of the well

☐ Accumulator fluid reservoir will be double the usable fluid volume of the accumulator system capacity. Fluid level will be maintained at manufacturer's recommendations. Usable fluid volume will be recorded. Reservior capacity will be recorded. Reservoir fluid level will be recorded along with manufacturer's recommendation. All will be kept on location through the end of the well.

☐ Closing unit system will have two independent power sources (not counting accumulator bottles) to close the preventers.

☐ Power for the closing unit pumps will be available to the unit at all times so that the pumps will automatically start when the closing valve manifold pressure decreases to the pre-set level. It is recommended to check that air line to accumulator pump is "ON" during each tour change.

☐ With accumulator bottles isolated, closing unit will be capable of opening the hydraulically-operated choke line valve (if used) plus close the annular preventer on the smallest size drill pipe within 2 minutes and obtain a minimum of 200 psi above maximum acceptable precharge pressure (see table above) on the closing manifold. Test pressure and closing time will be recorded and kept on location through the end of the well.

☐ Master controls for the BOPE system will be located at the accumulator and will be capable of opening and closing all preventer and the choke line valve (if used)

☐ Remote controls for the BOPE system will be readily accessible (clear path) to the driller and located on the rig floor (not in the dog house). Remote controls will be capable of closing all preventers.

☐ Record accumulator tests in drilling reports and IADC sheet

BOPE Test Checklist

The following item must be ckecked off prior to beginning test

☐ BLM will be given at least 4 hour notice prior to beginning BOPE testing

☐ Valve on casing head below test plug will be open

☐ Test will be performed using clear water.

The following item must be performed during the BOPE testing and then checked off

☐ BOPE will be pressure tested when initially installed, whenever any seal subject to test pressure is broken, following related repairs, and at a minimum of 30 days intervals. Test pressure and times will be recorded by a 3rd party on a test chart and kept on location through the end of the well.

☐ Test plug will be used

☐ Ram type preventer and all related well control equipment will be tested to 250 psi (low) and 5,000 psi (high).

☐ Annular type preventer will be tested to 250 psi (low) and 3,500 psi (high).

☐ Valves will be tested from the working pressure side with all down stream valves open. The check valve will be held open to test the kill line valve(s)

☐ Each pressure test will be held for 10 minutes with no allowable leak off.

☐ Master controls and remote controls to the closing unit (accumulator) must be function tested as part of the BOP testing

☐ Record BOP tests and pressures in drilling reports and IADC sheet

After Installation Checklist is complete, fill out the information below and email to Superintendent and Drilling Engineer <u>along with any/all BOP and accumulator test charts and reports from 3rd parties</u>.

Wellname: ______________________

Representative: ______________________

Date: ______________________

1. **FORMATION TOPS**

The estimated tops of important geologic markers are as follows:

FORMATION	SUB-SEA TVD	KBTVD	MD
Formation	Sub-Sea TVD	KBTVD	
Rustler	2507	650	
Castile	157	3000	
Lamar	-1543	4700	
Bell Canyon	-1823	4980	
Cherry Canyon	-2718	5875	
Brushy Canyon	-4268	7425	
Bone Spring Limestone	-5648	8805	
Upr. Avalon	-5718	8875	
Lateral TD (Upper Avalon)	-5893	9050	13903

2. **ESTIMATED DEPTH OF WATER, OIL, GAS & OTHER MINERAL BEARING FORMATIONS**

The estimated depths at which the top and bottom of the anticipated water, oil, gas, or other mineral bearing formations are expected to be encountered are as follows:

Substance	Formation	Depth
Deepest Expected Base of Fresh Water		500
Water	Rustler	650
Water	Bell Canyon	4980
Water	Cherry Canyon	5875
Oil/Gas	Brushy Canyon	7425
Oil/Gas	Bone Spring Limestone	8805
Oil/Gas	Upr. Avalon	8875

All shows of fresh water and minerals will be reported and protected.

3. **BOP EQUIPMENT**

Will have a minimum of a 5000 psi rig stack (see proposed schematic) for drill out below surface casing. Stack will be tested as specified in the attached testing requirements.

Chevron requests a variance to use a FMC UH2 Multibowl wellhead, which will be run through the rig foor on surface casing. BOPE will be nippled up and tested after cementing surface casing. Subsequent tests will be performed as needed, not to exceed 30 days. The field report from FMC and BOP test information will be provided in a subsequent report at the end of the well. Please see the attached wellhead schematic. An installation manual has been placed on file with the BLM office and remains unchanged from previous submittal.

4. **CASING PROGRAM**

a. The proposed casing program will be as follows:

Purpose	From	To	Hole Size	Csg Size	Weight	Grade	Thread	Condition
Surface	0'	670'	17-1/2"	13-3/8"	55 #	J55	STC	New
Intermediate	0'	4,530'	12-1/4"	9-5/8"	40 #	HCK-55	LTC	New
Production	0'	13,903'	8-3/4"	5-1/2"	20.0 #	HCP-110	TXP BTC S	New

b. Casing design subject to revision based on geologic conditions encountered.

c. *****A "Worst Case" casing design for wells in a particular area is used below to calculate the Casing Safety Factors. If for any reason the casing design for a particular well requires setting casing deeper than the following "worst case" design, then the Casing Safety Factors will be recalcuated & sent to the BLM prior to drilling.**

d. **Chevron will fill casing at a minimum of every 20 jts (840') while running for intermediate and production casing in order to maintain collapse SF.**

SF Calculations based on the following "Worst Case" casing design:

Surface Casing: 850'
Intermediate Casing: 4800'
Production Casing: 22,000' MD/9,200' TVD (12,800' VS @ 90 deg inc)

Casing String	Min SF Burst	Min SF Collapse	Min SF Tension	Min SF Tri-Axial
Surface	1.40	1.92	2.40	1.75
Intermediate	1.21	3.02	2.15	1.48
Production	1.30	2.51	2.48	1.51

Min SF is the smallest of a group of safety factors that include the following considerations:

	Surf	Int	Prod
Burst Design			
Pressure Test- Surface, Int, Prod Csg P external: Water P internal: Test psi + next section heaviest mud in csg	X	X	X
Displace to Gas- Surf Csg P external: Water P internal: Dry Gas from Next Csg Point	X		
Frac at Shoe, Gas to Surf- Int Csg P external: Water P internal: Dry Gas, 15 ppg Frac Gradient		X	
Stimulation (Frac) Pressures- Prod Csg P external: Water P internal: Max inj pressure w/ heaviest injected fluid			X
Tubing leak- Prod Csg (packer at KOP) P external: Water P internal: Leak just below surf, 8.7 ppg packer fluid			X
Collapse Design			
Full Evacuation P external: Water gradient in cement, mud above TOC P internal: none	X	X	X
Cementing- Surf, Int, Prod Csg P external: Wet cement P internal: water	X	X	X
Tension Design			
100k lb overpull	X	X	X

5. **CEMENTING PROGRAM**

Slurry	Type	Top	Bottom	Weight	Yield	%Excess	Sacks	Water
Surface				(ppg)	(sx/cu ft)	Open Hole		gal/sk
Tail	Class C	0'	670'	14.8	1.35	125	801	6.57
Intermediate								
Lead	50:50 Poz Class C	0'	3,530'	11.9	2.43	150	1022	14.21
Tail	Class C	3,530'	4,530'	14.8	1.33	85	464	6.37
Production								
1st Lead	50:50 Poz Class H	3,680'	8,562'	11.5	2.51	50	697	15.51
2nd Lead	TXI	8,562'	12,903'	12.5	1.62	35	917	9.64
Tail	Acid Soluble	12,903'	13,903'	15	2.18	0	116	11.42

1. Final cement volumes will be determined by caliper.
2. Surface casing shall have at least one centralizer installed on each of the bottom three joints starting with the shoe joint.
3. Production casing will have one centralizer on every joint for the first 1000' from TD, then every other joint to EOB, then every third joint to KOP, and then every forth joint to intermediate casing.

6. **MUD PROGRAM**

From	To	Type	Weight	F. Vis	Filtrate
0'	670'	Spud Mud	8.3 - 8.7	32 - 34	NC - NC
670'	4,530'	Brine	9.5 - 10.1	28 - 30	NC - NC
4,530'	8,562'	FW/Cut Brine	8.3 - 9.6	28 - 30	NC - NC
8,562'	9,312'	Cut Brine	8.3 - 9.6	28 - 30	15 - 25
9,312'	13,903'	FW/Cut Brine	8.3 - 9.6	28 - 30	15 - 25

A closed system will by utilized consisting of above ground steel tanks. All wastes accumulated during drilling operations will be contained in a portable trash cage and removed from location and deposited in an approved sanitary landfill. Sanitary wastes will be contained in a chemical porta-toilet and then hauled to an approved sanitary landfill.

All fluids and cuttings will be disposed of in accordance with New Mexico Oil Conservation Division rules and regulations.

A mud test shall be performed every 24 hours after mudding up to determine, as applicable: density, viscosity, gel strength, filtration, and pH.

Visual mud monitoring equipment shall be in place to detect volume changes indicating loss or gain of circulating fluid volume. When abnormal pressures are anticipated -- a pit volume totalizer (PVT), stroke counter, and flow sensor will be used to detect volume changes indicating loss or gain of circulating fluid volume.

A weighting agent and lost circulating material (LCM) will be onsite to mitigate pressure or lost circulation as hole conditions dictate.

7. **TESTING, LOGGING, AND CORING**

The anticipated type and amount of testing, logging, and coring are as follows:

a. Drill stem tests are not planned.
b. The logging program will be as follows:

TYPE	Logs	Interval	Timing	Vendor
Mudlogs	2 man mudlog	Int Csg to TD	Drillout of Int Csg	TBD
LWD	MWD Gamma	Int. and Prod. Hole	While Drilling	TBD

c. Conventional whole core samples are not planned.
d. A Directional Survey will be run.

8. **ABNORMAL PRESSURES AND HYDROGEN SULFIDE**

a. No abnormal pressures or temperatures are expected. Estimated BHP is: 4500 psi
b. Hydrogen sulfide gas is not anticipated. An H2S Contingency plan is attached with this APD in the event that H2S is encountered