## 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 | 13957 |
| | | | |
| | | | |
| | | | |

## 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' | 13,957' | 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<br>P external: Water<br>P internal: Test psi + next section heaviest mud in csg | X | X | X |
| Displace to Gas- Surf Csg<br>P external: Water<br>P internal: Dry Gas from Next Csg Point | X | | |
| Frac at Shoe, Gas to Surf- Int Csg<br>P external: Water<br>P internal: Dry Gas, 15 ppg Frac Gradient | | X | |
| Stimulation (Frac) Pressures- Prod Csg<br>P external: Water<br>P internal: Max inj pressure w/ heaviest injected fluid | | | X |
| Tubing leak- Prod Csg (packer at KOP)<br>P external: Water<br>P internal: Leak just below surf, 8.7 ppg packer fluid | | | X |
| **Collapse Design** | | | |
| Full Evacuation<br>P external: Water gradient in cement, mud above TOC<br>P internal: none | X | X | X |
| Cementing- Surf, Int, Prod Csg<br>P external: Wet cement<br>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' | 8,616' | 11.5 | 2.51 | 50 | 705 | 15.51 |
| 2nd Lead | TXI | 8,616' | 12,957' | 12.5 | 1.62 | 35 | 917 | 9.64 |
| Tail | Acid Soluble | 12,957' | 13,957' | 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' | 8,616' | FW/Cut Brine | 8.3 - 9.6 | 28 - 30 | NC - NC |
| 8,616' | 9,366' | Cut Brine | 8.3 - 9.6 | 28 - 30 | 15 - 25 |
| 9,366' | 13,957' | 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

# BLOWOUT PREVENTOR SCHEMATIC

## Minimum Requirements

**OPERATION** : Intermediate and Production Hole Sections

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

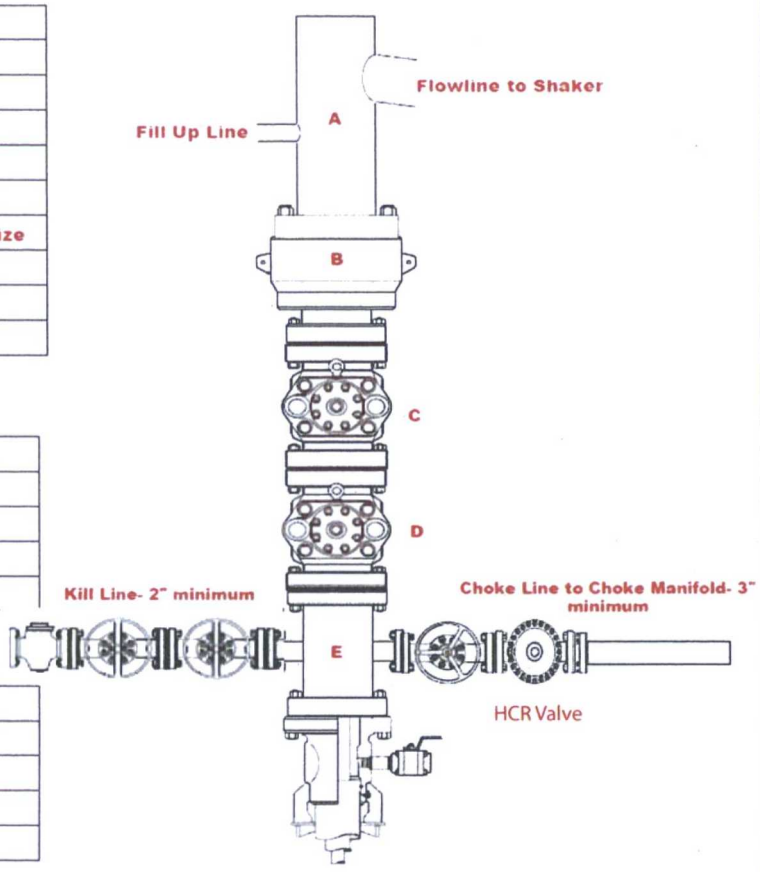
| | SIZE | PRESSURE | DESCRIPTION |
|---|---|---|---|
| A | | N/A | Bell Nipple |
| B | 13 5/8" | 5,000 psi | Annular |
| C | 13 5/8" | 5,000 psi | Pipe Ram |
| D | 13 5/8" | 5,000 psi | Blind Ram |
| E | 13 5/8" | 5,000 psi | Mud Cross |
| F | | | |
| DSA | | As required for each hole size | |
| C-Sec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

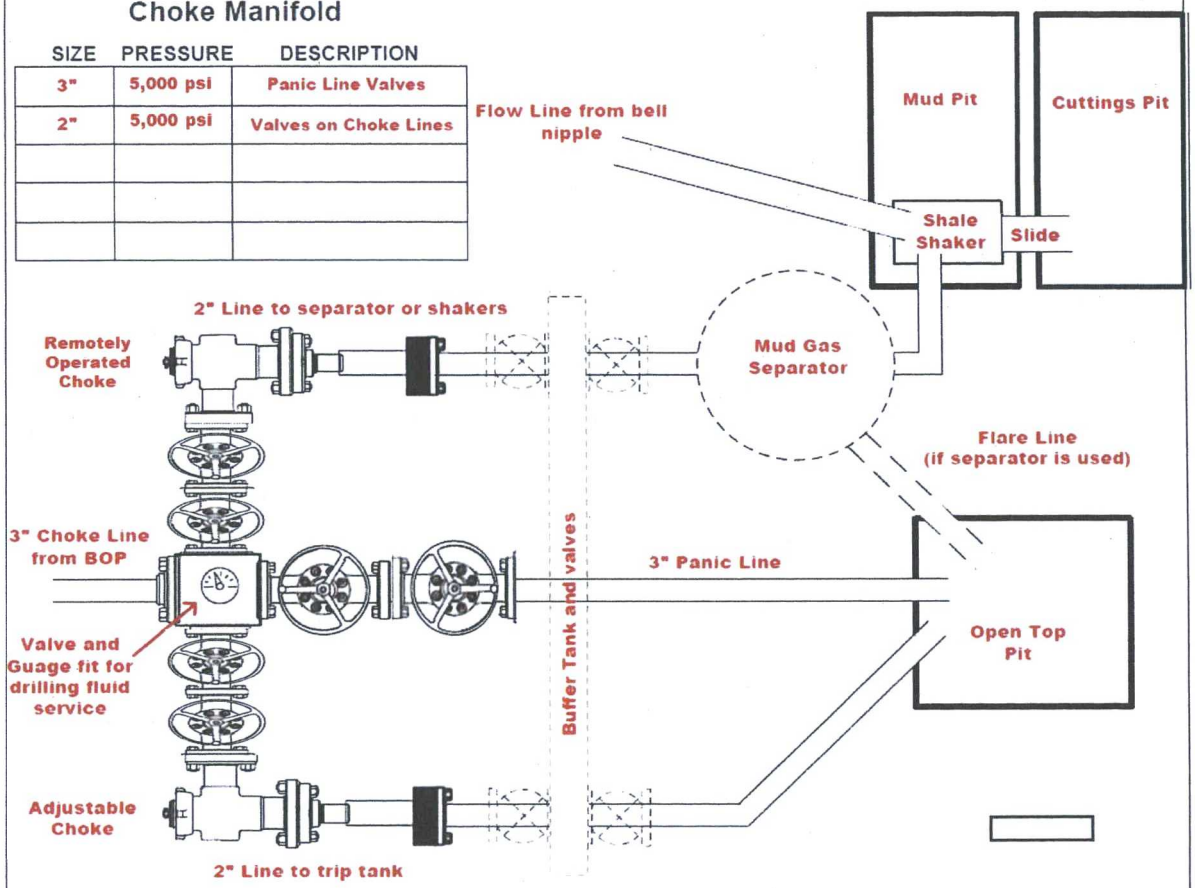
## Minimum Requirements

**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 along with any/all BOP and accumulator test charts and reports from 3rd parties.

**Wellname:** _____

**Representative:** _____

**Date:** _____

For the latest performance data, always visit our website: www.tenaris.com

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

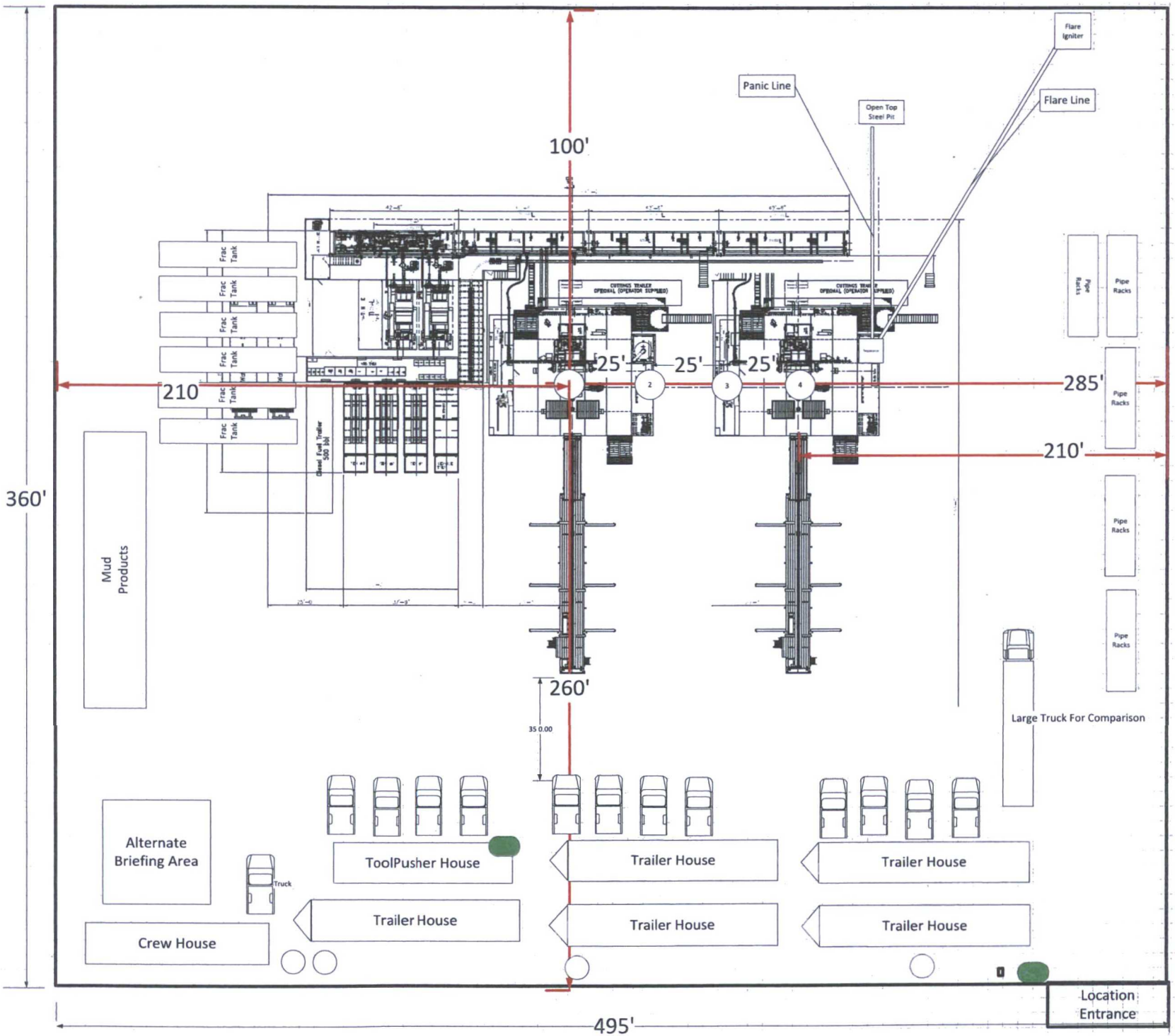
**(1)** Internal Pressure Capacity related to structural resistance only. Internal pressure leak resistance as per section 10.3 API 5C3 / ISO 10400 - 2007.

**(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

# Nabors Pace X SD Sec 15 Pad 9




*Rig layout shows rig in first and last well for illustration purposes.*

**H2S Monitor Locations**
- Bop/Cellar
- Rig Floor
- Shaker Skid
- Bell Nipple

**Flag Locations**
- Sign-in Shack
- Rig Floor
- Dog House

**10 Minute Escape Packs**
- 1 at Pits
- 1 at Trip Tank
- 1 at Accumulator
- 4 at Rig Floor

**45 Minute Escape Packs**
- 2 at Briefing Area
- 2 at Alternate Briefing Area

**Legend**
- H2S Monitor
- Flag