

Form 3160-3
(June 2015)FORM APPROVED
OMB No. 1004-0137
Expires: January 31, 2018

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT
APPLICATION FOR PERMIT TO DRILL OR REENTER

1a. Type of work: ☐ DRILL ☐ REENTER 1b. Type of Well: ☐ Oil Well ☐ Gas Well ☐ Other 1c. Type of Completion: ☐ Hydraulic Fracturing ☐ Single Zone ☐ Multiple Zone		5. Lease Serial No. 6. If Indian, Allottee or Tribe Name 7. If Unit or CA Agreement, Name and No. 8. Lease Name and Well No. 9. API Well No. 30-005-64399
2. Name of Operator 3a. Address 3b. Phone No. (include area code)		10. Field and Pool, or Exploratory 11. Sec., T. R. M. or Blk. and Survey or Area 12. County or Parish 13. State
4. Location of Well (Report location clearly and in accordance with any State requirements. *) At surface At proposed prod. zone		14. Distance in miles and direction from nearest town or post office* 15. Distance from proposed* location to nearest property or lease line, ft. (Also to nearest drig. unit line, if any) 16. No of acres in lease 17. Spacing Unit dedicated to this well 18. Distance from proposed location* to nearest well, drilling, completed, applied for, on this lease, ft. 19. Proposed Depth 20. BLM/BIA Bond No. in file 21. Elevations (Show whether DF, KDB, RT, GL, etc.) 22. Approximate date work will start* 23. Estimated duration
24. Attachments The following, completed in accordance with the requirements of Onshore Oil and Gas Order No. 1, and the Hydraulic Fracturing rule per 43 CFR 3162.3-3 (as applicable)		

- | | |
|---|---|
| 1. Well plat certified by a registered surveyor.
2. A Drilling Plan.
3. A Surface Use Plan (if the location is on National Forest System Lands, the SUPO must be filed with the appropriate Forest Service Office). | 4. Bond to cover the operations unless covered by an existing bond on file (see Item 20 above).
5. Operator certification.
6. Such other site specific information and/or plans as may be requested by the BLM. |
|---|---|

25. Signature Title	Name (Printed/Typed) Office	Date
Approved by (Signature) Title	Name (Printed/Typed) Office	Date

Application approval does not warrant or certify that the applicant holds legal or equitable title to those rights in the subject lease which would entitle the applicant to conduct operations thereon.
 Conditions of approval, if any, are attached.

Title 18 U.S.C. Section 1001 and Title 43 U.S.C. Section 1212, make it a crime for any person knowingly and willfully to make to any department or agency of the United States any false, fictitious or fraudulent statements or representations as to any matter within its jurisdiction.

(Continued on page 2)

*(Instructions on page 2)



C-102 Submit Electronically Via OCD Permitting	State of New Mexico Energy, Minerals & Natural Resources Department OIL CONSERVATION DIVISION	Revised July 9, 2024	
		Submittal Type:	☒ Initial Submittal
			☐ Amended Report
			☐ As Drilled

WELL LOCATION INFORMATION

API Number 30-005-64399	Pool Code 52770	Pool Name Round Tank; San Andres
Property Code 337180	Property Name CASTOR FEDERAL	Well Number 1H
OGRID No. 13837	Operator Name MACK ENERGY CORPORATION	Ground Level Elevation 3930.5
Surface Owner: ☐ State ☐ Fee ☐ Tribal ☒ Federal		Mineral Owner: ☐ State ☐ Fee ☐ Tribal ☒ Federal

Surface Location

UL A	Section 23	Township 15 S	Range 29 E	Lot	Ft. from N/S 1190 NORTH	Ft. from E/W 907 EAST	Latitude 33.0054941°N	Longitude 103.9935775°W	County CHAVES
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Bottom Hole Location

UL A	Section 24	Township 15 S	Range 29 E	Lot	Ft. from N/S 990 NORTH	Ft. from E/W 1 EAST	Latitude 33.0059892°N	Longitude 103.9734283°W	County CHAVES
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Dedicated Acres 160	Infill or Defining Well	Defining Well API	Overlapping Spacing Unit (Y/N)	Consolidation Code
Order Numbers.			Well setbacks are under Common Ownership: ☐ Yes ☐ No	

Kick Off Point (KOP)

UL A	Section 23	Township 15 S	Range 29 E	Lot	Ft. from N/S 1190 NORTH	Ft. from E/W 907 EAST	Latitude 33.0054941°N	Longitude 103.9935775°W	County CHAVES
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First Take Point (FTP)

UL D	Section 24	Township 15 S	Range 29 E	Lot	Ft. from N/S 990 NORTH	Ft. from E/W 100 WEST	Latitude 33.0060380°N	Longitude 103.9902932°W	County CHAVES
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Last Take Point (LTP)

UL A	Section 24	Township 15 S	Range 29 E	Lot	Ft. from N/S 990 NORTH	Ft. from E/W 100 EAST	Latitude 33.0059902°N	Longitude 103.9737512°W	County CHAVES
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Unitized Area or Area of Uniform Interest	Spacing Unit Type ☐ Horizontal ☐ Vertical	Ground Floor Elevation:
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OPERATOR CERTIFICATIONS

I hereby certify that the information contained herein is true and complete to the best of my knowledge and belief, and, if the well is a vertical or directional well, that this organization either owns a working interest or unleased mineral interest in the land including the proposed bottom hole location or has a right to drill this well at this location pursuant to a contract with an owner of a working interest run leased mineral interest, or to a voluntary pooling agreement or a compulsory pooling order here to fore entered by the division.

If this well is a horizontal well, I further certify that this organization has received the consent of at least one lessee or owner of a working interest or unleased mineral interest in each tract (in the target pool or formation) in which any part of the well's completed interval will be located or obtained a compulsory pooling order from the division.

Deana Weaver 4/15/2025
Signature Date

Deana Weaver

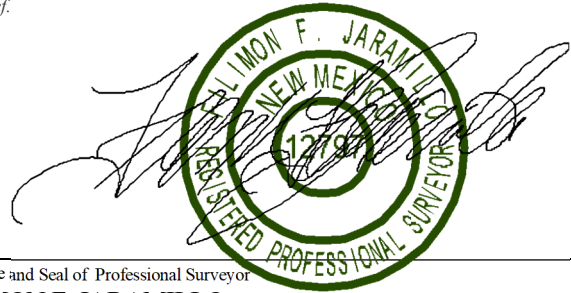
Printed Name

dweaver@mec.com

Email Address

SURVEYOR CERTIFICATIONS

I hereby certify that the well location shown on this plat was plotted from field notes of actual surveys made by me or under my supervision, and that the same is true and correct to the best of my belief.



Signature and Seal of Professional Surveyor
FILIMON F. JARAMILLO

Certificate Number

PLS 12797

Date of Survey

APRIL 15, 2025

SURVEY NO. 10049

Note: No allowable will be assigned to this completion until all interests have been consolidated or a non-standard unit has been approved by the division.

This grid represents a standard section. You may superimpose a non-standard section, or larger area, over this grid. Operators must outline the dedicated acreage in a red box, clearly show the well surface location and bottom hole location, if it is directionally drilled, with the dimensions from the section lines in the cardinal directions. If this is a horizontal wellbore show on this plat the location of the First Take Point and Last Take Point, and the point within the Completed interval (other than the First Take Point or Last Take Point) that is closest to any outer boundary of the tract.

Surveyors shall use the latest United States government survey or dependent resurvey. Well locations will be in reference to the New Mexico Principal Meridian. If the land is not surveyed, contact the OCD Engineering Bureau. Independent subdivision surveys will not be acceptable.

CASTOR FEDERAL 1H
EL. = 3930.5

GEODETIC COORDINATES
NAD 83 NMSP EAST
SURFACE LOCATION
N.= 729703.57
E.= 645492.47
LAT. = 33.0054941°N
LONG. = 103.9935775°W

LAST TAKE POINT
990' FNL, 100' FEL
N.= 729904.28
E.= 651569.80
LAT. = 33.0059902°N
LONG. = 103.9737512°W

CORNER COORDINATES TABLE
NAD 83 NMSP EAST

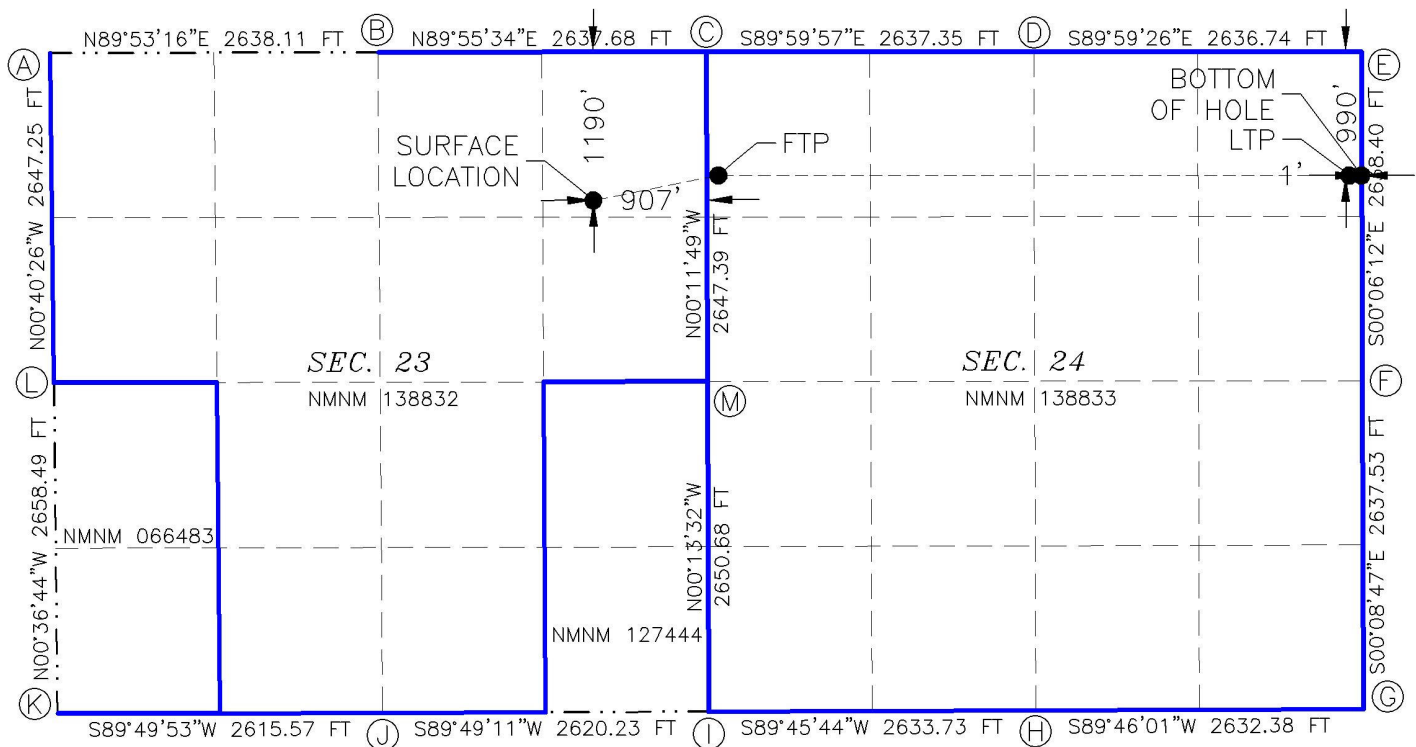
A - N.=	730885.92	E.=	641120.85
B - N.=	730891.08	E.=	643758.26
C - N.=	730894.48	E.=	646395.26
D - N.=	730894.44	E.=	649031.93
E - N.=	730894.01	E.=	651667.99
F - N.=	728256.29	E.=	651672.75
G - N.=	725619.45	E.=	651679.48
H - N.=	725608.75	E.=	649047.81
I - N.=	725597.82	E.=	646414.78
J - N.=	725589.58	E.=	643795.24
L - N.=	725581.88	E.=	641180.36
M - N.=	728239.53	E.=	641151.97
N - N.=	728247.79	E.=	646404.36

KICK OFF POINT
1190' FNL, 907' FEL
N.= 729703.57
E.= 645492.47
LAT. = 33.0054941°N
LONG. = 103.9935775°W

BOTTOM OF HOLE
990' FNL, 1' FEL
N.= 729904.26
E.= 651668.77
LAT. = 33.0059892°N
LONG. = 103.9734283°W

FIRST TAKE POINT (PPP 1)
990' FNL, 100' FWL
N.= 729904.74
E.= 646498.64
LAT. = 33.0060380°N
LONG. = 103.9902932°W

LEGEND
- SECTION LINE
- - - - - QUARTER LINE
- - - - - LEASE LINE
- - - - - WELL PATH



State of New Mexico
Energy, Minerals and Natural Resources Department
Oil Conservation Division
1220 South St. Francis Dr.
Santa Fe, NM 87505

Submit Electronically
Via E-permitting

NATURAL GAS MANAGEMENT PLAN

This Natural Gas Management Plan must be submitted with each Application for Permit to Drill (APD) for a new or recompleted well.

Section 1 – Plan Description

Effective May 25, 2021

I. Operator: Mack Energy Corporation **OGRID:** 013837 **Date:** 08 / 14 / 2024

II. Type: ☒ Original ☐ Amendment due to ☐ 19.15.27.9.D(6)(a) NMAC ☐ 19.15.27.9.D(6)(b) NMAC ☐ Other.

If Other, please describe: _____

III. Well(s): Provide the following information for each new or recompleted well or set of wells proposed to be drilled or proposed to be recompleted from a single well pad or connected to a central delivery point.

Well Name	API	ULSTR	Footages	Anticipated Oil BBL/D	Anticipated Gas MCF/D	Anticipated Produced Water BBL/D
Castor Federal 1H		Sec 23 T15S T29E	1190FNL 907FEL	100	100	1,000

IV. Central Delivery Point Name: DCP Midstream Linam Ranch Processing Plant/Durango Midstream[See 19.15.27.9(D)(1) NMAC]

V. Anticipated Schedule: Provide the following information for each new or recompleted well or set of wells proposed to be drilled or proposed to be recompleted from a single well pad or connected to a central delivery point.

Well Name	API	Spud Date	TD Reached Date	Completion Commencement Date	Initial Flow Back Date	First Production Date
Castor Federal 1H		02/01/2025	02/21/2025	03/21/2024	03/21/2024	03/21/2024

VI. Separation Equipment: ☒ Attach a complete description of how Operator will size separation equipment to optimize gas capture.

VII. Operational Practices: ☒ Attach a complete description of the actions Operator will take to comply with the requirements of Subsection A through F of 19.15.27.8 NMAC.

VIII. Best Management Practices: ☒ Attach a complete description of Operator's best management practices to minimize venting during active and planned maintenance.

Section 2 – Enhanced Plan**EFFECTIVE APRIL 1, 2022**

Beginning April 1, 2022, an operator that is not in compliance with its statewide natural gas capture requirement for the applicable reporting area must complete this section.

☒ Operator certifies that it is not required to complete this section because Operator is in compliance with its statewide natural gas capture requirement for the applicable reporting area.

IX. Anticipated Natural Gas Production:

Well	API	Anticipated Average Natural Gas Rate MCF/D	Anticipated Volume of Natural Gas for the First Year MCF

X. Natural Gas Gathering System (NGGS):

Operator	System	ULSTR of Tie-in	Anticipated Gathering Start Date	Available Maximum Daily Capacity of System Segment Tie-in

XI. Map. ☐ Attach an accurate and legible map depicting the location of the well(s), the anticipated pipeline route(s) connecting the production operations to the existing or planned interconnect of the natural gas gathering system(s), and the maximum daily capacity of the segment or portion of the natural gas gathering system(s) to which the well(s) will be connected.

XII. Line Capacity. The natural gas gathering system ☐ will ☐ will not have capacity to gather 100% of the anticipated natural gas production volume from the well prior to the date of first production.

XIII. Line Pressure. Operator ☐ does ☐ does not anticipate that its existing well(s) connected to the same segment, or portion, of the natural gas gathering system(s) described above will continue to meet anticipated increases in line pressure caused by the new well(s).

☐ Attach Operator's plan to manage production in response to the increased line pressure.

XIV. Confidentiality: ☐ Operator asserts confidentiality pursuant to Section 71-2-8 NMSA 1978 for the information provided in Section 2 as provided in Paragraph (2) of Subsection D of 19.15.27.9 NMAC, and attaches a full description of the specific information for which confidentiality is asserted and the basis for such assertion.

Section 3 - Certifications

Effective May 25, 2021

Operator certifies that, after reasonable inquiry and based on the available information at the time of submittal:

☒ Operator will be able to connect the well(s) to a natural gas gathering system in the general area with sufficient capacity to transport one hundred percent of the anticipated volume of natural gas produced from the well(s) commencing on the date of first production, taking into account the current and anticipated volumes of produced natural gas from other wells connected to the pipeline gathering system; or

☐ Operator will not be able to connect to a natural gas gathering system in the general area with sufficient capacity to transport one hundred percent of the anticipated volume of natural gas produced from the well(s) commencing on the date of first production, taking into account the current and anticipated volumes of produced natural gas from other wells connected to the pipeline gathering system.

If Operator checks this box, Operator will select one of the following:

Well Shut-In. ☐ Operator will shut-in and not produce the well until it submits the certification required by Paragraph (4) of Subsection D of 19.15.27.9 NMAC; or

Venting and Flaring Plan. ☐ Operator has attached a venting and flaring plan that evaluates and selects one or more of the potential alternative beneficial uses for the natural gas until a natural gas gathering system is available, including:

- (a) power generation on lease;
- (b) power generation for grid;
- (c) compression on lease;
- (d) liquids removal on lease;
- (e) reinjection for underground storage;
- (f) reinjection for temporary storage;
- (g) reinjection for enhanced oil recovery;
- (h) fuel cell production; and
- (i) other alternative beneficial uses approved by the division.

Section 4 - Notices

1. If, at any time after Operator submits this Natural Gas Management Plan and before the well is spud:

(a) Operator becomes aware that the natural gas gathering system it planned to connect the well(s) to has become unavailable or will not have capacity to transport one hundred percent of the production from the well(s), no later than 20 days after becoming aware of such information, Operator shall submit for OCD's approval a new or revised venting and flaring plan containing the information specified in Paragraph (5) of Subsection D of 19.15.27.9 NMAC; or

(b) Operator becomes aware that it has, cumulatively for the year, become out of compliance with its baseline natural gas capture rate or natural gas capture requirement, no later than 20 days after becoming aware of such information, Operator shall submit for OCD's approval a new or revised Natural Gas Management Plan for each well it plans to spud during the next 90 days containing the information specified in Paragraph (2) of Subsection D of 19.15.27.9 NMAC, and shall file an update for each Natural Gas Management Plan until Operator is back in compliance with its baseline natural gas capture rate or natural gas capture requirement.

2. OCD may deny or conditionally approve an APD if Operator does not make a certification, fails to submit an adequate venting and flaring plan which includes alternative beneficial uses for the anticipated volume of natural gas produced, or if OCD determines that Operator will not have adequate natural gas takeaway capacity at the time a well will be spud.

I certify that, after reasonable inquiry, the statements in and attached to this Natural Gas Management Plan are true and correct to the best of my knowledge and acknowledge that a false statement may be subject to civil and criminal penalties under the Oil and Gas Act.

Signature:	<i>Delilah Flores</i>
Printed Name:	Delilah Flores
Title:	Regulatory Technician I
E-mail Address:	delilah@mec.com
Date:	8/14/2024
Phone:	575-748-1288
OIL CONSERVATION DIVISION (Only applicable when submitted as a standalone form)	
Approved By:	
Title:	
Approval Date:	
Conditions of Approval:	

VI. Separation Equipment:

Mack Energy Corporation(MEC) production facilities include separation equipment designed to efficiently separate gas from liquid phases to optimize gas capture based on projected and estimated volumes from the targeted pool of our completion project. MEC will utilize flowback separation equipment and production separation equipment designed and built to industry specifications after the completion to optimize gas capture and send gas to sales or flare based on analytical composition. MEC operates facilities that are typically multi-well facilities. Production separation equipment is upgraded prior to new wells being completed, if determined to be undersized or inadequate. This equipment is already on-site and tied into our sales gas lines prior to the new drill operations.

VII. Operational Practices:

1. Subsection (A) Venting and Flaring of Natural Gas. MEC understands the requirements of NMAC 19.15.27.8 which outlines that the venting and flaring of natural gas during drilling, completion or production operations that constitutes waste as defined in 19.15.2 are prohibited.
2. Subsection (B) Venting and Flaring during drilling operations. This gas capture plan isn't for a well being drilled.
3. Subsection (C) Venting and flaring during completion or recompletion. Flowlines will be routed for flowback fluids into a completion or storage tank and if feasible under well conditions, flare rather than vent and commence operation of a separator as soon as it is technically feasible for a separator to function.
 - At any point in the well life (completion, production, inactive) an audio, visual and olfactory inspection be performed at prescribed intervals (weekly or monthly) pursuant to Subsection D of 19.15.27.8 NMAC, to confirm that all production equipment is operating properly and there are no leaks or releases.
4. Subsection (D) Venting and flaring during production operations
 - At any point in the well life (completion, production, inactive) an audio, visual and olfactory inspection be performed at prescribed intervals (weekly or monthly) pursuant to Subsection D of 19.15.27.8 NMAC, to confirm that all production equipment is operating properly and there are no leaks or releases.
 - Monitor manual liquid unloading for wells on-site or in close proximity (<30 minutes' drive time), take reasonable actions to achieve a stabilized rate and pressure at the earliest practical time, and take reasonable actions to minimize venting to the maximum extent practicable.
 - MEC will not vent or flare except during the approved activities listed in NMAC 19.15.27.8 (D) 14.
5. Subsection (E) Performance standards
 - All tanks and separation equipment are designed for maximum throughput and pressure to minimize waste.
 - If a flare is utilized during production operations it will have a continuous pilot and is located more than 100 feet from any known well or storage tanks.
 - At any point in the well life (completion, production, inactive) an audio, visual and olfactory inspection be performed at prescribed intervals (weekly or monthly) pursuant to Subsection D of 19.15.27.8 NMAC, to confirm that all production equipment is operating properly and there are no leaks or releases.

6. Subsection (F) Measurement or estimation of vented and flared natural gas
 - Measurement equipment is installed to measure the volume of natural gas flared from process piping.
 - When measurement isn't practicable, estimation of vented and flared natural gas will be completed as noted in 19.15.27.8 (F) 5-6.

VIII. Best Management Practices:

1. MEC has adequate storage and takeaway capacity for wells it chooses to complete as the flowlines at the sites are already in place and tied into a gathering system.
2. MEC will flare rather than vent vessel blowdown gas when technically feasible during active and/or planned maintenance to equipment on-site.
3. MEC combusts natural gas that would otherwise be vented or flared, when technically feasible.
4. MEC will shut in wells in the event of a takeaway disruption, emergency situation, or other operations where venting or flaring may occur due to equipment failures.
5. MEC has a gas gathering system in place(CTB-887)a with multiple purchaser's to limit venting or flaring, due to purchaser shut downs.



U.S. Department of the Interior
BUREAU OF LAND MANAGEMENT

Drilling Plan Data Report

03/27/2025

APD ID: 10400100456

Submission Date: 08/15/2024

Highlighted data
reflects the most
recent changes

Operator Name: MACK ENERGY CORPORATION

Well Name: CASTOR FEDERAL

Well Number: 1H

Well Type: OIL WELL

Well Work Type: Drill

[Show Final Text](#)

Section 1 - Geologic Formations

Formation ID	Formation Name	Elevation	True Vertical	Measured Depth	Lithologies	Mineral Resources	Producing Formatio
15285635	QUATERNARY	0	0	0	ANHYDRITE, SILTSTONE	NONE	N
15285636	RUSTLER	-300	300	300	ANHYDRITE, DOLOMITE, SILTSTONE	NATURAL GAS, OIL	N
15285637	TOP OF SALT	-418	418	418	ANHYDRITE, DOLOMITE, SILTSTONE	NATURAL GAS, OIL	N
15285638	BASE OF SALT	-1020	1020	1020	ANHYDRITE, DOLOMITE, SILTSTONE	NATURAL GAS, OIL	N
15285639	YATES	-1193	1193	1193	ANHYDRITE, DOLOMITE, SILTSTONE	NATURAL GAS, OIL	N
15285640	SEVEN RIVERS	-1417	1417	1417	ANHYDRITE, DOLOMITE, SILTSTONE	NATURAL GAS, OIL	N
15285641	QUEEN	-2004	2004	2004	ANHYDRITE, DOLOMITE, SILTSTONE	NATURAL GAS, OIL	Y
15285642	GRAYBURG	-2289	2289	2289	ANHYDRITE, DOLOMITE, SILTSTONE	NATURAL GAS, OIL	Y
15285643	SAN ANDRES	-2592	2592	2592	ANHYDRITE, DOLOMITE, SILTSTONE	NATURAL GAS, OIL	Y

Section 2 - Blowout Prevention

Pressure Rating (PSI): 3M

Rating Depth: 9258

Equipment: Rotation Head, Mud Gas Separator

Requesting Variance? NO

Variance request:

Testing Procedure: The BOP/BOPE test shall include a low pressure test from 250 to 300 psi. The test will be held for a minimum of 10 minutes if test is done with a test plug and 30 minutes without a test plug. The estimated Bottom Hole at TD is 120 degrees and estimated maximum bottom hole pressure is 1646 psig (0.052*3440'TVD*9.2) less than 2900 bottom hole pressure. Based on calculations we test BOP/BOPE to 2000 psi.

Choke Diagram Attachment:

choke_manifold_diagram_20240814111536.pdf

choke_manifold_20240814111536.pdf

Operator Name: MACK ENERGY CORPORATION

Well Name: CASTOR FEDERALWell Number: 1H

choke_manifold_diagram_20240814111536.pdf

choke_manifold_20240814111536.pdf

BOP Diagram Attachment:

bop_diagram_20240814111548.pdf

Section 3 - Casing

Casing ID	String Type	Hole Size	Csg Size	Condition	Standard	Tapered String	Top Set MD	Bottom Set MD	Top Set TVD	Bottom Set TVD	Top Set MSL	Bottom Set MSL	Calculated casing length MD	Grade	Weight	Joint Type	Collapse SF	Burst SF	Joint SF Type	Joint SF	Body SF Type	Body SF
1	SURFACE	17.5	13.375	NEW	API	N	0	325	0	325	3930	3605	325	J-55	48	ST&C	4.561	4.677	BUOY	32.535	BUOY	4.74
2	INTERMEDIATE	12.25	9.625	NEW	API	N	0	1200	0	1200	3930	2730	1200	J-55	36	LT&C	3.205	7.04	BUOY	10.787	BUOY	7.04
3	PRODUCTION	8.75	7.0	NEW	API	N	0	3560	0	3560	3930	370	3560	HCP-110	26	LT&C	4.086	3.317	BUOY	6.923	BUOY	3.317
4	PRODUCTION	8.75	5.5	NEW	API	N	3560	9258	3346	3440	584	490	5698	HCP-110	17	BUTT	4.797	3.547	BUOY	4.319	BUOY	3.547

Casing Attachments

Casing ID: 1StringSURFACE

Inspection Document:

Spec Document:

Tapered String Spec:

Casing Design Assumptions and Worksheet(s):

Castor_Federal_1H__Surface_20240814111822.pdf

Operator Name: MACK ENERGY CORPORATION

Well Name: CASTOR FEDERALWell Number: 1H

Casing Attachments

Casing ID: 2StringINTERMEDIATE

Inspection Document:

Spec Document:

Tapered String Spec:

Casing Design Assumptions and Worksheet(s):

Castor_Federal_1H___Intermediate_20240814135611.pdf

Casing ID: 3StringPRODUCTION

Inspection Document:

Spec Document:

Tapered String Spec:

Casing Design Assumptions and Worksheet(s):

Casing ID: 4StringPRODUCTION

Inspection Document:

Spec Document:

Tapered String Spec:

Casing Design Assumptions and Worksheet(s):

Castor_Federal_1H___Production_20240814140118.pdf

Section 4 - Cement

Operator Name: MACK ENERGY CORPORATION**Well Name:** CASTOR FEDERAL**Well Number:** 1H

String Type	Lead/Tail	Stage Tool Depth	Top MD	Bottom MD	Quantity(sx)	Yield	Density	Cu Ft	Excess%	Cement type	Additives
SURFACE	Lead		0	325	150	1.74	13.5	226	100	RFC+12% PF53+2%PF1+5ppsPF42+.125pps PF29	20 bbls gelled water. 50 sx of 11# Scavenger cmt.
SURFACE	Tail		0	325	200	1.32	14.8		100	Class C+1%PF1	20 bbls gelled water. 50 sx of 11# Scavenger cmt.
INTERMEDIATE	Lead		0	1200	250	1.73	13.5	376	50	Class C+4%PF20+.4pps PF44+.125pps PF29	20 bbls gelled water. 50 sx of 11# Scavenger cmt.
INTERMEDIATE	Tail		0	1200	200	1.34	14.8		100	Class C+1%PF1	20 bbls gelled water. 50 sx of 11# Scavenger cmt.
PRODUCTION	Lead		0	9258	325	2.82	11.5	2296	35	50/50 POZ/C+10%PF20+5% PF44+.5%PF79+3pps PF42+.4ppsPF45+.125 ppsPF29	20 bbls gelled water. 20 bbls chemical wash. 50 sx of #11 Scavenger cmt.
PRODUCTION	Tail		0	9258	1903	1.34	14.2		50	50/50 Poz/C5%PF44+2% PF13+.2%PF65+.2%PF 606+.4ppsPF45	20 bbls gelled water. 20 bbls chemical wash. 50 sx of #11 Scavenger cmt.

Section 5 - Circulating Medium

Mud System Type: Closed**Will an air or gas system be Used?** NO**Description of the equipment for the circulating system in accordance with 43 CFR 3172:****Diagram of the equipment for the circulating system in accordance with 43 CFR 3172:****Describe what will be on location to control well or mitigate other conditions:** BOPE Brine Water**Describe the mud monitoring system utilized:** Pason PVT with Pit Volume Recorder.

Circulating Medium Table

Operator Name: MACK ENERGY CORPORATION**Well Name:** CASTOR FEDERAL**Well Number:** 1H

Top Depth	Bottom Depth	Mud Type	Min Weight (lbs/gal)	Max Weight (lbs/gal)	Density (lbs/cu ft)	Gel Strength (lbs/100 sqft)	PH	Viscosity (CP)	Salinity (ppm)	Filtration (cc)	Additional Characteristics
0	325	SPUD MUD	8.5	10	74.8	0.1	11		15	15	
325	1200	LSND/GEL	8.3	10	74.8	0.1	11		12000	15	
1200	9258	LSND/GEL	8.3	9.2	74.8	0.1	11		12000	15	The estimated bottom hole at TD is 120 degrees and estimated maximum bottom hole pressure is 1646 psig (0.052*3440'TVD*9.2) less than 2900 bottom hole pressure.

Section 6 - Test, Logging, Coring

List of production tests including testing procedures, equipment and safety measures:

None

List of open and cased hole logs run in the well:

CNL/FDC,GAMMA RAY LOG,FORMATION DENSITY COMPENSATED LOG,

Coring operation description for the well:

Will evaluate after logging to determine the necessity for sidewall coring.

Section 7 - Pressure

Anticipated Bottom Hole Pressure: 1646

Anticipated Surface Pressure: 889

Anticipated Bottom Hole Temperature(F): 95

Anticipated abnormal pressures, temperatures, or potential geologic hazards? NO

Describe:

Contingency Plans geohazards description:

Contingency Plans geohazards

Hydrogen Sulfide drilling operations plan required? NO

Hydrogen sulfide drilling operations

Operator Name: MACK ENERGY CORPORATION**Well Name:** CASTOR FEDERAL**Well Number:** 1H**Section 8 - Other Information****Proposed horizontal/directional/multi-lateral plan submission:**

Castor_Federal_1H___Horizontal_Spacing_20240814144001.pdf

Castor_Federal_1H___Preliminary_Horizontal_Well_Plan_1_20240814144011.pdf

Castor_Federal_1H___Escape_Route_20240814144026.pdf

Castor_Federal_1H___Drilling_Plan_20240814144034.pdf

Castor_Federal_1H___H2S_20240814144041.pdf

Castor_Federal_1H___Natural_Gas_Management_Plan_20250219092318.pdf

Other proposed operations facets description:**Other proposed operations facets attachment:****Other Variance attachment:**

Variance_request_20240814144921.pdf

CCC__Rig_6_20240814144946.pdf

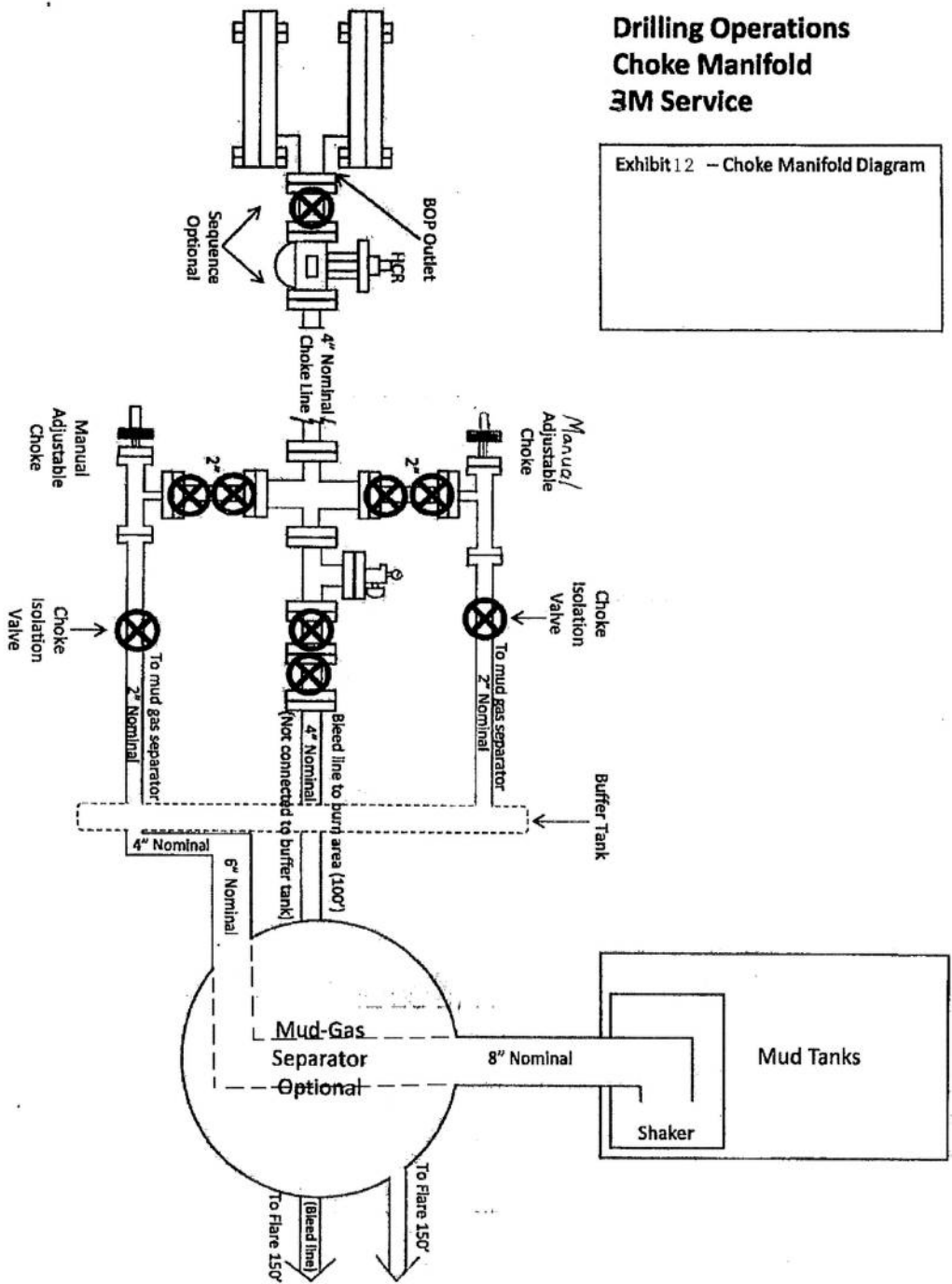
Cactus_Wellhead_installation_Procedure_20240814144910.pdf

Hose_cert_rig_3_20250116092009.pdf

Mack Energy Corporation
MANIFOLD SCHEMATIC
Exhibit #12

Drilling Operations
Choke Manifold
3M Service

Exhibit 12 - Choke Manifold Diagram



Mack Energy Corporation

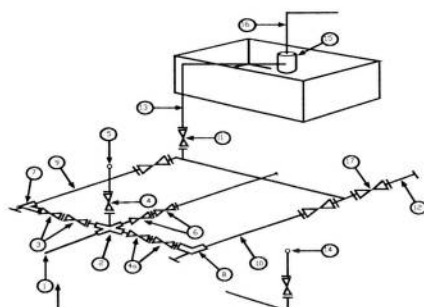
Exhibit #11

MINIMUM CHOKE MANIFOLD

3,000, 5,000, and 10,000 PSI Working Pressure

3M will be used

3 MWP - 5 MWP - 10 MWP



Mud Pit

Reserve Pit

* Location of separator optional

Below Substructure

Minimum requirements

No.		3,000 MWP			5,000 MWP			10,000 MWP		
		I.D.	Nominal	Rating	I.D.	Nominal	Rating	I.D.	Nominal	Rating
1	Line from drilling Spool		3"	3,000		3"	5,000		3"	10,000
2	Cross 3" x 3" x 3" x 2"			3,000			5,000			
2	Cross 3" x 3" x 3" x 2"									10,000
3	Valve Gate Plug	3 1/8		3,000	3 1/8		5,000	3 1/8		10,000
4	Valve Gate Plug	1 13/16		3,000	1 13/16		5,000	1 13/16		10,000
4a	Valves (1)	2 1/16		3,000	2 1/16		5,000	2 1/16		10,000
5	Pressure Gauge			3,000			5,000			10,000
6	Valve Gate Plug	3 1/8		3,000	3 1/8		5,000	3 1/8		10,000
7	Adjustable Choke (3)	2"		3,000	2"		5,000	2"		10,000
8	Adjustable Choke	1"		3,000	1"		5,000	2"		10,000
9	Line		3"	3,000		3"	5,000		3"	10,000
10	Line		2"	3,000		2"	5,000		2"	10,000
11	Valve Gate Plug	3 1/8		3,000	3 1/8		5,000	3 1/8		10,000
12	Line		3"	1,000		3"	1,000		3"	2,000
13	Line		3"	1,000		3"	1,000		3"	2,000
14	Remote reading compound Standpipe pressure gauge			3,000			5,000			10,000
15	Gas Separator		2' x 5'			2' x 5'			2' x 5'	
16	Line		4"	1,000		4"	1,000		4"	2,000
17	Valve Gate Plug	3 1/8		3,000	3 1/8		5,000	3 1/8		10,000

(1) Only one required in Class 3M

(2) Gate valves only shall be used for Class 10 M

(3) Remote operated hydraulic choke required on 5,000 psi and 10,000 psi for drilling.

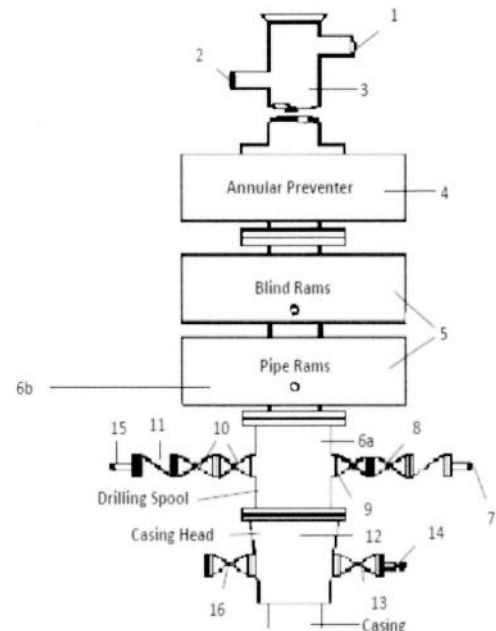
EQUIPMENT SPECIFICATIONS AND INSTALLATION INSTRUCTION

- All connections in choke manifold shall be welded, studded, flanged or Cameron clamp of comparable rating.
- All flanges shall be API 6B or 6BX and ring gaskets shall be API RX or BX. Use only BX for 10 MWP.
- All lines shall be securely anchored.
- Chokes shall be equipped with tungsten carbide seats and needles, and replacements shall be available.
- alternate with automatic chokes, a choke manifold pressure gauge shall be located on the rig floor in conjunction with the standpipe pressure gauge.
- Line from drilling spool to choke manifold should be as straight as possible. Lines downstream from chokes shall make turns by large bends or 90 degree bends using bull plugged tees

Mack Energy Corporation
Minimum Blowout Preventer Requirements
5000 psi Working Pressure
13 5/8 inch- 5 MWP
11 Inch - 5 MWP

Stack Requirements

NO.	Items	Min. I.D.	Min. Nominal
1	Flowline		2"
2	Fill up line		2"
3	Drilling nipple		
4	Annular preventer		
5	Two single or one dual hydraulically operated rams		
6a	Drilling spool with 2" min. kill line and 3" min choke line outlets		2" Choke
6b	2" min. kill line and 3" min. choke line outlets in ram. (Alternate to 6a above)		
7	Valve Gate Plug	3 1/8	
8	Gate valve-power operated	3 1/8	
9	Line to choke manifold		3"
10	Valve Gate Plug	2 1/16	
11	Check valve	2 1/16	
12	Casing head		
13	Valve Gate Plug	1 13/16	
14	Pressure gauge with needle valve		
15	Kill line to rig mud pump manifold		2"



OPTIONAL

16	Flanged Valve	1 13/16	
----	---------------	---------	--

CONTRACTOR'S OPTION TO FURNISH:

1. All equipment and connections above bradenhead or casinghead. Working pressure of preventers to be 2000 psi minimum.
2. Automatic accumulator (80 gallons, minimum) capable of closing BOP in 30 seconds or less and, holding them closed against full rated working pressure.
3. BOP controls, to be located near drillers' position.
4. Kelly equipped with Kelly cock.
5. Inside blowout preventer or its equivalent on derrick floor at all times with proper threads to fit pipe being used.
6. Kelly saver-sub equipped with rubber casing protector at all times.
7. Plug type blowout preventer tester.
8. Extra set pipe rams to fit drill pipe in use on location at all times.
9. Type RX ring gaskets in place of Type R.

MEC TO FURNISH:

1. Bradenhead or casing head and side valves.
2. Wear bushing. If required.

GENERAL NOTES:

1. Deviations from this drawing may be made only with the express permission of MEC's Drilling Manager.
2. All connections, valves, fittings, piping, etc., subject to well or pump pressure must be flanged (suitable clamp connections acceptable) and have minimum working pressure equal to rated working pressure of preventers up through choke valves must be full opening and suitable for high pressure mud service.
3. Controls to be of standard design and each marked, showing opening and closing position
4. Chokes will be positioned so as not to hamper or delay changing of choke beans.

Replaceable parts for adjustable choke, or bean sizes, retainers, and choke wrenches to be conveniently located for immediate use.

5. All valves to be equipped with hand-wheels or handles ready for immediate use.
6. Choke lines must be suitably anchored.
7. Handwheels and extensions to be connected and ready for use.
8. Valves adjacent to drilling spool to be kept open. Use outside valves except for emergency.
9. All seamless steel control piping (2000 psi working pressure) to have flexible joints to avoid stress. Hoses will be permitted.
10. Casinghead connections shall not be used except in case of emergency.
11. Does not use kill line for routine fill up operations.

Casing DesignWell: Castor Federal #1H

String Size & Function:9 5/8 in surface intermediate x

Total Depth:1200 ft TVD:1200 ft

Pressure Gradient for Calculations(While drilling)

Mud weight, collapse:10.1 #/gal Safety Factor Collapse:1.125

Mud weight, burst:10.1 #/gal Safety Factor Burst:1.25

Mud weight for joint strength:10.1 #/gal Safety Factor Joint Strength1.8

BHP @ TD for:collapse:630.24 psi Burst:630.24 psi, joint strength:630.24 psi

Partially evacuated hole? Pressure gradient remaining:10.1 #/gal

Max. Shut in surface pressure:500 psi

1st segment	1200 ft	to	0 ft	Make up Torque ft-lbs			Total ft =	1200
O.D.	Weight	Grade	Threads	opt.	min.	mx.		
9.625 inches	36 #/ft	J-55	LT&C	3,940	2,960	4,930		
Collapse Resistance	Internal Yield	Joint Strength		Body Yield		Drift		
2,020 psi	3,520 psi	394 ,000 #		564 ,000 #		8.765		

2nd segment	ft	to	ft	Make up Torque ft-lbs			Total ft =	0
O.D.	Weight	Grade	Threads	opt.	min.	mx.		
inches	#/ft							
Collapse Resistance	Internal Yield	Joint Strength		Body Yield		Drift		
psi	psi	,000 #		,000 #				

3rd segment	0 ft	to	0 ft	Make up Torque ft-lbs			Total ft =	0
O.D.	Weight	Grade	Threads	opt.	min.	mx.		
inches	#/ft							
Collapse Resistance	Internal Yield	Joint Strength		Body Yield		Drift		
psi	psi	,000 #		,000 #				

4th segment	0 ft	to	0 ft	Make up Torque ft-lbs			Total ft =	0
O.D.	Weight	Grade	Threads	opt.	min.	mx.		
inches	#/ft							
Collapse Resistance	Internal Yield	Joint Strength		Body Yield		Drift		
psi	psi	,000 #		,000 #				

5th segment	0 ft	to	0 ft	Make up Torque ft-lbs			Total ft =	0
O.D.	Weight	Grade	Threads	opt.	min.	mx.		
inches	#/ft							
Collapse Resistance	Internal Yield	Joint Strength		Body Yield		Drift		
psi	psi	,000 #		,000 #				

6th segment	0 ft	to	0 ft	Make up Torque ft-lbs			Total ft =	0
O.D.	Weight	Grade	Threads	opt.	min.	mx.		
inches	#/ft							
Collapse Resistance	Internal Yield	Joint Strength		Body Yield		Drift		
psi	psi	,000 #		,000 #				

Select	1st segment bottom	1500	S.F.	Actual	Desire
			collapse	3.205128	>= 1.125
	1200 ft to 0 ft		burst-b	7.04	>= 1.25
	9.625 0 J-55 LT&C		burst-t	7.04	
	Top of segment 1 (ft)	0	S.F.	Actual	Desire
Select	2nd segment from bottom		collapse	#DIV/0!	>= 1.125
			burst-b	0	>= 1.25
	0 ft to 0 ft		burst-t	0	
	0 0 0 0		jnt strngth	10.78734	>= 1.8

Top of segment 2 (ft)					S.F.	Actual		Desire
Select	3rd segment from bottom				collapse	#DIV/0!	>=	1.125
					burst-b	0	>=	1.25
	0 ft	to	0 ft		burst-t	0		
	0	0	0	0	jnt strngth	0	>=	1.8
Top of segment 3 (ft)					S.F.	Actual		Desire
Select	4th segment from bottom				collapse	#DIV/0!	>=	1.125
					burst-b	0	>=	1.25
	0 ft	to	0 ft		burst-t	0		
	0	0	0	0	jnt strngth	0	>=	1.8
Top of segment 4 (ft)					S.F.	Actual		Desire
Select	5th segment from bottom				collapse	#DIV/0!	>=	1.125
					burst-b	0	>=	1.25
	0 ft	to	ft		burst-t	0		
	0	0	0	0	jnt strngth	0	>=	1.8
Top of segment 5 (ft)					S.F.	Actual		Desire
Select	6th segment from bottom				collapse	#DIV/0!	>=	1.125
					burst-b	0	>=	1.25
	0 ft	to	ft		burst-t	0		
	0	0	0	0	jnt strngth	0	>=	1.8
Top of segment 6 (ft)					jnt strngth		>=	1.8

use in colapse calculations across different pressured formations

Three gradient pressure function

Depth of evaluation: 1,200 ft

516

psi @ 1,200 ft

Top of salt: 2,400 ft

fx #1

516

Base of salt: 3,700 ft

fx #2

900

TD of intermediate: 4,600 ft

fx #3

540

Pressure gradient to be used above each top to be used as a function of depth. ex. psi/ft

fx #1

fx #2

fx #3

0.43

0.75

0.45

- 1) Calculate neutral point for buckling with temperature affects computed also
- 2) Surface burst calculations & kick tolerance in surface pressure for burst
- 3) Do a comparison test to determine which value is lower joint strength or body yield to use in tensile strength calculations
- 4) Raise joint strength safety factor up to next level on page #2
- 5) Sour service what pipe can be used with proper degrading of strength factors and as function of temp

Adjust for best combination of safety factors

		Secondary
S.F. Collapse bottom of segment:		
S.F. Collapse top of segment:		#DIV/0!
S.F. Burst bottom of segment:		
S.F. Burst top of segment		
S.F. Joint strength bottom of segment:		260.582
S.F. Joint strength top of segment:		
S.F. Body yield strength bottom of segment:		373.016
S.F. Body yield strength top of segment:		15.4418

Collapse calculations for 1st segment - casing evacuated

Buoyancy factor collapse:	0.84547	
calculations for bottom of segment @	1200 ft	
hydrostatic pressure collapse - backside:	630.24 psi	
Axial load @ bottom of section	0 lbs	previous segments
Axial load factor:	0	load/(pipe body yield strength)
Collapse strength reduction factor:	1	Messrs, Westcott, Dunlop, Kemler,1940
Adjusted collapse rating of segment:	2020 psi	
Actual safety factor	3.20513	adjusted casing rating / actual pressure

calculations for top of segment @	0 ft	
hydrostatic pressure collapse - backside:	0 psi	
Axial load @ top of section	36524.3 lbs	previous segments + (this segment x BF)
Axial load factor:	0.06476	load/(pipe body yield strength)
Collapse strength reduction factor:	0.98121	Messrs, Westcott, Dunlop, Kemler,1940
Adjusted collapse rating of segment:	1982.04 psi	
Actual safety factor	#DIV/0!	adjusted casing rating / actual pressure

Burst calculations for 1st segment - Completion fracture treatment

calculations for bottom of segment @	1200 ft	
Differential burst pressure	500 psi	(frac. pres.-mud pres.) + max. surf. pres.
Burst rating of segment	3520 psi	
Actual safety factor	7.04	casing rating / differential burst pressure

calculations for top of segment @	0 ft	
Differential burst pressure	500 psi	(frac. pres.-mud pres.) + max. surf. pres.
Burst rating of segment	3520 psi	
Actual safety factor	7.04	casing rating / differential burst pressure

Joint strength calculations for 1st segment

Buoyancy factor for joint strength calc.:	0.84547
---	---------

calculations for bottom of segment @	1200 ft	
Axial load @ bottom of section	1512 lbs	weight of previous segments
Joint Strength of segment	394000 lbs	
Body Yield Strength of segment	564000 lbs	
Actual safety factor joint strength	260.582	csg joint strength / axial load
Actual safety factor body yield	373.016	csg body yield strength / axial load

calculations for top of segment @	0 ft	
Axial load @ top of section	36524.3 lbs	weight of previous segments + (this segment x BF)
Joint Strength of segment	394000 lbs	
Body Yield Strength of segment	564000 lbs	
Actual safety factor joint strength	10.7873	csg joint strength / axial load
Actual safety factor body yield	15.4418	csg body yield strength / axial load

Adjust for best combination of safety factors

	Secondary
S.F. Collapse bottom of segment:	
S.F. Collapse top of segment:	#DIV/0!
S.F. Burst bottom of segment:	
S.F. Burst top of segment	
S.F. Joint strength bottom of segment:	0
S.F. Joint strength top of segment:	
S.F. Body yield strength bottom of segment:	0
S.F. Body yield strength top of segment:	0

Collapse calculations for 2nd segment - casing evacuated

Buoyancy factor collapse:	0.84547
---------------------------	---------

calculations for bottom of segment @	0 ft	
hydrostatic pressure collapse - backside:	0 psi	
Axial load @ bottom of section	36524.3 lbs	load @ top of last segment
Axial load factor:	#DIV/0!	load/(pipe body yield strength)
Collapse strength reduction factor:	#DIV/0!	Messrs, Westcott, Dunlop, Kemler,1940
Adjusted collapse rating of segment:	#DIV/0! psi	
Actual safety factor	#DIV/0!	adjusted casing rating / actual pressure

calculations for top of segment @	0 ft	
hydrostatic pressure collapse - backside:	0 psi	
Axial load @ top of section	36524.3 lbs	previous segments + (this segment x BF)
Axial load factor:	#DIV/0!	load/(pipe body yield strength)
Collapse strength reduction factor:	#DIV/0!	Messrs, Westcott, Dunlop, Kemler,1940
Adjusted collapse rating of segment:	#DIV/0! psi	
Actual safety factor	#DIV/0!	adjusted casing rating / actual pressure

Burst calculations for 2nd segment - Completion fracture treatment

calculations for bottom of segment @	0 ft	
Differential burst pressure	500 psi	(frac. pres.-mud pres.) + max. surf. pres.
Burst rating of segment	0 psi	
Actual safety factor	0	casing rating / differential burst pressure

calculations for top of segment @	0 ft
-----------------------------------	------

Differential burst pressure	500 psi	(frac. pres.-mud pres.) + max. surf. pres.
Burst rating of segment	0 psi	
Actual safety factor	0	casing rating / differential burst pressure

Joint strength calculations for 2nd segment

Buoyancy factor for joint strength calc.:	0.84547	
calculations for bottom of segment @	0 ft	
Axial load @ bottom of section	36524.3 lbs	weight of previous segments
Joint Strength of segment	0 lbs	
Body Yield Strength of segment	0 lbs	
Actual safety factor joint strength	0	csg joint strength / axial load
Actual safety factor body yield	0	csg body yield strength / axial load
calculations for top of segment @	0 ft	
Axial load @ top of section	36524.3 lbs	weight of previous segments + (this segment x BF)
Joint Strength of segment	0 lbs	
Body Yield Strength of segment	0 lbs	
Actual safety factor joint strength	0	csg joint strength / axial load
Actual safety factor body yield	0	csg body yield strength / axial load

Adjust for best combination of safety factors

S.F. Collapse bottom of segment:	Secondary
S.F. Collapse top of segment:	#DIV/0!
S.F. Burst bottom of segment:	
S.F. Burst top of segment	
S.F. Joint strength bottom of segment:	0
S.F. Joint strength top of segment:	
S.F. Body yield strength bottom of segment:	0
S.F. Body yield strength top of segment:	0

Collapse calculations for 3rd segment - casing evacuated

Buoyancy factor collapse:	0.84547	
calculations for bottom of segment @	0 ft	
hydrostatic pressure collapse - backside:	0 psi	
Axial load @ bottom of section	36524.3 lbs	load @ top of last segment
Axial load factor:	#DIV/0!	load/(pipe body yield strength)
Collapse strength reduction factor:	#DIV/0!	Messrs, Westcott, Dunlop, Kemler,1940
Adjusted collapse rating of segment:	#DIV/0! psi	
Actual safety factor	#DIV/0!	adjusted casing rating / actual pressure
calculations for top of segment @	0 ft	
hydrostatic pressure collapse - backside:	0 psi	
Axial load @ top of section	36524.3 lbs	previous segments + (this segment x BF)
Axial load factor:	#DIV/0!	load/(pipe body yield strength)
Collapse strength reduction factor:	#DIV/0!	Messrs, Westcott, Dunlop, Kemler,1940
Adjusted collapse rating of segment:	#DIV/0! psi	
Actual safety factor	#DIV/0!	adjusted casing rating / actual pressure

Burst calculations for 3rd segment - Completion fracture treatment

calculations for bottom of segment @	0 ft	
Differential burst pressure	500 psi	(frac. pres.-mud pres.) + max. surf. pres.
Burst rating of segment	0 psi	
Actual safety factor	0	casing rating / differential burst pressure
calculations for top of segment @	0 ft	
Differential burst pressure	500 psi	(frac. pres.-mud pres.) + max. surf. pres.
Burst rating of segment	0 psi	
Actual safety factor	0	casing rating / differential burst pressure

Joint strength calculations for 3rd segment

Buoyancy factor for joint strength calc.:		
calculations for bottom of segment @	0 ft	
Axial load @ bottom of section	36524.3 lbs	load @ top of last segment
Joint Strength of segment	0 lbs	
Body Yield Strength of segment	0 lbs	
Actual safety factor joint strength	0	csg joint strength / axial load
Actual safety factor body yield	0	csg body yield strength / axial load
calculations for top of segment @	0 ft	
Axial load @ top of section	36524.3 lbs	weight of previous segments + (this segment x BF)

Joint Strength of segment	0 lbs	
Body Yield Strength of segment	0 lbs	
Actual safety factor joint strength	0	csg joint strength / axial load
Actual safety factor body yield	0	csg body yield strength / axial load

Adjust for best combination of safety factors

	Secondary
S.F. Collapse bottom of segment:	
S.F. Collapse top of segment:	#DIV/0!
S.F. Burst bottom of segment:	
S.F. Burst top of segment:	
S.F. Joint strength bottom of segment:	0
S.F. Joint strength top of segment:	
S.F. Body yield strength bottom of segment:	0
S.F. Body yield strength top of segment:	0

Collapse calculations for 4th segment - casing evacuated

Buoyancy factor collapse:	0.84547	
calculations for bottom of segment @	0 ft	
hydrostatic pressure collapse - backside:	0 psi	
Axial load @ bottom of section	36524.3 lbs	load @ top of last segment
Axial load factor:	#DIV/0!	load/(pipe body yield strength)
Collapse strength reduction factor:	#DIV/0!	Messrs, Westcott, Dunlop, Kemler,1940
Adjusted collapse rating of segment:	#DIV/0! psi	
Actual safety factor	#DIV/0!	adjusted casing rating / actual pressure

calculations for top of segment @	0 ft	
hydrostatic pressure collapse - backside:	0 psi	
Axial load @ top of section	36524.3 lbs	previous segments + (this segment x BF)
Axial load factor:	#DIV/0!	load/(pipe body yield strength)
Collapse strength reduction factor:	#DIV/0!	Messrs, Westcott, Dunlop, Kemler,1940
Adjusted collapse rating of segment:	#DIV/0! psi	
Actual safety factor	#DIV/0!	adjusted casing rating / actual pressure

Burst calculations for 4th segment - Completion fracture treatment

calculations for bottom of segment @	0 ft	
Differential burst pressure	500 psi	(frac. pres.-mud pres.) + max. surf. pres.
Burst rating of segment	0 psi	
Actual safety factor	0	casing rating / differential burst pressure
calculations for top of segment @	0 ft	
Differential burst pressure	500 psi	(frac. pres.-mud pres.) + max. surf. pres.
Burst rating of segment	0 psi	
Actual safety factor	0	casing rating / differential burst pressure

Joint strength calculations for 4th segment

Buoyancy factor for joint strength calc.:	0.84547	
calculations for bottom of segment @	0 ft	
Axial load @ bottom of section	36524.3 lbs	load @ top of last segment
Joint Strength of segment	0 lbs	
Body Yield Strength of segment	0 lbs	
Actual safety factor joint strength	0	csg joint strength / axial load
Actual safety factor body yield	0	csg body yield strength / axial load
calculations for top of segment @	0 ft	
Axial load @ top of section	36524.3 lbs	weight of previous segments + (this segment x BF)
Joint Strength of segment	0 lbs	
Body Yield Strength of segment	0 lbs	
Actual safety factor joint strength	0	csg joint strength / axial load
Actual safety factor body yield	0	csg body yield strength / axial load

Adjust for best combination of safety factors

	Secondary
S.F. Collapse bottom of segment:	
S.F. Collapse top of segment:	#DIV/0!
S.F. Burst bottom of segment:	
S.F. Burst top of segment:	
S.F. Joint strength bottom of segment:	0
S.F. Joint strength top of segment:	
S.F. Body yield strength bottom of segment:	0
S.F. Body yield strength top of segment:	0

Collapse calculations for 5th segment - casing evacuated

Buoyancy factor collapse:	0.84547	
calculations for bottom of segment @	0 ft	
hydrostatic pressure collapse - backside:	0 psi	
Axial load @ bottom of section	36524.3 lbs	load @ top of last segment
Axial load factor:	#DIV/0!	load/(pipe body yield strength)
Collapse strength reduction factor:	#DIV/0!	Messrs, Westcott, Dunlop, Kemler,1940
Adjusted collapse rating of segment:	#DIV/0! psi	
Actual safety factor	#DIV/0!	adjusted casing rating / actual pressure
calculations for top of segment @	0 ft	
hydrostatic pressure collapse - backside:	0 psi	
Axial load @ top of section	36524.3 lbs	previous segments + (this segment x BF)
Axial load factor:	#DIV/0!	load/(pipe body yield strength)
Collapse strength reduction factor:	#DIV/0!	Messrs, Westcott, Dunlop, Kemler,1940
Adjusted collapse rating of segment:	#DIV/0! psi	
Actual safety factor	#DIV/0!	adjusted casing rating / actual pressure

Burst calculations for 5th segment - Completion fracture treatment

calculations for bottom of segment @	0 ft	
Differential burst pressure	500 psi	(frac. pres.-mud pres.) + max. surf. pres.
Burst rating of segment	0 psi	
Actual safety factor	0	casing rating / differential burst pressure
calculations for top of segment @	0 ft	
Differential burst pressure	500 psi	(frac. pres.-mud pres.) + max. surf. pres.
Burst rating of segment	0 psi	
Actual safety factor	0	casing rating / differential burst pressure

Joint strength calculations for 5th segment

Buoyancy factor for joint strength calc.:	0.84547	
calculations for bottom of segment @	0 ft	
Axial load @ bottom of section	36524.3 lbs	load @ top of last segment
Joint Strength of segment	0 lbs	
Body Yield Strength of segment	0 lbs	
Actual safety factor joint strength	0	csg joint strength / axial load
Actual safety factor body yield	0	csg body yield strength / axial load
calculations for top of segment @	0 ft	
Axial load @ top of section	36524.3 lbs	weight of previous segments + (this segment x BF)
Joint Strength of segment	0 lbs	
Body Yield Strength of segment	0 lbs	
Actual safety factor joint strength	0	csg joint strength / axial load
Actual safety factor body yield	0	csg body yield strength / axial load

Adjust for best combination of safety factors

S.F. Collapse bottom of segment:	Secondary
S.F. Collapse top of segment:	#DIV/0!
S.F. Burst bottom of segment:	
S.F. Burst top of segment	
S.F. Joint strength bottom of segment:	0
S.F. Joint strength top of segment:	
S.F. Body yield strength bottom of segment:	0
S.F. Body yield strength top of segment:	0

Collapse calculations for 6th segment - casing evacuated

Buoyancy factor collapse:	0.84547	
calculations for bottom of segment @	0 ft	
hydrostatic pressure collapse - backside:	0 psi	
Axial load @ bottom of section	36524.3 lbs	load @ top of last segment
Axial load factor:	#DIV/0!	load/(pipe body yield strength)
Collapse strength reduction factor:	#DIV/0!	Messrs, Westcott, Dunlop, Kemler,1940
Adjusted collapse rating of segment:	#DIV/0! psi	
Actual safety factor	#DIV/0!	adjusted casing rating / actual pressure
calculations for top of segment @	0 ft	
hydrostatic pressure collapse - backside:	0 psi	
Axial load @ top of section	36524.3 lbs	previous segments + (this segment x BF)
Axial load factor:	#DIV/0!	load/(pipe body yield strength)
Collapse strength reduction factor:	#DIV/0!	Messrs, Westcott, Dunlop, Kemler,1940
Adjusted collapse rating of segment:	#DIV/0! psi	
Actual safety factor	#DIV/0!	adjusted casing rating / actual pressure

Burst calculations for 6th segment - Completion fracture treatment

calculations for bottom of segment @	0 ft	
Differential burst pressure	500 psi	(frac. pres.-mud pres.) + max. surf. pres.
Burst rating of segment	0 psi	
Actual safety factor	0	casing rating / differential burst pressure
calculations for top of segment @	0 ft	
Differential burst pressure	500 psi	(frac. pres.-mud pres.) + max. surf. pres.
Burst rating of segment	0 psi	
Actual safety factor	0	casing rating / differential burst pressure

Joint strength calculations for 6th segment

Buoyancy factor for joint strength calc.:	0.84547	
calculations for bottom of segment @	0 ft	
Axial load @ bottom of section	36524.3 lbs	load @ top of last segment
Joint Strength of segment	0 lbs	
Body Yield Strength of segment	0 lbs	
Actual safety factor joint strength	0	csg joint strength / axial load
Actual safety factor body yield	0	csg body yield strength / axial load
calculations for top of segment @	0 ft	
Axial load @ top of section	36524.3 lbs	weight of previous segments + (this segment x BF)
Joint Strength of segment	0 lbs	
Body Yield Strength of segment	0 lbs	
Actual safety factor joint strength	0	csg joint strength / axial load
Actual safety factor body yield	0	csg body yield strength / axial load

Casing Design Well: Castor Federal #1H

String Size & Function: 7 x 5.5 in Production x

Total Depth: 9258 ft TVD: 3440 ft

Pressure Gradient for Calculations				(While drilling)	
Mud weight, collapse:	10	#/gal	Safety Factor Collapse:	1.125	
Mud weight, burst:	10	#/gal	Safety Factor Burst:	1.25	
Mud weight for joint strength:	10	#/gal	Safety Factor Joint Strength	1.8	
BHP @ TD for:	collapse:	1788.8	psi	Burst:	1788.8
				joint strength:	1788.8
					psi

Partially evacuated hole? Pressure gradient remaining: 10 #/gal

Max. Shut in surface pressure: 3000 psi

1st segment	9258 ft	to	3560 ft	Make up Torque ft-lbs	Total ft =	5698
O.D.	Weight	Grade	Threads	opt.	min.	mx.
5.5 inches	17 #/ft	HCP-110	Buttress	4,620	3,470	5,780
Collapse Resistance	Internal Yield	Joint Strength	Body Yield	Drift		
8,580 psi	10,640 psi-lrcr	568 ,000 #	546 ,000 #	4.767		

2nd segment	3560 ft	to	0 ft	Make up Torque ft-lbs	Total ft =	3560
O.D.	Weight	Grade	Threads	opt.	min.	mx.
7 inches	26 #/ft	HCP-110	Buttress	6,930	5,200	8,660
Collapse Resistance	Internal Yield	Joint Strength	Body Yield	Drift		
7,800 psi	9,950 psi-lrcr	853 ,000 #	830 ,000 #	6.151		

3rd segment	0 ft	to	0 ft	Make up Torque ft-lbs	Total ft =	0
O.D.	Weight	Grade	Threads	opt.	min.	mx.
7 inches	26 #/ft	HCP-110	LT&C	6930	5200	8660
Collapse Resistance	Internal Yield	Joint Strength	Body Yield	Drift		
7,800 psi	9,950 psi	693 ,000 #	830 ,000 #	6.151		

4th segment	0 ft	to	0 ft	Make up Torque ft-lbs	Total ft =	0
O.D.	Weight	Grade	Threads	opt.	min.	mx.
inches	#/ft					
Collapse Resistance	Internal Yield	Joint Strength	Body Yield	Drift		
psi	psi	,000 #	,000 #			

5th segment	0 ft	to	0 ft	Make up Torque ft-lbs	Total ft =	0
O.D.	Weight	Grade	Threads	opt.	min.	mx.
inches	#/ft					
Collapse Resistance	Internal Yield	Joint Strength	Body Yield	Drift		
psi	psi	,000 #	,000 #			

6th segment	0 ft	to	0 ft	Make up Torque ft-lbs	Total ft =	0
O.D.	Weight	Grade	Threads	opt.	min.	mx.
inches	#/ft					
Collapse Resistance	Internal Yield	Joint Strength	Body Yield	Drift		
psi	psi	,000 #	,000 #			

Select	1st segment bottom	5698	S.F.	Actual	Desire
			collapse	4.796512	>= 1.125
	9258 ft to 3560 ft		burst-b	3.546667	>= 1.25
	5.5 0 HCP-110 Buttress		burst-t	3.546667	
	Top of segment 1 (ft)	3560	S.F.	Actual	Desire
Select	2nd segment from bottom		collapse	4.085954	>= 1.125
			burst-b	3.316667	>= 1.25
	3560 ft to 0 ft		burst-t	3.316667	
	7 26 HCP-110 Buttress		jnt strngth	6.922988	>= 1.8

Top of segment 2 (ft)		0	S.F.	Actual		Desire
Select	3rd segment from bottom		collapse	#DIV/0!	>=	1.125
			burst-b	3.316667	>=	1.25
			burst-t	3.316667		
			jnt strngth	5.316503	>=	1.8
0 ft to 0 ft						
7 26 HCP-110 LT&C						
Top of segment 3 (ft)		0	S.F.	Actual		Desire
Select	4th segment from bottom		collapse	#DIV/0!	>=	1.125
			burst-b	0	>=	1.25
			burst-t	0		
			jnt strngth	4.31927	>=	1.8
0 ft to 0 ft						
0 0 0 0						
Top of segment 4 (ft)			S.F.	Actual		Desire
Select	5th segment from bottom		collapse	#DIV/0!	>=	1.125
			burst-b	0	>=	1.25
			burst-t	0		
			jnt strngth	0	>=	1.8
0 ft to ft						
0 0 0 0						
Top of segment 5 (ft)			S.F.	Actual		Desire
Select	6th segment from bottom		collapse	#DIV/0!	>=	1.125
			burst-b	0	>=	1.25
			burst-t	0		
			jnt strngth	0	>=	1.8
0 ft to ft						
0 0 0 0						
Top of segment 6 (ft)			jnt strngth		>=	1.8

use in colapse calculations across different pressured formations

Three gradient pressure function

Depth of evaluation: 1,200 ft

516

psi @ 1,200 ft

Top of salt: 2,400 ft

fx #1

516

Base of salt: 3,700 ft

fx #2

900

TD of intermediate: 4,600 ft

fx #3

540

Pressure gradient to be used above each top to be used as a function of depth. ex. psi/ft

fx #1	fx #2	fx #3
0.43	0.75	0.45

- 1) Calculate neutral point for buckling with temperature affects computed also
- 2) Surface burst calculations & kick tolerance in surface pressure for burst
- 3) Do a comparison test to determine which value is lower joint strength or body yield to use in tensile strength calculations
- 4) Raise joint strength safety factor up to next level on page #2
- 5) Sour service what pipe can be used with proper degrading of strength factors and as function of temp

Adjust for best combination of safety factors

	Secondary
S.F. Collapse bottom of segment:	
S.F. Collapse top of segment:	4.4047
S.F. Burst bottom of segment:	
S.F. Burst top of segment	
S.F. Joint strength bottom of segment:	795.518
S.F. Joint strength top of segment:	
S.F. Body yield strength bottom of segment:	764.706
S.F. Body yield strength top of segment:	6.65484

Collapse calculations for 1st segment - casing evacuated

Buoyancy factor collapse:	0.847	
calculations for bottom of segment @	3440 ft	
hydrostatic pressure collapse - backside:	1788.8 psi	
Axial load @ bottom of section	0 lbs	previous segments
Axial load factor:	0	load/(pipe body yield strength)
Collapse strength reduction factor:	1	Messrs, Westcott, Dunlop, Kemler,1940
Adjusted collapse rating of segment:	8580 psi	
Actual safety factor	4.79651	adjusted casing rating / actual pressure

calculations for top of segment @	3560 ft	
hydrostatic pressure collapse - backside:	1851.2 psi	
Axial load @ top of section	82045.5 lbs	previous segments + (this segment x BF)
Axial load factor:	0.15027	load/(pipe body yield strength)
Collapse strength reduction factor:	0.95035	Messrs, Westcott, Dunlop, Kemler,1940
Adjusted collapse rating of segment:	8153.99 psi	
Actual safety factor	4.4047	adjusted casing rating / actual pressure

Burst calculations for 1st segment - Completion fracture treatment

calculations for bottom of segment @	9258 ft	
Differential burst pressure	3000 psi	(frac. pres.-mud pres.) + max. surf. pres.
Burst rating of segment	10640 psi	
Actual safety factor	3.54667	casing rating / differential burst pressure
calculations for top of segment @	3560 ft	
Differential burst pressure	3000 psi	(frac. pres.-mud pres.) + max. surf. pres.
Burst rating of segment	10640 psi	
Actual safety factor	3.54667	casing rating / differential burst pressure

Joint strength calculations for 1st segment

Buoyancy factor for joint strength calc.:	0.847	
calculations for bottom of segment @	9258 ft	
Axial load @ bottom of section	714 lbs	weight of previous segments
Joint Strength of segment	568000 lbs	
Body Yield Strength of segment	546000 lbs	
Actual safety factor joint strength	795.518	csg joint strength / axial load
Actual safety factor body yield	764.706	csg body yield strength / axial load
calculations for top of segment @	3560 ft	
Axial load @ top of section	82045.5 lbs	weight of previous segments + (this segment x BF)
Joint Strength of segment	568000 lbs	
Body Yield Strength of segment	546000 lbs	
Actual safety factor joint strength	6.92299	csg joint strength / axial load
Actual safety factor body yield	6.65484	csg body yield strength / axial load

Adjust for best combination of safety factors

	Secondary
S.F. Collapse bottom of segment:	
S.F. Collapse top of segment:	#DIV/0!
S.F. Burst bottom of segment:	
S.F. Burst top of segment	
S.F. Joint strength bottom of segment:	10.3967
S.F. Joint strength top of segment:	
S.F. Body yield strength bottom of segment:	10.1163
S.F. Body yield strength top of segment:	5.17315

Collapse calculations for 2nd segment - casing evacuated

Buoyancy factor collapse:	0.847	
calculations for bottom of segment @	3560 ft	
hydrostatic pressure collapse - backside:	1851.2 psi	
Axial load @ bottom of section	82045.5 lbs	load @ top of last segment
Axial load factor:	0.09885	load/(pipe body yield strength)
Collapse strength reduction factor:	0.96973	Messrs, Westcott, Dunlop, Kemler,1940
Adjusted collapse rating of segment:	7563.92 psi	
Actual safety factor	4.08595	adjusted casing rating / actual pressure
calculations for top of segment @	0 ft	
hydrostatic pressure collapse - backside:	0 psi	
Axial load @ top of section	160444 lbs	previous segments + (this segment x BF)
Axial load factor:	0.19331	load/(pipe body yield strength)
Collapse strength reduction factor:	0.93217	Messrs, Westcott, Dunlop, Kemler,1940
Adjusted collapse rating of segment:	7270.89 psi	
Actual safety factor	#DIV/0!	adjusted casing rating / actual pressure

Burst calculations for 2nd segment - Completion fracture treatment

calculations for bottom of segment @	3560 ft	
Differential burst pressure	3000 psi	(frac. pres.-mud pres.) + max. surf. pres.
Burst rating of segment	9950 psi	
Actual safety factor	3.31667	casing rating / differential burst pressure
calculations for top of segment @	0 ft	

Differential burst pressure	3000 psi	(frac. pres.-mud pres.) + max. surf. pres.
Burst rating of segment	9950 psi	
Actual safety factor	3.31667	casing rating / differential burst pressure

Joint strength calculations for 2nd segment

Buoyancy factor for joint strength calc.:	0.847	
calculations for bottom of segment @	3560 ft	
Axial load @ bottom of section	82045.5 lbs	weight of previous segments
Joint Strength of segment	853000 lbs	
Body Yield Strength of segment	830000 lbs	
Actual safety factor joint strength	10.3967	csg joint strength / axial load
Actual safety factor body yield	10.1163	csg body yield strength / axial load
calculations for top of segment @	0 ft	
Axial load @ top of section	160444 lbs	weight of previous segments + (this segment x BF)
Joint Strength of segment	853000 lbs	
Body Yield Strength of segment	830000 lbs	
Actual safety factor joint strength	5.3165	csg joint strength / axial load
Actual safety factor body yield	5.17315	csg body yield strength / axial load

Adjust for best combination of safety factors

S.F. Collapse bottom of segment:	Secondary
S.F. Collapse top of segment:	#DIV/0!
S.F. Burst bottom of segment:	
S.F. Burst top of segment	
S.F. Joint strength bottom of segment:	4.31927
S.F. Joint strength top of segment:	
S.F. Body yield strength bottom of segment:	5.17315
S.F. Body yield strength top of segment:	5.17315

Collapse calculations for 3rd segment - casing evacuated

Buoyancy factor collapse:	0.847	
calculations for bottom of segment @	0 ft	
hydrostatic pressure collapse - backside:	0 psi	
Axial load @ bottom of section	160444 lbs	load @ top of last segment
Axial load factor:	0.19331	load/(pipe body yield strength)
Collapse strength reduction factor:	0.93217	Messrs, Westcott, Dunlop, Kemler,1940
Adjusted collapse rating of segment:	7270.89 psi	
Actual safety factor	#DIV/0!	adjusted casing rating / actual pressure
calculations for top of segment @	0 ft	
hydrostatic pressure collapse - backside:	0 psi	
Axial load @ top of section	160444 lbs	previous segments + (this segment x BF)
Axial load factor:	0.19331	load/(pipe body yield strength)
Collapse strength reduction factor:	0.93217	Messrs, Westcott, Dunlop, Kemler,1940
Adjusted collapse rating of segment:	7270.89 psi	
Actual safety factor	#DIV/0!	adjusted casing rating / actual pressure

Burst calculations for 3rd segment - Completion fracture treatment

calculations for bottom of segment @	0 ft	
Differential burst pressure	3000 psi	(frac. pres.-mud pres.) + max. surf. pres.
Burst rating of segment	9950 psi	
Actual safety factor	3.31667	casing rating / differential burst pressure
calculations for top of segment @	0 ft	
Differential burst pressure	3000 psi	(frac. pres.-mud pres.) + max. surf. pres.
Burst rating of segment	9950 psi	
Actual safety factor	3.31667	casing rating / differential burst pressure

Joint strength calculations for 3rd segment

Buoyancy factor for joint strength calc.:		
calculations for bottom of segment @	0 ft	
Axial load @ bottom of section	160444 lbs	load @ top of last segment
Joint Strength of segment	693000 lbs	
Body Yield Strength of segment	830000 lbs	
Actual safety factor joint strength	4.31927	csg joint strength / axial load
Actual safety factor body yield	5.17315	csg body yield strength / axial load
calculations for top of segment @	0 ft	
Axial load @ top of section	160444 lbs	weight of previous segments + (this segment x BF)

Joint Strength of segment	693000 lbs	
Body Yield Strength of segment	830000 lbs	
Actual safety factor joint strength	4.31927	csg joint strength / axial load
Actual safety factor body yield	5.17315	csg body yield strength / axial load

Adjust for best combination of safety factors

	Secondary
S.F. Collapse bottom of segment:	
S.F. Collapse top of segment:	#DIV/0!
S.F. Burst bottom of segment:	
S.F. Burst top of segment:	
S.F. Joint strength bottom of segment:	0
S.F. Joint strength top of segment:	
S.F. Body yield strength bottom of segment:	0
S.F. Body yield strength top of segment:	0

Collapse calculations for 4th segment - casing evacuated

Buoyancy factor collapse:	0.847	
calculations for bottom of segment @	0 ft	
hydrostatic pressure collapse - backside:	0 psi	
Axial load @ bottom of section	160444 lbs	load @ top of last segment
Axial load factor:	#DIV/0!	load/(pipe body yield strength)
Collapse strength reduction factor:	#DIV/0!	Messrs, Westcott, Dunlop, Kemler,1940
Adjusted collapse rating of segment:	#DIV/0! psi	
Actual safety factor	#DIV/0!	adjusted casing rating / actual pressure

calculations for top of segment @	0 ft	
hydrostatic pressure collapse - backside:	0 psi	
Axial load @ top of section	160444 lbs	previous segments + (this segment x BF)
Axial load factor:	#DIV/0!	load/(pipe body yield strength)
Collapse strength reduction factor:	#DIV/0!	Messrs, Westcott, Dunlop, Kemler,1940
Adjusted collapse rating of segment:	#DIV/0! psi	
Actual safety factor	#DIV/0!	adjusted casing rating / actual pressure

Burst calculations for 4th segment - Completion fracture treatment

calculations for bottom of segment @	0 ft	
Differential burst pressure	3000 psi	(frac. pres.-mud pres.) + max. surf. pres.
Burst rating of segment	0 psi	
Actual safety factor	0	casing rating / differential burst pressure
calculations for top of segment @	0 ft	
Differential burst pressure	3000 psi	(frac. pres.-mud pres.) + max. surf. pres.
Burst rating of segment	0 psi	
Actual safety factor	0	casing rating / differential burst pressure

Joint strength calculations for 4th segment

Buoyancy factor for joint strength calc.:	0.847	
calculations for bottom of segment @	0 ft	
Axial load @ bottom of section	160444 lbs	load @ top of last segment
Joint Strength of segment	0 lbs	
Body Yield Strength of segment	0 lbs	
Actual safety factor joint strength	0	csg joint strength / axial load
Actual safety factor body yield	0	csg body yield strength / axial load
calculations for top of segment @	0 ft	
Axial load @ top of section	160444 lbs	weight of previous segments + (this segment x BF)
Joint Strength of segment	0 lbs	
Body Yield Strength of segment	0 lbs	
Actual safety factor joint strength	0	csg joint strength / axial load
Actual safety factor body yield	0	csg body yield strength / axial load

Adjust for best combination of safety factors

	Secondary
S.F. Collapse bottom of segment:	
S.F. Collapse top of segment:	#DIV/0!
S.F. Burst bottom of segment:	
S.F. Burst top of segment:	
S.F. Joint strength bottom of segment:	0
S.F. Joint strength top of segment:	
S.F. Body yield strength bottom of segment:	0
S.F. Body yield strength top of segment:	0

Collapse calculations for 5th segment - casing evacuated

Buoyancy factor collapse:	0.847	
calculations for bottom of segment @	0 ft	
hydrostatic pressure collapse - backside:	0 psi	
Axial load @ bottom of section	160444 lbs	load @ top of last segment
Axial load factor:	#DIV/0!	load/(pipe body yield strength)
Collapse strength reduction factor:	#DIV/0!	Messrs, Westcott, Dunlop, Kemler,1940
Adjusted collapse rating of segment:	#DIV/0! psi	
Actual safety factor	#DIV/0!	adjusted casing rating / actual pressure
calculations for top of segment @	0 ft	
hydrostatic pressure collapse - backside:	0 psi	
Axial load @ top of section	160444 lbs	previous segments + (this segment x BF)
Axial load factor:	#DIV/0!	load/(pipe body yield strength)
Collapse strength reduction factor:	#DIV/0!	Messrs, Westcott, Dunlop, Kemler,1940
Adjusted collapse rating of segment:	#DIV/0! psi	
Actual safety factor	#DIV/0!	adjusted casing rating / actual pressure

Burst calculations for 5th segment - Completion fracture treatment

calculations for bottom of segment @	0 ft	
Differential burst pressure	3000 psi	(frac. pres.-mud pres.) + max. surf. pres.
Burst rating of segment	0 psi	
Actual safety factor	0	casing rating / differential burst pressure
calculations for top of segment @	0 ft	
Differential burst pressure	3000 psi	(frac. pres.-mud pres.) + max. surf. pres.
Burst rating of segment	0 psi	
Actual safety factor	0	casing rating / differential burst pressure

Joint strength calculations for 5th segment

Buoyancy factor for joint strength calc.:	0.847	
calculations for bottom of segment @	0 ft	
Axial load @ bottom of section	160444 lbs	load @ top of last segment
Joint Strength of segment	0 lbs	
Body Yield Strength of segment	0 lbs	
Actual safety factor joint strength	0	csg joint strength / axial load
Actual safety factor body yield	0	csg body yield strength / axial load
calculations for top of segment @	0 ft	
Axial load @ top of section	160444 lbs	weight of previous segments + (this segment x BF)
Joint Strength of segment	0 lbs	
Body Yield Strength of segment	0 lbs	
Actual safety factor joint strength	0	csg joint strength / axial load
Actual safety factor body yield	0	csg body yield strength / axial load

Adjust for best combination of safety factors

S.F. Collapse bottom of segment:	Secondary
S.F. Collapse top of segment:	#DIV/0!
S.F. Burst bottom of segment:	
S.F. Burst top of segment	
S.F. Joint strength bottom of segment:	0
S.F. Joint strength top of segment:	
S.F. Body yield strength bottom of segment:	0
S.F. Body yield strength top of segment:	0

Collapse calculations for 6th segment - casing evacuated

Buoyancy factor collapse:	0.847	
calculations for bottom of segment @	0 ft	
hydrostatic pressure collapse - backside:	0 psi	
Axial load @ bottom of section	160444 lbs	load @ top of last segment
Axial load factor:	#DIV/0!	load/(pipe body yield strength)
Collapse strength reduction factor:	#DIV/0!	Messrs, Westcott, Dunlop, Kemler,1940
Adjusted collapse rating of segment:	#DIV/0! psi	
Actual safety factor	#DIV/0!	adjusted casing rating / actual pressure
calculations for top of segment @	0 ft	
hydrostatic pressure collapse - backside:	0 psi	
Axial load @ top of section	160444 lbs	previous segments + (this segment x BF)
Axial load factor:	#DIV/0!	load/(pipe body yield strength)
Collapse strength reduction factor:	#DIV/0!	Messrs, Westcott, Dunlop, Kemler,1940
Adjusted collapse rating of segment:	#DIV/0! psi	
Actual safety factor	#DIV/0!	adjusted casing rating / actual pressure

Burst calculations for 6th segment - Completion fracture treatment

calculations for bottom of segment @	0 ft	
Differential burst pressure	3000 psi	(frac. pres.-mud pres.) + max. surf. pres.
Burst rating of segment	0 psi	
Actual safety factor	0	casing rating / differential burst pressure
calculations for top of segment @	0 ft	
Differential burst pressure	3000 psi	(frac. pres.-mud pres.) + max. surf. pres.
Burst rating of segment	0 psi	
Actual safety factor	0	casing rating / differential burst pressure

Joint strength calculations for 6th segment

Buoyancy factor for joint strength calc.:	0.847	
calculations for bottom of segment @	0 ft	
Axial load @ bottom of section	160444 lbs	load @ top of last segment
Joint Strength of segment	0 lbs	
Body Yield Strength of segment	0 lbs	
Actual safety factor joint strength	0	csg joint strength / axial load
Actual safety factor body yield	0	csg body yield strength / axial load
calculations for top of segment @	0 ft	
Axial load @ top of section	160444 lbs	weight of previous segments + (this segment x BF)
Joint Strength of segment	0 lbs	
Body Yield Strength of segment	0 lbs	
Actual safety factor joint strength	0	csg joint strength / axial load
Actual safety factor body yield	0	csg body yield strength / axial load

Casing DesignWell: Castor Federal #1H

String Size & Function:13 3/8 in surface x intermediate

Total Depth:325 ft

Pressure Gradient for Calculations(While drilling)

Mud weight, collapse:9.6 #/galSafety Factor Collapse:1.125

Mud weight, burst:9.6 #/galSafety Factor Burst:1.25

Mud weight for joint strength:9.6 #/galSafety Factor Joint Strength1.8

BHP @ TD for:collapse:162.24 psiBurst:162.24 psi, joint strength:162.24 psi

Partially evacuated hole?Pressure gradient remaining:10 #/gal

Max. Shut in surface pressure:500 psi

1st segment	325 ft	to	0 ft	Make up Torque ft-lbs			Total ft =	325
O.D.	Weight	Grade	Threads	opt.	min.	mx.		
13.375 inches	48 #/ft	J-55	ST&C	3,220	2,420	4,030		
Collapse Resistance	Internal Yield	Joint Strength		Body Yield		Drift		
740	2,370 psi	433 ,000 #		744 ,000 #		12.559		

2nd segment	0 ft	to	0 ft	Make up Torque ft-lbs			Total ft =	0
O.D.	Weight	Grade	Threads	opt.	min.	mx.		
inches	#/ft							
Collapse Resistance	Internal Yield	Joint Strength		Body Yield		Drift		
psi	psi	,000 #		,000 #				

3rd segment	0 ft	to	0 ft	Make up Torque ft-lbs			Total ft =	0
O.D.	Weight	Grade	Threads	opt.	min.	mx.		
inches	#/ft							
Collapse Resistance	Internal Yield	Joint Strength		Body Yield		Drift		
psi	psi	,000 #		,000 #				

4th segment	0 ft	to	0 ft	Make up Torque ft-lbs			Total ft =	0
O.D.	Weight	Grade	Threads	opt.	min.	mx.		
inches	#/ft							
Collapse Resistance	Internal Yield	Joint Strength		Body Yield		Drift		
psi	psi	,000 #		,000 #				

5th segment	0 ft	to	0 ft	Make up Torque ft-lbs			Total ft =	0
O.D.	Weight	Grade	Threads	opt.	min.	mx.		
inches	#/ft							
Collapse Resistance	Internal Yield	Joint Strength		Body Yield		Drift		
psi	psi	,000 #		,000 #				

6th segment	0 ft	to	0 ft	Make up Torque ft-lbs			Total ft =	0
O.D.	Weight	Grade	Threads	opt.	min.	mx.		
inches	#/ft							
Collapse Resistance	Internal Yield	Joint Strength		Body Yield		Drift		
psi	psi	,000 #		,000 #				

Select	1st segment bottom	325	S.F.	Actual	Desire
			collapse	4.561144	>= 1.125
	325 ft to 0 ft		burst-b	4.67677	>= 1.25
	13.375 0 J-55 ST&C		burst-t	4.74	
	Top of segment 1 (ft)	0	S.F.	Actual	Desire
Select	2nd segment from bottom		collapse	#DIV/0!	>= 1.125
			burst-b	0	>= 1.25
	0 ft to 0 ft		burst-t	0	
	0 0 0 0		jnt strngth	32.53518	>= 1.8

Top of segment 2 (ft)			S.F.	Actual	Desire
Select	3rd segment from bottom		collapse	#DIV/0!	>= 1.125
			burst-b	0	>= 1.25
	0 ft to 0 ft		burst-t	0	
	0 0 0 0		jnt strngth	0	>= 1.8
Top of segment 3 (ft)			S.F.	Actual	Desire
Select	4th segment from bottom		collapse	#DIV/0!	>= 1.125
			burst-b	0	>= 1.25
	0 ft to 0 ft		burst-t	0	
	0 0 0 0		jnt strngth	0	>= 1.8
Top of segment 4 (ft)			S.F.	Actual	Desire
Select	5th segment from bottom		collapse	#DIV/0!	>= 1.125
			burst-b	0	>= 1.25
	0 ft to ft		burst-t	0	
	0 0 0 0		jnt strngth	0	>= 1.8
Top of segment 5 (ft)			S.F.	Actual	Desire
Select	6th segment from bottom		collapse	#DIV/0!	>= 1.125
			burst-b	0	>= 1.25
	0 ft to ft		burst-t	0	
	0 0 0 0		jnt strngth	0	>= 1.8
Top of segment 6 (ft)			jnt strngth		>= 1.8

use in colapse calculations across different pressured formations

Three gradient pressure function

Depth of evaluation: 1,200 ft

516

psi @ 1,200 ft

Top of salt: 2,400 ft

fx #1

516

Base of salt: 3,700 ft

fx #2

900

TD of intermediate: 4,600 ft

fx #3

540

Pressure gradient to be used above each top to be used as a function of depth. ex. psi/ft

fx #1	fx #2	fx #3
0.43	0.75	0.45

- 1) Calculate neutral point for buckling with temperature affects computed also
- 2) Surface burst calculations & kick tolerance in surface pressure for burst
- 3) Do a comparison test to determine which value is lower joint strength or body yield to use in tensile strength calculations
- 4) Raise joint strength safety factor up to next level on page #2
- 5) Sour service what pipe can be used with proper degrading of strength factors and as function of temp

Adjust for best combination of safety factors

		Secondary
S.F. Collapse bottom of segment:		
S.F. Collapse top of segment:		#DIV/0!
S.F. Burst bottom of segment:		
S.F. Burst top of segment		
S.F. Joint strength bottom of segment:		214.782
S.F. Joint strength top of segment:		
S.F. Body yield strength bottom of segment:		369.048
S.F. Body yield strength top of segment:		55.9034

Collapse calculations for 1st segment - casing evacuated

Buoyancy factor collapse:	0.85312	
calculations for bottom of segment @	325 ft	
hydrostatic pressure collapse - backside:	162.24 psi	
Axial load @ bottom of section	0 lbs	previous segments
Axial load factor:	0	load/(pipe body yield strength)
Collapse strength reduction factor:	1	Messrs, Westcott, Dunlop, Kemler,1940
Adjusted collapse rating of segment:	740 psi	
Actual safety factor	4.56114	adjusted casing rating / actual pressure

calculations for top of segment @	0 ft	
hydrostatic pressure collapse - backside:	0 psi	
Axial load @ top of section	13308.7 lbs	previous segments + (this segment x BF)
Axial load factor:	0.01789	load/(pipe body yield strength)
Collapse strength reduction factor:	0.9952	Messrs, Westcott, Dunlop, Kemler,1940
Adjusted collapse rating of segment:	736.448 psi	
Actual safety factor	#DIV/0!	adjusted casing rating / actual pressure

Burst calculations for 1st segment - Completion fracture treatment

calculations for bottom of segment @	325 ft	
Differential burst pressure	506.76 psi	(frac. pres.-mud pres.) + max. surf. pres.
Burst rating of segment	2370 psi	
Actual safety factor	4.67677	casing rating / differential burst pressure

calculations for top of segment @	0 ft	
Differential burst pressure	500 psi	(frac. pres.-mud pres.) + max. surf. pres.
Burst rating of segment	2370 psi	
Actual safety factor	4.74	casing rating / differential burst pressure

Joint strength calculations for 1st segment

Buoyancy factor for joint strength calc.:	0.85312
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calculations for bottom of segment @	325 ft	
Axial load @ bottom of section	2016 lbs	weight of previous segments
Joint Strength of segment	433000 lbs	
Body Yield Strength of segment	744000 lbs	
Actual safety factor joint strength	214.782	csg joint strength / axial load
Actual safety factor body yield	369.048	csg body yield strength / axial load

calculations for top of segment @	0 ft	
Axial load @ top of section	13308.7 lbs	weight of previous segments + (this segment x BF)
Joint Strength of segment	433000 lbs	
Body Yield Strength of segment	744000 lbs	
Actual safety factor joint strength	32.5352	csg joint strength / axial load
Actual safety factor body yield	55.9034	csg body yield strength / axial load

Adjust for best combination of safety factors

	Secondary
S.F. Collapse bottom of segment:	
S.F. Collapse top of segment:	#DIV/0!
S.F. Burst bottom of segment:	
S.F. Burst top of segment	
S.F. Joint strength bottom of segment:	0
S.F. Joint strength top of segment:	
S.F. Body yield strength bottom of segment:	0
S.F. Body yield strength top of segment:	0

Collapse calculations for 2nd segment - casing evacuated

Buoyancy factor collapse:	0.85312
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calculations for bottom of segment @	0 ft	
hydrostatic pressure collapse - backside:	0 psi	
Axial load @ bottom of section	13308.7 lbs	load @ top of last segment
Axial load factor:	#DIV/0!	load/(pipe body yield strength)
Collapse strength reduction factor:	#DIV/0!	Messrs, Westcott, Dunlop, Kemler,1940
Adjusted collapse rating of segment:	#DIV/0! psi	
Actual safety factor	#DIV/0!	adjusted casing rating / actual pressure

calculations for top of segment @	0 ft	
hydrostatic pressure collapse - backside:	0 psi	
Axial load @ top of section	13308.7 lbs	previous segments + (this segment x BF)
Axial load factor:	#DIV/0!	load/(pipe body yield strength)
Collapse strength reduction factor:	#DIV/0!	Messrs, Westcott, Dunlop, Kemler,1940
Adjusted collapse rating of segment:	#DIV/0! psi	
Actual safety factor	#DIV/0!	adjusted casing rating / actual pressure

Burst calculations for 2nd segment - Completion fracture treatment

calculations for bottom of segment @	0 ft	
Differential burst pressure	500 psi	(frac. pres.-mud pres.) + max. surf. pres.
Burst rating of segment	0 psi	
Actual safety factor	0	casing rating / differential burst pressure

calculations for top of segment @	0 ft
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Differential burst pressure	500 psi	(frac. pres.-mud pres.) + max. surf. pres.
Burst rating of segment	0 psi	
Actual safety factor	0	casing rating / differential burst pressure

Joint strength calculations for 2nd segment

Buoyancy factor for joint strength calc.:	0.85312	
calculations for bottom of segment @	0 ft	
Axial load @ bottom of section	13308.7 lbs	weight of previous segments
Joint Strength of segment	0 lbs	
Body Yield Strength of segment	0 lbs	
Actual safety factor joint strength	0	csg joint strength / axial load
Actual safety factor body yield	0	csg body yield strength / axial load
calculations for top of segment @	0 ft	
Axial load @ top of section	13308.7 lbs	weight of previous segments + (this segment x BF)
Joint Strength of segment	0 lbs	
Body Yield Strength of segment	0 lbs	
Actual safety factor joint strength	0	csg joint strength / axial load
Actual safety factor body yield	0	csg body yield strength / axial load

Adjust for best combination of safety factors

S.F. Collapse bottom of segment:	Secondary
S.F. Collapse top of segment:	#DIV/0!
S.F. Burst bottom of segment:	
S.F. Burst top of segment	
S.F. Joint strength bottom of segment:	0
S.F. Joint strength top of segment:	
S.F. Body yield strength bottom of segment:	0
S.F. Body yield strength top of segment:	0

Collapse calculations for 3rd segment - casing evacuated

Buoyancy factor collapse:	0.85312	
calculations for bottom of segment @	0 ft	
hydrostatic pressure collapse - backside:	0 psi	
Axial load @ bottom of section	13308.7 lbs	load @ top of last segment
Axial load factor:	#DIV/0!	load/(pipe body yield strength)
Collapse strength reduction factor:	#DIV/0!	Messrs, Westcott, Dunlop, Kemler,1940
Adjusted collapse rating of segment:	#DIV/0! psi	
Actual safety factor	#DIV/0!	adjusted casing rating / actual pressure
calculations for top of segment @	0 ft	
hydrostatic pressure collapse - backside:	0 psi	
Axial load @ top of section	13308.7 lbs	previous segments + (this segment x BF)
Axial load factor:	#DIV/0!	load/(pipe body yield strength)
Collapse strength reduction factor:	#DIV/0!	Messrs, Westcott, Dunlop, Kemler,1940
Adjusted collapse rating of segment:	#DIV/0! psi	
Actual safety factor	#DIV/0!	adjusted casing rating / actual pressure

Burst calculations for 3rd segment - Completion fracture treatment

calculations for bottom of segment @	0 ft	
Differential burst pressure	500 psi	(frac. pres.-mud pres.) + max. surf. pres.
Burst rating of segment	0 psi	
Actual safety factor	0	casing rating / differential burst pressure
calculations for top of segment @	0 ft	
Differential burst pressure	500 psi	(frac. pres.-mud pres.) + max. surf. pres.
Burst rating of segment	0 psi	
Actual safety factor	0	casing rating / differential burst pressure

Joint strength calculations for 3rd segment

Buoyancy factor for joint strength calc.:		
calculations for bottom of segment @	0 ft	
Axial load @ bottom of section	13308.7 lbs	load @ top of last segment
Joint Strength of segment	0 lbs	
Body Yield Strength of segment	0 lbs	
Actual safety factor joint strength	0	csg joint strength / axial load
Actual safety factor body yield	0	csg body yield strength / axial load
calculations for top of segment @	0 ft	
Axial load @ top of section	13308.7 lbs	weight of previous segments + (this segment x BF)

Joint Strength of segment	0 lbs	
Body Yield Strength of segment	0 lbs	
Actual safety factor joint strength	0	csg joint strength / axial load
Actual safety factor body yield	0	csg body yield strength / axial load

Adjust for best combination of safety factors

	Secondary
S.F. Collapse bottom of segment:	
S.F. Collapse top of segment:	#DIV/0!
S.F. Burst bottom of segment:	
S.F. Burst top of segment:	
S.F. Joint strength bottom of segment:	0
S.F. Joint strength top of segment:	
S.F. Body yield strength bottom of segment:	0
S.F. Body yield strength top of segment:	0

Collapse calculations for 4th segment - casing evacuated

Buoyancy factor collapse:	0.85312	
calculations for bottom of segment @	0 ft	
hydrostatic pressure collapse - backside:	0 psi	
Axial load @ bottom of section	13308.7 lbs	load @ top of last segment
Axial load factor:	#DIV/0!	load/(pipe body yield strength)
Collapse strength reduction factor:	#DIV/0!	Messrs, Westcott, Dunlop, Kemler,1940
Adjusted collapse rating of segment:	#DIV/0! psi	
Actual safety factor	#DIV/0!	adjusted casing rating / actual pressure
calculations for top of segment @	0 ft	
hydrostatic pressure collapse - backside:	0 psi	
Axial load @ top of section	13308.7 lbs	previous segments + (this segment x BF)
Axial load factor:	#DIV/0!	load/(pipe body yield strength)
Collapse strength reduction factor:	#DIV/0!	Messrs, Westcott, Dunlop, Kemler,1940
Adjusted collapse rating of segment:	#DIV/0! psi	
Actual safety factor	#DIV/0!	adjusted casing rating / actual pressure

Burst calculations for 4th segment - Completion fracture treatment

calculations for bottom of segment @	0 ft	
Differential burst pressure	500 psi	(frac. pres.-mud pres.) + max. surf. pres.
Burst rating of segment	0 psi	
Actual safety factor	0	casing rating / differential burst pressure
calculations for top of segment @	0 ft	
Differential burst pressure	500 psi	(frac. pres.-mud pres.) + max. surf. pres.
Burst rating of segment	0 psi	
Actual safety factor	0	casing rating / differential burst pressure

Joint strength calculations for 4th segment

Buoyancy factor for joint strength calc.:	0.85312	
calculations for bottom of segment @	0 ft	
Axial load @ bottom of section	13308.7 lbs	load @ top of last segment
Joint Strength of segment	0 lbs	
Body Yield Strength of segment	0 lbs	
Actual safety factor joint strength	0	csg joint strength / axial load
Actual safety factor body yield	0	csg body yield strength / axial load
calculations for top of segment @	0 ft	
Axial load @ top of section	13308.7 lbs	weight of previous segments + (this segment x BF)
Joint Strength of segment	0 lbs	
Body Yield Strength of segment	0 lbs	
Actual safety factor joint strength	0	csg joint strength / axial load
Actual safety factor body yield	0	csg body yield strength / axial load

Adjust for best combination of safety factors

	Secondary
S.F. Collapse bottom of segment:	
S.F. Collapse top of segment:	#DIV/0!
S.F. Burst bottom of segment:	
S.F. Burst top of segment:	
S.F. Joint strength bottom of segment:	0
S.F. Joint strength top of segment:	
S.F. Body yield strength bottom of segment:	0
S.F. Body yield strength top of segment:	0

Collapse calculations for 5th segment - casing evacuated

Buoyancy factor collapse:	0.85312	
calculations for bottom of segment @	0 ft	
hydrostatic pressure collapse - backside:	0 psi	
Axial load @ bottom of section	13308.7 lbs	load @ top of last segment
Axial load factor:	#DIV/0!	load/(pipe body yield strength)
Collapse strength reduction factor:	#DIV/0!	Messrs, Westcott, Dunlop, Kemler,1940
Adjusted collapse rating of segment:	#DIV/0! psi	
Actual safety factor	#DIV/0!	adjusted casing rating / actual pressure
calculations for top of segment @	0 ft	
hydrostatic pressure collapse - backside:	0 psi	
Axial load @ top of section	13308.7 lbs	previous segments + (this segment x BF)
Axial load factor:	#DIV/0!	load/(pipe body yield strength)
Collapse strength reduction factor:	#DIV/0!	Messrs, Westcott, Dunlop, Kemler,1940
Adjusted collapse rating of segment:	#DIV/0! psi	
Actual safety factor	#DIV/0!	adjusted casing rating / actual pressure

Burst calculations for 5th segment - Completion fracture treatment

calculations for bottom of segment @	0 ft	
Differential burst pressure	500 psi	(frac. pres.-mud pres.) + max. surf. pres.
Burst rating of segment	0 psi	
Actual safety factor	0	casing rating / differential burst pressure
calculations for top of segment @	0 ft	
Differential burst pressure	500 psi	(frac. pres.-mud pres.) + max. surf. pres.
Burst rating of segment	0 psi	
Actual safety factor	0	casing rating / differential burst pressure

Joint strength calculations for 5th segment

Buoyancy factor for joint strength calc.:	0.85312	
calculations for bottom of segment @	0 ft	
Axial load @ bottom of section	13308.7 lbs	load @ top of last segment
Joint Strength of segment	0 lbs	
Body Yield Strength of segment	0 lbs	
Actual safety factor joint strength	0	csg joint strength / axial load
Actual safety factor body yield	0	csg body yield strength / axial load
calculations for top of segment @	0 ft	
Axial load @ top of section	13308.7 lbs	weight of previous segments + (this segment x BF)
Joint Strength of segment	0 lbs	
Body Yield Strength of segment	0 lbs	
Actual safety factor joint strength	0	csg joint strength / axial load
Actual safety factor body yield	0	csg body yield strength / axial load

Adjust for best combination of safety factors

S.F. Collapse bottom of segment:	Secondary
S.F. Collapse top of segment:	#DIV/0!
S.F. Burst bottom of segment:	
S.F. Burst top of segment	
S.F. Joint strength bottom of segment:	0
S.F. Joint strength top of segment:	
S.F. Body yield strength bottom of segment:	0
S.F. Body yield strength top of segment:	0

Collapse calculations for 6th segment - casing evacuated

Buoyancy factor collapse:	0.85312	
calculations for bottom of segment @	0 ft	
hydrostatic pressure collapse - backside:	0 psi	
Axial load @ bottom of section	13308.7 lbs	load @ top of last segment
Axial load factor:	#DIV/0!	load/(pipe body yield strength)
Collapse strength reduction factor:	#DIV/0!	Messrs, Westcott, Dunlop, Kemler,1940
Adjusted collapse rating of segment:	#DIV/0! psi	
Actual safety factor	#DIV/0!	adjusted casing rating / actual pressure
calculations for top of segment @	0 ft	
hydrostatic pressure collapse - backside:	0 psi	
Axial load @ top of section	13308.7 lbs	previous segments + (this segment x BF)
Axial load factor:	#DIV/0!	load/(pipe body yield strength)
Collapse strength reduction factor:	#DIV/0!	Messrs, Westcott, Dunlop, Kemler,1940
Adjusted collapse rating of segment:	#DIV/0! psi	
Actual safety factor	#DIV/0!	adjusted casing rating / actual pressure

Burst calculations for 6th segment - Completion fracture treatment

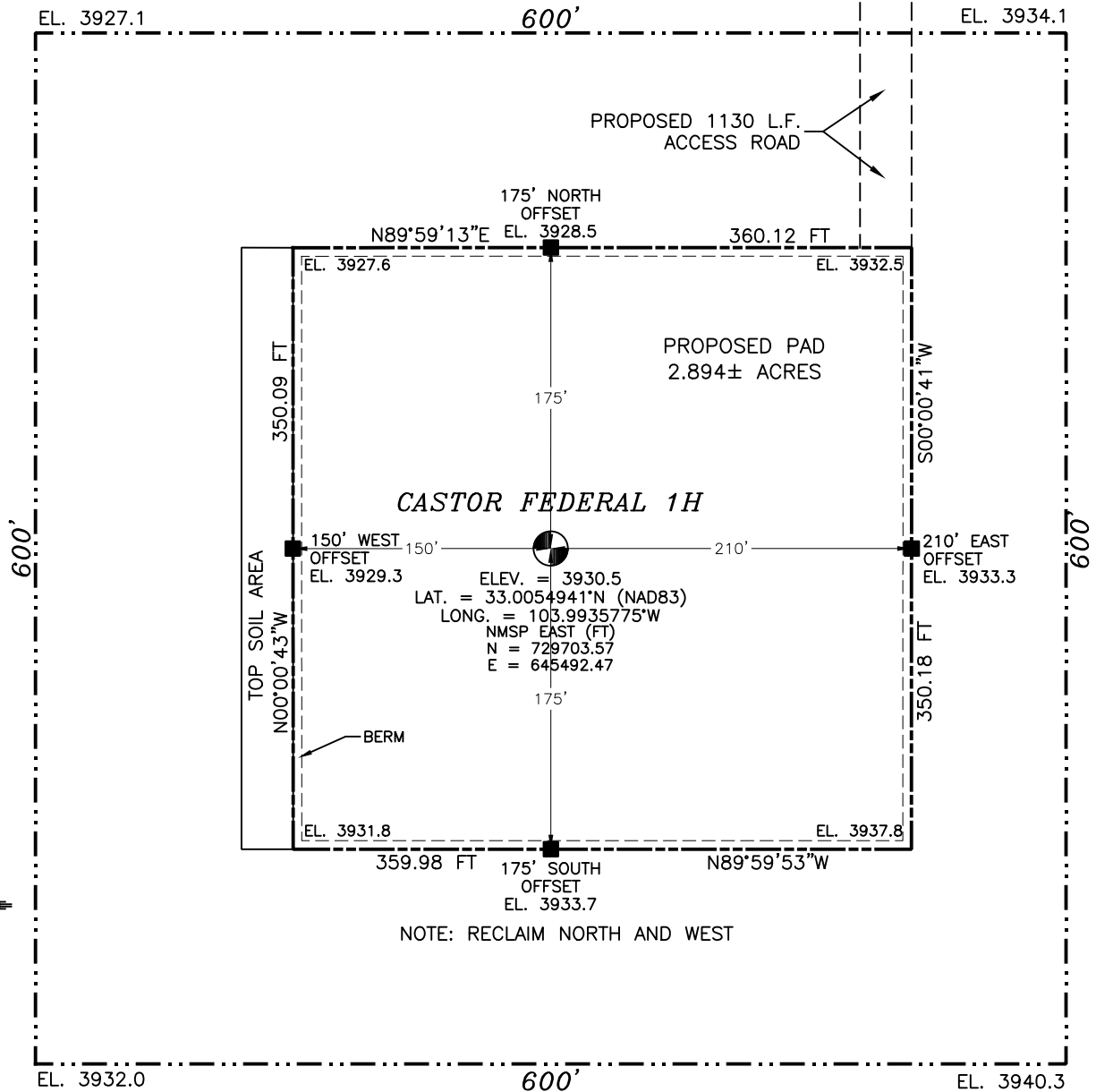
calculations for bottom of segment @	0 ft	
Differential burst pressure	500 psi	(frac. pres.-mud pres.) + max. surf. pres.
Burst rating of segment	0 psi	
Actual safety factor	0	casing rating / differential burst pressure
calculations for top of segment @	0 ft	
Differential burst pressure	500 psi	(frac. pres.-mud pres.) + max. surf. pres.
Burst rating of segment	0 psi	
Actual safety factor	0	casing rating / differential burst pressure

Joint strength calculations for 6th segment

Buoyancy factor for joint strength calc.:	0.85312	
calculations for bottom of segment @	0 ft	
Axial load @ bottom of section	13308.7 lbs	load @ top of last segment
Joint Strength of segment	0 lbs	
Body Yield Strength of segment	0 lbs	
Actual safety factor joint strength	0	csg joint strength / axial load
Actual safety factor body yield	0	csg body yield strength / axial load
calculations for top of segment @	0 ft	
Axial load @ top of section	13308.7 lbs	weight of previous segments + (this segment x BF)
Joint Strength of segment	0 lbs	
Body Yield Strength of segment	0 lbs	
Actual safety factor joint strength	0	csg joint strength / axial load
Actual safety factor body yield	0	csg body yield strength / axial load

SECTION 23, TOWNSHIP 15 SOUTH, RANGE 29 EAST, N.M.P.M.
CHAVES COUNTY, STATE OF NEW MEXICO
SITE MAP

ESCAPE ROUTE



010 50 100 200

SCALE 1" = 100'

DIRECTIONS TO LOCATION

FROM THE INTERSECTION OF ST. HWY. 249 & CO. RD. 217 (HAGERMAN CUTOFF) GO SOUTH ON CO. RD. APPROX. 2.7 MILES, TURN RIGHT (WEST) ON 20' CALICHE LEASE ROAD AND GO WEST APPROX. 0.2 MILES TO BEGIN ROAD SURVEY. FOLLOW ROAD SURVEY SOUTH APPROX. 1130' TO THE NORTHEAST PAD CORNER FOR THIS LOCATION.

I, FILMON F. JARAMILLO, A NEW MEXICO REGISTERED PROFESSIONAL SURVEYOR CERTIFY THAT I DIRECTED AND SUPERVISED THIS SURVEY, THAT THIS SURVEY WAS MADE IN ACCORDANCE WITH THE MINIMUM STANDARDS FOR SURVEYING PRACTICE IN THE STATE OF NEW MEXICO.

FILMON F. JARAMILLO, REGISTERED PROFESSIONAL SURVEYOR NO. 7984

MADRON SURVEYING, INC.

301 SOUTH CANAL
(575) 234-3327

MACK ENERGY CORPORATION
CASTOR FEDERAL 1H

LOCATED 1190 FT. FROM THE NORTH LINE
AND 907 FT. FROM THE EAST LINE OF
SECTION 23, TOWNSHIP 15 SOUTH,
RANGE 29 EAST, N.M.P.M.
CHAVES COUNTY, STATE OF NEW MEXICO

MARCH 7, 2024

SURVEY NO. 10049

CARLSBAD, NEW MEXICO

Attached to Form 3160-3

Mack Energy Corporation

Castor Federal #1H NMNM-138832

SHL : 1190 FNL & 907 FEL, NENE, Sec. 23 T15S R29E

BHL : 990 FNL & 1 FEL, NENE, Sec. 24 T15S R29E

Chaves County, NM

DRILLING PROGRAM

1. Geologic Name of Surface Formation

Quaternary

2. Estimated Tops of Important Geologic Markers:

Top Salt	418'
Base Salt	1020'
Yates	1193'
Seven Rivers	1417'
Queen	2004'
Grayburg	2289'
San Andres	2592'

3. Estimated Depths of Anticipated Fresh Water, Oil and Gas:

Water Sand	128'	Fresh Water
Yates	1193'	Oil/Gas
Seven Rivers	1417'	Oil/Gas
Queen	2004'	Oil/Gas
Grayburg	2289'	Oil/Gas
San Andres	2592'	Oil/Gas

No other formations are expected to give up oil, gas or fresh water in measurable quantities. Setting 13 3/8" casing to 325' and circulating cement back to surface will protect the surface fresh water sand. Salt section and shallower zones above TD, which contain commercial quantities of oil and/or gas, will have cement circulated across them by cementing 5 1/2" production casing, sufficient cement will be pumped to circulate back to surface.

4. Casing Program:

Hole Size	Interval	OD Casing	Wt, Grade, Jt, cond, collapse/burst/tension
17 1/2"	0-325'	13 3/8"	48#, J-55, ST&C, New, 4.561144/4.67677/4.74
12 1/4"	0-1200'	9 5/8"	36#, J-55, LT&C, New, 3.205128/7.04/7.04
8 3/4"	0-3560'	7"	26#, HCP-110, LT&C, New, 4.085954/3.316667/3.316667
8 3/4"	3560-9258'	5 1/2"	17#, HCP-110, Buttress, New, 4.796512/3.546667/3.546667

Variance request: A variance is requested to use a Multi Bowl System and Flex Hose as the choke line from the BOP to the Choke Manifold. If this hose is used, a copy of the manufacturer's certification and pressure test will be kept on the rig.

Perforations – 3896 TD 3440 TVD 9150 TD 3440 TVD

Attached to Form 3160-3

Mack Energy Corporation

Castor Federal #1H NMNM-138832

SHL : 1190 FNL & 907 FEL, NENE, Sec. 23 T15S R29E

BHL : 990 FNL & 1 FEL, NENE, Sec. 24 T15S R29E

Chaves County, NM

5. Cement Program:

13 3/8" Surface Casing: Lead 150sx, RFC+12%PF53+2%PF1+5ppsPF42+.125ppsPF29, yld 1.74, wt 13.5 ppg, 7.357gals/sx Tail: 200sx, Class C+1% PF1, yld 1.32, wt 14.8 ppg, 6.323 gals/sx, excess 100%

9 5/8" Intermediate Casing: Lead 250 sx, Class C+4%F20+.4pps PF44+.125 PF29, yld 1.73, wt 13.5 ppg, 9.102 gals/sx, excess 100%, Slurry Top-Surface Tail 200sx, Class C + 1% PF1, yld 1.34, wt 14.8 ppg, 6.323 gals/sx, excess 100%

7" & 5 1/2" Production Casing: Lead 325sx Poz/C+10%PF20+5%PF44+.5PF79+3ppsPF42+.4ppsPF45+.125ppsPF29, yld 2.82, wt 11.5 ppg, 16.421 gals/sx, excess 35%, Slurry Top-Surface Tail 1903sx, 50/50 Poz/C+5% (BWOW) PF44+2% PF20+.2% PF13+.2%PF65+.2% PF65+.2%PF606+.4pps PF45, yield 1.34, wt 14.2, 6.085 gals/sx, 50% excess, Slurry Top 2525'

Option 2 – Run a DV tool @1400' +/- if an air pocket is encountered. Cmt Stage 1-2050 sx 50/50 POZ/C +5% (BWOW) PF44+2% PF20+0.2% PF13+0.2% PF606 +0.1% FP 153+0.4pps PF45, yld 1.34, density 14.2, mix H2O gals/sx 6085, 50% excess, Slurry Top 1400' cmt State 2-200 sx C+2% PF1, yld 1.34, density 14.8, 0% excess, Slurry Top Surface. 2,205.1 Cy/Ft per Line/Ft.

6. Minimum Specifications for Pressure Control:

The blowout preventer equipment (BOP) shown in Exhibit #10 will consist of a double ram-type (3000 psi WP) minimum preventer. This unit will be hydraulically operated and the ram type preventer will be equipped with blind rams on top of 4 1/2" drill pipe rams on bottom. The 11" BOP will be nipped up on the 8 5/8" surface casing and tested by a 3rd party to 2000 psi used continuously until TD is reached. All BOP's and accessory equipment will be tested to 2000 psi before drilling out of intermediate casing. Pipe rams will be operationally checked each 24-hour period. Blind rams will be operationally checked on each trip out of the hole. These checks will be noted on the daily tour sheets. Other accessories to the BOP equipment (Exhibit #10) will include a Kelly cock and floor safety valve and choke lines and choke manifold (Exhibit #11) with a minimum 3000 psi WP rating

7. Types and Characteristics of the Proposed Mud System:

The well will be drilled to TD with a combination of fresh and cut brine mud system. The applicable depths and properties of this system are as follows:

DEPTH	TYPE	WEIGHT	VISCOSITY	WATERLOSS
0-325'	Fresh Water	8.5	28	N.C.
325'-1,200'	Cut Brine	9.1	29	N.C.
1,200-TD	Cut Brine	9.1	29	N.C.

Attached to Form 3160-3

Mack Energy Corporation

Castor Federal #1H NMNM-138832

SHL : 1190 FNL & 907 FEL, NENE, Sec. 23 T15S R29E

BHL : 990 FNL & 1 FEL, NENE, Sec. 24 T15S R29E

Chaves County, NM

Sufficient mud materials to maintain mud properties and meet minimum lost circulation and weight increase requirements will be kept at the well site at all times.

8. Auxiliary Well Control and Monitoring Equipment:

- A. Kelly cock will be kept in the drill string at all times.
- B. A full opening drill pipe-stabbing valve with proper drill pipe connections will be on the rig floor at all times.

9. Logging, Testing and Coring Program:

- A. The electric logging program will consist of GR-Dual Laterolog, Spectral Density, Dual Spaced Neutron, CSNG Log from T.D. to 8 5/8 casing shoe.
- B. Drill Stem test is not anticipated.
- C. No conventional coring is anticipated.
- D. Further testing procedures will be determined at TD.

10. Abnormal Conditions, Pressures, Temperatures and Potential Hazards:

No abnormal pressures or temperatures are anticipated. The estimated bottom hole at TD is 120 degrees and estimated maximum bottom hole pressure is 1646' psig $(0.052 \times 3440' \text{TVD} \times 9.2)$. Low levels of Hydrogen sulfide have been monitors in producing wells in the area, so H2S may be present while drilling of the well; a plan is attached to the Drilling program. No major loss of circulation zones has been reported in offsetting wells.

11. Anticipated Starting Date and Duration of Operations:

Road and location work will not begin until approval has been received from the BLM. The anticipated spud date is February 1, 2025. Once commenced, the drilling operation should be finished in approximately 20 days. If the well is productive, an additional 30 days will be required for completion and testing before a decision is made to install permanent facilities.

Attachment to Exhibit #10
NOTES REGARDING THE BLOWOUT PREVENTERS
Castor Federal #1H
Chaves County, New Mexico

1. Drilling nipple to be so constructed that it can be removed without use of a welder through rotary table opening, with minimum I.D. equal to preventer bore.
2. Wear ring to be properly installed in head.
3. Blow out preventer and all fittings must be in good condition, 2000 psi WP minimum.

Attached to Form 3160-3

Mack Energy Corporation

Castor Federal #1H NMNM-138832

SHL : 1190 FNL & 907 FEL, NENE, Sec. 23 T15S R29E

BHL : 990 FNL & 1 FEL, NENE, Sec. 24 T15S R29E

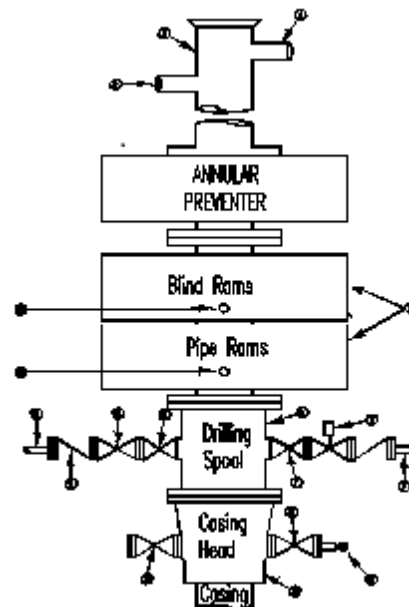
Chaves County, NM

-
4. All fittings to be flanged.
 5. Safety valve must be available on rig floor at all times with proper connections, valve to be full 2000 psi WP minimum.
 6. All choke and fill lines to be securely anchored especially ends of choke lines.
 7. Equipment through which bit must pass shall be at least as large as the diameter of the casing being drilled through.
 8. Kelly cock on Kelly.
 9. Extension wrenches and hands wheels to be properly installed.
 10. Blow out preventer control to be located as close to driller's position as feasible.
 11. Blow out preventer closing equipment to include minimum 40-gallon accumulator, two independent sources of pump power on each closing unit installation all API specifications.

Mack Energy Corporation
Minimum Blowout Preventer Requirements
3000 psi Working Pressure
13 3/8 inch- 3 MWP
11 Inch - 3 MWP
EXHIBIT #10

Stack Requirements

NO.	Items	Min. I.D.	Min. Nominal
1	Flowline		2"
2	Fill up line		2"
3	Drilling nipple		
4	Annular preventer		
5	Two single or one dual hydraulically operated rams		
6a	Drilling spool with 2" min. kill line and 3" min choke line outlets		2" Choke
6b	2" min. kill line and 3" min. choke line outlets in ram. (Alternate to 6a above)		
7	Valve Gate Plug	3 1/8	
8	Gate valve-power operated	3 1/8	
9	Line to choke manifold		3"
10	Valve Gate Plug	2 1/16	
11	Check valve	2 1/16	
12	Casing head		
13	Valve Gate Plug	1 13/16	
14	Pressure gauge with needle valve		
15	Kill line to rig mud pump manifold		2"



OPTIONAL

16	Flanged Valve	1 13/16	
----	---------------	---------	--

CONTRACTOR'S OPTION TO FURNISH:

1. All equipment and connections above bradenhead or casinghead. Working pressure of preventers to be 2000 psi minimum.
2. Automatic accumulator (80 gallons, minimum) capable of closing BOP in 30 seconds or less and, holding them closed against full rated working pressure.
3. BOP controls, to be located near drillers' position.
4. Kelly equipped with Kelly cock.
5. Inside blowout preventer or its equivalent on derrick floor at all times with proper threads to fit pipe being used.
6. Kelly saver-sub equipped with rubber casing protector at all times.
7. Plug type blowout preventer tester.
8. Extra set pipe rams to fit drill pipe in use on location at all times.
9. Type RX ring gaskets in place of Type R.

MEC TO FURNISH:

1. Bradenhead or casing head and side valves.
2. Wear bushing. If required.

GENERAL NOTES:

1. Deviations from this drawing may be made only with the express permission of MEC's Drilling Manager.
2. All connections, valves, fittings, piping, etc., subject to well or pump pressure must be flanged (suitable clamp connections acceptable) and have minimum working pressure equal to rated working pressure of preventers up through choke valves must be full opening and suitable for high pressure mud service.
3. Controls to be of standard design and each marked, showing opening and closing position
4. Chokes will be positioned so as not to hamper or delay changing of choke beans.

- Replaceable parts for adjustable choke, or bean sizes, retainers, and choke wrenches to be conveniently located for immediate use.
5. All valves to be equipped with hand-wheels or handles ready for immediate use.
6. Choke lines must be suitably anchored.
7. Handwheels and extensions to be connected and ready for use.
8. Valves adjacent to drilling spool to be kept open. Use outside valves except for emergency.
9. All seamless steel control piping (2000 psi working pressure) to have flexible joints to avoid stress. Hoses will be permitted.
10. Casinghead connections shall not be used except in case of emergency.
11. Does not use kill line for routine fill up operations.

Mack Energy Corporation

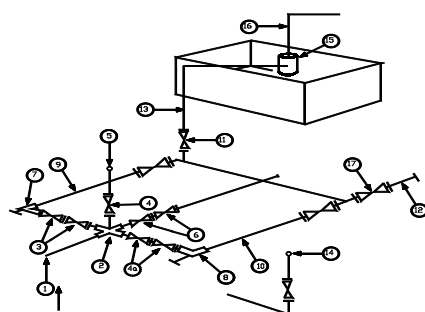
Exhibit #11

MINIMUM CHOKE MANIFOLD

3,000, 5,000, and 10,000 PSI Working Pressure

3M will be used

3 MWP - 5 MWP - 10 MWP



Mud Pit

Reserve Pit

* Location of separator optional

Below Substructure

Minimum requirements

No.		3,000 MWP			5,000 MWP			10,000 MWP		
		I.D.	Nominal	Rating	I.D.	Nominal	Rating	I.D.	Nominal	Rating
1	Line from drilling Spool		3"	3,000		3"	5,000		3"	10,000
2	Cross 3" x 3" x 3" x 2"			3,000			5,000			
2	Cross 3" x 3" x 3" x 2"									10,000
3	Valve Gate Plug	3 1/8		3,000	3 1/8		5,000	3 1/8		10,000
4	Valve Gate Plug	1 13/16		3,000	1 13/16		5,000	1 13/16		10,000
4a	Valves (1)	2 1/16		3,000	2 1/16		5,000	2 1/16		10,000
5	Pressure Gauge			3,000			5,000			10,000
6	Valve Gate Plug	3 1/8		3,000	3 1/8		5,000	3 1/8		10,000
7	Adjustable Choke (3)	2"		3,000	2"		5,000	2"		10,000
8	Adjustable Choke	1"		3,000	1"		5,000	2"		10,000
9	Line		3"	3,000		3"	5,000		3"	10,000
10	Line		2"	3,000		2"	5,000		2"	10,000
11	Valve Gate Plug	3 1/8		3,000	3 1/8		5,000	3 1/8		10,000
12	Line		3"	1,000		3"	1,000		3"	2,000
13	Line		3"	1,000		3"	1,000		3"	2,000
14	Remote reading compound Standpipe pressure quage			3,000			5,000			10,000
15	Gas Separator		2' x5'			2' x5'			2' x5'	
16	Line		4"	1,000		4"	1,000		4"	2,000
17	Valve Gate Plug	3 1/8		3,000	3 1/8		5,000	3 1/8		10,000

- (1) Only one required in Class 3M
- (2) Gate valves only shall be used for Class 10 M
- (3) Remote operated hydraulic choke required on 5,000 psi and 10,000 psi for drilling.

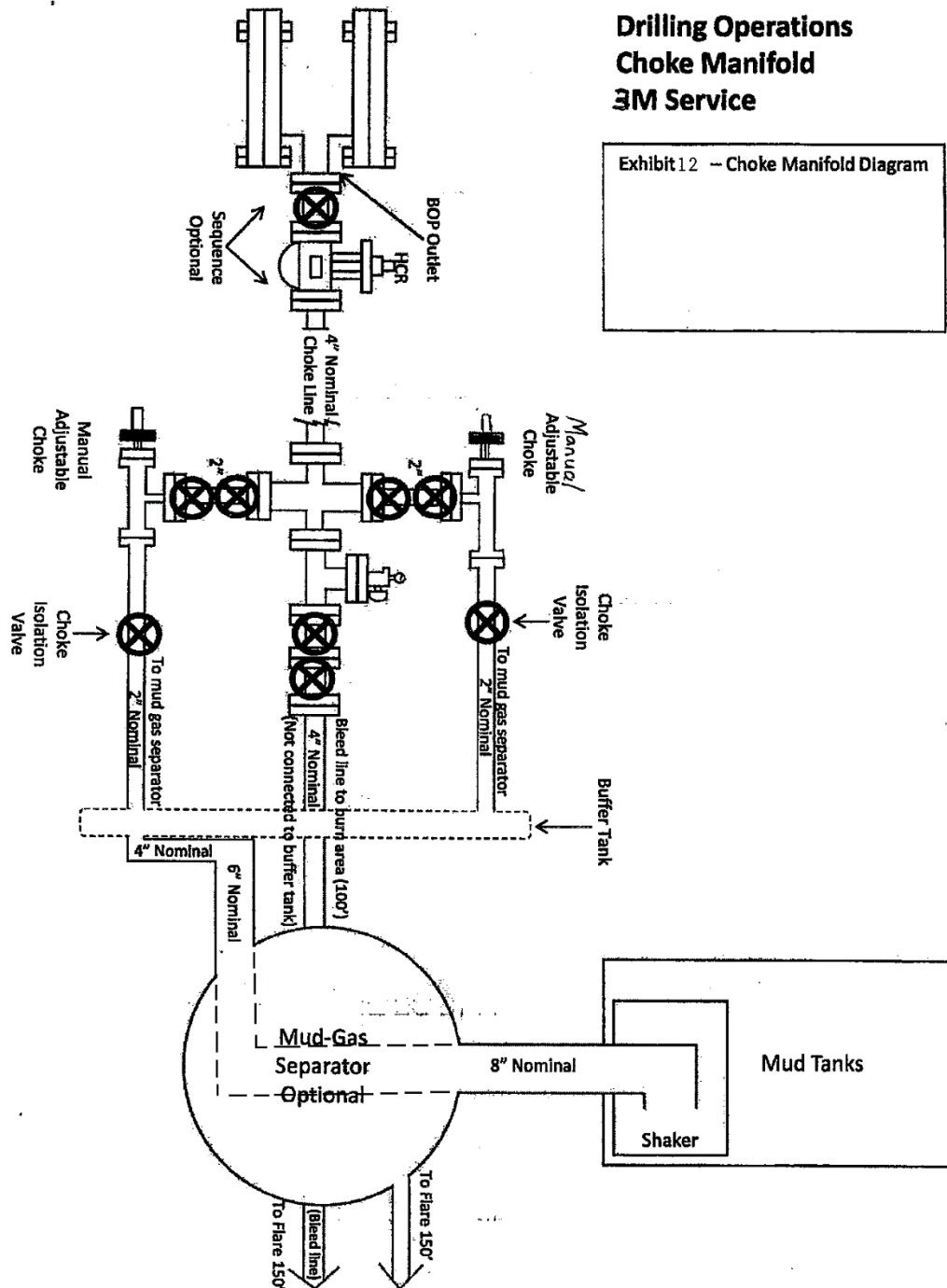
EQUIPMENT SPECIFICATIONS AND INSTALLATION INSTRUCTION

1. All connections in choke manifold shall be welded, studded, flanged or Cameron clamp of comparable rating.
2. All flanges shall be API 6B or 6BX and ring gaskets shall be API RX or BX. Use only BX for 10 MWP.
3. All lines shall be securely anchored.
4. Chokes shall be equipped with tungsten carbide seats and needles, and replacements shall be available.
5. alternate with automatic chokes, a choke manifold pressure gauge shall be located on the rig floor in conjunction with the standpipe pressure gauge.
6. Line from drilling spool to choke manifold should be as straight as possible. Lines downstream from chokes shall make turns by large bends or 90 degree bends using bull plugged tees

Mack Energy Corporation

MANIFOLD SCHEMATIC

Exhibit #12





Installation Procedure Prepared For:

Mack Energy Corporation
13-3/8" x 9-5/8" x 7" 10M
MBU-LR Wellhead System With
CTH-DBLHPS Tubing Head

Publication # IP0228

May, 2014

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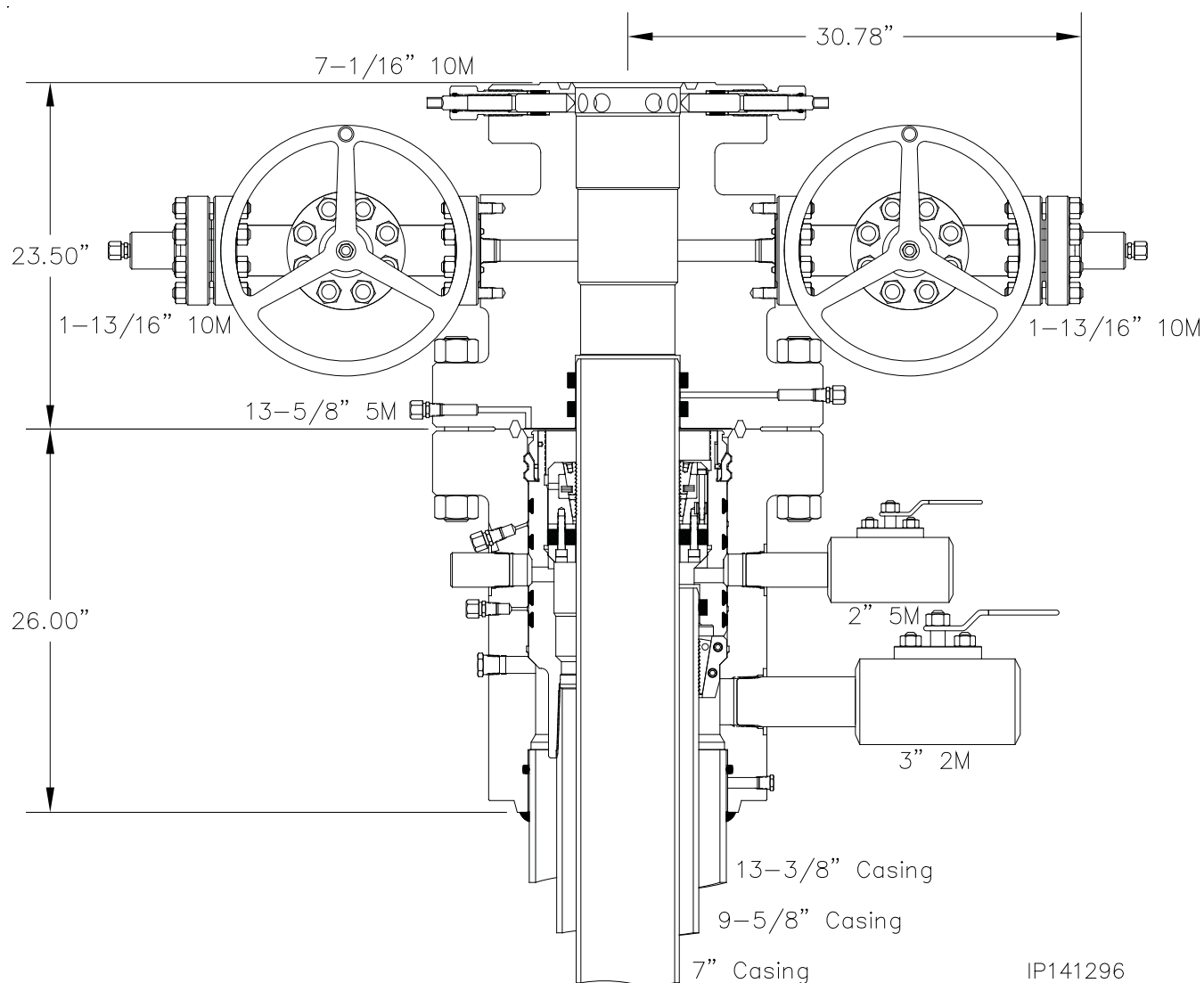
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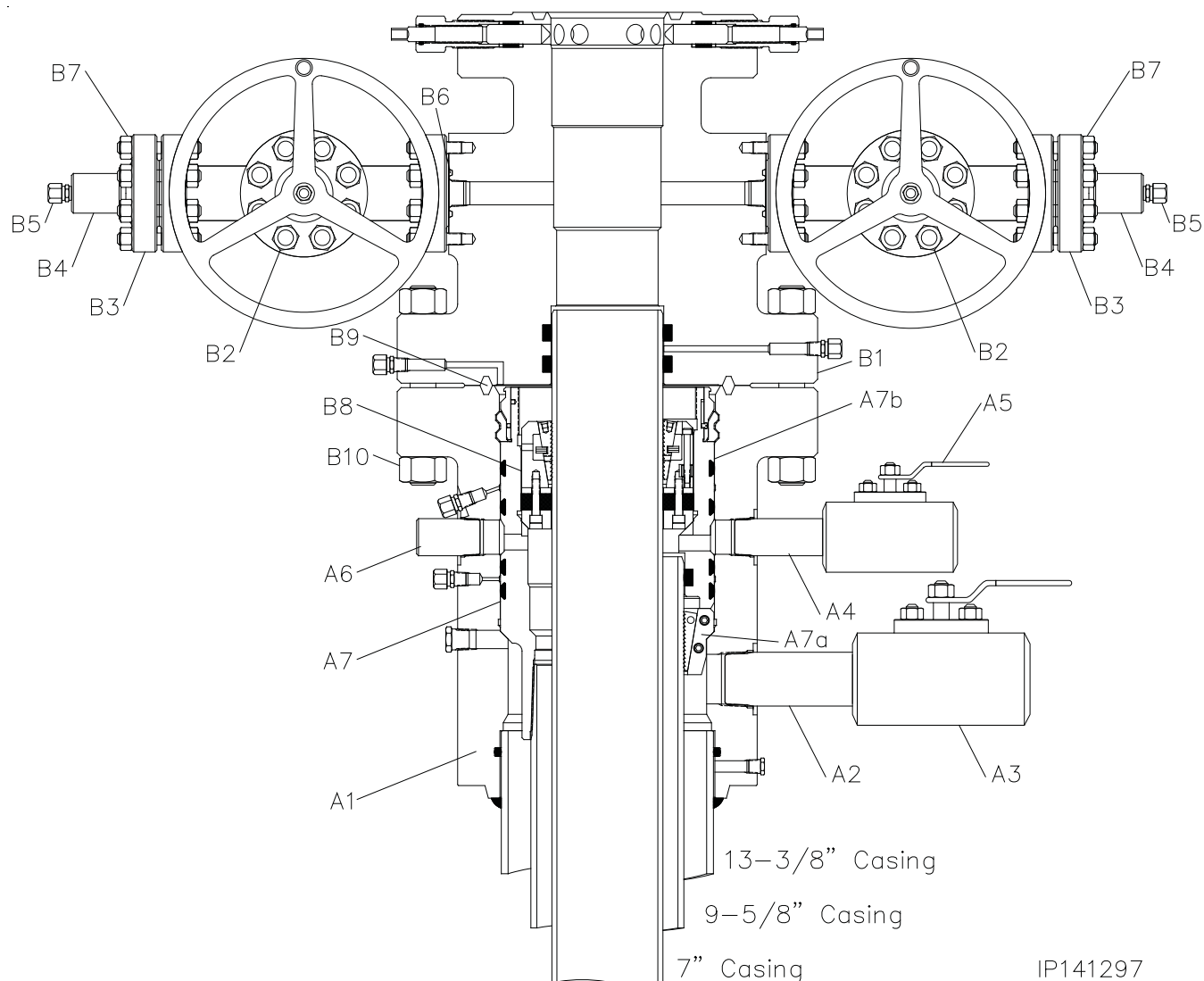
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System Drawing



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Bill of Materials



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MBU-LR HOUSING ASSEMBLY		
Item	Qty	Description
A1	1	Housing, CW, MBU-LR, 13-5/8" 5M x 13-3/8" SOW, with two 2" line pipe upper outlets and one 3" line pipe lower outlet, one piece, 6A-PU-AA-1-1 Part # 102513
A2	1	Nipple, 3" line pipe x 12" long, XH Part # 101610
A3	1	Ball Valve, KF, AH, 3 RP 2M LP, DI: Body, CS: Trim, nylon seats, HNBR: seals, with handle standard non-nace service Part # 100535
A4	1	Nipple, 2" line pipe x 6" long, XH Part # NP6A
A5	1	Ball Valve, 2" RP, 5M LP x 2" LP, WCB body, 304SS ball, CR13 stem, RPTFE seats, API 596 Part # 103877
A6	1	Bull Plug, 2" line pipe solid, 4130 60K Part # BP2P
A7	1	Casing Hanger, CW, MBU-LR, 13-5/8" x 9-5/8" LC box bottom x 11.250" 4 Stub Acme 2G LH box top, mandrel, 6A-U-AA-1-1 Part # 100482

EMERGENCY EQUIPMENT		
Item	Qty	Description
A7a	1	Casing Hanger, CW, MBU-LR, 13-5/8" x 9-5/8" 6A-PU-DD-3-1 Part # 100569
A7b	1	Packoff, CW, MBU-LR Emergency, 13-5/8" x 11" x 9-5/8" with 11.250" 4 Stub Acme 2G LH top, slotted for CL outlets, 6A-PU-AA-1-1 Part # 100538

TUBING HEAD ASSEMBLY		
Item	Qty	Description
B1	1	Tubing Head, CW, CTH-DBLHPS, 7, 13-5/8" 5M x 7-1/16" 10M, with two 1-13/16" 10M studded outlets 6A-PU-EE-0,5-2-1 Part #
B2	2	Gate Valve, DSG-22, 1-13/16" 10M, flanged end, EE-0,5 trim, (6A-PU-EE-0,5-3-1) Part # 102284
B3	2	Companion Flange, 1-13/16" 10M x 2" line pipe (5,000 psi max WP), (6A-PU-EE-NL-1) Part # 200010
B4	2	Bull Plug, 2" line pipe x 1/2" line pipe, API 6A-DD-NL Part # BP2T
B5	2	Fitting, Grease, Vented Cap, 1/2" NPT, Alloy Non-Nace Part # FTG1
B6	4	Ring Gasket, 151, 1-13/16" 10M Part # BX151
B7	16	Studs, all thread with two nuts, black, 3/4" x 5-1/2" long, B7/2H Part # 780080
B8	1	Casing Hanger, C22, 11" x 7" Part # 50020
B9	1	Ring Gasket, 160, 13-5/8" 5M Part # BX160
B10	16	Studs, all thread with two nuts, black, 1-5/8" x 12-3/4" long, B7/2H Part # 780087

RECOMMENDED SERVICE TOOLS		
Item	Qty	Description
ST1	1	Test Plug/Retrieving Tool, CW, 13-5/8" x 4-1/2" IF, 1-1/4" LP bypass and spring loaded lift dogs Part # 800002
ST2	1	Wear Bushing, CW, MBU-LR-LWR, 13-5/8" x 12.38" ID x 20.31" long Part # 100546
ST3	1	Casing Hanger Running Tool, CW, MBU-LR, 13-5/8" x 9-5/8" long casing box top x 11.250" 4 Stub Acme LH pin bottom, 4140 110K Part # 102304
ST4	1	Packoff Running Tool, CW, MBU-LR, 13-5/8" x 4-1/2" IF box bottom and top, with 11.250" 4 Stub Acme 2G LH pin bottom Part # 100556
ST5	1	Test Plug/Retrieving Tool, CW, 11" x 4-1/2" IF, 1-1/4" LP bypass and spring loaded lift dogs Part # 800001
ST6	1	Wear Bushing, MBU-LR-UPR, 13-5/8" x 11" x 9.00" I.D. x 16.0" long Part # 102789
ST7	1	Wash Tool, CW, Casing Hanger, MBU-LR/MBS2, fluted, 13-5/8" x 4-1/2" IF box top threads, fabricated Part # 102787

TA CAP ASSEMBLY		
Item	Qty	Description
C1	1	Flange, Blind, 7-1/16" 10M x 1/2 LP, With Two 3/4" Part # 101464
C2	1	Needle Valve, MFA, 1/2" Line Pipe, 10M Part # NVA
C3	12	Studs, All Thread With Two Nuts, Black, 1-1/2" X 11-3/4" Long, B7/H2 Part # 780082



Mack Energy Corporation.
13-3/8" x 9-5/8" x 7" 10M MBU-LR Wellhead System
With CTH-DBLHPS Tubing Head

IP 0228
Page 3

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Stage 1 — Install the MBU-LR Wellhead Housing

1. Run the conductor and 13-3/8" surface casing to the required depth and cement as required.
2. Determine the correct elevation for the MBU-LR Wellhead Assembly.
3. Cut the 13-3/8" at 53.5" below the cellar to accommodate the wellhead. Grind stub level with the horizon and place an 1/8" x 1/8" bevel on the OD of the stub.

Note: The slip on and weld preparation is 4.25" in depth.

4. Examine the **13-5/8" 5M x 13-3/8" SOW MBU-LR Wellhead Assembly (Item A1)**. Verify the following:
 - bore is clean and undamaged
 - weld socket is clean and free of grease and debris and o-ring is in place and in good condition
 - all seal areas are clean and undamaged
 - valves are intact and in good condition

5. Align and level the Wellhead Assembly over the casing stub, orienting the outlets so they will be compatible with the drilling equipment.

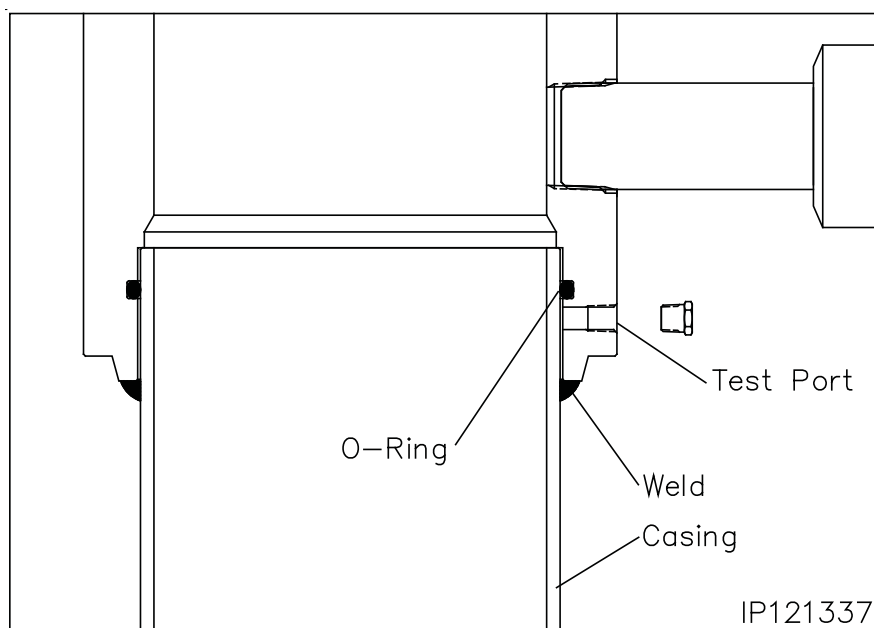
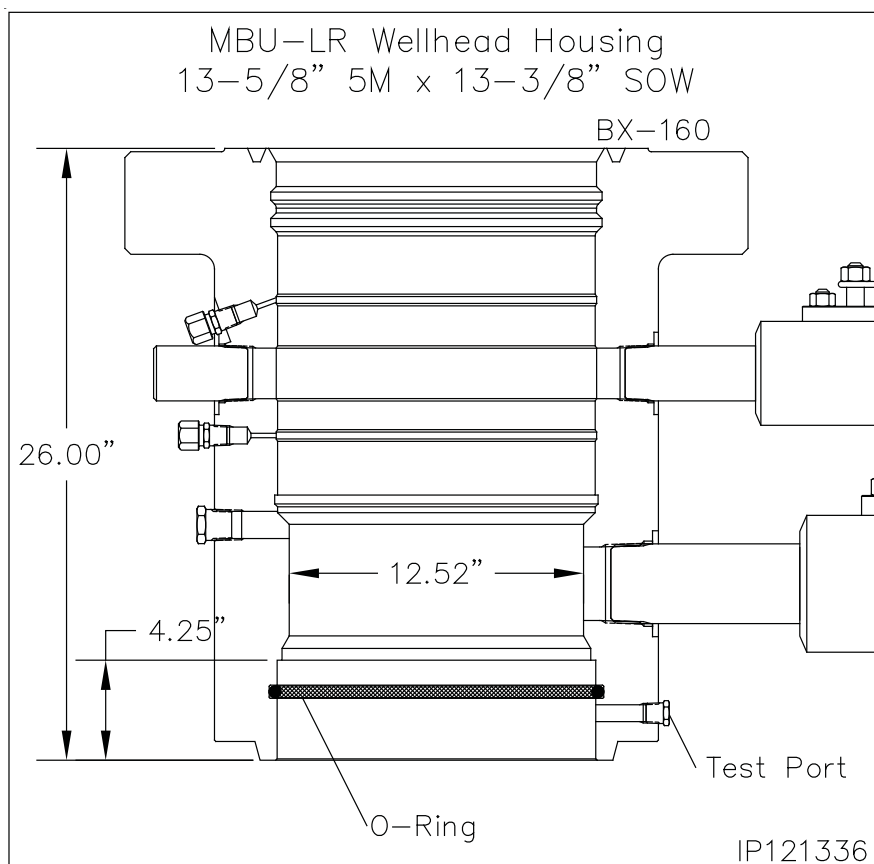
6. Remove the pipe plug from the port on the bottom of the Head.

7. Slowly and carefully lower the assembly over the casing stub, weld and test the MBU-LR housing to the surface casing.

8. Replace the pipe plug in the port on the bottom of the housing.

Note: The weld should be a fillet-type weld with legs no less than the wall thickness of the casing. Legs of 1/2" to 5/8" are adequate for most jobs.

Refer to the back of this publication for the **Recommended Procedure for Field Welding Pipe to Wellhead Parts for Pressure Seal** and for field testing of the weld connection.



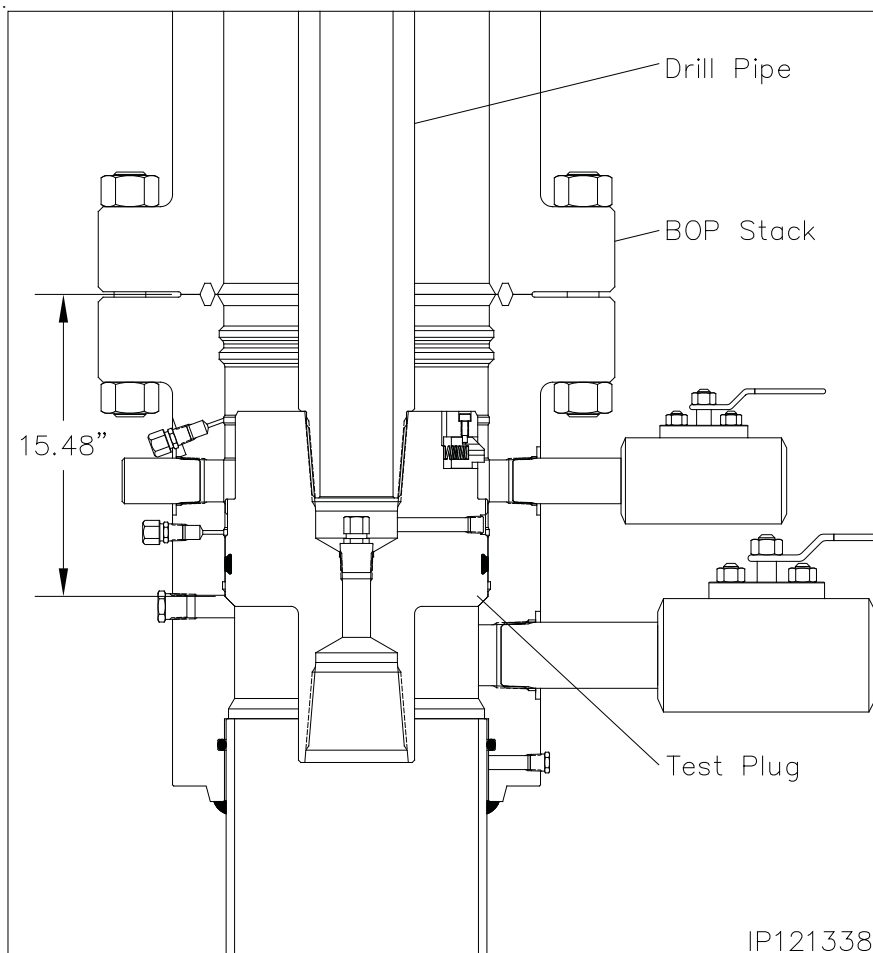
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Stage 2 — Test the BOP Stack

Immediately after making up the BOP stack and periodically during the drilling of the well for the next casing string the BOP stack (connections and rams) must be tested.

1. Examine the **13-5/8" Nominal x 4-1/2" IF CW Test Plug/Retrieving Tool (Item ST1)**. Verify the following:
 - 1-1/4" VR plug and weep hole plug are in place and tightened securely
 - elastomer seal is in place and in good condition
 - retractable lift lugs are in place, clean, and free to move
 - drill pipe threads are clean and in good condition

Note: Prior to installing the BOP it is recommended to attain an accurate RKB dimension for future use for accurately landing test plugs and casing hangers. This dimension is attained by dropping a tape measure from the rig floor to the top of the wellhead flange. Pull tape taut and record the dimension from the wellhead to the top of the rig floor or kelly bushings. Ensure this dimension is placed on the BOP board in the dog house and on the drillers daily report sheet.



IP121338

2. Position the test plug with the elastomer seal down and the lift lugs up and make up the tool to a joint of drill pipe.
3. Remove the 1/2" NPT pipe plug from the weep hole if pressure is to be supplied through the drill pipe.
4. Open the housing side outlet valve.
5. Lightly lubricate the test plug seal with oil or light grease.
6. Carefully lower the test plug through the BOP and land it on the load shoulder in the housing, 15.48" below the top of the housing.
7. Close the BOP rams on the pipe and test the BOP to 5,000 psi.

Note: Any leakage past the test plug will be clearly visible at the open side outlet valve.
8. After a satisfactory test is achieved, release the pressure and open the rams.
9. Remove as much fluid as possible from the BOP stack and the retrieve the test plug with a straight vertical lift.
10. Repeat this procedure as required during the drilling of the hole section.

Note: When performing the BOP blind ram test it is highly recommended to suspend a stand of drill pipe below the test plug to ensure the plug stays in place while disconnecting from it with the drill pipe.

WARNING: Ensure that the lift lugs are up and the elastomer seal is down

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Stage 3 — Run the Lower Wear Bushing

Note: Always use a Wear Bushing while drilling to protect the load shoulders from damage by the drill bit or rotating drill pipe. The Wear Bushing **must be retrieved** prior to running the casing.

1. Examine the **13-5/8" Nominal MBU-LR-LWR Wear Bushing (Item ST2)**. Verify the following
 - internal bore is clean and in good condition
 - o-ring is in place and in good condition
 - shear o-ring cord is in place and in good condition
 - paint anti-rotation lugs white and allow paint to dry

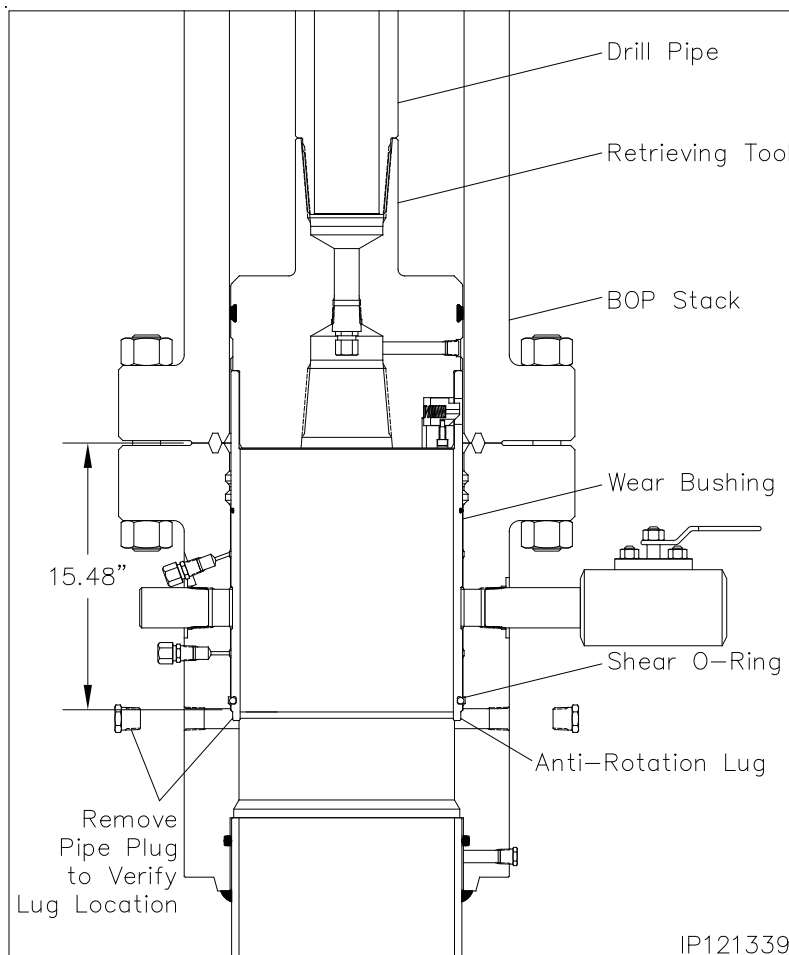
Run the Wear Bushing Before Drilling

2. Orient the **13-5/8" Nominal x 4-1/2" IF CW Test Plug/Retrieving Tool (Item ST1)** with drill pipe connection up.
3. Attach the Retrieving Tool to a joint of drill pipe.
4. Align the retractable lift lugs of the tool with the retrieval holes of the bushing and the carefully lower the tool into the Wear Bushing until the lugs snap into place.

Note: If the lugs did not align with the holes, rotate the tool in either direction until they snap into place.

5. Apply a heavy coat of grease, not dope, to the OD of the bushing.
6. Slowly lower the Tool/Bushing Assembly through the BOP stack and land it on the load shoulder in the housing, 15.48" below the top of the housing.
7. Rotate the drill pipe clockwise (right) to locate the stop lugs in their mating notches in the head. When properly aligned the bushing will drop an additional 1/2".
8. Remove one of the 1" sight port pipe plugs from the OD of the housing and look through the hole to verify the lug has engaged the slot. The painted lug will be clearly visible through the port. Reinstall the pipe plug and tighten securely.

Note: The Shear O-Ring on bottom of the bushing will locate in a groove above the load shoulder in the head to act as a retaining device for the bushing.



9. Remove the Tool from the Wear Bushing by rotating the drill pipe counter clockwise (left) 1/4 turn and lifting straight up.
10. Once set is highly recommended to inject a minimum of two full tubes of grease through the housing test ports To keep trash from accumulating behind the bushing.
11. Drill as required.

Note: It is highly recommended to retrieve, clean, inspect, grease, and reset the wear bushing each time the hole is tripped during the drilling of the hole section.

Retrieve the Wear Bushing After Drilling

12. Make up the Retrieving Tool to the drill pipe .
13. Slowly lower the Tool into the Wear Bushing.
14. Pick up and balance the riser weight.
15. Rotate the Retrieving Tool clockwise until a positive stop is felt. This indicates the lugs have snapped into the holes in the bushing.
16. Retrieve the Wear Bushing, and remove it and the Retrieving Tool from the drill string.

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Stage 4 — Hang Off the 9-5/8" Casing

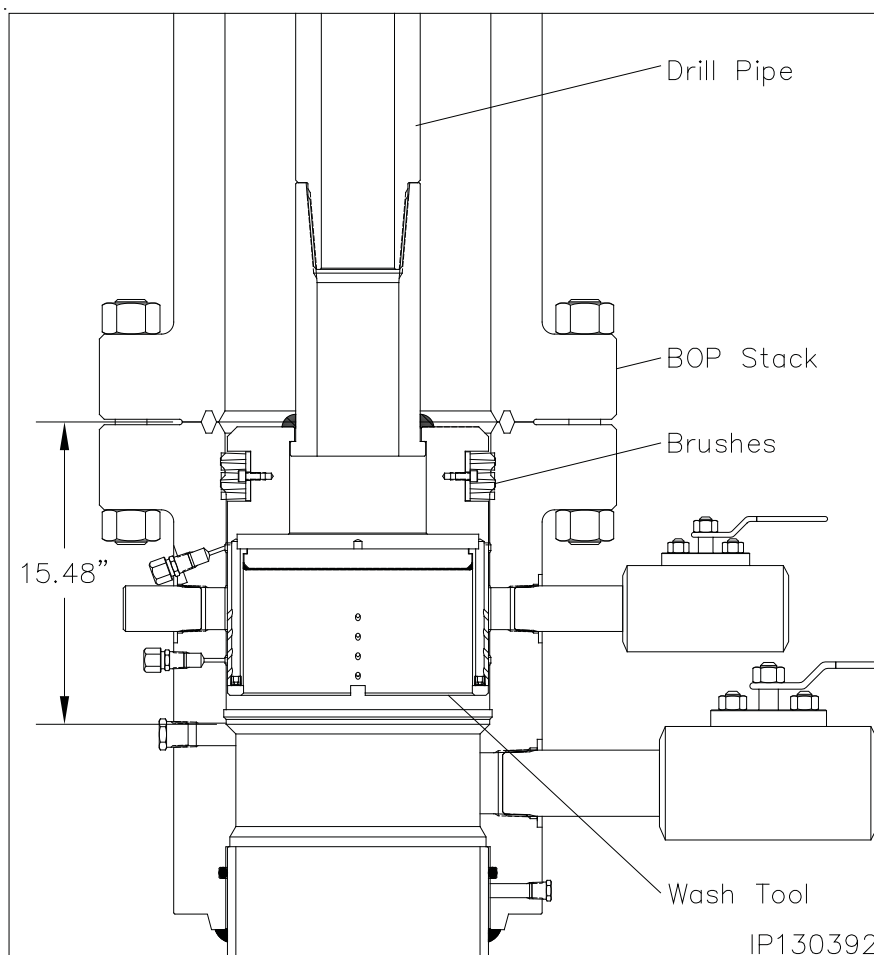
Due to the possible build up of debris in the bore and locking groove of the MBU-LR wellhead it is recommended to run the 13-5/8" Wash Tool prior to running the 9-5/8 casing.

Running the 13-5/8" Wash Tool

1. Examine the **13-5/8" x 4-1/2" IF Wash Tool (Item ST7)**. Verify the following:
 - drill pipe threads and bore are clean and in good condition
 - all ports are open and free of debris
 - brushes are securely attached and in good condition
2. Orient the Wash Tool with drill pipe box up. Make up a joint of drill pipe to the tool.
3. Carefully lower the Wash Tool through the BOP and land it on top of the 9-5/8" casing hanger, 15.48" below the top flange of the housing.
4. Place a paint mark on the drill pipe level with the rig floor and then pick up on the tool approximately 1".
5. Attach a high pressure water line to the end of the drill pipe and pump water through the tool and up the Diverter stack.
6. While flushing, raise and lower the tool the full length of the wellhead and BOP stack. The drill pipe should be slowly rotate while raising and lowering to wash the inside of the housing and BOP stack to remove all caked on debris.
7. Once washing is complete, shut down pumps and then open the housing lower outlet valve and drain the BOP stack.

Note: If returns are not clean, continue flushing until they are.

8. Once the returns are clean and free of debris, retrieve the tool to the rig floor.



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Stage 4 — Hang Off the 9-5/8" Casing

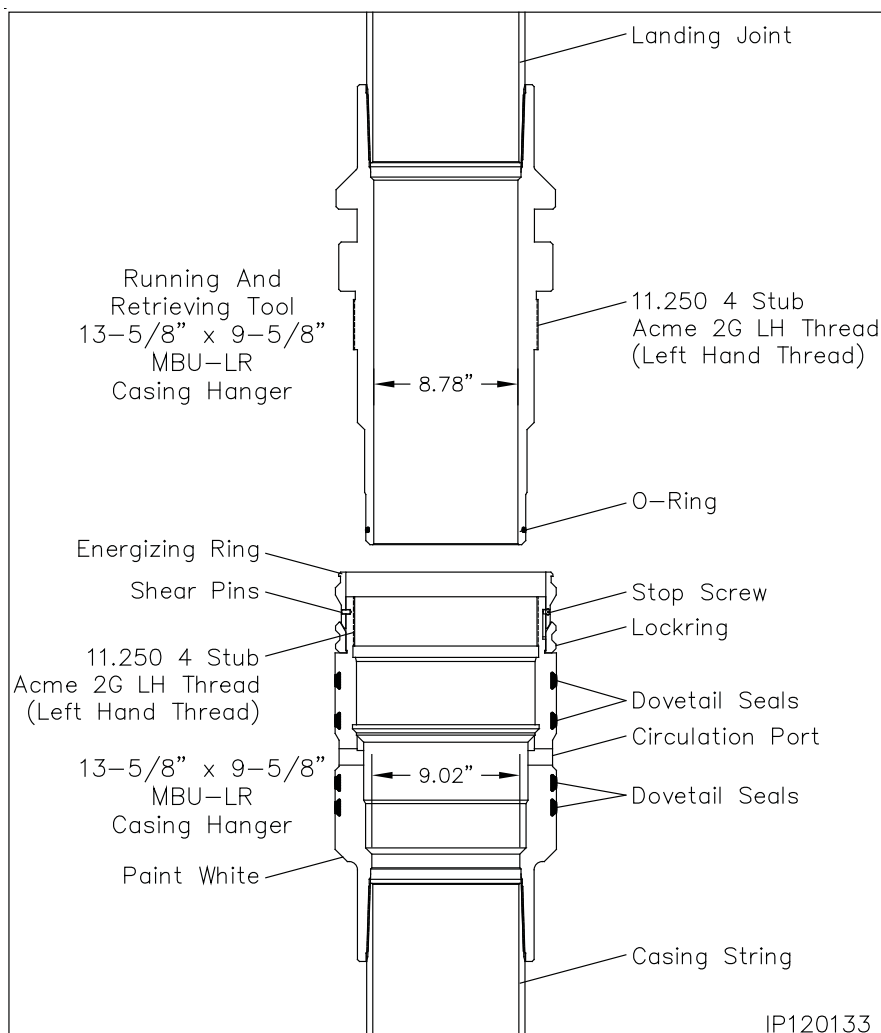
The 9-5/8" MBU-LR casing hanger and running and retrieving tool should be shipped to location pre assembled as a full joint. If not, follow steps 1 through for assembling on the pipe rack.

1. Examine the **13-5/8" x 9-5/8" LC MBU-LR Casing Hanger (Item A7)**. Verify the following:

- bore and internal Acme threads are clean and in good condition
- locking is in place and free to rotate
- energizing ring is in its upper most position and secured with shear pins
- dovetail seals are clean and in good condition
- pup joint is in good condition and properly made up. Thoroughly clean, inspect, and lubricate pin threads
- paint the 45° load shoulder white as indicated

2. Examine the **13-5/8" x 9-5/8" LC MBU-LR Casing Hanger Running and Retrieving Tool (Item ST3)**. Verify the following:

- bore is clean and free of debris
- O.D. Acme threads are clean and in good condition
- o-ring is in place and in good condition
- proper length landing joint is made up in top of the tool with thread lock compound



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Stage 4 — Hang Off the 9-5/8" Casing

3. Thoroughly clean and lightly lubricate the mating Acme threads and seal surfaces of the hanger and running tool.
4. Carefully slide the running tool into the hanger and then rotate the tool clockwise (Right) to locate the thread start and then counter clockwise (Left) approximately 8 turns or until the tool makes contact with the top of the energizing ring.

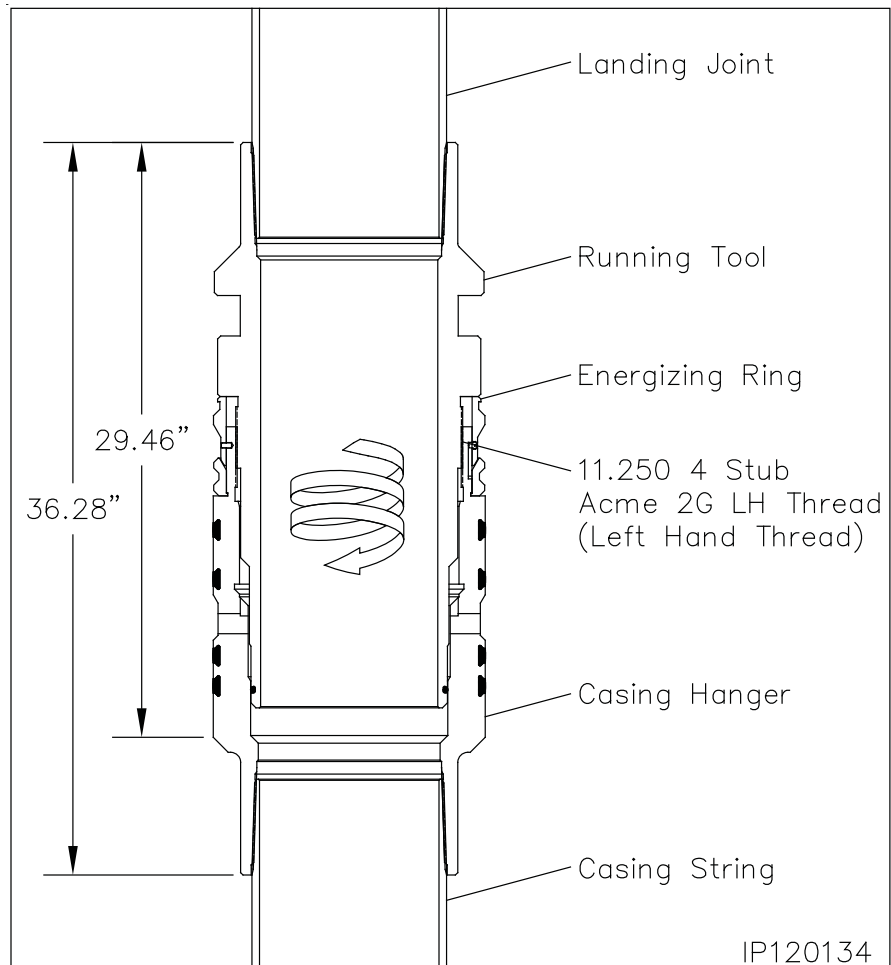
WARNING: Do Not apply torque to the Hanger/Tool connection.

5. Run the 9-5/8" casing as required and space out appropriately for the mandrel casing hanger.

Note: If the 9-5/8" casing becomes stuck and the mandrel casing hanger can not be landed, Refer to **Stage 4A** for the emergency procedure.

6. Set the last joint of casing run in the floor slips.
7. Pick up the casing hanger/running tool assembly and make it up in the casing string. Torque connection to thread manufacturer's optimum make up torque.
8. Using chain tongs only, back off the running tool with clockwise rotation (Right) one full turn to verify ease of operation and then re make the connection with counter clockwise rotation (Left) just until contact with the energizing ring is.

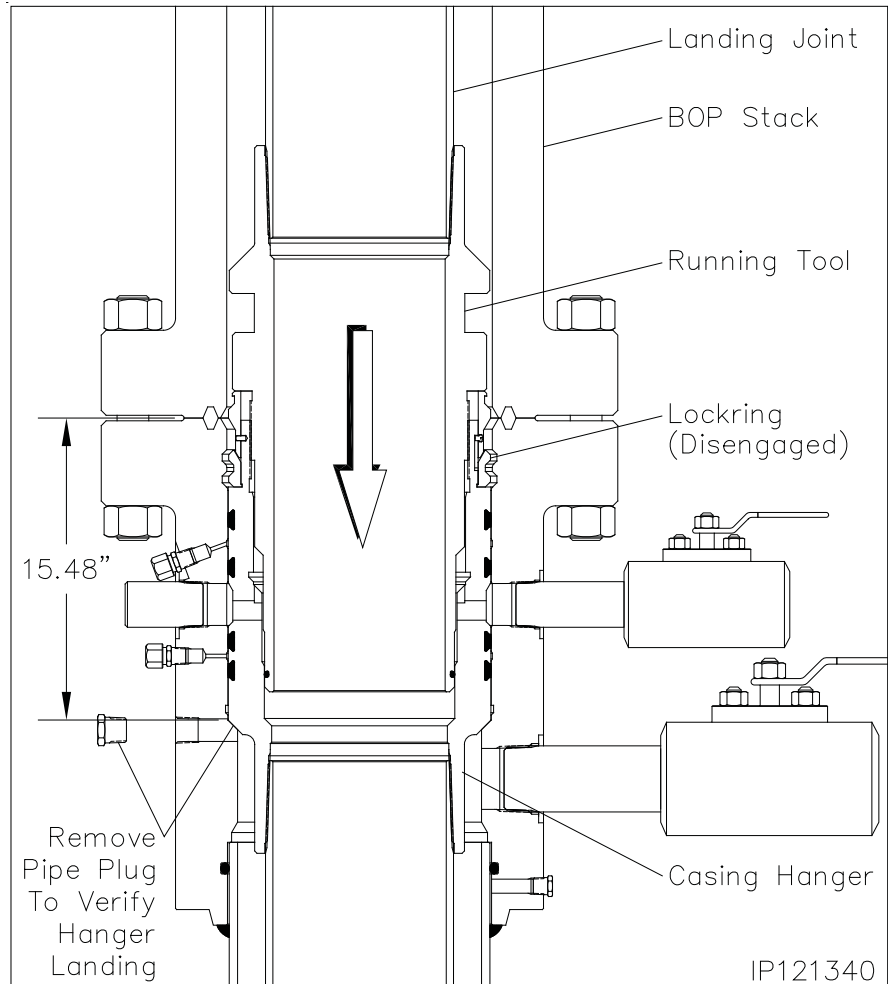
WARNING: Do Not apply torque to the Hanger/Tool connection.



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Stage 4 — Hang Off the 9-5/8" Casing

9. Calculate the total landing dimension by adding the previously attained RKB dimension and 15.48", the depth of the wellhead.
10. Drain the BOP stack and wellhead through the 3" ball valve.
11. Starting at the top of the 45° angle load shoulder of the casing hanger measure up 5 feet and place a horizontal paint mark on the landing joint and write 5 next to the mark.
12. Using the 5 foot stick, slowly and carefully lower the Hanger through the BOP, marking the landing joint at five foot increments until you come to the calculated total landing dimension. Place a paint mark on the landing joint at that dimension and write the landing dimension next to the mark. Place an additional mark on the landing joint 1-1/2" above the first mark and write engaged.
13. Continue carefully lowering the hanger through the BOP stack and land it on the load shoulder in the housing, 15.48" below the top of the MBU-LR housing and slack off all weight and verify that the landing dimension paint mark has aligned with the rig floor.
14. Locate the 1" LP sight port on the lower O.D. of the housing and remove the pipe plug.
15. Look through the port to verify the hanger is properly landed. The white painted load shoulder will be clearly visible in the open port.
16. Reinstall the 1" pipe plug and tighten securely.

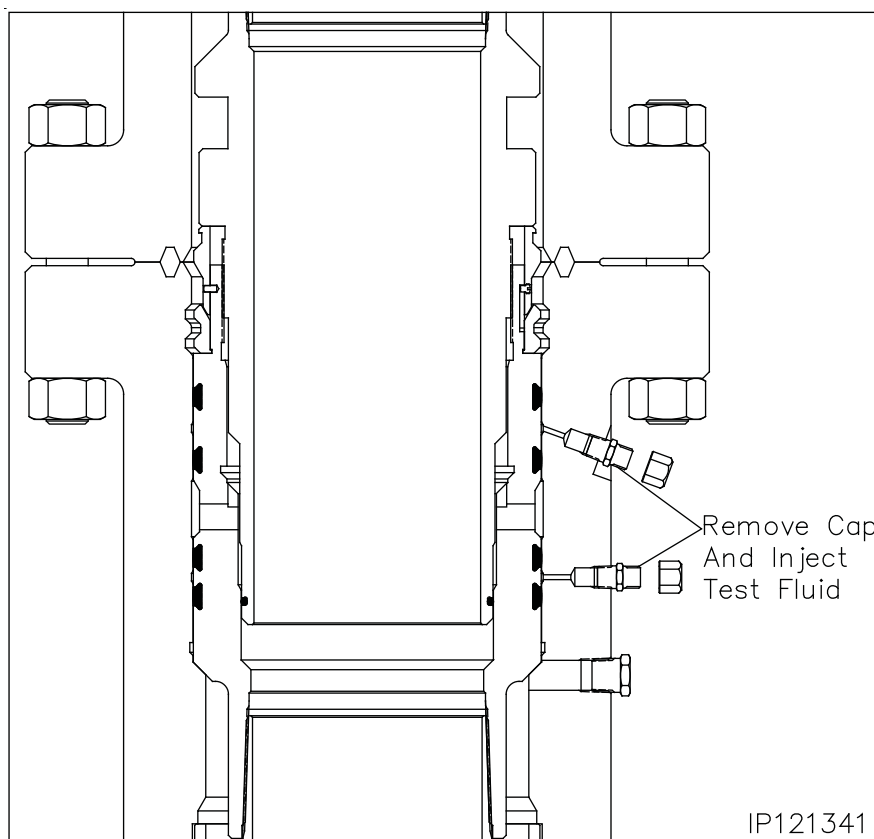


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Stage 4 — Hang Off the 9-5/8" Casing

Seal Test

17. Locate the upper and lower seal test fittings on the O.D. of the housing and remove the dust caps from both fittings.
18. Attach a test pump to one of the open fittings and pump clean test fluid between the seals until a stable test pressure of 5,000 psi is attained.
19. If a leak develops, bleed off test pressure, remove the hanger from the wellhead and replace the leaking seals.
20. Repeat steps 17 through 19 for the remaining seal test.
21. After satisfactory test are achieved, bleed off all test pressure, remove test pump and reinstall the dust caps on the open fittings



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Stage 4 — Hang Off the 9-5/8" Casing

Engaging the Lockring

22. Using Chain Tongs Only located 180° apart, rotate the landing joint approximately 6 turns counter clockwise (Left) to engage the casing hanger locking in its mating groove in the bore of the MBU-LR housing.

Note: Approximately 800 to 900 ft. lbs. of torque will be required to break over the shear pins in the hanger. The torque will drop off and then increase slightly when the energizing ring pushes the locking out. A positive stop will be encountered when the locking is fully engaged.

Note: When properly engaged the second paint mark on the landing joint will align with the rig floor.

WARNING: It is imperative that the landing joint remain concentric with the well bore when rotating to engage the locking. This can be accomplished with the use of the air hoist.

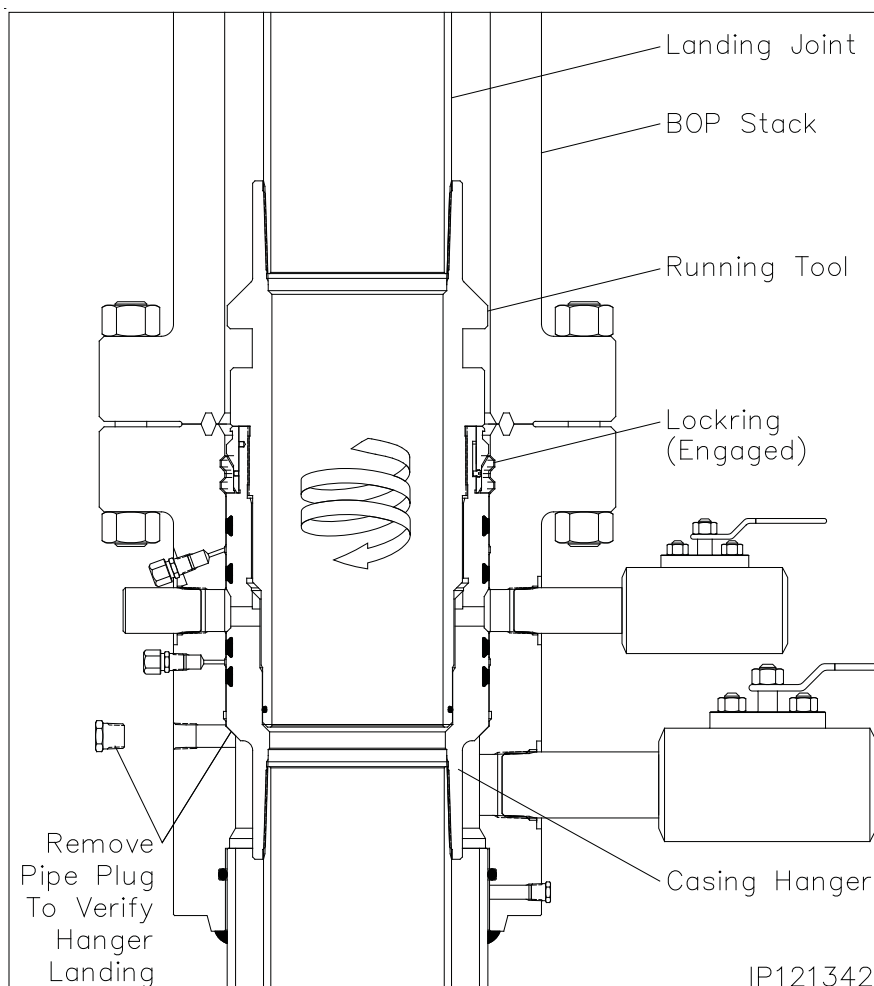
WARNING: If the required turns to engage the locking or not met or excessive torque is encountered, remove the casing hanger and call Houston Engineering.

23. Back off the landing joint/running tool approximately three turns clockwise (Right). Using the elevators, exert a 30,000 lbs. over string weight pull on the landing joint to confirm positive locking engagement.

24. Slack off all weight and place a vertical paint mark on the landing joint to verify if the casing string rotates during the cementing process.

Note: It is not necessary to remake the casing hanger running tool connection after the over pull. If desired two counter clockwise rotations may be made but full make up is not required.

25. Cement the casing as required, taking returns through the lower 3" outlet.



26. With cement in place, bleed off cement pressure and remove cementing equipment.

27. If well condition permit, remove the 1" sight port pipe plug to observe if the hanger rotates during the removal of the running tool.

28. Using Chain Tongs Only located 180° apart, retrieve the Running Tool and landing joint by rotating the landing joint clockwise (Right) an additional 11 turns or until the tool comes free of the hanger. Retrieve the tool with a straight vertical lift.

29. Reinstall the 1" pipe plug and tighten securely.

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Stage 4 — Hang Off the 9-5/8" Casing

Retrieving The Casing Hanger

In the event that the casing hanger needs to be removed, the 13-5/8" x 9-5/8" MBU-LR Casing Hanger Running and retrieving tool can be fitted with a retrieval latch that will lift the casing hanger energizing ring and allow the locking to disengage.

1. Examine the **13-5/8" x 9-5/8" LC MBU-LR Casing Hanger Running and Retrieving Tool (Item ST3)**. Verify the following:
 - bore is clean and free of debris
 - O.D. Acme threads are clean and in good condition
 - o-ring is in place and in good condition
 - proper length landing joint is made up in top of the tool with thread lock compound
 - retrieval latch is available and in good condition

2. Thoroughly clean and lightly the latch groove of the tool with oil or light grease.

3. Remove the (4) 1/2" cap screws retaining the two halves of the retrieval latch.

4. Install the retrieval latch around the Retrieving Tool body as indicated and reinstall the 1/2" cap screws. Tighten screws securely.

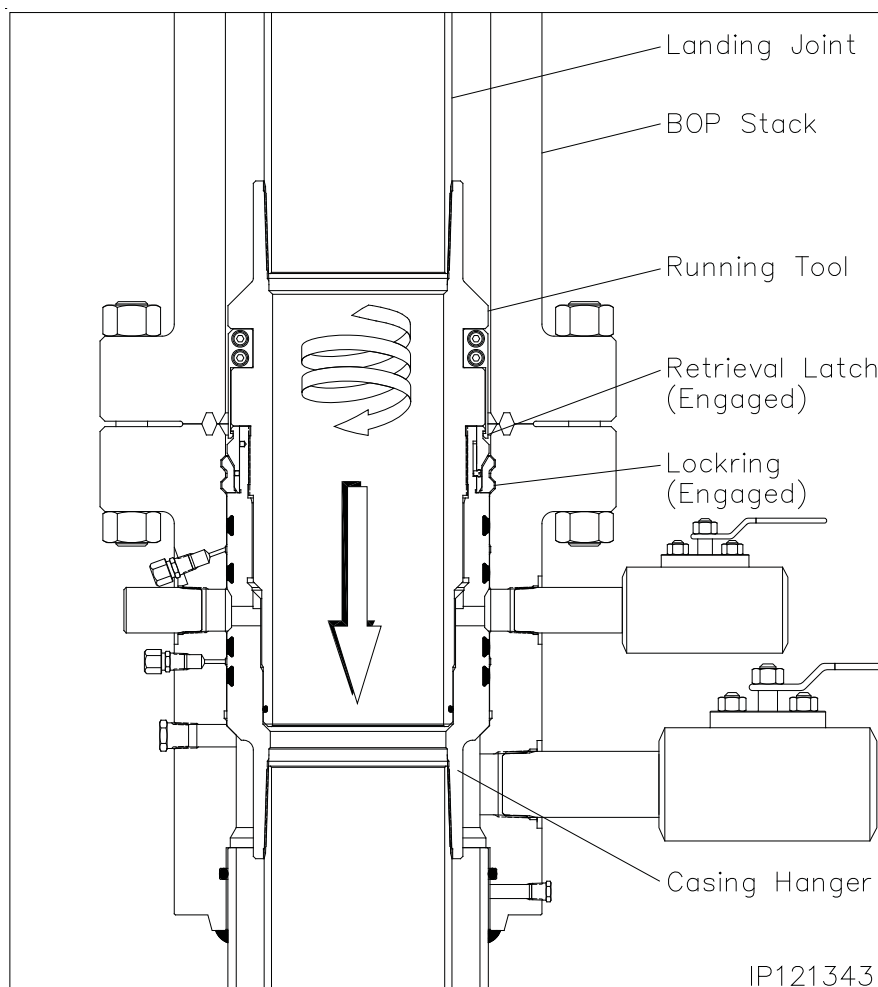
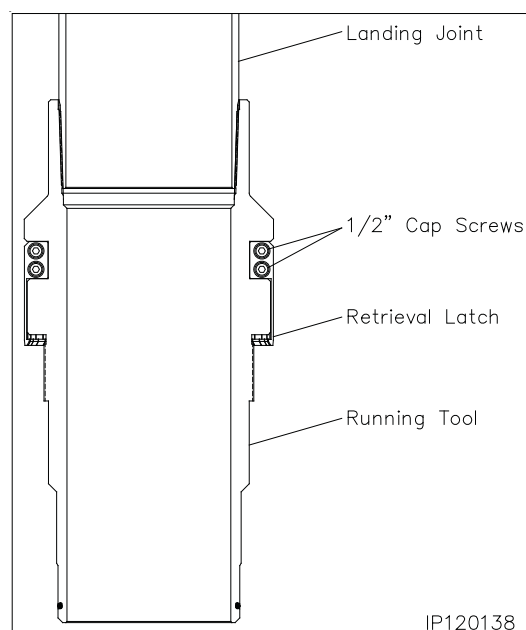
WARNING: Ensure the latch rotates freely on the tool. If not remove and check the latch and tool for burrs or imperfections in the groove.

5. Thoroughly clean and lightly lubricate the seal surfaces and Acme threads of the tool with oil or a light grease.
6. Using the casing elevators, carefully lower the tool through the BOP stack and into the casing hanger bore until the tool contacts the top of the hanger Acme threads.

Note: Contact should be made at previously attained RKB dimension.

7. Using chain tongs only located **180° apart**, rotate the landing joint clockwise (Right) to locate the thread start then counter clockwise (Left) approximately 13 turns.

WARNING: Slowly make the last two revolutions. The torque will increase slightly as the latch passes over the top of the energizing ring and snaps into position under the lip of the ring.



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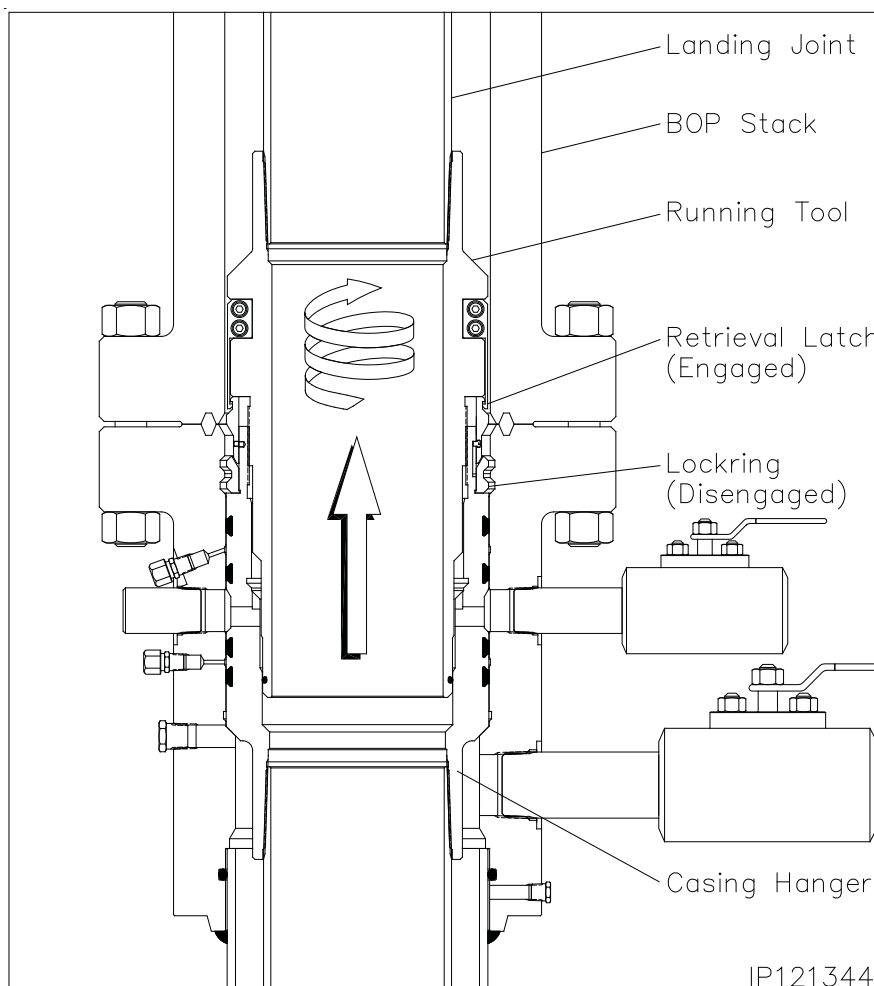
Stage 4 — Hang Off the 9-5/8" Casing

WARNING: The landing joint must remain concentric with the well bore when screwing into the hanger.

8. With positive engagement attained, reposition the tongs for clockwise (Right) rotation and then rotate the landing joint approximately 6 turns to lift the energizing ring and release the lockring.

Note: The landing joint should rise approximately 1-1/2" and come to a positive stop against the stop screws.

9. Halt rotation and remove the chain tongs.
10. Using the drill pipe elevators, slowly pick up on the casing hanger and retrieve it from the wellhead.
11. With the tool and hanger at the rig floor, set the casing in the floor slips and slack off.
12. Rotate the landing joint counter clockwise (Left) one turn.
13. Remove the (4) 1/2" cap screws from the retrieval latch and remove the latch assembly from the tool.
14. Remove the casing hanger and running tool from the casing string.

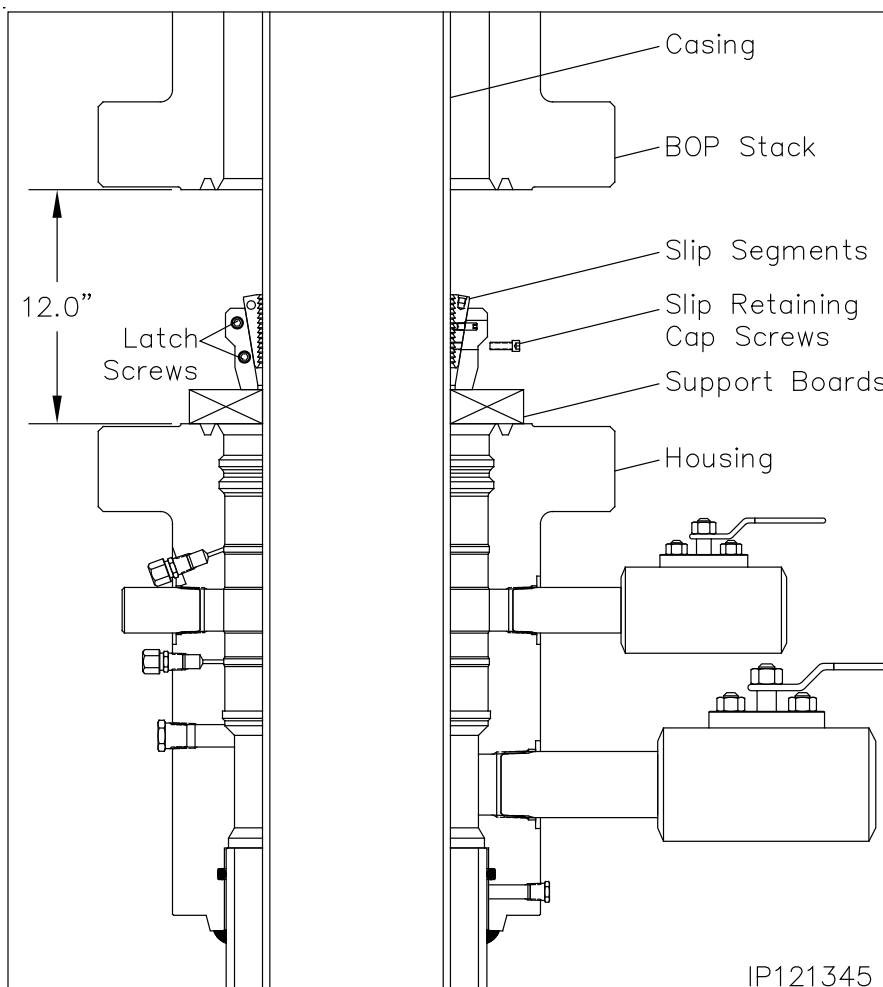
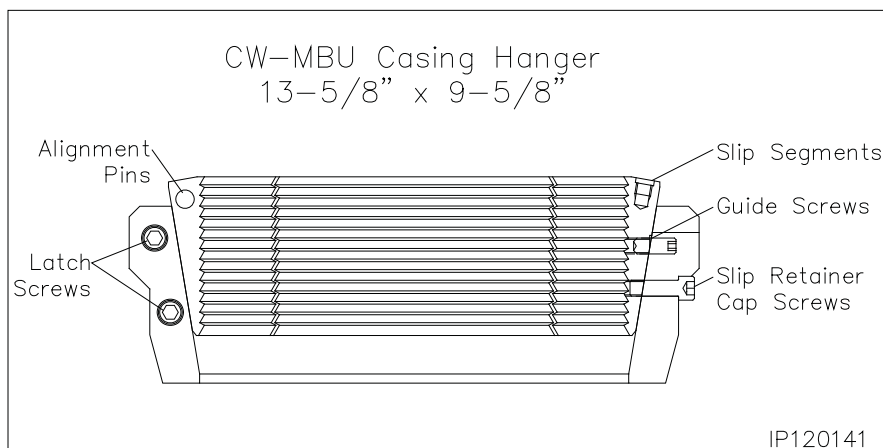


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Stage 4A — Hang Off the 9-5/8" Casing (Emergency)

Note: The following procedure should be followed **ONLY** if the 9-5/8" casing should become stuck in the hole. If the casing did not get stuck and is hung off with the Mandrel Casing Hanger, skip this stage.

1. Cement the hole as required.
2. Drain the BOP stack through the housing side outlet valve.
3. Separate the connection between the BOP and the MBU-LR housing.
4. Pick up on the BOP stack a minimum of 12" and secure with safety slings.
5. Washout as required.
6. Examine the **13-5/8" x 9-5/8" MBU Slip Casing Hanger (Item A7a)**. Verify the following:
 - slips and internal bore are clean and in good condition
 - all screws are in place
7. There are two latch screws located in the top of the casing hanger. Using a 5/16" Allen wrench, remove the two latch screws located 180° apart and separate the hanger into two halves.
8. Place two boards on the housing flange against the casing to support the Hanger.
9. Pick up one half of the hanger and place it around the casing and on top of the boards.
10. Pick up the second hanger half and place it around the casing adjacent the first half.
11. Slide the two hanger halves together ensuring the slip alignment pins properly engage the opposing hanger half.
12. Reinstall the latch screws and tighten securely.



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Stage 4A — Hang Off the 9-5/8" Casing (Emergency)

13. Prepare to lower the Hanger into the housing bowl.

WARNING: Do Not Drop the Casing Hanger!

14. Grease the Casing Hanger's body and remove the slip retaining screws.
15. Remove the boards and allow the Hanger to slide into the housing bowl. When properly positioned the top of the hanger will be approximately 14.05" below the top of the housing.
16. Pull tension on the casing to the desired hanging weight and then slack off.

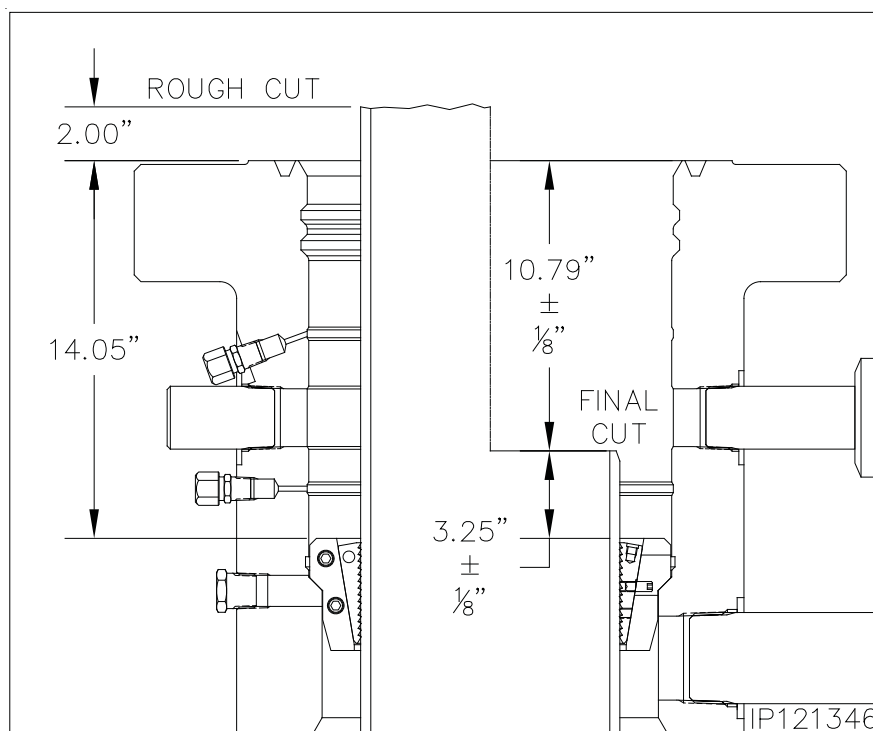
Note: A sharp decrease on the weight indicator will signify that the Hanger has taken weight and at what point, If this does not occur, pull tension again and slack off once more.

WARNING: Because of the potential fire hazard and the risk of loss of life and property, It is highly recommended to check the casing annulus and pipe bore for gas with an approved sensing device prior to cutting off the casing. If gas is present, do not use an open flame torch to cut the casing. It will be necessary to use a air driven mechanical cutter which is spark free.

17. Rough cut the casing approximately 2" above the top flange and move the excess casing out of the way.

WARNING: Install the long wear bushing in the housing to ensure the housing bore is not damaged with the torch or cutting debris.

18. Final cut the casing at $10.79" \pm 1/8"$ below the housing flange or $3.25" \pm 1/8"$ above the hanger body.
19. Grind the casing stub level and then place a $3/16" \times 3/8"$ bevel on the O.D. and a I.D. chamfer to match the minimum bore of the packoff to be installed.



Note: There must not be any rough edges on the casing or the seals of the Packoff will be damaged.

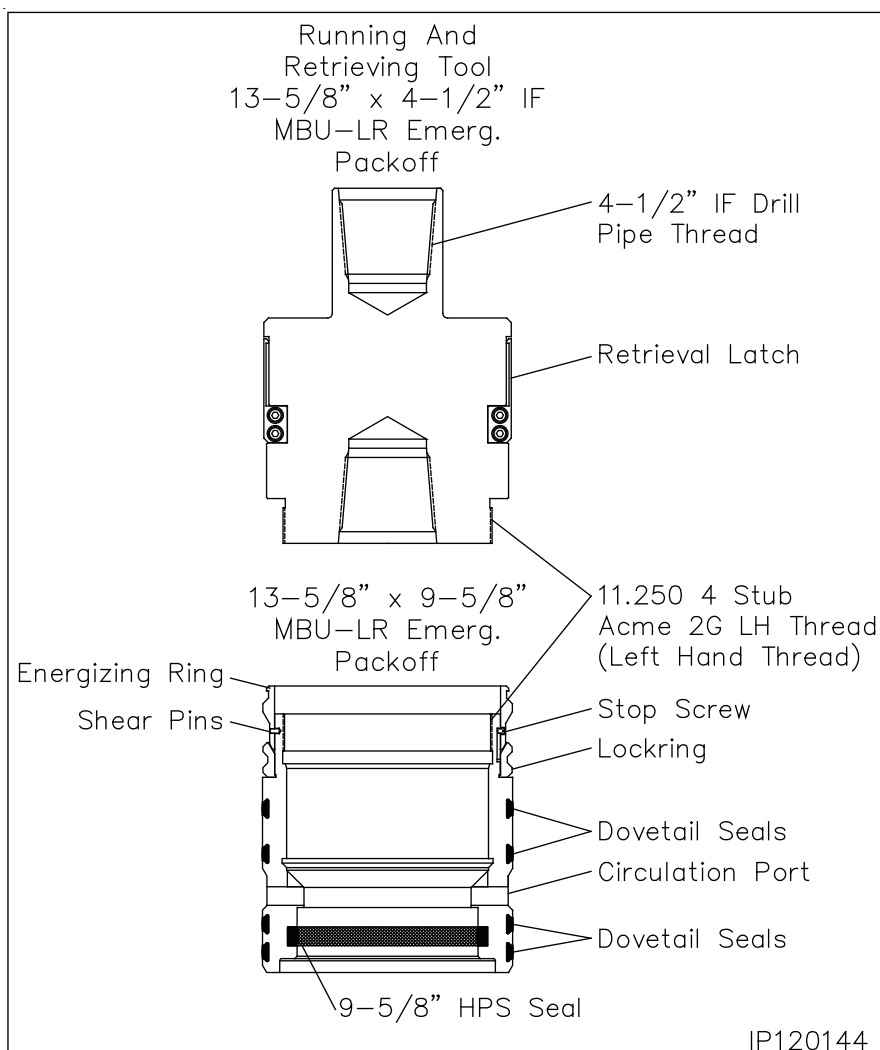
20. Remove the wear bushing and then thoroughly clean the housing bowl, removing all cement and cutting debris.

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Stage 4B — Install the 9-5/8" MBU-LR Emergency Packoff

The following steps detail the installation of the CW MBU-LR Packoff Assembly for the emergency casing hanger.

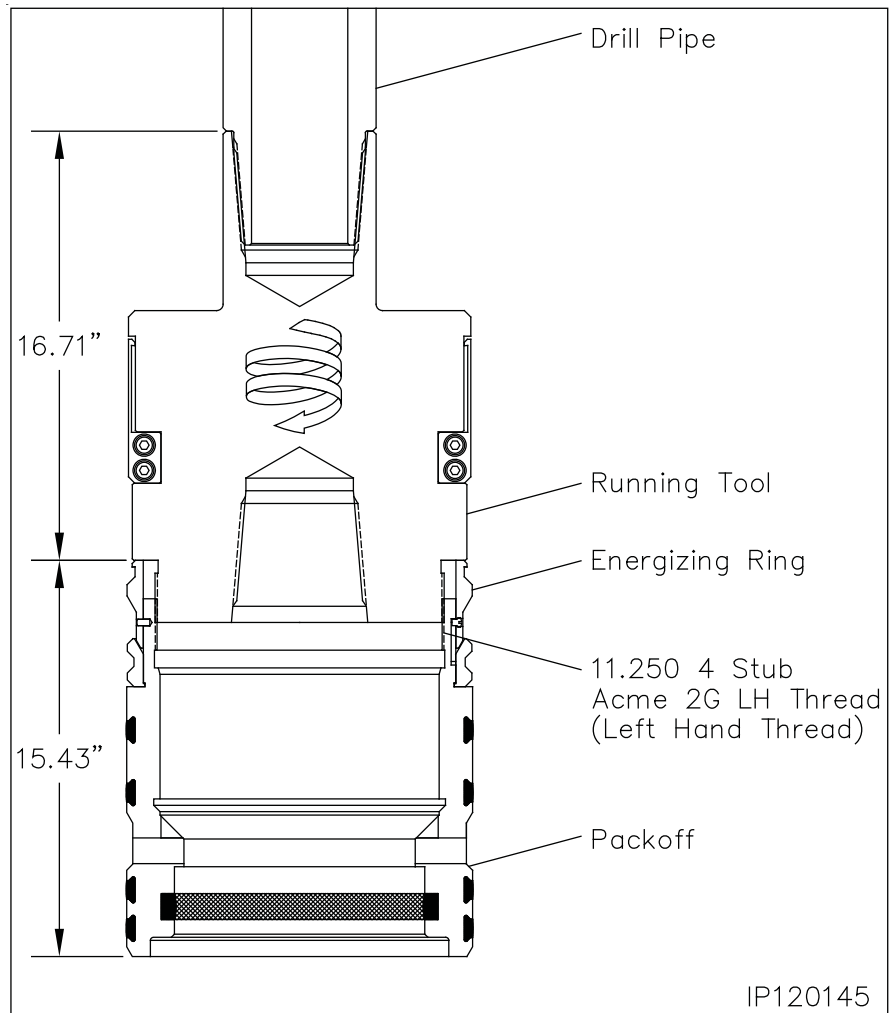
1. Examine the **13-5/8" Nominal x 9-5/8" x 11.250" 4 Stub Acme 2G LH box top MBU-LR Packoff Assembly (Item A7b)**. Verify the following:
 - all elastomer seals are in place and undamaged
 - internal bore, and ports, are clean and in good condition
 - locking is fully retracted
 - energizer ring is in its upper most position and retained with shear pins
 - anti-rotation plunger is in place, free to move
2. Lubricate the ID of the 'HPS' seal and the OD of the dovetail seals liberally with a light oil or grease.
3. Examine the **13-5/8" Nominal x 4-1/2" IF x 11.250" 4 Stub Acme 2G LH box top MBU-LR Packoff Running Tool (Item ST4)**. Verify the following:
 - Acme threads are clean and in good condition
 - actuation sleeve is clean, in good condition and rotates freely
 - retrieval latch is removed and stored in safe place



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Stage 4B — Install the 9-5/8" MBU-LR Emergency Packoff

4. Make up a 4-1/2" IF drill collar to the top of the Running Tool and tighten connection to thread manufacturer's maximum make up torque.
5. Run in the hole with two stands of drill pipe and set in floor slips.
6. Thoroughly clean and lightly lubricate the mating Acme threads of the running tool and packoff with oil or light grease.
7. Pick up the packoff and carefully pass it over the drill pipe and set it on top of the floor slips.
8. Pick up the Running Tool with landing joint and make it up to the drill pipe in the floor slips.
9. Pick up the packoff and thread it onto the running tool with clockwise (Right) rotation until the Energizing Ring makes contact with the bottom shoulder of the tool. Approximately 4 turns.
10. Thoroughly clean and lightly lubricate the packoff ID 'HPS' seal and the OD dovetail seals with oil or light grease.



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Stage 4B — Install the 9-5/8" MBU-LR Emergency Packoff

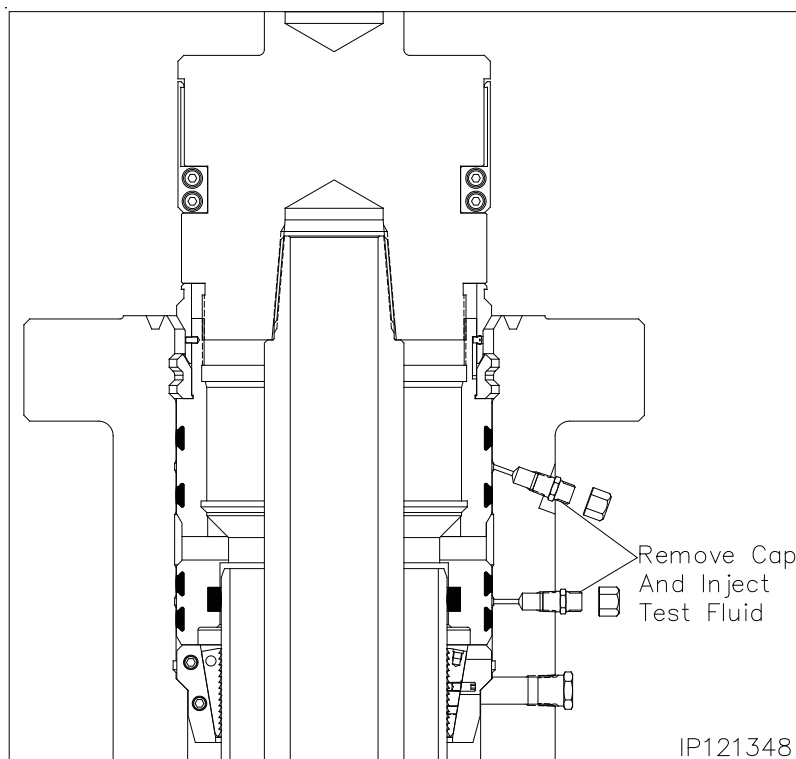
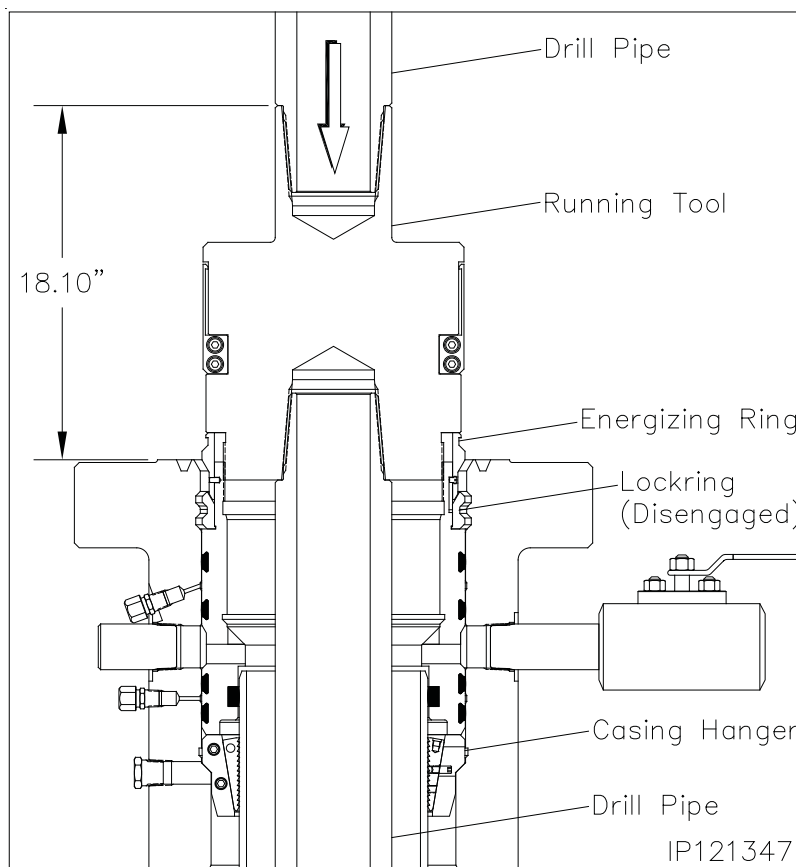
Landing the Packoff

1. Pick up the drill string and remove the floor slips.
2. Carefully lower the packoff through the rig floor and into the housing until it lands on top of the slip hanger.

Note: When properly positioned the top of the running tool will be approximately 18.10" above the top of the MBU-LR Housing

Seal Test

3. Locate the upper and lower seal test fittings on the O.D. of the housing and remove the dust caps from both fittings.
4. Attach a test pump to one of the open fittings and pump clean test fluid between the seals until a stable test pressure of 5,000 psi is attained.
5. If a leak develops, bleed off test pressure, remove the hanger from the wellhead and replace the leaking seals.
6. Repeat steps 3 through 5 for the remaining seal test.
7. After satisfactory test are achieved, bleed off all test pressure, remove test pump and reinstall the dust caps on the open fittings



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Stage 4B — Install the 9-5/8" MBU-LR Emergency Packoff

Engaging the Lockring

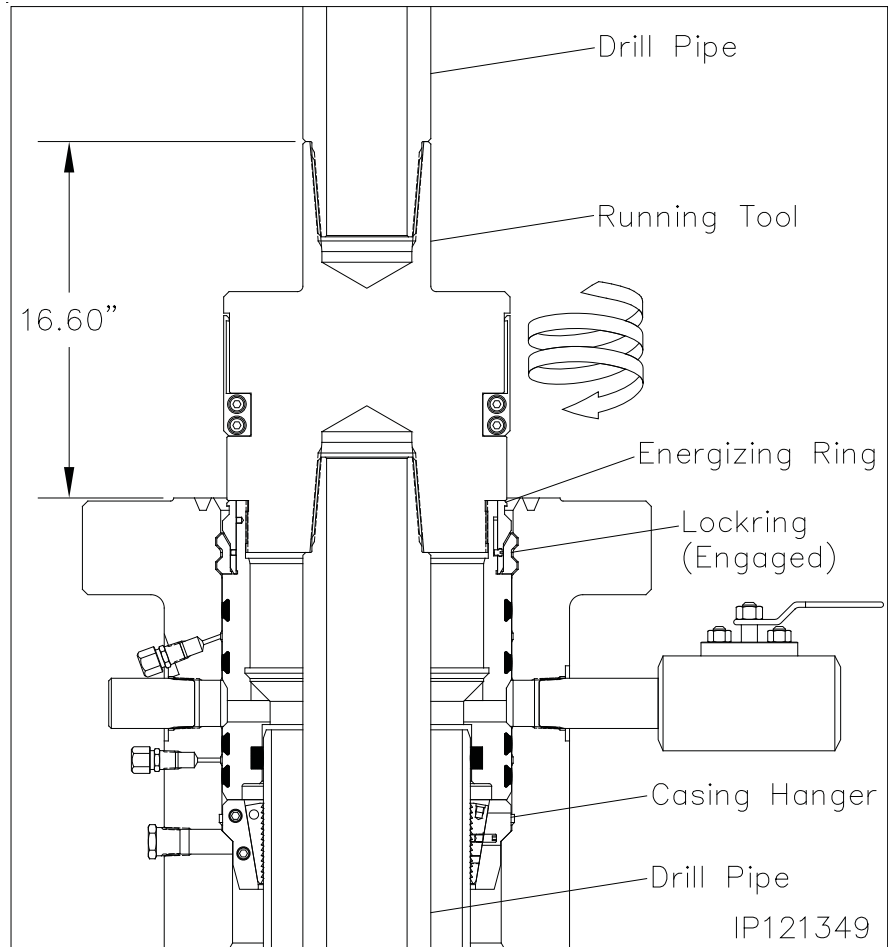
8. Using only chain tongs, rotate the landing joint approximately 6 turns counter clockwise (Left) to engage the packoff locking in its mating groove in the bore of the MBU-LR housing.

Note: Approximately 800 to 900 ft. lbs. of torque will be required to break over the shear pins in the packoff. The torque will drop off and then increase slightly when the energizing ring pushes the locking out. A positive stop will be encountered when the locking is fully engaged.

WARNING: It is imperative that the drill pipe landing joint remain concentric with the well bore when rotating to engage the locking. This can be accomplished with the use of the air hoist.

WARNING: If the required turns to engage the locking or not met or excessive torque is encountered, remove the packoff and call Houston Engineering.

9. Back off the landing joint/running tool approximately three turns. Using the drill pipe elevators, exert a 20,000 lbs. pull on the landing joint.
10. Using only chain tongs, rotate the landing joint clockwise until the tool comes free of the packoff (approximately 9 turns) and then retrieve the tool with a straight vertical lift.



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Stage 4B — Install the 9-5/8" MBU-LR Emergency Packoff

In the event the packoff is required to be removed after the locking is engaged the following procedure is to be followed.

Retrieving the Packoff

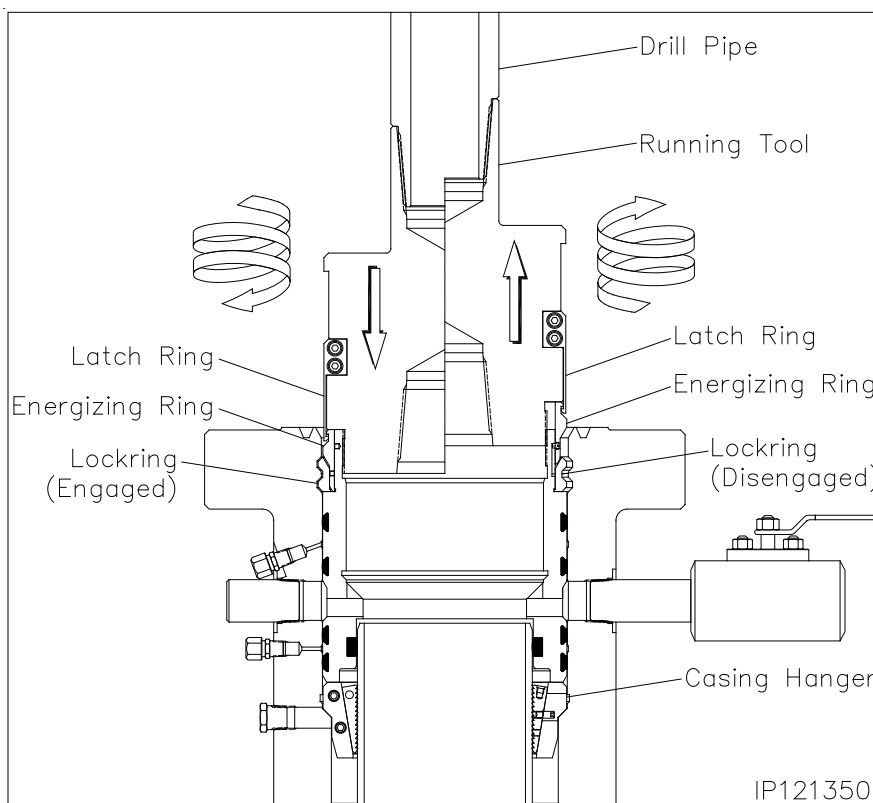
1. Locate the retrieval latch assembly with (4) 1/2" cap screws
2. Install the retrieval latch onto the running tool with the latch fingers facing down and install the cap screws and tighten them securely.
3. Ensure the retrieval latch freely rotates on the running tool actuation sleeve.
4. Carefully lower the running tool into the packoff.
5. Rotate the drill pipe clockwise (Right) to locate the thread start and then counter clockwise (Left) (approximately 10 turns) to a positive stop.

Note: At this point the retrieval latches will have passed over the energizing ring and snapped into place.

6. Rotate the drill pipe clockwise (approximately 6-1/2 turns) to a positive stop. The drill pipe should rise approximately 1-1/2".

Warning: Do not exceed the 6-1/2 turns or the packoff may be seriously damaged.

7. Carefully pick up on the drill pipe and remove the packoff from the MBU-LR wellhead with a straight vertical lift.
8. Redress the Packoff and reset as previously outlined.



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Stage 5 — Test the BOP Stack

Immediately after making up the BOP stack and periodically during the drilling of the well for the next casing string the BOP stack (connections and rams) must be tested.

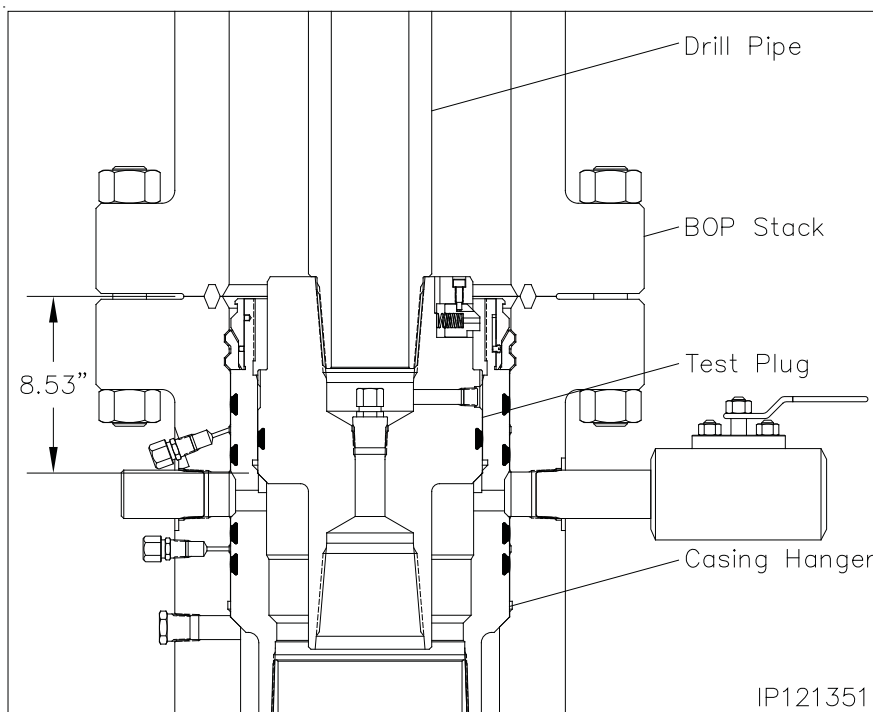
1. Examine the **11" Nominal x 4-1/2" IF CW Test Plug/Retrieving Tool (Item ST5)**. Verify the following:
 - 1-1/4" VR plug and weep hole plug are in place and tightened securely
 - elastomer seal is in place and in good condition
 - retractable lift lugs are in place, clean, and free to move
 - drill pipe threads are clean and in good condition

Note: Prior to installing the BOP it is recommended to attain an accurate RKB dimension for future use for accurately landing test plugs and casing hangers. This dimension is attained by dropping a tape measure from the rig floor to the top of the wellhead flange. Pull tape taut and record the dimension from the wellhead to the top of the rig floor or kelly bushings. Ensure this dimension is placed on the BOP board in the dog house and on the drillers daily report sheet.

2. Position the test plug with the elastomer seal down and the lift lugs up and make up the tool to a joint of drill pipe.

WARNING: Ensure that the lift lugs are up and the elastomer seal is down

3. Remove the 1/2" NPT pipe plug from the weep hole if pressure is to be supplied through the drill pipe.



4. Open the housing upper side outlet valve.
5. Lightly lubricate the test plug seal with oil or light grease.
6. Carefully lower the test plug through the BOP and land it on the load shoulder in the packoff, 8.53" below the top of the housing.
7. Close the BOP rams on the pipe and test the BOP to 5,000 psi.
8. After a satisfactory test is achieved, release the pressure and open the rams.
9. Remove as much fluid as possible from the BOP stack and the retrieve the test plug with a straight vertical lift.
10. Repeat this procedure as required during the drilling of the hole section.

Note: When performing the BOP blind ram test it is highly recommended to suspend a stand of drill pipe below the test plug to ensure the plug stays in place while disconnecting from it with the drill pipe.

Note: Any leakage past the test plug will be clearly visible at the open side outlet valve.

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Stage 6 — Run the Upper Wear Bushing

Note: Always use a Wear Bushing while drilling to protect the load shoulders from damage by the drill bit or rotating drill pipe. The Wear Bushing **must be retrieved** prior to running the casing.

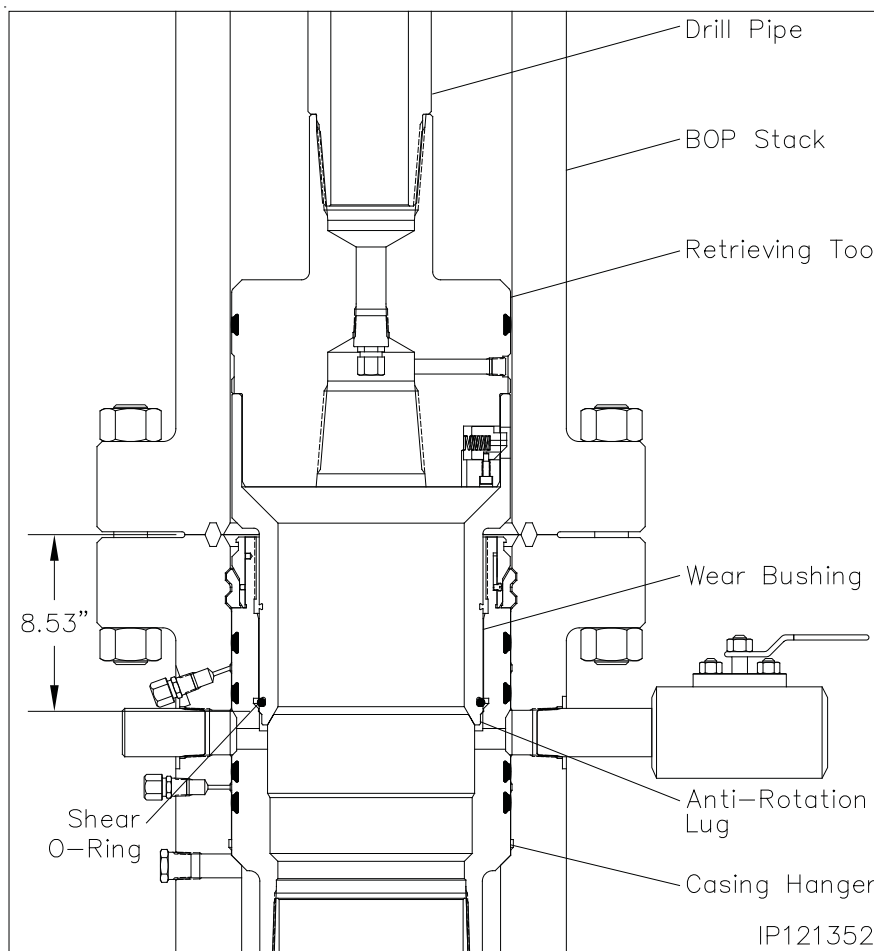
1. Examine the **13-5/8" x 11" x 9.00" ID MBU-LR-UPR Wear Bushing (Item ST6)**. Verify the following
 - internal bore is clean and in good condition
 - o-ring is in place and in good condition
 - shear o-ring cord is in place and in good condition
 - paint anti-rotation lugs white and allow paint to dry

Run the Wear Bushing Before Drilling

2. Orient the **13-5/8" Nominal x 4-1/2" IF CW Test Plug/Retrieving Tool (Item ST1)** with drill pipe connection up.
3. Attach the Retrieving Tool to a joint of drill pipe.
4. Align the retractable lift lugs of the tool with the retrieval holes of the bushing and the carefully lower the tool into the Wear Bushing until the lugs snap into place.

Note: If the lugs did not align with the holes, rotate the tool in either direction until they snap into place.

5. Apply a heavy coat of grease, not dope, to the OD of the bushing.
6. Slowly lower the Tool/Bushing Assembly through the BOP stack and land it on the load shoulder in the packoff, 8.53" below the top of the housing.
7. Rotate the drill pipe clockwise (right) to locate the stop lugs in their mating notches in the packoff. When properly aligned the bushing will drop an additional 1/2".



Note: The Shear O-Ring on bottom of the bushing will locate in a groove above the load shoulder in the head to act as a retaining device for the bushing.

8. Remove the Tool from the Wear Bushing by rotating the drill pipe counter clockwise (left) 1/4 turn and lifting straight up
9. Drill as required.

Note: It is highly recommended to retrieve, clean, inspect, grease, and reset the wear bushing each time the hole is tripped during the drilling of the hole section.

Retrieve the Wear Bushing After Drilling

10. Make up the Retrieving Tool to the drill pipe.
11. Slowly lower the Tool into the Wear Bushing.
12. Pick up and balance the riser weight.
13. Rotate the Retrieving Tool clockwise until a positive stop is felt. This indicates the lugs have snapped into the holes in the bushing.
14. Retrieve the Wear Bushing, and remove it and the Retrieving Tool from the drill string.

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Stage 7 — Hang Off the 7" Casing

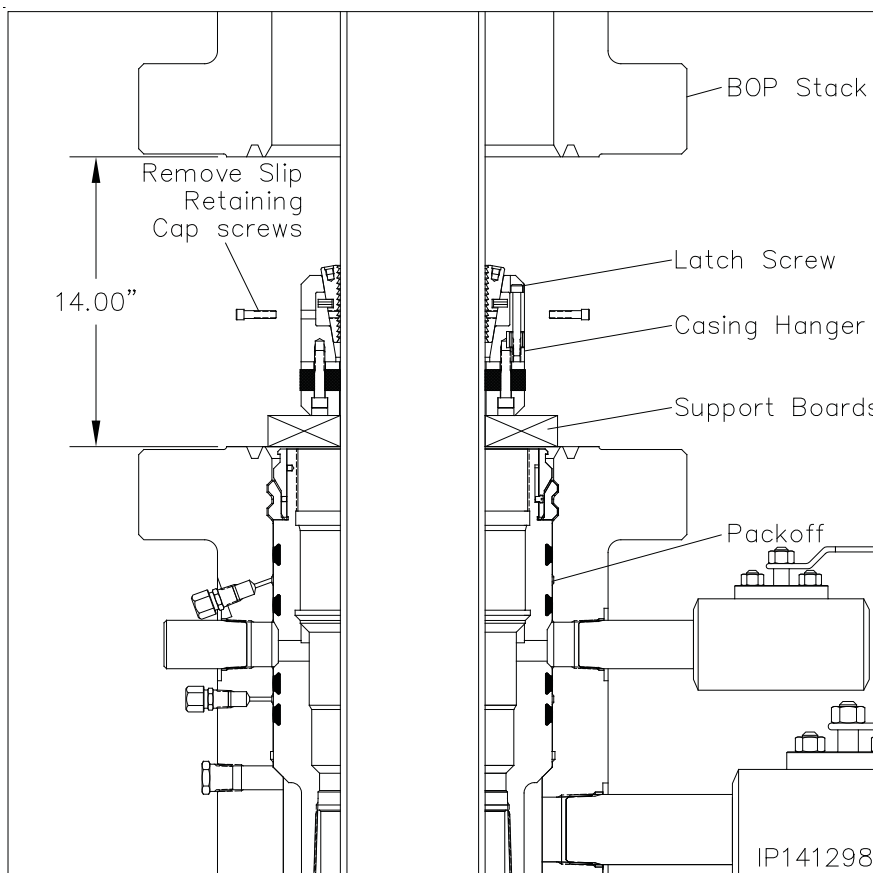
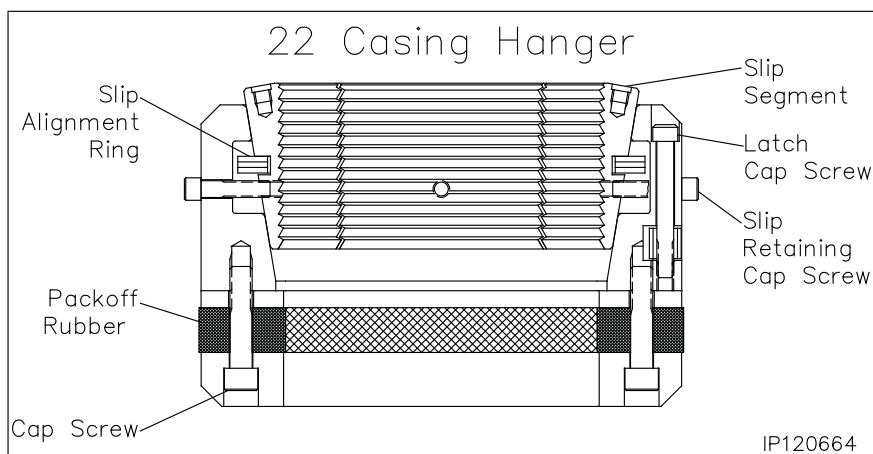
1. Run the 7" casing string as required and cement in place.
2. Drain the housing bowl through the upper side outlet.
3. Separate the BOP from the MBU-LR housing and lift the BOP approximately 14" above the housing and secure BOP with safety slings.
4. Using a fresh water hose, thoroughly wash out the packoff bowl.

Note: Casing Head side outlet valve to remain open while setting the casing hanger.

5. Examine the **11" X 7" C22 Casing Hanger (Item B9)**. Verify the following:
 - slips and internal bore are clean and in good condition
 - all screws are in place
 - seal element is in good condition

Note: Ensure that the packoff rubber does not protrude beyond the O.D. of the casing hanger body. If it is, loosen the compression cap screws in the top of the hanger.

6. Remove the latch screw to open the Hanger.
7. Place two boards on the Casing Head flange against the casing to support the Hanger.
8. Wrap the Hanger around the casing and replace the latch screw.
9. Prepare to lower the Hanger into the Casing Head bowl.
10. Grease the Casing Hanger's body and remove the slip retaining cap screws.



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Stage 7 — Hang Off the 7" Casing

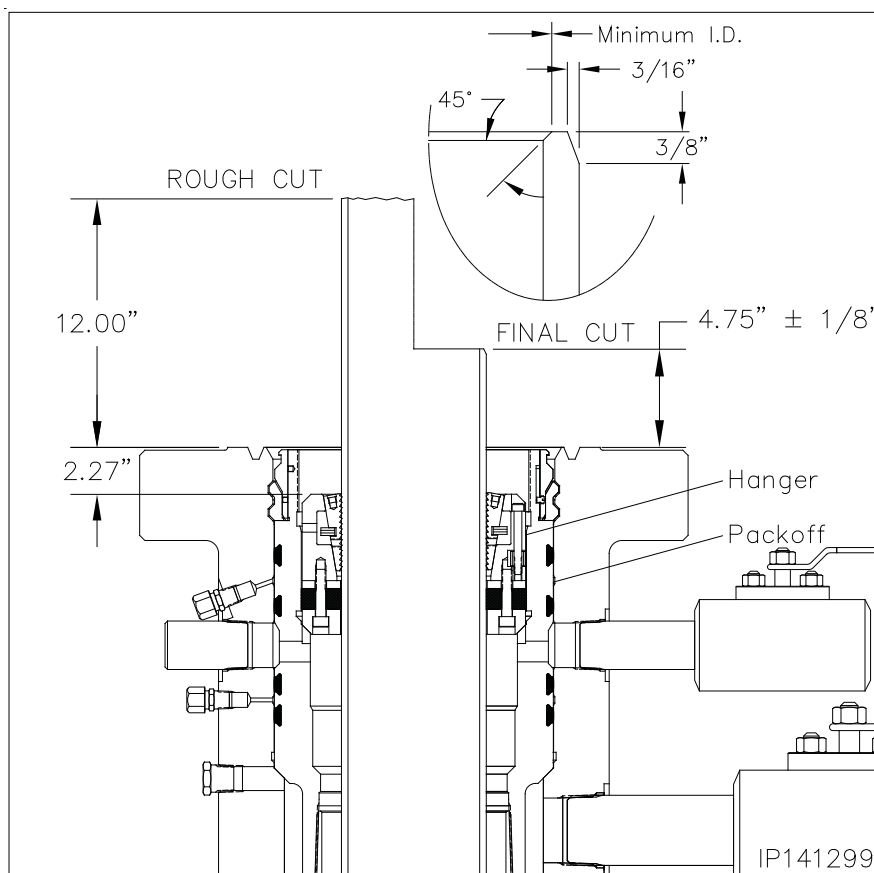
11. Remove the boards and allow the Hanger to slide into the packoff bowl. When the Hanger is down, the top of the hanger body will be approximately 2.27" below the top of the housing, pull tension on the casing to the desired hanging weight and then slack off..

Note: A sharp decrease on the weight indicator will signify that the Hanger has taken weight and at what point, If this does not occur, pull tension again and slack off once more.

WARNING: Because of the potential fire hazard and the risk of loss of life and property, It is highly recommended to check the casing annulus and pipe bore for gas with an approved sensing device prior to cutting off the casing. If gas is present, do not use an open flame torch to cut the casing. It will be necessary to use a air driven mechanical cutter which is spark free.

12. Rough cut the casing approximately 12" above the top flange and move the excess casing and BOP out of the way.
13. Final cut the casing at $4.75" \pm 1/8"$ above the top flange of the housing.
14. Grind the casing stub level and then place a $3/16" \times 3/8"$ bevel on the O.D. and a I.D. chamfer to match the minimum bore of the tubing head to be installed.
15. Using a high pressure water hose thoroughly clean the top of the casing hanger and void area above the hanger. Ensure all cutting debris are removed .
16. Fill the void above the hanger with clean test fluid to the top of the flange.

WARNING: Do Not over fill the void with test fluid - trapped fluid under the ring gasket may prevent a good seal from forming



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Stage 8 — Install the Tubing Head

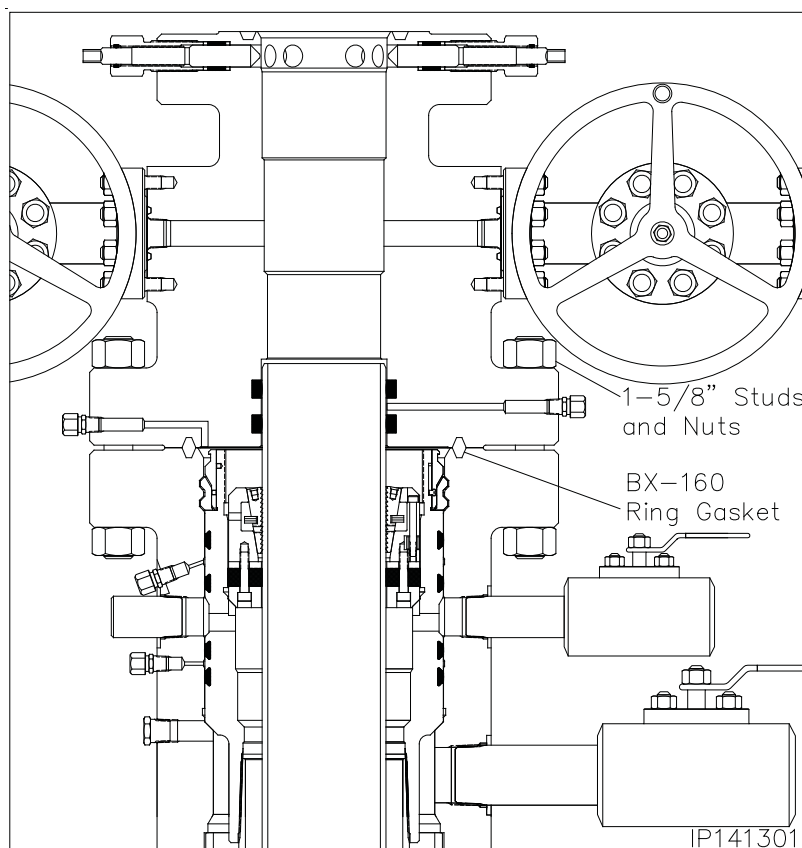
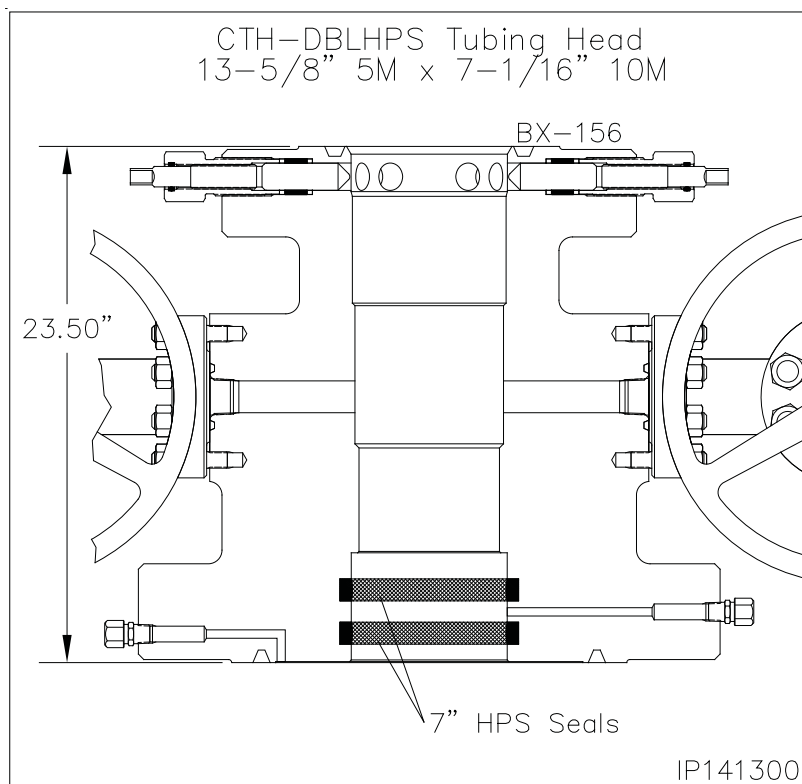
- Examine the **13-5/8" 5M x 7-1/16" 10M CW, CTH-DBLHPS Tubing Head (Item B1)**. Verify the following:
 - seal area and bore are clean and in good condition
 - HPS Secondary Seals** are in place and in good condition
 - all peripheral equipment is intact and undamaged
- Clean the mating ring grooves of the MBU-LR and Tubing Head.
- Lightly lubricate the ID of the Tubing Head HPS Seals, and the casing stub with a light grease.

Note: Excessive grease may prevent a good seal from forming!

- Install a new **BX-160 Ring Gasket (Item B14)** in the ring groove of the MBU-LR Housing.
- Pick up the Tubing Head and suspend it above the MBU-LR Housing and casing stub.
- Orient the Tubing Head so the outlets are in the proper position and then carefully lower the head and DSPA over the casing stub and land it on the ring gasket.

Warning: Do Not damage the HPS Seal or their sealing ability will be impaired!

- Make up the flange connection using the DSPA studs and nuts, tightening them in an alternating cross pattern.

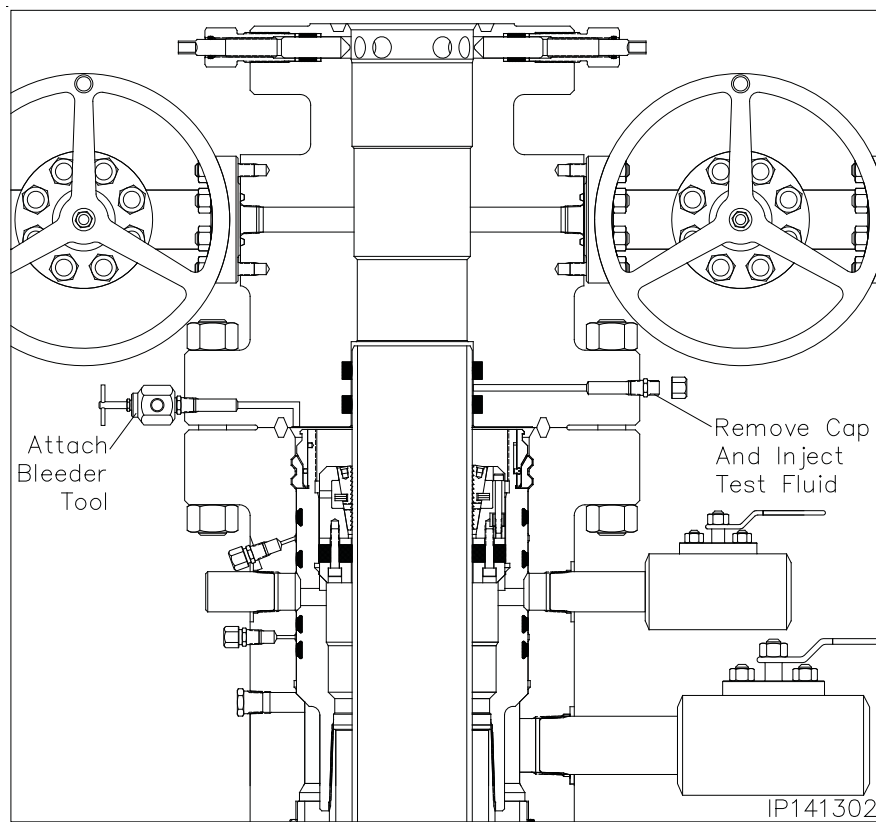


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Stage 8 — Install the Tubing Head

Seal Test

1. Locate the "SEAL TEST" fitting and one of the "FLG TEST" fittings on the Tubing Head and remove the dust cap from both fittings.
2. Attach a Bleeder Tool to the open "FLG TEST" fitting and open the Tool.
3. Attach a Hydraulic Test Pump to the "SEAL TEST" fitting and pump clean test fluid between the HPS Seals until a test pressure of **10,000 psi. or 80% of casing collapse — whichever is less**
4. Hold the test pressure for fifteen (15) minutes or as desired by the drilling supervisor.
5. If pressure drops a leak has developed. Take the appropriate action in the table below.
6. Repeat steps 1 - 5 until a satisfactory test is achieved.
7. When a satisfactory test is achieved, remove Test Pump, drain test fluid, and reinstall the dust cap on the open "SEAL TEST" fitting.



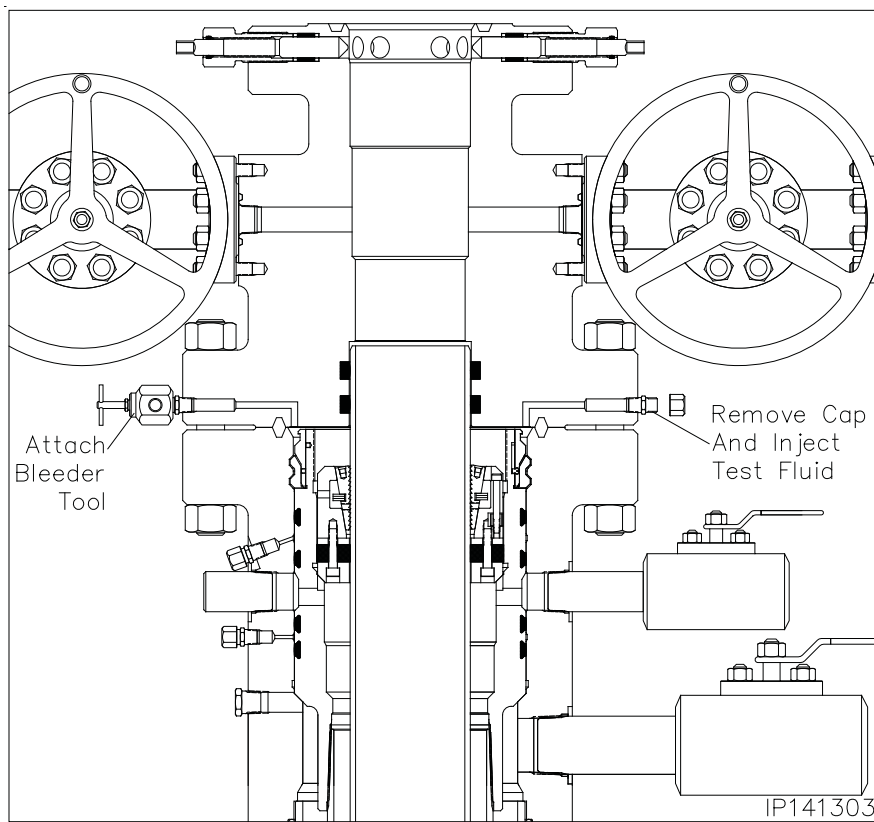
Seal Test	
Leak Location	Appropriate Action
Open bleeder tool - Lower HPS seal leaking	Remove Tubing Head and replace leaking seals. Reland and retest seals
Into the Tubing Head bore- Upper HPS Seal is Leaking	

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Stage 8 — Install the Tubing Head

Flange Test

1. Locate the remaining "FLG TEST" fitting on the Tubing Head and remove the dust cap from the fitting.
2. Attach a test pump to the open "FLG TEST" fitting and pump clean test fluid into the flange connection until a continuous stream flows from the open "FLG TEST" bleeder tool.
3. Close the bleeder tool and continue pumping test fluid to **5,000 psi. or 80% of casing collapse — whichever is less.**
4. Hold the test pressure for fifteen (15) minutes or as desired by the drilling supervisor.
5. If pressure drops a leak has developed. Take the appropriate action from the adjacent chart.
6. Repeat steps 1 through 6 until a satisfactory test is achieved.
7. Once a satisfactory test is achieved, remove the test pump and "FLG TEST" bleeder tool, drain test fluid, and reinstall the dust caps on the open fittings.



Flange Test	
Leak Location	Appropriate Action
Into casing annulus - casing hanger seal element is leaking	Remove tubing head, spear casing and reset the casing hanger. Redress the casing, reinstall the Tubing Head and retest
Flange connection - Ring gasket is leaking	Further tighten the flange connection

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Recommended Procedure for Field Welding Pipe to Wellhead Parts for Pressure Seal

- 1. Introduction and Scope.** The following recommended procedure has been prepared with particular regard to attaining pressure-tight weld when attaching casing heads, flanges, etc., to casing. Although most of the high strength casing used (such as N-80) is not normally considered field weldable, some success may be obtained by using the following or similar procedures.

Caution: In some wellheads, the seal weld is also a structural weld and can be subjected to high tensile stresses. Consideration must therefore be given by competent authority to the mechanical properties of the weld and its heat affected zone.
- 2. Welding Conditions.** Unfavorable welding conditions must be avoided or minimized in every way possible, as even the most skilled welder cannot successfully weld steels that are susceptible to cracking under adverse working conditions, or when the work is rushed. Work above the welder on the drilling floor should be avoided. The weld should be protected from dripping mud, water, and oil and from wind, rain, or other adverse weather conditions. The drilling mud, water, or other fluids must be lowered in the casing and kept at a low level until the weld has properly cooled. It is the responsibility of the user to provide supervision that will assure favorable working conditions, adequate time, and the necessary cooperation of the rig personnel.
- 3. Welding.** The welding should be done by the shielded metal-arc or other approved process.
- 4. Filler Metal.** Filler Metals. For root pass, it's recommended to use E6010, E6011 (AC), E6019 or equivalent electrodes. The E7018 or E7018-A1 electrodes may also be used for root pass operations but has the tendency to trap slag in tight grooves. The E6010, E6011 and E6019 offer good penetration and weld deposit ductility with relatively high intrinsic hydrogen content. Since the E7018 and E7018-A1 are less susceptible to hydrogen induced cracking, it is recommended for use as the filler metal for completion of the weld groove after the root pass is completed. The E6010, E6011 (AC), E6019, E7018 and E7018-A1 are classified under one of the following codes AWS A5.1 (latest edition): Mild Steel covered electrodes or the AWS A5.5 (latest edition): Low Alloy Steel Covered Arc-Welding Electrodes. The low hydrogen electrodes, E7018 and E7018-A1, should not be exposed to the atmosphere until ready for use. It's recommended that hydrogen electrodes remain in their sealed containers. When a job arises, the container shall be opened and all unused remaining electrodes to be stored in heat electrode storage ovens. Low hydrogen electrodes exposed to the atmosphere, except water, for more than two hours should be dried 1 to 2 hours at 600°F to 700 °F (316°C to 371 °C) just before use. It's recommended for any low hydrogen electrode containing water on the surface should be scrapped.
- 5. Preparation of Base Metal.** The area to be welded should be dry and free of any paint, grease/oil and dirt. All rust and heat-treat surface scale shall be ground to bright metal before welding.

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Recommended Procedure for Field Welding Pipe to Wellhead Parts for Pressure Seal

6. **Preheating.** Prior to any heating, the wellhead member shall be inspected for the presence of any o-rings or other polymeric seals. If any o-rings or seals are identified then preheating requires close monitoring as noted in paragraph 6a. Before applying preheat, the fluid should be bailed out of the casing to a point several inches (>6" or 150 mm) below the weld joint/location. Preheat both the casing and wellhead member for a minimum distance of three (3) inches on each side of the weld joint using a suitable preheating torch in accordance with the temperatures shown below in a and b. The preheat temperature should be checked by the use of heat sensitive crayons. Special attention must be given to preheating the thick sections of wellhead parts to be welded, to insure uniform heating and expansion with respect to the relatively thin casing.
 - a. Wellhead members containing o-rings and other polymeric seals have tight limits on the preheat and interpass temperatures. Those temperatures must be controlled at 200°F to 325°F or 93 °C to 160°C and closely monitored to prevent damage to the o-ring or seals.
 - b. Wellhead members not containing o-rings and other polymeric seals should be maintained at a preheat and interpass temperature of 400°F to 600°F or 200°C to 300°C.
7. **Welding Technique.** Use a 1/8 or 5/32-inch (3.2 or 4.0 mm) E6010 or E7018 electrode and step weld the first bead (root pass); that, weld approximately 2 to 4 inches (50 to 100 mm) and then move diametrically opposite this point and weld 2 to 4 inches (50 to 100 mm) halfway between the first two welds, move diametrically opposite this weld, and so on until the first pass is completed. This second pass should be made with a 5/32-inch (4.0 mm) low hydrogen electrode of the proper strength and may be continuous. The balance of the welding groove may then be filled with continuous passes without back stepping or lacing, using a 3/16-inch (4.8 mm) low hydrogen electrode. All beads should be stringer beads with good penetration. There should be no undercutting and weld shall be workmanlike in appearance.
 - a. Test ports should be open when welding is performed to prevent pressure buildup within the test cavity.
 - b. During welding the temperature of the base metal on either side of the weld should be maintained at 200 to 300°F (93 to 149°C).
 - c. Care should be taken to insure that the welding cable is properly grounded to the casing, but ground wire should not be welded to the casing or the wellhead. Ground wire should be firmly clamped to the casing, the wellhead, or fixed in position between pipe slips. Bad contact may cause sparking, with resultant hard spots beneath which incipient cracks may develop. The welding cable should not be grounded to the steel derrick, nor to the rotary-table base.
8. **Cleaning.** All slag or flux remaining on any welding bead should be removed before laying the next bead. This also applies to the completed weld.
9. **Defects.** Any cracks or blow holes that appear on any bead should be removed to sound metal by chipping or grinding before depositing the next bead.
10. **Postheating.** Post-heating should be performed at the temperatures shown below and held at that temperature for no less than one hour followed by a slow cooling. The post-heating temperature should be in accordance with the following paragraphs.
 - a. Wellhead members containing o-rings and other polymeric seals have tight limits on the post-heating temperatures. Those temperatures must be controlled at 250°F to 300°F or 120 °C to 150°C and closely monitored to prevent damage to the o-ring or seals.
 - b. Wellhead members not containing o-rings and other polymeric seals should be post-heated at a temperature of 400°F to 600°F or 200°C to 300°C.
11. **Cooling. *Rapid cooling must be avoided.*** To assure slow cooling, welds should be protected from extreme weather conditions (cold, rain, high winds, etc.) by the use of suitable insulating material. (Specially designed insulating blankets are available at many welding supply stores.) Particular attention should be given to maintaining uniform cooling of the thick sections of the wellhead parts and the relatively thin casing, as the relatively thin casing will pull away from the head or hanger if allowed to cool more rapidly. The welds should cool in air to less than 200°F (93°C) (measured with a heat sensitive crayon) prior to permitting the mud to rise in the casing.
12. **Test the Weld.** After cooling, test the weld. The weld must be cool otherwise the test media will crack the weld. The test pressure should be no more than 80% of the casing collapse pressure.

Certificate of Conformance

DW INDUSTRIES INC.

6287 Long Drive

Houston, TX 77087

Tel. 713 644-8372

Fax 713-644-4947

Name of Customer:		AUSTIN HOSE			
Purchase Order Information	Purchase Order Number:	4115582	Drawing Reference Number: (Specification)	CUSTOMER SPECIFICATION	
	Part Number:	5604-4825S-R35	Age Control:	N/A	
	NSN	N/A	Lot Number:	19040198	
	Part Description:	HOSE ASSEMBLY	QTY Ordered:	1	

I DO HEREBY CERTIFY, AS THE AUTHORIZED REPRESENTATIVE OF DW INDUSTRIES, THAT THE PRODUCT LISTED ABOVE ARE OF THE QUALITY SPECIFIED AND CONFORM TO ALL REQUIREMENTS OF THE PURCHASE ORDER, INCLUDING: QUALITY CONTROL CLAUSES, DESIGN SPECIFICATIONS, DRAWINGS, PRESERVATION, PACKAGING, PACKING, MARKING, AND PHYSICAL IDENTIFICATION REQUIREMENTS AND HAS BEEN PROCESSED IN ACCORDANCE WITH ISO-9001:2015, API Q1 AND API SPEC 7K.

Certificate Issue Date: 04/19/19



Richard Weaver
Quality Assurance,
DW Industries Inc.

Castor Federal #1H, Plan 1

Operator Mack Energy Corp	Units feet, °/100ft	10:16 Tuesday, May 7, 2024 Page 1 of 4
Field	County Chaves	Vertical Section Azimuth 90
Well Name Castor Federal #1H	State New Mexico	Survey Calculation Method Minimum Curvature
Plan 1	Country USA	Database Access

Location SL: 1190 FNL & 907 FEL Section 23-T15S-R29E BHL: 990 FNL & 1 FEL Section 24-T15S-29E	Map Zone UTM	Lat Long Ref
Site	Surface X 1949006	Surface Long
Slot Name	Surface Y 11982074	Surface Lat
Well Number 1H	Surface Z 3954.6	Global Z Ref KB
Project	Ground Level 3937.3	Local North Ref Grid

DIRECTIONAL WELL PLAN

MD*	INC*	AZI*	TVD*	N*	E*	DLS*	V. S.*	MapE*	MapN*	SysTVD*
ft	deg	deg	ft	ft	ft	°/100ft	ft	ft	ft	ft
*** TIE (at MD = 2524.00)										
2524.00	0.00	0.0	2524.00	0.00	0.00		0.00	1949006.00	11982074.00	1430.60
2550.00	0.00	0.0	2550.00	0.00	0.00	0.00	0.00	1949006.00	11982074.00	1404.60
2600.00	0.00	0.0	2600.00	0.00	0.00	0.00	0.00	1949006.00	11982074.00	1354.60
*** KOP 8 DEGREE (at MD = 2624.00)										
2624.00	0.00	0.0	2624.00	0.00	0.00	0.00	0.00	1949006.00	11982074.00	1330.60
2650.00	2.08	73.0	2649.99	0.14	0.45	8.00	0.45	1949006.45	11982074.14	1304.61
2700.00	6.08	73.0	2699.86	1.18	3.85	8.00	3.85	1949009.85	11982075.18	1254.74
2750.00	10.08	73.0	2749.35	3.23	10.57	8.00	10.57	1949016.57	11982077.23	1205.25
2800.00	14.08	73.0	2798.23	6.29	20.58	8.00	20.58	1949026.58	11982080.29	1156.37
2850.00	18.08	73.0	2846.27	10.34	33.82	8.00	33.82	1949039.82	11982084.34	1108.33
2900.00	22.08	73.0	2893.22	15.36	50.23	8.00	50.23	1949056.23	11982089.36	1061.38
2950.00	26.08	73.0	2938.86	21.32	69.74	8.00	69.74	1949075.74	11982095.32	1015.74
3000.00	30.08	73.0	2982.96	28.20	92.24	8.00	92.24	1949098.24	11982102.20	971.64
3050.00	34.08	73.0	3025.32	35.96	117.63	8.00	117.63	1949123.63	11982109.96	929.28
3100.00	38.08	73.0	3065.72	44.57	145.78	8.00	145.78	1949151.78	11982118.57	888.88
3150.00	42.08	73.0	3103.97	53.98	176.56	8.00	176.56	1949182.56	11982127.98	850.63
3200.00	46.08	73.0	3139.88	64.15	209.82	8.00	209.82	1949215.82	11982138.15	814.72
3250.00	50.08	73.0	3173.28	75.02	245.39	8.00	245.39	1949251.39	11982149.02	781.32
3300.00	54.08	73.0	3204.00	86.55	283.10	8.00	283.10	1949289.10	11982160.55	750.60
*** 55 DEGREE TANGENT (at MD = 3311.50)										
3311.50	55.00	73.0	3210.67	89.29	292.06	8.00	292.06	1949298.06	11982163.29	743.93
3350.00	55.00	73.0	3232.76	98.51	322.22	0.00	322.22	1949328.22	11982172.51	721.84
3400.00	55.00	73.0	3261.44	110.49	361.39	0.00	361.39	1949367.39	11982184.49	693.16
3450.00	55.00	73.0	3290.11	122.46	400.55	0.00	400.55	1949406.55	11982196.46	664.49
3500.00	55.00	73.0	3318.79	134.44	439.72	0.00	439.72	1949445.72	11982208.44	635.81
*** 10 DEGREE BUILD (at MD = 3511.50)										
3511.50	55.00	73.0	3325.39	137.19	448.73	0.00	448.73	1949454.73	11982211.19	629.21
3550.00	58.42	75.1	3346.52	146.01	479.67	10.00	479.67	1949485.67	11982220.01	608.08
3600.00	62.90	77.7	3371.02	156.24	522.02	10.00	522.02	1949528.02	11982230.24	583.58
3650.00	67.43	80.0	3392.02	165.01	566.53	10.00	566.53	1949572.53	11982239.01	562.58
3700.00	71.99	82.2	3409.36	172.25	612.84	10.00	612.84	1949618.84	11982246.25	545.24
3750.00	76.57	84.3	3422.90	177.91	660.62	10.00	660.62	1949666.62	11982251.91	531.70
3800.00	81.17	86.3	3432.56	181.94	709.50	10.00	709.50	1949715.50	11982255.94	522.04
3850.00	85.77	88.2	3438.24	184.31	759.10	10.00	759.10	1949765.10	11982258.31	516.36
*** LANDING POINT (at MD = 3895.81)										
3895.81	90.00	90.0	3439.93	185.02	804.86	10.00	804.86	1949810.86	11982259.02	514.67
3900.00	90.00	90.0	3439.93	185.02	809.06	0.00	809.06	1949815.06	11982259.02	514.67
3950.00	90.00	90.0	3439.93	185.02	859.06	0.00	859.06	1949865.06	11982259.02	514.67

Castor Federal #1H, Plan 1

Operator	Mack Energy Corp			Units	feet, °/100ft		10:16 Tuesday, May 7, 2024 Page 2 of 4				
Field				County	Chaves		Vertical Section Azimuth		90		
Well Name	Castor Federal #1H			State	New Mexico		Survey Calculation Method		Minimum Curvature		
Plan	1			Country	USA		Database		Access		
Location				SL: 1190 FNL & 907 FEL Section 23-T15S-R29E BHL: 990 FNL & 1 FEL Section 24-T15S-29E		Map Zone		UTM		Lat Long Ref	
Site						Surface X		1949006		Surface Long	
Slot Name						Surface Y		11982074		Surface Lat	
Well Number				1H		Surface Z		3954.6		Global Z Ref KB	
Project				MD/TVD Ref KB		Ground Level		3937.3		Local North Ref Grid	
DIRECTIONAL WELL PLAN											
MD*	INC*	AZI*	TVD*	N*	E*	DLS*	V. S.*	MapE*	MapN*	SysTVD*	
ft	deg	deg	ft	ft	ft	°/100ft	ft	ft	ft	ft	
4000.00	90.00	90.0	3439.93	185.02	909.06	0.00	909.06	1949915.06	11982259.02	514.67	
4050.00	90.00	90.0	3439.93	185.02	959.06	0.00	959.06	1949965.06	11982259.02	514.67	
4100.00	90.00	90.0	3439.93	185.02	1009.06	0.00	1009.06	1950015.06	11982259.02	514.67	
4150.00	90.00	90.0	3439.93	185.02	1059.06	0.00	1059.06	1950065.06	11982259.02	514.67	
4200.00	90.00	90.0	3439.93	185.02	1109.06	0.00	1109.06	1950115.06	11982259.02	514.67	
4250.00	90.00	90.0	3439.93	185.02	1159.06	0.00	1159.06	1950165.06	11982259.02	514.67	
4300.00	90.00	90.0	3439.93	185.02	1209.06	0.00	1209.06	1950215.06	11982259.02	514.67	
4350.00	90.00	90.0	3439.93	185.02	1259.06	0.00	1259.06	1950265.06	11982259.02	514.67	
4400.00	90.00	90.0	3439.93	185.02	1309.06	0.00	1309.06	1950315.06	11982259.02	514.67	
4450.00	90.00	90.0	3439.93	185.02	1359.06	0.00	1359.06	1950365.06	11982259.02	514.67	
4500.00	90.00	90.0	3439.93	185.02	1409.06	0.00	1409.06	1950415.06	11982259.02	514.67	
4550.00	90.00	90.0	3439.93	185.02	1459.06	0.00	1459.06	1950465.06	11982259.02	514.67	
4600.00	90.00	90.0	3439.93	185.02	1509.06	0.00	1509.06	1950515.06	11982259.02	514.67	
4650.00	90.00	90.0	3439.93	185.02	1559.06	0.00	1559.06	1950565.06	11982259.02	514.67	
4700.00	90.00	90.0	3439.93	185.02	1609.06	0.00	1609.06	1950615.06	11982259.02	514.67	
4750.00	90.00	90.0	3439.93	185.02	1659.06	0.00	1659.06	1950665.06	11982259.02	514.67	
4800.00	90.00	90.0	3439.93	185.02	1709.06	0.00	1709.06	1950715.06	11982259.02	514.67	
4850.00	90.00	90.0	3439.93	185.02	1759.06	0.00	1759.06	1950765.06	11982259.02	514.67	
4900.00	90.00	90.0	3439.93	185.02	1809.06	0.00	1809.06	1950815.06	11982259.02	514.67	
4950.00	90.00	90.0	3439.93	185.02	1859.06	0.00	1859.06	1950865.06	11982259.02	514.67	
5000.00	90.00	90.0	3439.93	185.02	1909.06	0.00	1909.06	1950915.06	11982259.02	514.67	
5050.00	90.00	90.0	3439.93	185.02	1959.06	0.00	1959.06	1950965.06	11982259.02	514.67	
5100.00	90.00	90.0	3439.93	185.02	2009.06	0.00	2009.06	1951015.06	11982259.02	514.67	
5150.00	90.00	90.0	3439.93	185.02	2059.06	0.00	2059.06	1951065.06	11982259.02	514.67	
5200.00	90.00	90.0	3439.93	185.02	2109.06	0.00	2109.06	1951115.06	11982259.02	514.67	
5250.00	90.00	90.0	3439.93	185.02	2159.06	0.00	2159.06	1951165.06	11982259.02	514.67	
5300.00	90.00	90.0	3439.93	185.02	2209.06	0.00	2209.06	1951215.06	11982259.02	514.67	
5350.00	90.00	90.0	3439.93	185.02	2259.06	0.00	2259.06	1951265.06	11982259.02	514.67	
5400.00	90.00	90.0	3439.93	185.02	2309.06	0.00	2309.06	1951315.06	11982259.02	514.67	
5450.00	90.00	90.0	3439.93	185.02	2359.06	0.00	2359.06	1951365.06	11982259.02	514.67	
5500.00	90.00	90.0	3439.93	185.02	2409.06	0.00	2409.06	1951415.06	11982259.02	514.67	
5550.00	90.00	90.0	3439.93	185.02	2459.06	0.00	2459.06	1951465.06	11982259.02	514.67	
5600.00	90.00	90.0	3439.93	185.02	2509.06	0.00	2509.06	1951515.06	11982259.02	514.67	
5650.00	90.00	90.0	3439.93	185.02	2559.06	0.00	2559.06	1951565.06	11982259.02	514.67	
5700.00	90.00	90.0	3439.93	185.02	2609.06	0.00	2609.06	1951615.06	11982259.02	514.67	
5750.00	90.00	90.0	3439.93	185.02	2659.06	0.00	2659.06	1951665.06	11982259.02	514.67	
5800.00	90.00	90.0	3439.93	185.02	2709.06	0.00	2709.06	1951715.06	11982259.02	514.67	

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Castor Federal #1H, Plan 1										
Operator Mack Energy Corp		Units feet, °/100ft		10:16 Tuesday, May 7, 2024 Page 3 of 4						
Field		County Chaves		Vertical Section Azimuth 90						
Well Name Castor Federal #1H		State New Mexico		Survey Calculation Method Minimum Curvature						
Plan 1		Country USA		Database Access						
Location SL: 1190 FNL & 907 FEL Section 23-T15S-R29E BHL: 990 FNL & 1 FEL Section 24-T15S-29E				Map Zone UTM			Lat Long Ref			
Site					Surface X 1949006		Surface Long			
Slot Name		UWI		Surface Y 11982074			Surface Lat			
Well Number 1H		API		Surface Z 3954.6			Global Z Ref KB			
Project		MD/TVD Ref KB		Ground Level 3937.3			Local North Ref Grid			
DIRECTIONAL WELL PLAN										
MD*	INC*	AZI*	TVD*	N*	E*	DLS*	V. S.*	MapE*	MapN*	SysTVD*
ft	deg	deg	ft	ft	ft	°/100ft	ft	ft	ft	ft
5850.00	90.00	90.0	3439.93	185.02	2759.06	0.00	2759.06	1951765.06	11982259.02	514.67
5900.00	90.00	90.0	3439.93	185.02	2809.06	0.00	2809.06	1951815.06	11982259.02	514.67
5950.00	90.00	90.0	3439.93	185.02	2859.06	0.00	2859.06	1951865.06	11982259.02	514.67
6000.00	90.00	90.0	3439.93	185.02	2909.06	0.00	2909.06	1951915.06	11982259.02	514.67
6050.00	90.00	90.0	3439.93	185.02	2959.06	0.00	2959.06	1951965.06	11982259.02	514.67
6100.00	90.00	90.0	3439.93	185.02	3009.06	0.00	3009.06	1952015.06	11982259.02	514.67
6150.00	90.00	90.0	3439.93	185.02	3059.06	0.00	3059.06	1952065.06	11982259.02	514.67
6200.00	90.00	90.0	3439.93	185.02	3109.06	0.00	3109.06	1952115.06	11982259.02	514.67
6250.00	90.00	90.0	3439.93	185.02	3159.06	0.00	3159.06	1952165.06	11982259.02	514.67
6300.00	90.00	90.0	3439.93	185.02	3209.06	0.00	3209.06	1952215.06	11982259.02	514.67
6350.00	90.00	90.0	3439.93	185.02	3259.06	0.00	3259.06	1952265.06	11982259.02	514.67
6400.00	90.00	90.0	3439.93	185.02	3309.06	0.00	3309.06	1952315.06	11982259.02	514.67
6450.00	90.00	90.0	3439.93	185.02	3359.06	0.00	3359.06	1952365.06	11982259.02	514.67
6500.00	90.00	90.0	3439.93	185.02	3409.06	0.00	3409.06	1952415.06	11982259.02	514.67
6550.00	90.00	90.0	3439.93	185.02	3459.06	0.00	3459.06	1952465.06	11982259.02	514.67
6600.00	90.00	90.0	3439.93	185.02	3509.06	0.00	3509.06	1952515.06	11982259.02	514.67
6650.00	90.00	90.0	3439.93	185.02	3559.06	0.00	3559.06	1952565.06	11982259.02	514.67
6700.00	90.00	90.0	3439.93	185.02	3609.06	0.00	3609.06	1952615.06	11982259.02	514.67
6750.00	90.00	90.0	3439.93	185.02	3659.06	0.00	3659.06	1952665.06	11982259.02	514.67
6800.00	90.00	90.0	3439.93	185.02	3709.06	0.00	3709.06	1952715.06	11982259.02	514.67
6850.00	90.00	90.0	3439.93	185.02	3759.06	0.00	3759.06	1952765.06	11982259.02	514.67
6900.00	90.00	90.0	3439.93	185.02	3809.06	0.00	3809.06	1952815.06	11982259.02	514.67
6950.00	90.00	90.0	3439.93	185.02	3859.06	0.00	3859.06	1952865.06	11982259.02	514.67
7000.00	90.00	90.0	3439.93	185.02	3909.06	0.00	3909.06	1952915.06	11982259.02	514.67
7050.00	90.00	90.0	3439.93	185.02	3959.06	0.00	3959.06	1952965.06	11982259.02	514.67
7100.00	90.00	90.0	3439.93	185.02	4009.06	0.00	4009.06	1953015.06	11982259.02	514.67
7150.00	90.00	90.0	3439.93	185.02	4059.06	0.00	4059.06	1953065.06	11982259.02	514.67
7200.00	90.00	90.0	3439.93	185.02	4109.06	0.00	4109.06	1953115.06	11982259.02	514.67
7250.00	90.00	90.0	3439.93	185.02	4159.06	0.00	4159.06	1953165.06	11982259.02	514.67
7300.00	90.00	90.0	3439.93	185.02	4209.06	0.00	4209.06	1953215.06	11982259.02	514.67
7350.00	90.00	90.0	3439.93	185.02	4259.06	0.00	4259.06	1953265.06	11982259.02	514.67
7400.00	90.00	90.0	3439.93	185.02	4309.06	0.00	4309.06	1953315.06	11982259.02	514.67
7450.00	90.00	90.0	3439.93	185.02	4359.06	0.00	4359.06	1953365.06	11982259.02	514.67
7500.00	90.00	90.0	3439.93	185.02	4409.06	0.00	4409.06	1953415.06	11982259.02	514.67
7550.00	90.00	90.0	3439.93	185.02	4459.06	0.00	4459.06	1953465.06	11982259.02	514.67
7600.00	90.00	90.0	3439.93	185.02	4509.06	0.00	4509.06	1953515.06	11982259.02	514.67
7650.00	90.00	90.0	3439.93	185.02	4559.06	0.00	4559.06	1953565.06	11982259.02	514.67

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Castor Federal #1H, Plan 1

Operator	Mack Energy Corp			Units	feet, °/100ft		10:16 Tuesday, May 7, 2024 Page 4 of 4			
Field				County	Chaves		Vertical Section Azimuth		90	
Well Name	Castor Federal #1H			State	New Mexico		Survey Calculation Method		Minimum Curvature	
Plan	1			Country	USA		Database		Access	
Location	SL: 1190 FNL & 907 FEL Section 23-T15S-R29E BHL: 990 FNL & 1 FEL Section 24-T15S-29E					Map Zone	UTM		Lat Long Ref	
Site						Surface X	1949006		Surface Long	
Slot Name						Surface Y	11982074		Surface Lat	
Well Number	1H					Surface Z	3954.6		Global Z Ref KB	
Project						Ground Level	3937.3		Local North Ref Grid	
DIRECTIONAL WELL PLAN										
MD*	INC*	AZI*	TVD*	N*	E*	DLS*	V. S.*	MapE*	MapN*	SysTVD*
ft	deg	deg	ft	ft	ft	°/100ft	ft	ft	ft	ft
7700.00	90.00	90.0	3439.93	185.02	4609.06	0.00	4609.06	1953615.06	11982259.02	514.67
7750.00	90.00	90.0	3439.93	185.02	4659.06	0.00	4659.06	1953665.06	11982259.02	514.67
7800.00	90.00	90.0	3439.93	185.02	4709.06	0.00	4709.06	1953715.06	11982259.02	514.67
7850.00	90.00	90.0	3439.93	185.02	4759.06	0.00	4759.06	1953765.06	11982259.02	514.67
7900.00	90.00	90.0	3439.93	185.02	4809.06	0.00	4809.06	1953815.06	11982259.02	514.67
7950.00	90.00	90.0	3439.93	185.02	4859.06	0.00	4859.06	1953865.06	11982259.02	514.67
8000.00	90.00	90.0	3439.93	185.02	4909.06	0.00	4909.06	1953915.06	11982259.02	514.67
8050.00	90.00	90.0	3439.93	185.02	4959.06	0.00	4959.06	1953965.06	11982259.02	514.67
8100.00	90.00	90.0	3439.93	185.02	5009.06	0.00	5009.06	1954015.06	11982259.02	514.67
8150.00	90.00	90.0	3439.93	185.02	5059.06	0.00	5059.06	1954065.06	11982259.02	514.67
8200.00	90.00	90.0	3439.93	185.02	5109.06	0.00	5109.06	1954115.06	11982259.02	514.67
8250.00	90.00	90.0	3439.93	185.02	5159.06	0.00	5159.06	1954165.06	11982259.02	514.67
8300.00	90.00	90.0	3439.93	185.02	5209.06	0.00	5209.06	1954215.06	11982259.02	514.67
8350.00	90.00	90.0	3439.93	185.02	5259.06	0.00	5259.06	1954265.06	11982259.02	514.67
8400.00	90.00	90.0	3439.93	185.02	5309.06	0.00	5309.06	1954315.06	11982259.02	514.67
8450.00	90.00	90.0	3439.93	185.02	5359.06	0.00	5359.06	1954365.06	11982259.02	514.67
8500.00	90.00	90.0	3439.93	185.02	5409.06	0.00	5409.06	1954415.06	11982259.02	514.67
8550.00	90.00	90.0	3439.93	185.02	5459.06	0.00	5459.06	1954465.06	11982259.02	514.67
8600.00	90.00	90.0	3439.93	185.02	5509.06	0.00	5509.06	1954515.06	11982259.02	514.67
8650.00	90.00	90.0	3439.93	185.02	5559.06	0.00	5559.06	1954565.06	11982259.02	514.67
8700.00	90.00	90.0	3439.93	185.02	5609.06	0.00	5609.06	1954615.06	11982259.02	514.67
8750.00	90.00	90.0	3439.93	185.02	5659.06	0.00	5659.06	1954665.06	11982259.02	514.67
8800.00	90.00	90.0	3439.93	185.02	5709.06	0.00	5709.06	1954715.06	11982259.02	514.67
8850.00	90.00	90.0	3439.93	185.02	5759.06	0.00	5759.06	1954765.06	11982259.02	514.67
8900.00	90.00	90.0	3439.93	185.02	5809.06	0.00	5809.06	1954815.06	11982259.02	514.67
8950.00	90.00	90.0	3439.93	185.02	5859.06	0.00	5859.06	1954865.06	11982259.02	514.67
9000.00	90.00	90.0	3439.93	185.02	5909.06	0.00	5909.06	1954915.06	11982259.02	514.67
9050.00	90.00	90.0	3439.93	185.02	5959.06	0.00	5959.06	1954965.06	11982259.02	514.67
9100.00	90.00	90.0	3439.93	185.02	6009.06	0.00	6009.06	1955015.06	11982259.02	514.67
9150.00	90.00	90.0	3439.93	185.02	6059.06	0.00	6059.06	1955065.06	11982259.02	514.67
9200.00	90.00	90.0	3439.93	185.02	6109.06	0.00	6109.06	1955115.06	11982259.02	514.67
9250.00	90.00	90.0	3439.93	185.02	6159.06	0.00	6159.06	1955165.06	11982259.02	514.67
*** TD (at MD = 9257.81)										
9257.81	90.00	90.0	3439.93	185.02	6166.86	0.00	6166.86	1955172.86	11982259.02	514.67

**PECOS DISTRICT
DRILLING OPERATIONS
CONDITIONS OF APPROVAL**

OPERATOR'S NAME:	Mack Energy Corporation
LEASE NO.:	NMNM-138833
WELL NAME & NO.:	Castor Federal 1H
SURFACE HOLE FOOTAGE:	1190' FNL & 0907' FEL
BOTTOM HOLE FOOTAGE:	0990' FNL & 0001' FEL Sec. 24, T. 15 S., R 29 E.
LOCATION:	Section 23, T. 15 S., R 29 E., NMPM
COUNTY:	Chaves County, New Mexico

The Gamma Ray and Neutron well logs must be run from total depth to surface and e-mailed to McKitric Wier at mwier@blm.gov or hard copy mailed to 2909 West Second Street Roswell, NM 88201 to his attention.

The BLM is to be notified in advance for a representative to witness:

- a. Spudding well (minimum of 24 hours)
- b. Setting and/or Cementing of all casing strings (minimum of 4 hours)
- c. BOPE tests (minimum of 4 hours)

☒ **Chaves and Roosevelt Counties**

Call the Roswell Field Office, 2909 West Second St., Roswell NM 88201.

During office hours call (575) 627-0272.

After hours call (575) 627-0205.

A. Hydrogen Sulfide

1. **Hydrogen Sulfide (H₂S) monitors shall be installed prior to drilling out the surface shoe. If H₂S is detected in concentrations greater than 100 ppm, the Hydrogen Sulfide area shall meet Onshore Order 6 requirements, which includes equipment and personnel/public protection items. If Hydrogen Sulfide is encountered, provide measured values and formations to the BLM.**
2. Unless the production casing has been run and cemented or the well has been properly plugged, the drilling rig shall not be removed from over the hole without prior approval. **If the drilling rig is removed without approval – an Incident of Non-Compliance will be written and will be a “Major” violation.**
3. Floor controls are required for 3M or Greater systems. These controls will be on the rig floor, unobstructed, readily accessible to the driller and will be operational at all times during drilling and/or completion activities. Rig floor is defined as the area immediately around the rotary table; the area immediately above the substructure on which the draw works is located, this does not include the dog house or stairway area.

4. The record of the drilling rate along with the GR/N well log run from TD to surface (horizontal well – vertical portion of hole) shall be submitted to the BLM office as well as all other logs run on the borehole 30 days from completion. If available, a digital copy of the logs is to be submitted in addition to the paper copies. The Rustler top and top and bottom of Salt are to be recorded on the Completion Report.

B. CASING

Changes to the approved APD casing program need prior approval if the items substituted are of lesser grade or different casing size or are Non-API. The Operator can exchange the components of the proposal with that of superior strength (i.e. changing from J-55 to N-80, or from 36# to 40#). Changes to the approved cement program need prior approval if the altered cement plan has less volume or strength or if the changes are substantial (i.e. Multistage tool, ECP, etc.). The initial wellhead installed on the well will remain on the well with spools used as needed.

Wait on cement (WOC) for Water Basin:

After cementing but before commencing any tests, the casing string shall stand cemented under pressure until both of the following conditions have been met: 1) cement reaches a minimum compressive strength of 500 psi at the shoe, 2) until cement has been in place at least 8 hours. WOC time will be recorded in the driller's log. See individual casing strings for details regarding lead cement slurry requirements.

Provide compressive strengths including hours to reach required 500 pounds compressive strength prior to cementing each casing string. Have well specific cement details onsite prior to pumping the cement for each casing string.

No pea gravel permitted for remedial or fall back remedial without prior authorization from the BLM engineer.

Medium Cave/Karst

Possibility of water flows in the Rustler, Queen, Salado and Artesia Group.

Possibility of lost circulation in the Rustler, Artesia Group, and San Andres.

1. The **13-3/8** inch surface casing shall be set at approximately **325** feet (a minimum of 25 feet into the Rustler Anhydrite and above the salt) and cemented to the surface. **If salt is encountered, set casing at least 25 feet above the salt.**
 - a. If cement does not circulate to the surface, the appropriate BLM office shall be notified and a temperature survey utilizing an electronic type temperature survey with surface log readout will be used or a cement bond log shall be run to verify the top of the cement. Temperature survey will be run a minimum of six hours after pumping cement and ideally between 8-10 hours after completing the cement job.

- b. **Wait on cement (WOC) time for a primary cement job is to include the lead cement slurry.**
 - c. Wait on cement (WOC) time for a remedial job will be a minimum of 4 hours after bringing cement to surface or 500 pounds compressive strength, whichever is greater.
 - d. If cement falls back, remedial cementing will be done prior to drilling out that string.
2. The minimum required fill of cement behind the **9-5/8** inch intermediate casing is:
- ☒ Cement to surface. If cement does not circulate see B.1.a, c-d above.

Centralizers required on horizontal leg, must be type for horizontal service and a minimum of one every other joint.

3. The minimum required fill of cement behind the **7 X 5-1/2** inch production casing is:

Option #1:

- ☒ Cement to surface. If cement does not circulate, contact the appropriate BLM office.

Option #2:

Operator has proposed DV tool at depth of 1400', but will adjust cement proportionately if moved. DV tool shall be set a minimum of 50' below previous shoe and a minimum of 200' above current shoe. Operator shall submit sundry if DV tool depth cannot be set in this range. If an ECP is used, it is to be set a minimum of 50' below the shoe to provide cement across the shoe. If it cannot be set below the shoe, a CBL shall be run to verify cement coverage.

- a. First stage to DV tool:
 - ☒ Cement to circulate. If cement does not circulate, contact the appropriate BLM office before proceeding with second stage cement job. Operator should have plans as to how they will achieve circulation on the next stage.
- b. Second stage above DV tool:
 - ☒ Cement to surface. If cement does not circulate, contact the appropriate BLM office. **Excess calculates to 16% - Additional cement maybe required.**

4. If hardband drill pipe is rotated inside casing, returns will be monitored for metal. If metal is found in samples, drill pipe will be pulled and rubber protectors which have a larger diameter than the tool joints of the drill pipe will be installed prior to continuing drilling operations.

C. PRESSURE CONTROL

1. Variance approved to use flex line from BOP to choke manifold. Check condition of flexible line from BOP to choke manifold, replace if exterior is damaged or if line fails test. Line to be as straight as possible with no hard bends and is to be anchored according to Manufacturer's requirements. The flexible hose can be exchanged with a hose of equal size and equal or greater pressure rating. **Anchor requirements, specification sheet and hydrostatic pressure test certification matching the hose in service, to be onsite for review. These documents shall be posted in the company man's trailer and on the rig floor.** If the BLM inspector questions the straightness of the hose, a BLM engineer will be contacted and will review in the field or via picture supplied by inspector to determine if changes are required (operator shall expect delays if this occurs).
2. **Operator has proposed a multi-bowl wellhead assembly. This assembly will only be tested when installed on the surface casing. Minimum working pressure of the blowout preventer (BOP) and related equipment (BOPE) required for drilling below the surface casing shoe shall be 3000 (3M) psi (testing to 2,000 psi).**
 - a. Wellhead shall be installed by manufacturer's representatives, submit documentation with subsequent sundry.
 - b. If the welding is performed by a third party, the manufacturer's representative shall monitor the temperature to verify that it does not exceed the maximum temperature of the seal.
 - c. Manufacturer representative shall install the test plug for the initial BOP test.
 - d. Operator shall perform the intermediate casing integrity test to 70% of the casing burst. This will test the multi-bowl seals.
 - e. If the cement does not circulate and one inch operations would have been possible with a standard wellhead, the well head shall be cut off, cementing operations performed and another wellhead installed.

3. The appropriate BLM office shall be notified a minimum of 4 hours in advance for a representative to witness the tests.
 - a. In a water basin, for all casing strings utilizing slips, these are to be set as soon as the crew and rig are ready and any fallback cement remediation has been done. The casing cut-off and BOP installation can be initiated four hours after installing the slips, which will be approximately six hours after bumping the plug. For those casing strings not using slips, the minimum wait time before cut-off is eight hours after bumping the plug. BOP/BOPE testing can begin after cut-off or once cement reaches 500 psi compressive strength (including lead when specified), whichever is greater. However, if the float does not hold, cut-off cannot be initiated until cement reaches 500 psi compressive strength (including lead when specified).
 - b. The tests shall be done by an independent service company utilizing a test plug **not a cup or J-packer**.
 - c. The test shall be run on a 5000 psi chart for a 2-3M BOP/BOP, on a 10000 psi chart for a 5M BOP/BOPE and on a 15000 psi chart for a 10M BOP/BOPE. If a linear chart is used, it shall be a one hour chart. A circular chart shall have a maximum 2 hour clock. If a twelve hour or twenty-four hour chart is used, tester shall make a notation that it is run with a two hour clock.
 - d. The results of the test shall be reported to the appropriate BLM office.
 - e. All tests are required to be recorded on a calibrated test chart. **A copy of the BOP/BOPE test chart and a copy of independent service company test will be submitted to the appropriate BLM office.**
 - f. The BOP/BOPE test shall include a low pressure test from 250 to 300 psi. The test will be held for a minimum of 10 minutes if test is done with a test plug and 30 minutes without a test plug. This test shall be performed prior to the test at full stack pressure.

D. DRILL STEM TEST

If drill stem tests are performed, Onshore Order 2.III.D shall be followed.

E. WASTE MATERIAL AND FLUIDS

All waste (i.e. drilling fluids, trash, salts, chemicals, sewage, gray water, etc.) created as a result of drilling operations and completion operations shall be safely contained and disposed of properly at a waste disposal facility. No waste material or fluid shall be disposed of on the well location or surrounding area.

Porto-johns and trash containers will be on-location during fracturing operations or any other crew-intensive operations.

JAM 02252025

Attached to Form 3160-3

Mack Energy Corporation

Castor Federal #1H NMNM-138832

SHL : 1190 FNL & 907 FEL, NENE, Sec. 23 T15S R29E

BHL : 990 FNL & 1 FEL, NENE, Sec. 24 T15S R29E

Chaves County, NM

Mack Energy Corporation Onshore Order #6 Hydrogen Sulfide Drilling Operation Plan

I. HYDROGEN SULFIDE TRAINING

All personnel, whether regularly assigned, contracted, or employed on an unscheduled basis, will receive training from a qualified instructor in the following areas prior to commencing drilling operations on this well:

1. The hazards and characteristics of hydrogen sulfide (H₂S)
2. The proper use and maintenance of personal protective equipment and life support systems.
3. The proper use of H₂S detectors, alarms, warning systems, briefing areas, evacuation procedures, and prevailing winds.
4. The proper techniques for first aid and rescue procedures.

In addition, supervisory personnel will be trained in the following areas:

1. The effects of H₂S on metal components. If high tensile tubulars are to be used, personnel will be trained in their special maintenance requirements.
2. Corrective action and shut-in procedures when drilling or reworking a well and blowout prevention and well control procedures.
3. The contents and requirements of the H₂S Drilling Operations Plan and Public Protection Plan.

There will be an initial training session just prior to encountering a known or probable H₂S zone (within 3 days or 500 feet) and weekly H₂S and well control drills for all personnel in each crew. The initial training session shall include a review of the site specific H₂S Drilling Operations Plan and the Public Protection Plan. **The concentrations of H₂S of wells in this area from surface to TD are low enough that a contingency plan is not required.**

II. H₂S SAFETY EQUIPMENT AND SYSTEMS

Note: All H₂S safety equipment and systems will be installed, tested, and operational when drilling reaches a depth of 500 feet above, or three days prior to penetrating the first zone containing or reasonably expected to contain H₂S.

1. Well Control Equipment:

- A. Flare line.
- B. Choke manifold.
- C. Blind rams and pipe rams to accommodate all pipe sizes with properly sized closing unit.
- D. Auxiliary equipment may include if applicable: annular preventer & rotating head.

Attached to Form 3160-3

Mack Energy Corporation

Castor Federal #1H NMNM-138832

SHL : 1190 FNL & 907 FEL, NENE, Sec. 23 T15S R29E

BHL : 990 FNL & 1 FEL, NENE, Sec. 24 T15S R29E

Chaves County, NM

2. Protective equipment for essential personnel:

- A. Mark II Survive air 30-minute units located in the doghouse and at briefing areas, as indicated on well site diagram.

3. H2S detection and monitoring equipment:

- A. 1 portable H2S monitors positioned on location for best coverage and response. These units have warning lights and audible sirens when H2S levels of 20 PPM are reached.

4. Visual warning systems:

- A. Wind direction indicators as shown on well site diagram (Exhibit #8).
- B. Caution/Danger signs (Exhibit #7) shall be posted on roads providing direct access to location. Signs will be painted a high visibility yellow with black lettering of sufficient size to be readable at a reasonable distance from the immediate location. Bilingual signs will be used, when appropriate. See example attached.

5. Mud program:

- A. The mud program has been designed to minimize the volume of H2S circulated to surface. Proper mud weight, safe drilling practices and the use of H2S scavengers will minimize hazards when penetrating H2S bearing zones.

6. Metallurgy:

- A. All drill strings, casings, tubing, wellhead, blowout preventer, drilling spool, kill lines, choke manifold and lines, and valves shall be suitable for H2S service.
- B. All elastomers used for packing and seals shall be H2S trim.

7. Communication:

- A. Radio communications in company vehicles including cellular telephone and 2-way radio.
- B. Land line (telephone) communication at Office.

8. Well testing:

- A. Drill stem testing will be performed with a minimum number of personnel in the immediate vicinity, which are necessary to safely and adequately conduct the test. The drill stem testing will be conducted during daylight hours and formation fluids will not be flowed to the surface. All drill-stem-testing operations conducted in an H2S environment will use the closed chamber method of testing.

Attached to Form 3160-3

Mack Energy Corporation

Castor Federal #1H NMNM-138832

SHL : 1190 FNL & 907 FEL, NENE, Sec. 23 T15S R29E

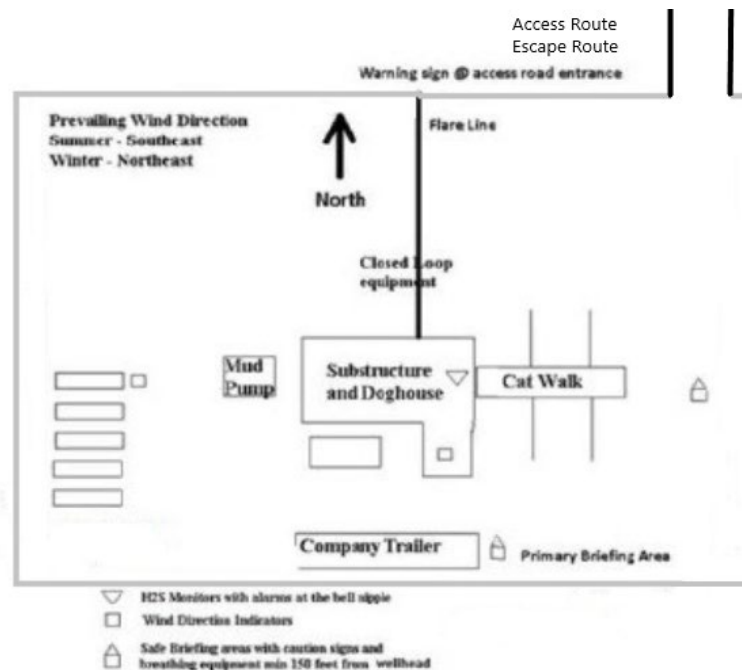
BHL : 990 FNL & 1 FEL, NENE, Sec. 24 T15S R29E

Chaves County, NM

B. There will be no drill stem testing.

EXHIBIT #7**WARNING****YOU ARE ENTERING AN H2S****AUTHORIZED PERSONNEL ONLY**

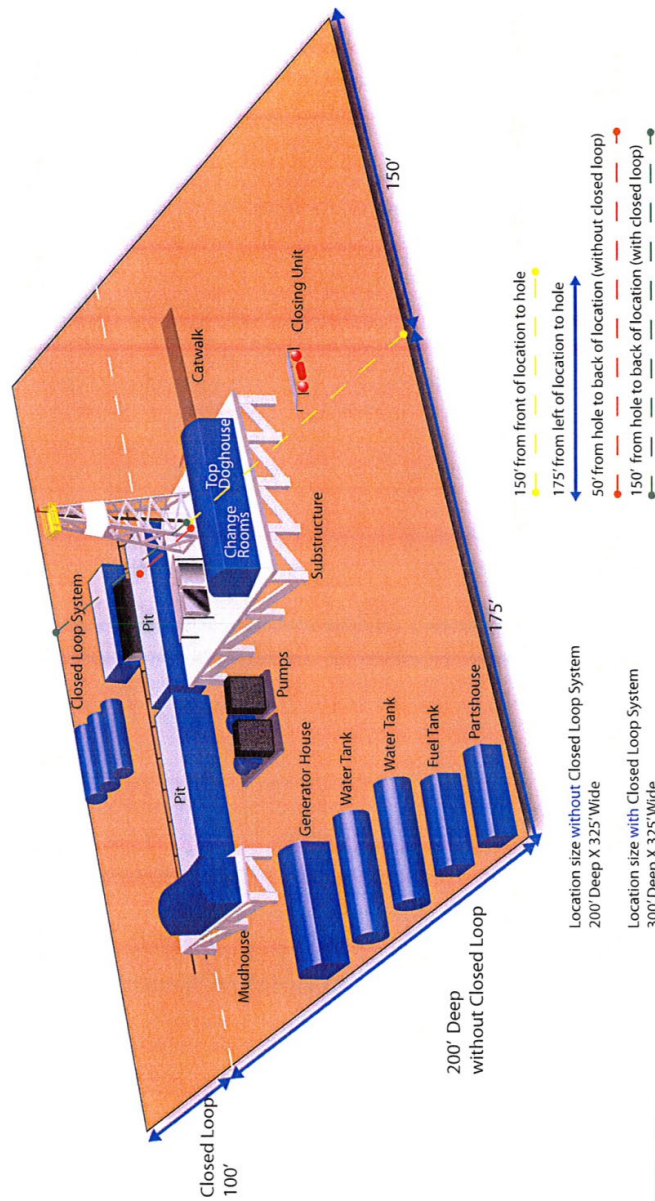
- 1. BEARDS OR CONTACT LENSES NOT ALLOWED**
- 2. HARD HATS REQUIRED**
- 3. SMOKING IN DESIGNATED AREAS ONLY**
- 4. BE WIND CONSCIOUS AT ALL TIMES**
- 5. CHECK WITH MACK ENERGY FOREMAN AT OFFICE**

MACK ENERGY CORPORATION**1-575-748-1288**

DRILLING LOCATION H2S SAFTY EQUIPMENT

Exhibit # 8

Location Layout



Silver Oak Drilling ~ 10 Bilco Road, Artesia, NM 88210 ~ 575.746.4405
 info@silveroakdrilling.com ~ www.silveroakdrilling.com

Mack Energy Corporation Call List, Chaves County

Artesia (575)	Cellular	Office
Jim Krogman.....	432-934-1596.....	748-1288
Emilio Martinez.....	432-934-7586.....	748-1288

Agency Call List (575)**Roswell**

State Police.....	622-7200
City Police.....	624-6770
Sheriff's Office.....	624-7590
Ambulance.....	624-7590
Fire Department.....	624-7590
LEPC (Local Emergency Planning Committee.....	624-6770
NMOCD.....	748-1283
Bureau of Land Management.....	627-0272

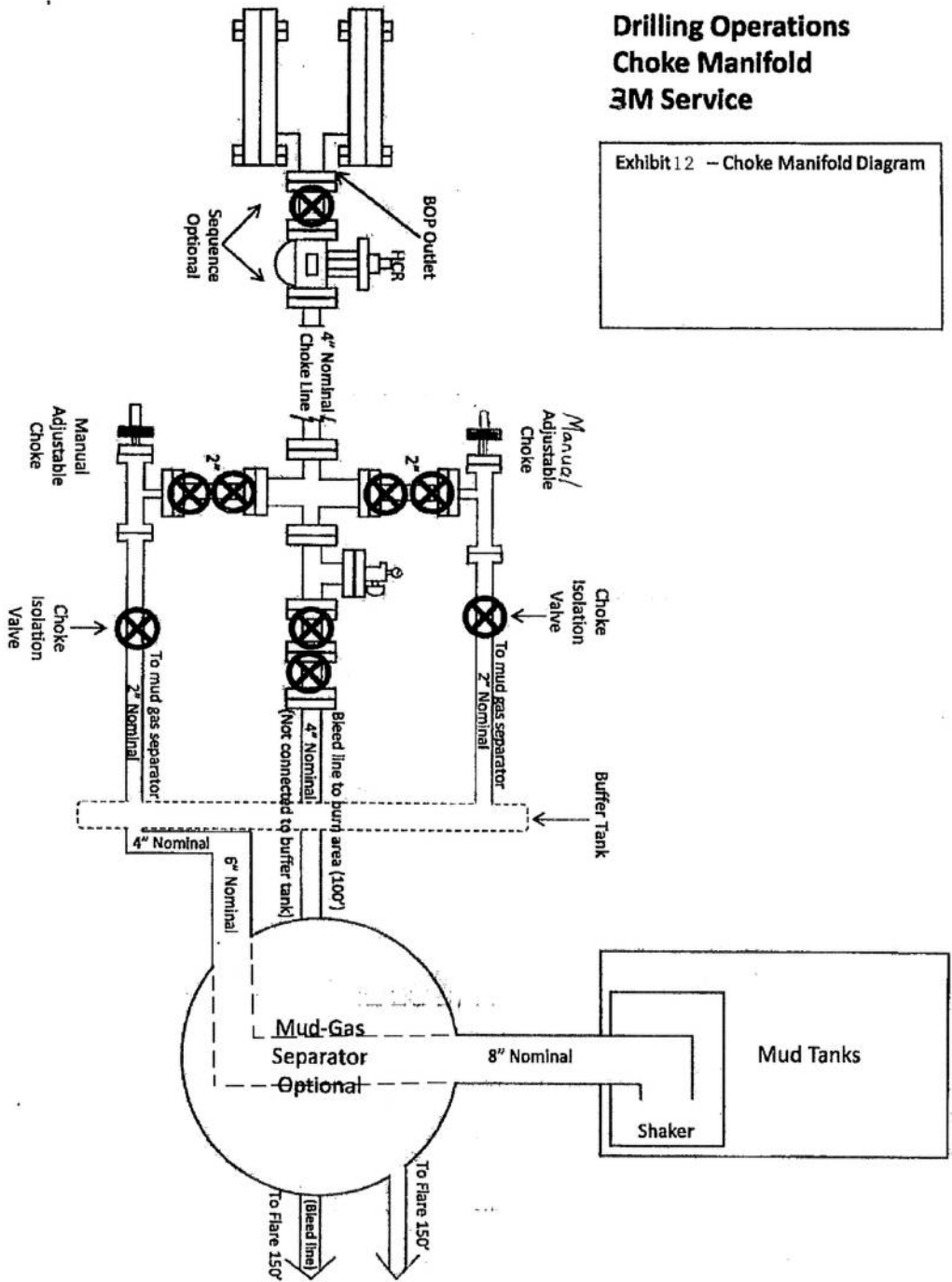
Emergency Services

Boots & Coots IWC.....	1-800-256-9688 or (281)931-8884
Cudd pressure Control.....	(915)699-0139 or (915)563-3356
Halliburton.....	746-2757
Par Five.....	748-9539
Flight For Life-Lubbock, TX.....	(806)743-9911
Aerocare-Lubbock, TX.....	(806)747-8923
Med Flight Air Amb-Albuquerque, NM.....	(505)842-4433
Lifeguard Air Med Svc. Albuquerque, NM.....	(505)272-3115

Mack Energy Corporation
MANIFOLD SCHEMATIC
Exhibit #12

Drilling Operations
Choke Manifold
3M Service

Exhibit 12 - Choke Manifold Diagram



Mack Energy Corporation

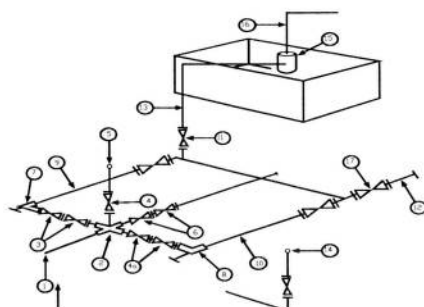
Exhibit #11

MINIMUM CHOKE MANIFOLD

3,000, 5,000, and 10,000 PSI Working Pressure

3M will be used

3 MWP - 5 MWP - 10 MWP



Mud Pit

Reserve Pit

* Location of separator optional

Below Substructure

Minimum requirements

No.		3,000 MWP			5,000 MWP			10,000 MWP		
		I.D.	Nominal	Rating	I.D.	Nominal	Rating	I.D.	Nominal	Rating
1	Line from drilling Spool		3"	3,000		3"	5,000		3"	10,000
2	Cross 3" x 3" x 3" x 2"			3,000			5,000			
2	Cross 3" x 3" x 3" x 2"									10,000
3	Valve Gate Plug	3 1/8		3,000	3 1/8		5,000	3 1/8		10,000
4	Valve Gate Plug	1 13/16		3,000	1 13/16		5,000	1 13/16		10,000
4a	Valves (1)	2 1/16		3,000	2 1/16		5,000	2 1/16		10,000
5	Pressure Gauge			3,000			5,000			10,000
6	Valve Gate Plug	3 1/8		3,000	3 1/8		5,000	3 1/8		10,000
7	Adjustable Choke (3)	2"		3,000	2"		5,000	2"		10,000
8	Adjustable Choke	1"		3,000	1"		5,000	2"		10,000
9	Line		3"	3,000		3"	5,000		3"	10,000
10	Line		2"	3,000		2"	5,000		2"	10,000
11	Valve Gate Plug	3 1/8		3,000	3 1/8		5,000	3 1/8		10,000
12	Line		3"	1,000		3"	1,000		3"	2,000
13	Line		3"	1,000		3"	1,000		3"	2,000
14	Remote reading compound Standpipe pressure quage			3,000			5,000			10,000
15	Gas Separator		2' x 5'			2' x 5'			2' x 5'	
16	Line		4"	1,000		4"	1,000		4"	2,000
17	Valve Gate Plug	3 1/8		3,000	3 1/8		5,000	3 1/8		10,000

(1) Only one required in Class 3M

(2) Gate valves only shall be used for Class 10 M

(3) Remote operated hydraulic choke required on 5,000 psi and 10,000 psi for drilling.

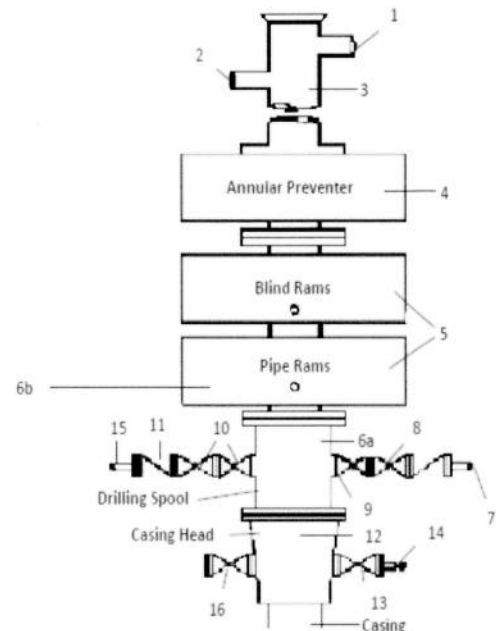
EQUIPMENT SPECIFICATIONS AND INSTALLATION INSTRUCTION

- All connections in choke manifold shall be welded, studded, flanged or Cameron clamp of comparable rating.
- All flanges shall be API 6B or 6BX and ring gaskets shall be API RX or BX. Use only BX for 10 MWP.
- All lines shall be securely anchored.
- Chokes shall be equipped with tungsten carbide seats and needles, and replacements shall be available.
- alternate with automatic chokes, a choke manifold pressure gauge shall be located on the rig floor in conjunction with the standpipe pressure gauge.
- Line from drilling spool to choke manifold should be as straight as possible. Lines downstream from chokes shall make turns by large bends or 90 degree bends using bull plugged tees

Mack Energy Corporation
Minimum Blowout Preventer Requirements
5000 psi Working Pressure
13 5/8 inch- 5 MWP
11 Inch - 5 MWP

Stack Requirements

NO.	Items	Min. I.D.	Min. Nominal
1	Flowline		2"
2	Fill up line		2"
3	Drilling nipple		
4	Annular preventer		
5	Two single or one dual hydraulically operated rams		
6a	Drilling spool with 2" min. kill line and 3" min choke line outlets		2" Choke
6b	2" min. kill line and 3" min. choke line outlets in ram. (Alternate to 6a above)		
7	Valve Gate Plug	3 1/8	
8	Gate valve-power operated	3 1/8	
9	Line to choke manifold		3"
10	Valve Gate Plug	2 1/16	
11	Check valve	2 1/16	
12	Casing head		
13	Valve Gate Plug	1 13/16	
14	Pressure gauge with needle valve		
15	Kill line to rig mud pump manifold		2"



OPTIONAL

16	Flanged Valve	1 13/16	
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CONTRACTOR'S OPTION TO FURNISH:

1. All equipment and connections above bradenhead or casinghead. Working pressure of preventers to be 2000 psi minimum.
2. Automatic accumulator (80 gallons, minimum) capable of closing BOP in 30 seconds or less and, holding them closed against full rated working pressure.
3. BOP controls, to be located near drillers' position.
4. Kelly equipped with Kelly cock.
5. Inside blowout preventer or its equivalent on derrick floor at all times with proper threads to fit pipe being used.
6. Kelly saver-sub equipped with rubber casing protector at all times.
7. Plug type blowout preventer tester.
8. Extra set pipe rams to fit drill pipe in use on location at all times.
9. Type RX ring gaskets in place of Type R.

MEC TO FURNISH:

1. Bradenhead or casing head and side valves.
2. Wear bushing. If required.

GENERAL NOTES:

1. Deviations from this drawing may be made only with the express permission of MEC's Drilling Manager.
2. All connections, valves, fittings, piping, etc., subject to well or pump pressure must be flanged (suitable clamp connections acceptable) and have minimum working pressure equal to rated working pressure of preventers up through choke valves must be full opening and suitable for high pressure mud service.
3. Controls to be of standard design and each marked, showing opening and closing position
4. Chokes will be positioned so as not to hamper or delay changing of choke beans.

Replaceable parts for adjustable choke, or bean sizes, retainers, and choke wrenches to be conveniently located for immediate use.

5. All valves to be equipped with hand-wheels or handles ready for immediate use.
6. Choke lines must be suitably anchored.
7. Handwheels and extensions to be connected and ready for use.
8. Valves adjacent to drilling spool to be kept open. Use outside valves except for emergency.
9. All seamless steel control piping (2000 psi working pressure) to have flexible joints to avoid stress. Hoses will be permitted.
10. Casinghead connections shall not be used except in case of emergency.
11. Does not use kill line for routine fill up operations.

Sante Fe Main Office
Phone: (505) 476-3441

General Information
Phone: (505) 629-6116

Online Phone Directory
<https://www.emnrd.nm.gov/oed/contact-us>

State of New Mexico
Energy, Minerals and Natural Resources
Oil Conservation Division
1220 S. St Francis Dr.
Santa Fe, NM 87505

CONDITIONS

Action 446231

CONDITIONS

Operator: MACK ENERGY CORP P.O. Box 960 Artesia, NM 882110960	OGRID: 13837
	Action Number: 446231
	Action Type: [C-101] BLM - Federal/Indian Land Lease (Form 3160-3)

CONDITIONS

Created By	Condition	Condition Date
delilah	Cement is required to circulate on both surface and intermediate1 strings of casing.	3/27/2025
delilah	If cement does not circulate on any string, a Cement Bond Log (CBL) is required for that string of casing.	3/27/2025
ward.rikala	Notify the OCD 24 hours prior to casing & cement.	4/16/2025
ward.rikala	File As Drilled C-102 and a directional Survey with C-104 completion packet.	4/16/2025
ward.rikala	Once the well is spud, to prevent ground water contamination through whole or partial conduits from the surface, the operator shall drill without interruption through the fresh water zone or zones and shall immediately set in cement the water protection string.	4/16/2025
ward.rikala	Oil base muds are not to be used until fresh water zones are cased and cemented providing isolation from the oil or diesel. This includes synthetic oils. Oil based mud, drilling fluids and solids must be contained in a steel closed loop system.	4/16/2025