Devon Energy Prod. Co., L.P./Cotton Draw Unit 507H

1. Geologic Formations

TVD of target	10452	Pilot hole depth	
MD at TD:	19956	Deepest expected fresh water:	676

Basin

Formation	Depth (TVD) from KB	Water/Mineral Bearing/ Target Zone?	Hazards*
Rustler	676		
Salado	1004		
Base of Salt	4254		
Delaware	4484		
Brushy Canyon	6852		
1st BSPG Lime	83672		
1st BSPG Sand	9442		
2nd BSPG Lime	9667		
2nd BSPG Sand	10061		
3rd BSPG Lime	10537		

*H2S, water flows, loss of circulation, abnormal pressures, etc.

2. Casing Program

Hole Size	Casing Interval		Csg. Size	Weight (lbs)	Grade	Conn.	SF Collapse	SF Burst	SF Tension
	From	To							
17.5"	0	788'	13.375"	48	H-40	STC	1.74	2.45	4.13
12.25"	0	4,350'	9.625"	40	J-55	LTC	1.19	1.42	3.98
8.75"	0	19,956'	5.5"	17	P110	BTC	2.18	2.7	3.21
				BLM Minimum Safety Factor			1.125	1	1.6 Dry 1.8 Wet

All casing strings will be tested in accordance with Onshore Oil and Gas Order #2 III.B.1.h

Must have table for contingency casing

	Y or N
Is casing new? If used, attach certification as required in Onshore Order #1	Y
Does casing meet API specifications? If no, attach casing specification sheet.	Y
Is premium or uncommon casing planned? If yes attach casing specification sheet.	N
Does the above casing design meet or exceed BLM's minimum standards? If not provide justification (loading assumptions, casing design criteria).	Y
Will the intermediate pipe be kept at a minimum 1/3 fluid filled to avoid approaching the collapse pressure rating of the casing?	Y
Is well located within Capitan Reef?	N
If yes, does production casing cement tie back a minimum of 50' above the Reef?	
Is well within the designated 4 string boundary.	
Is well located in SOPA but not in R-111-P?	N
If yes, are the first 2 strings cemented to surface and 3rd string cement tied back 500' into previous casing?	
Is well located in R-111-P and SOPA?	N
If yes, are the first three strings cemented to surface?	
Is 2nd string set 100' to 600' below the base of salt?	
Is well located in high Cave/Karst?	N
If yes, are there two strings cemented to surface?	
(For 2 string wells) If yes, is there a contingency casing if lost circulation occurs?	
Is well located in critical Cave/Karst?	N
If yes, are there three strings cemented to surface?	

2. Cementing Program

Casing	# Sks	Wt. lb/ gal	H_2O gal/sk	Yld ft3/ sack	500# Comp. Strength (hours)	Slurry Description
13-3/8" Surface	613	14.8	6.34	1.34	6	Tail: Class C Cement + 1% Calcium Chloride
9-5/8" Inter.	737	12.9	9.81	1.85	14	Lead: (65:35) Class C Cement: Poz (Fly Ash): 6% BWOC Bentonite + 5% BWOW Sodium Chloride + 0.125 lbs/sack Poly-E-Flake
	306	14.8	6.32	1.33	6	Tail: Class C Cement + 0.125 lbs/sack Poly-E-Flake
5-1/2" Prod	623	9	13.5	3.27	21	Lead: Tuned Light® Cement
	2462	14.5	5.31	1.2	25	Tail: (50:50) Class H Cement: Poz (Fly Ash) + 0.5% bwoc HALAD-344 + 0.4% bwoc CFR-3 + 0.2% BWOC HR-601 + 2% bwoc Bentonite
5-1/2" Prod Two Stage	599	10.9	20.6	3.31	24	1st Stage Lead: (50:40:10) Class C: Silicalite: Enhancer 923 + 10% BWOC Bentonite + 0.05% BWOC SA-1015 + 0.3% BWOC HR-800 + 0.2% BWOC FE-2 + 0.125 lb/sk Pol-E-Flake + 0.5 lb/sk D-Air 5000
	2462	14.5	5.31	1.2	25	1st Stage Tail: (50:50) Class H Cement: Poz (Fly Ash) + 0.5% bwoc HALAD-344 + 0.4% bwoc CFR-3 + 0.2% BWOC HR-601 + 2% bwoc Bentonite
	DV Tool = 4400ft					
	20	10.9	20.6	3.31	24	2nd Stage Lead: (50:40:10) Class C: Silicalite: Enhancer 923 + 10% BWOC Bentonite + 0.05% BWOC SA-1015 + 0.3% BWOC HR-800 + 0.2% BWOC FE-2 + 0.125 lb/sk Pol-E-Flake + 0.5 lb/sk D-Air 5000
	30	14.8	6.32	1.33	6	2nd Stage Tail: Class C Cement + 0.125 lbs/sack Poly-E-Flake

DV tool depth(s) will be adjusted based on hole conditions and cement volumes will be adjusted proportionally. DV tool will be set a minimum of 50 feet below previous casing and a minimum of 200 feet above current shoe. Lab reports with the 500 psi compressive strength time for the cement will be onsite for review.

Casing String	TOC	% Excess
13-3/8" Surface	0'	50%
9-5/8" Intermediate	0'	30%
5-1/2" Production Casing	4150'	25%
5-1/2" Production Casing Two Stage Option	1St Stage = 4400' / 2nd Stage = 4150'	25%

4. Pressure Control Equipment

N	A variance is requested for the use of a diverter on the surface casing. See attached for schematic.

BOP installed and tested before drilling which hole?	Size?	Min. Required WP	Type		✓	Tested to:
12-1/4"	13-5/8"	3M	Annular		x	50% of working pressure
			Blind Ram			3M
			Pipe Ram			
			Double Ram		x	
			Other*			
8-3/4"	13-5/8"	3M	Annular		x	50% testing pressure
			Blind Ram			3M
			Pipe Ram			
			Double Ram		x	
			Other *			
			Annular			
			Blind Ram			
			Pipe Ram			
			Double Ram			
			Other *			

*Specify if additional ram is utilized.

BOP/BOPE will be tested by an independent service company to 250 psi low and the high pressure indicated above per Onshore Order 2 requirements. The System may be upgraded to a higher pressure but still tested to the working pressure listed in the table above. If the system is upgraded all the components installed will be functional and tested.

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 will include a Kelly cock and floor safety valve (inside BOP) and choke lines and choke manifold. See attached schematics.

Y	Formation integrity test will be performed per Onshore Order #2. On Exploratory wells or on that portion of any well approved for a 5M BOPE system or greater, a pressure integrity test of each casing shoe shall be performed. Will be tested in accordance with Onshore Oil and Gas Order #2 III.B.1.i.

<table>
<tr><td rowspan="2">Y</td><td colspan="2">A variance is requested for the use of a flexible choke line from the BOP to Choke Manifold. See attached for specs and hydrostatic test chart.</td></tr>
<tr><td>Y</td><td>Are anchors required by manufacturer?</td></tr>
<tr><td>Y</td><td colspan="2">A multibowl wellhead is being used. The BOP will be tested per Onshore Order #2 after installation on the surface casing which will cover testing requirements for a maximum of 30 days. If any seal subject to test pressure is broken the system must be tested.

Devon proposes using 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.
• Wellhead will be installed by wellhead representatives.
• If the welding is performed by a third party, the wellhead representative will monitor the temperature to verify that it does not exceed the maximum temperature of the seal.
• Wellhead representative will install the test plug for the initial BOP test.
• Wellhead company will install a solid steel body pack-off to completely isolate the lower head after cementing intermediate casing. After installation of the pack-off, the pack-off and the lower flange will be tested to 3M, as shown on the attached schematic. Everything above the pack-off will not have been altered whatsoever from the initial nipple up. Therefore the BOP components will not be retested at that time.
• If the cement does not circulate and one inch operations would have been possible with a standard wellhead, the well head will be cut and top out operations will be conducted.
• Devon will pressure test all seals above and below the mandrel (but still above the casing) to full working pressure rating.
• Devon will test the casing to 0.22 psi/ft or 1500 psi, whichever is greater, as per Onshore Order #2.

After running the 13-3/8" surface casing, a 13-5/8" BOP/BOPE system with a minimum rating of 3M will be installed on the wellhead system and will undergo a 250 psi low pressure test followed by a 3,000 psi high pressure test. The 3,000 psi high and 250 psi low test will cover testing requirements a maximum of 30 days, as per Onshore Order #2. If the well is not complete within 30 days of this BOP test, another full BOP test will be conducted, as per Onshore Order #2.
After running the 9-5/8' intermediate casing with a mandrel hanger, the 13-5/8" BOP/BOPE system with a minimum rating of 3M will already be installed on the wellhead.

The pipe rams will be operated and checked each 24 hour period and each time the drill pipe is out of the hole. These tests will be logged in the daily driller's log. A 2" kill line and 3" choke line will be incorporated into the drilling spool below the ram BOP. In addition to the rams and annular preventer, additional BOP accessories include a kelly cock, floor safety valve, choke lines, and choke manifold rated at 3,000 psi WP.</td></tr>
</table>

	Devon requests a variance to use a flexible line with flanged ends between the BOP and the choke manifold (choke line). The line will be kept as straight as possible with minimal turns

5. Mud Program

Depth		Type	Weight (ppg)	Viscosity	Water Loss
From	To				
0	788'	FW Gel	8.6-8.8	28-34	N/C
788'	4,350'	Saturated Brine	10.0-10.2	28-34	N/C
4,350'	19,956'	Cut Brine	8.5-9.3	28-34	N/C

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

What will be used to monitor the loss or gain of fluid?	PVT/Pason/Visual Monitoring

6. Logging and Testing Procedures

Logging, Coring and Testing.	
x	Will run GR/CNL from TD to surface (horizontal well – vertical portion of hole). Stated logs run will be in the Completion Report and submitted to the BLM.
	No Logs are planned based on well control or offset log information.
	Drill stem test? If yes, explain
	Coring? If yes, explain

Additional logs planned		Interval
	Resistivity	Int. shoe to KOP
	Density	Int. shoe to KOP
X	CBL	Production casing
X	Mud log	Intermediate shoe to TD
	PEX	

7. Drilling Conditions

Condition	Specify what type and where?
BH Pressure at deepest TVD	4658 psi
Abnormal Temperature	No

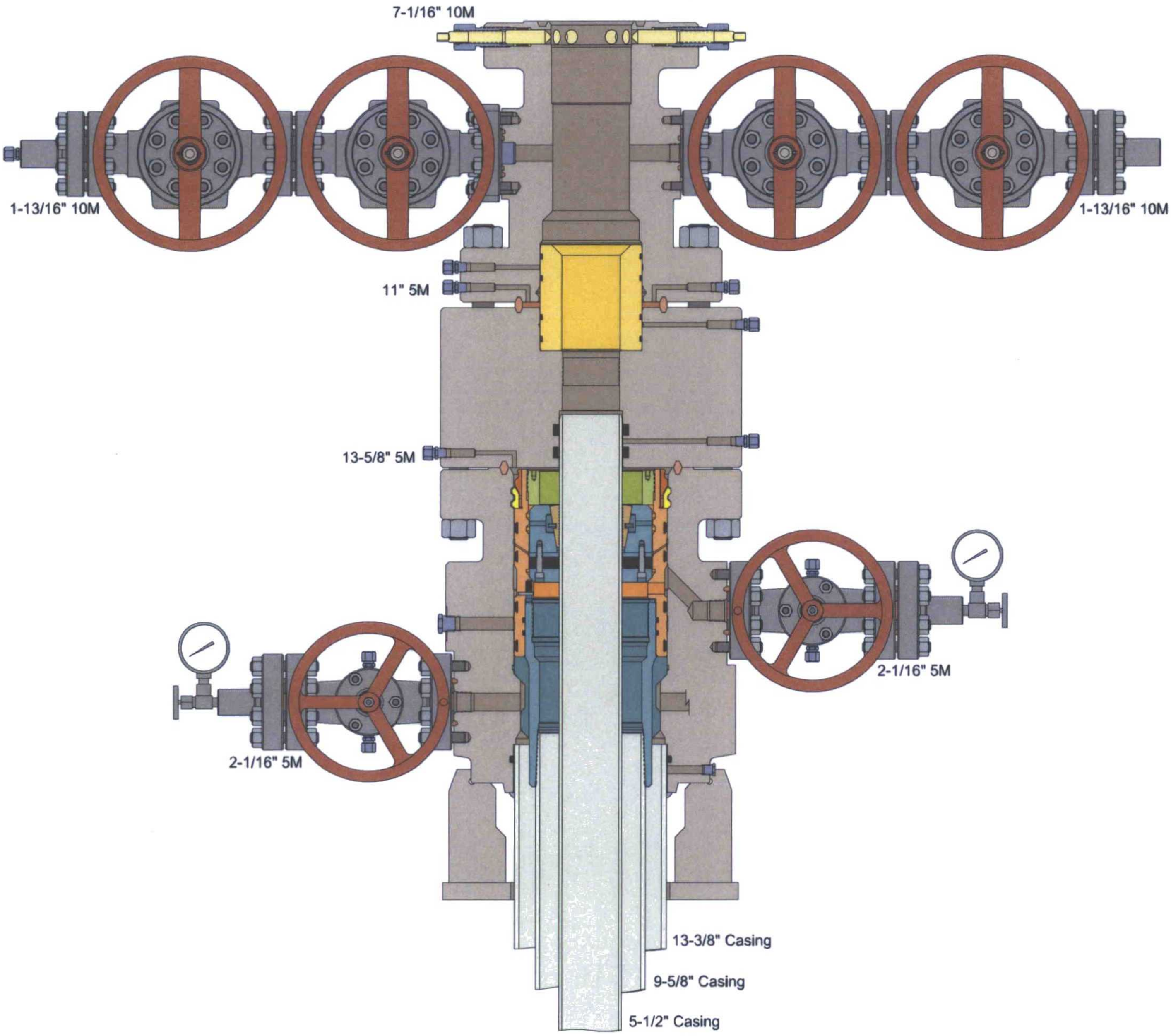
Mitigation measure for abnormal conditions. Describe. Lost circulation material/sweeps/mud scavengers.

Hydrogen Sulfide (H2S) monitors will be installed prior to drilling out the surface shoe. If H2S is detected in concentrations greater than 100 ppm, the operator will comply with the provisions of Onshore Oil and Gas Order #6. If Hydrogen Sulfide is encountered, measured values and formations will be provided to the BLM.	
N	H2S is present
Y	H2S Plan attached

8. Other facets of operation

Is this a walking operation? No
Will be pre-setting casing? No

Attachments
_X_ Directional Plan
___ Other, describe



7-1/16" 10M
1-13/16" 10M
1-13/16" 10M
11" 5M
13-5/8" 5M
2-1/16" 5M
2-1/16" 5M
13-3/8" Casing
9-5/8" Casing
5-1/2" Casing

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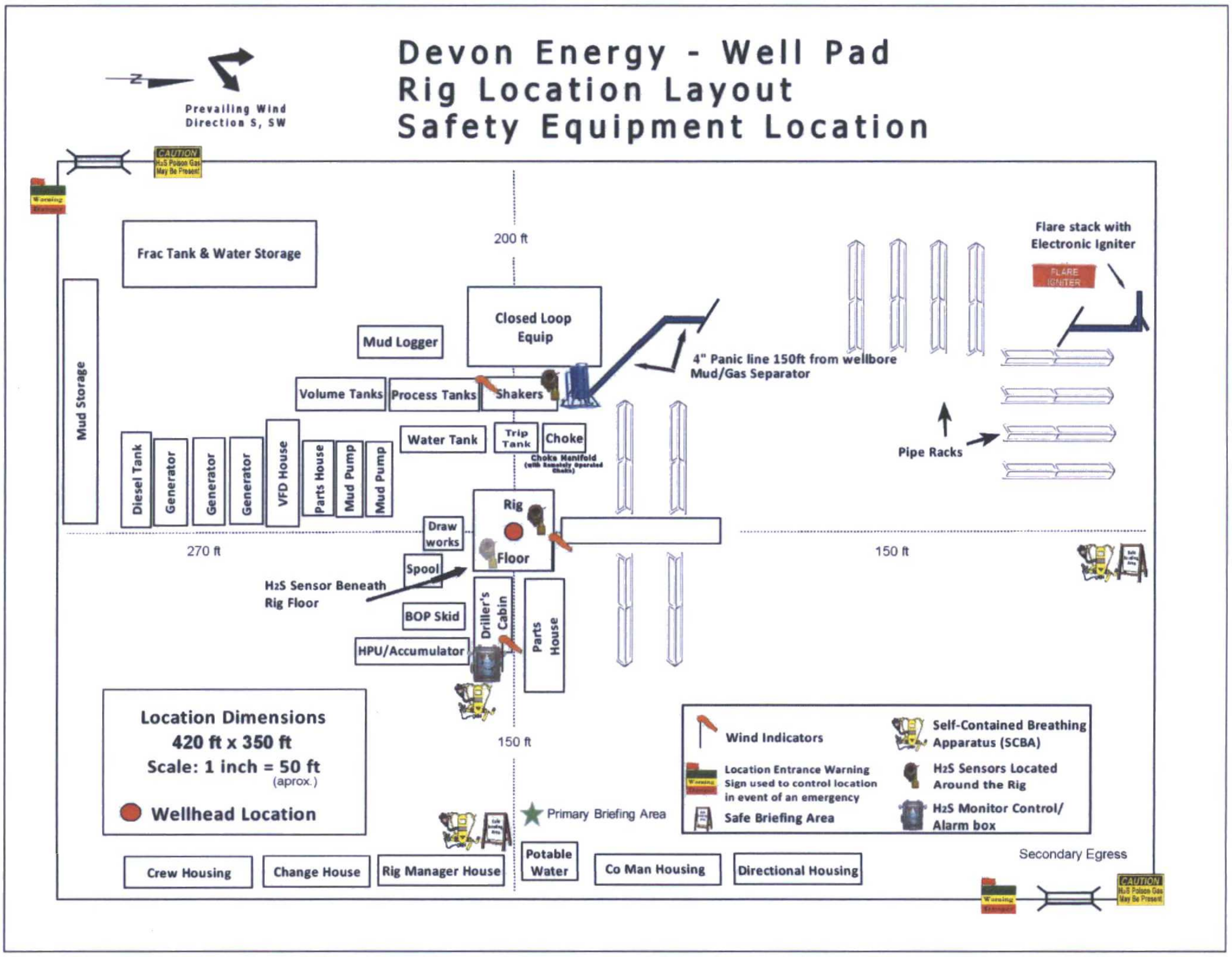
Devon's proposed wellhead manufactures will be FMC Technologies, Cactus Wellhead, or Cameron.

Cotton Draw Unit 507H



Casing Assumptions and Load Cases

Surface

All casing design assumptions were ran in Stress Check to determine safety factor which meet or exceed both Devon Energy and BLM minimum requirements. All casing strings will be filled while running in hole in order to not exceed collapse rating of the pipe.

Surface Casing Burst Design		
Load Case	**External Pressure**	**Internal Pressure**
Pressure Test	Formation Pore Pressure	Max mud weight of next hole-section plus Test psi
Drill Ahead	Formation Pore Pressure	Max mud weight of next hole section
Displace to Gas	Formation Pore Pressure	Dry gas from next casing point

Surface Casing Collapse Design		
Load Case	**External Pressure**	**Internal Pressure**
Full Evacuation	Water gradient in cement, mud above TOC	None
Cementing	Wet cement weight	Water (8.33ppg)

Surface Casing Tension Design	
Load Case	**Assumptions**
Overpull	100kips
Runing in hole	3 ft/s
Service Loads	N/A

Casing Assumptions and Load Cases

Intermediate

All casing design assumptions were ran in Stress Check to determine safety factor which meet or exceed both Devon Energy and BLM minimum requirements. All casing strings will be filled while running in hole in order to not exceed collapse rating of the pipe.

Intermediate Casing Burst Design		
Load Case	**External Pressure**	**Internal Pressure**
Pressure Test	Formation Pore Pressure	Max mud weight of next hole-section plus Test psi
Drill Ahead	Formation Pore Pressure	Max mud weight of next hole section
Fracture @ Shoe	Formation Pore Pressure	Dry gas

Intermediate Casing Collapse Design		
Load Case	**External Pressure**	**Internal Pressure**
Full Evacuation	Water gradient in cement, mud above TOC	None
Cementing	Wet cement weight	Water (8.33ppg)

Intermediate Casing Tension Design	
Load Case	**Assumptions**
Overpull	100kips
Runing in hole	2 ft/s
Service Loads	N/A

All casing design assumptions were ran in Stress Check to determine safety factor which meet or exceed both Devon Energy and BLM minimum requirements. All casing strings will be filled while running in hole in order to not exceed collapse rating of the pipe.

Production Casing Burst Design		
Load Case	**External Pressure**	**Internal Pressure**
Pressure Test	Formation Pore Pressure	Fluid in hole (water or produced water) + test psi
Tubing Leak	Formation Pore Pressure	Packer @ KOP, leak below surface 8.6 ppg packer fluid
Stimulation	Formation Pore Pressure	Max frac pressure with heaviest frac fluid

Production Casing Collapse Design		
Load Case	**External Pressure**	**Internal Pressure**
Full Evacuation	Water gradient in cement, mud above TOC.	None
Cementing	Wet cement weight	Water (8.33ppg)

Production Casing Tension Design	
Load Case	**Assumptions**
Overpull	100kips
Runing in hole	2 ft/s
Service Loads	N/A

Contingency Production Cement

Additional Info for String	3	Additional String Description	
Stage Tool Depth	4400		

Lead

Top MD of Segment	4150	Btm MD of Segment	4250	Cement Type	C
Additives	C SA-1015 + 0.3% BWOC HR-800 + 0.2% BWOC	Quanity (sks)	20	Yield (cu.ft./sk)	3.31
Density (lbs/gal)	10.9	Volume (cu.ft.)	66	Percent Excess	25

Tail

Top MD of Segment	4250	Top MD of Segment	4400	Cement Type	H
Additives	0.125 lbs/sack Poly-E-Flake	Quanity (sks)	30	Yield (cu.ft./sk)	1.33
Density (lbs/gal)	14.8	Volume (cu.ft.)	39	Percent Excess	25

Contingency Production Cement

Additional Info for String	3	Additional String Description	
Stage Tool Depth	4400		

Lead

Top MD of Segment	4400	Btm MD of Segment	10600	Cement Type	C
Additives	C SA-1015 + 0.3% BWOC HR-800 + 0.2% BWOC	Quanity (sks)	599	Yield (cu.ft./sk)	3.27
Density (lbs/gal)	10.9	Volume (cu.ft.)	1958	Percent Excess	25

Tail

Top MD of Segment	10600	Top MD of Segment	19956	Cement Type	H
Additives	ALAD-344 + 0.4% bwoc CFR-3 + 0.2% BWOC H	Quanity (sks)	2462	Yield (cu.ft./sk)	1.2
Density (lbs/gal)	14.8	Volume (cu.ft.)	2954.4	Percent Excess	25

Continental
CONTITECH

Fluid Technology

ContiTech Beattie Corp.
Website: www.contitechbeattie.com

Monday, June 14, 2010

RE: Drilling & Production Hoses
Lifting & Safety Equipment

To Helmerich & Payne,

A Continental ContiTech hose assembly can perform as intended and suitable for the application regardless of whether the hose is secured or unsecured in its configuration. As a manufacturer of High Pressure Hose Assemblies for use in Drilling & Production, we do offer the corresponding lifting and safety equipment, this has the added benefit of easing the lifting and handling of each hose assembly whilst affording hose longevity by ensuring correct handling methods and procedures as well as securing the hose in the unlikely event of a failure; but in no way does the lifting and safety equipment affect the performance of the hoses providing the hoses have been handled and installed correctly It is good practice to use lifting & safety equipment but not mandatory

Should you have any questions or require any additional information/clarifications then please do not hesitate to contact us.

ContiTech Beattie is part of the Continental AG Corporation and can offer the full support resources associated with a global organization.

Best regards,

Robin Hodgson
Sales Manager
ContiTech Beattie Corp

ContiTech Beattie Corp,
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RIG 212

PHOENIX

QUALITY DOCUMENT

PHOENIX RUBBER INDUSTRIAL LTD.

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Phone: (3662) 556-737 • Fax: (3662) 566-738

SALES & MARKETING: H-1092 Budapest, Ráday u. 42-44. Hungary • H-1440 Budapest, P. O. Box 26
Phone: (361) 456-4200 · Fax: (361) 217-2972, 456-4273 · www.taurusemerge.hu

QUALITY CONTROL INSPECTION AND TEST CERTIFICATE			CERT. N°: 552
PURCHASER: Phoenix Beattie Co.			P.O. N°: 1519FA-871
PHOENIX RUBBER order N°: 170466	HOSE TYPE: 3" ID Choke and Kill Hose		
HOSE SERIAL N°: 34128	NOMINAL / ACTUAL LENGTH: 11,43 m		
W.P. 68,96 MPa 10000 psi	T.P. 103,4 MPa 15000 psi	Duration: 60 min.	

Pressure test with water at ambient temperature

See attachment. (1 page)

↑ 10 mm = 10 Min.
→ 10 mm = 25 MPa

COUPLINGS

Type	Serial N°	Quality	Heat N°
3" coupling with 4 1/16" Flange end	720 719	AISI 4130 AISI 4130	C7626 47357

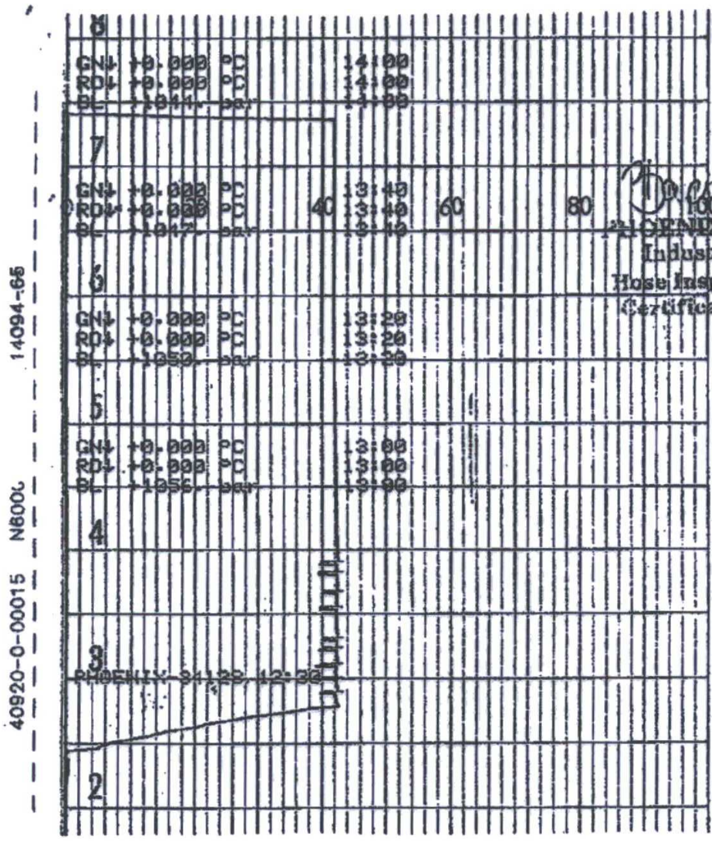
API Spec 16 C
Temperature rate:"B"

All metal parts are flawless

WE CERTIFY THAT THE ABOVE HOSE HAS BEEN MANUFACTURED IN ACCORDANCE WITH THE TERMS OF THE ORDER AND PRESSURE TESTED AS ABOVE WITH SATISFACTORY RESULT.

Date:	Inspector	Quality Control
29. April. 2002.		PHOENIX RUBBER Industrial Ltd. Hose Inspection and Certification Dept.

VERIFIED TRUE COPY
PHOENIX RUBBER Q.C.



PHOENIX RUBBER
Industrial Ltd.
Hose Inspection and
Certification Dept.

VERIFIED TRUE CO
PHOENIX RUBBER Q.C.

13-5/8" 3M BOPE & Closed Loop Equipment Schematic