APPENDIX M

CASING, BOP/BOPE, AND MIT PRESSURE TESTS

First Intermediate and Surface CIT Pressure Testing

BATTLE Energy Services

FORM: TEST CHART CALIBRATION

DATE:	10/10/16
CALIBRATOR:	AlFREDO
SIGNED:	[signature]
CHART NUMBER:	20
MODEL:	TECH CAL
SERIAL NUMBER:	03455
PRESSURE RATING:	5,000 psi
MANUFACTURER DATE:	
CERTIFIED GUAGE:	VA13197
	Accuracy of this recorder is +/- 0.5% of indicated range

BATTLE Energy Services

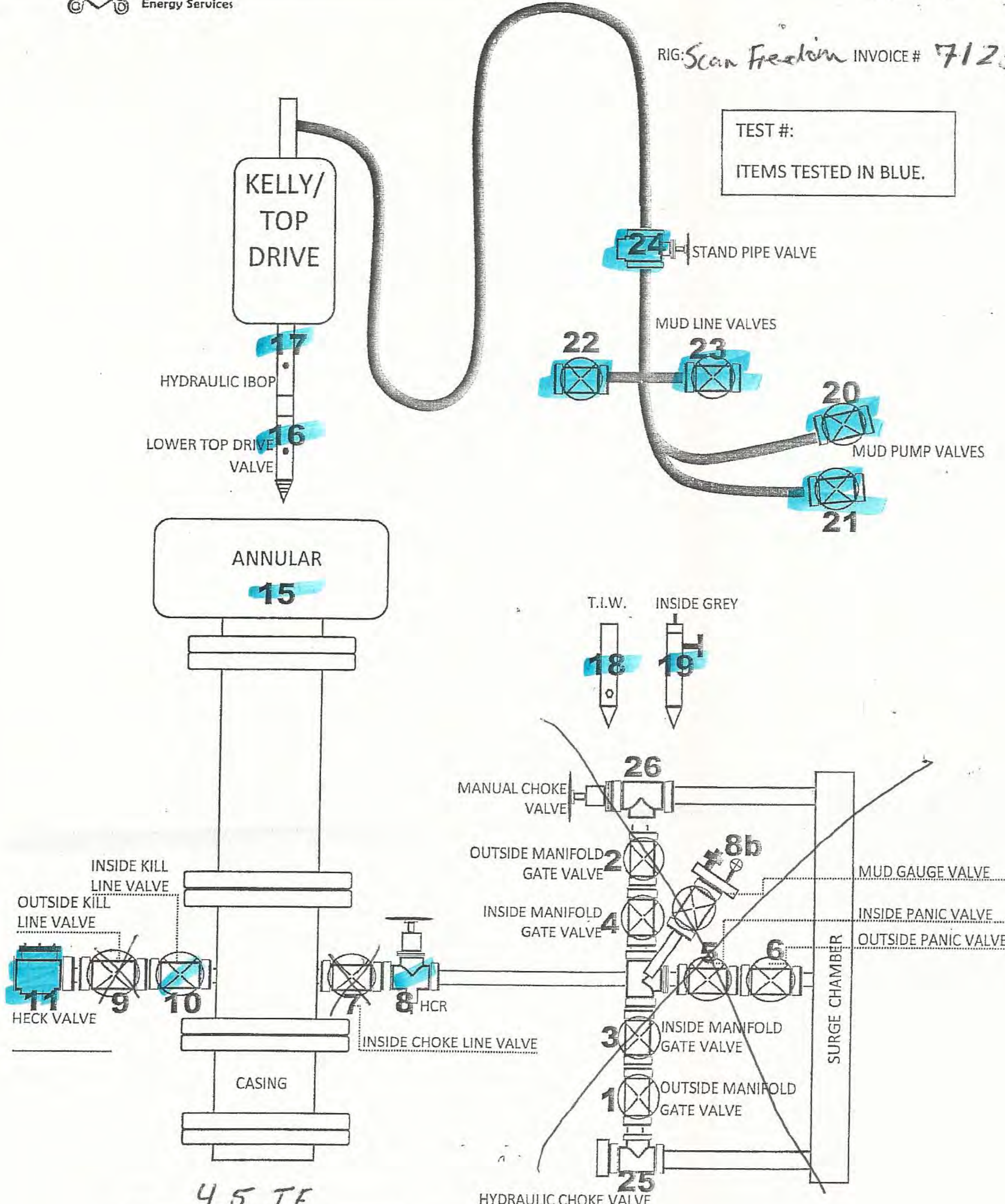
BOP Test Diagram

Date 11-5-2016

RIG: Scan Freedom INVOICE # 7125

TEST #:

ITEMS TESTED IN BLUE.



4.5 IF

DRILL PIPE & TYPE

20"

PLUG/CUP SIZE AND TYPE

BATTLE Energy Services

PO Box 7
Lovington, NM 88260
(575) 942-9472

Invoice
B 7125

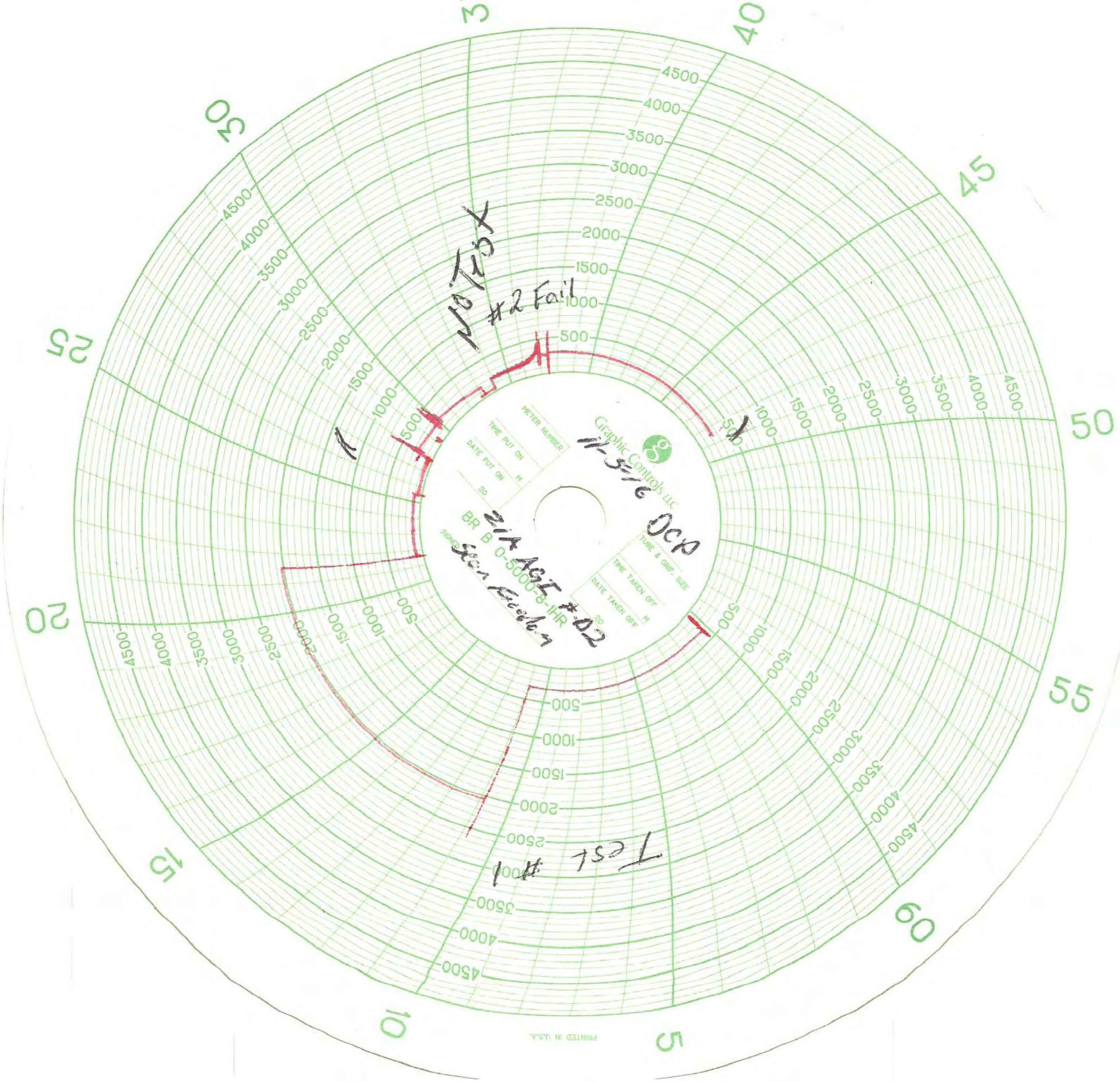
Date 11-5-2016 Start Time ______ ☐ am ☐ pm
Company DCP Midstream State NM County Lea
Lease ZIA AGI #02
Company Man ______ Tester Blake/Sal Truck # 41
Tool Pusher ______ Plug Size 20"
Drilling Contractor Scan Rig # Frontier Pipe Thread Size 4½IF

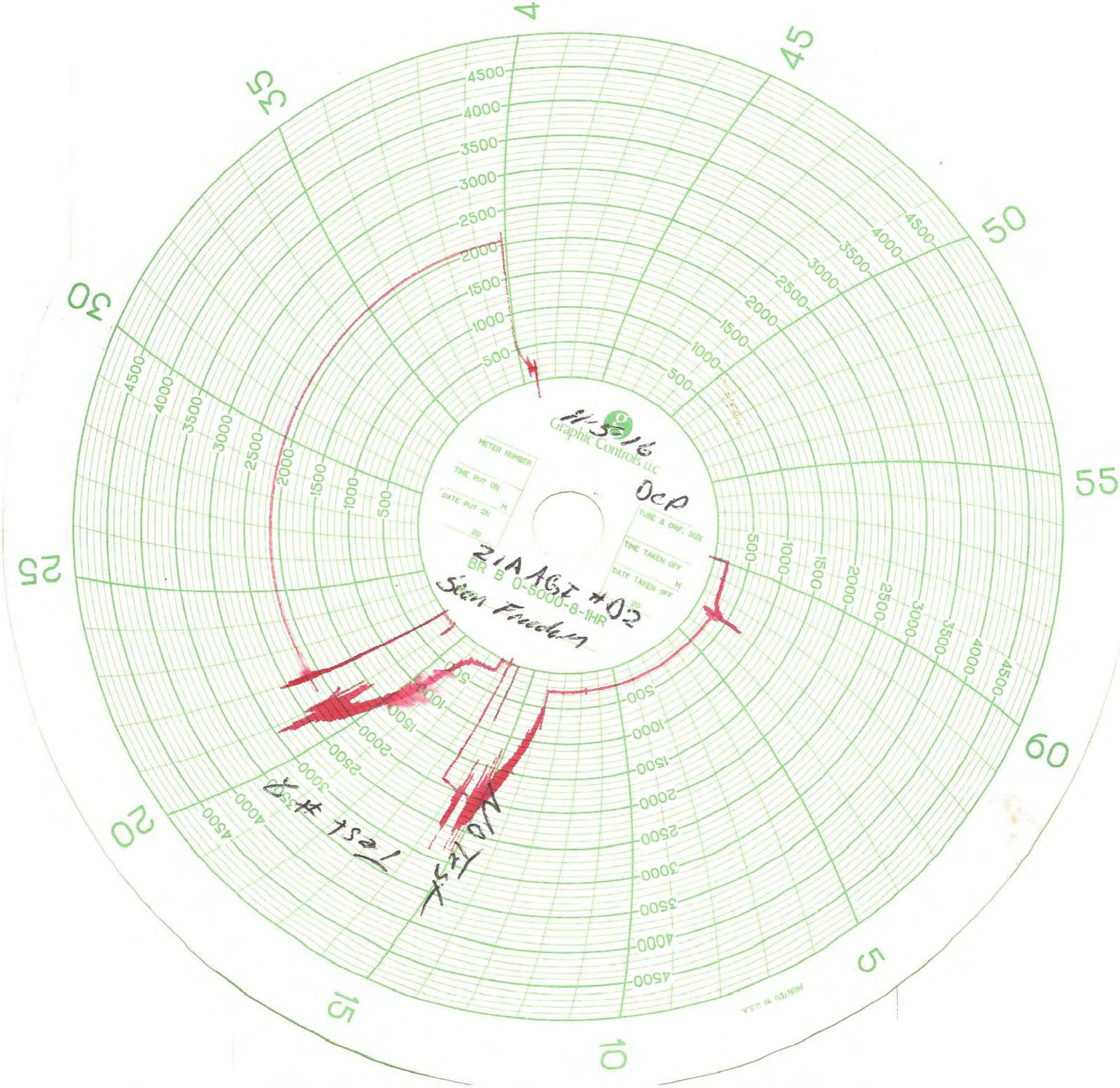
Test Pressures
BOP: ______
Annular: 2000
Casing: 1000
Pumps: 2,000

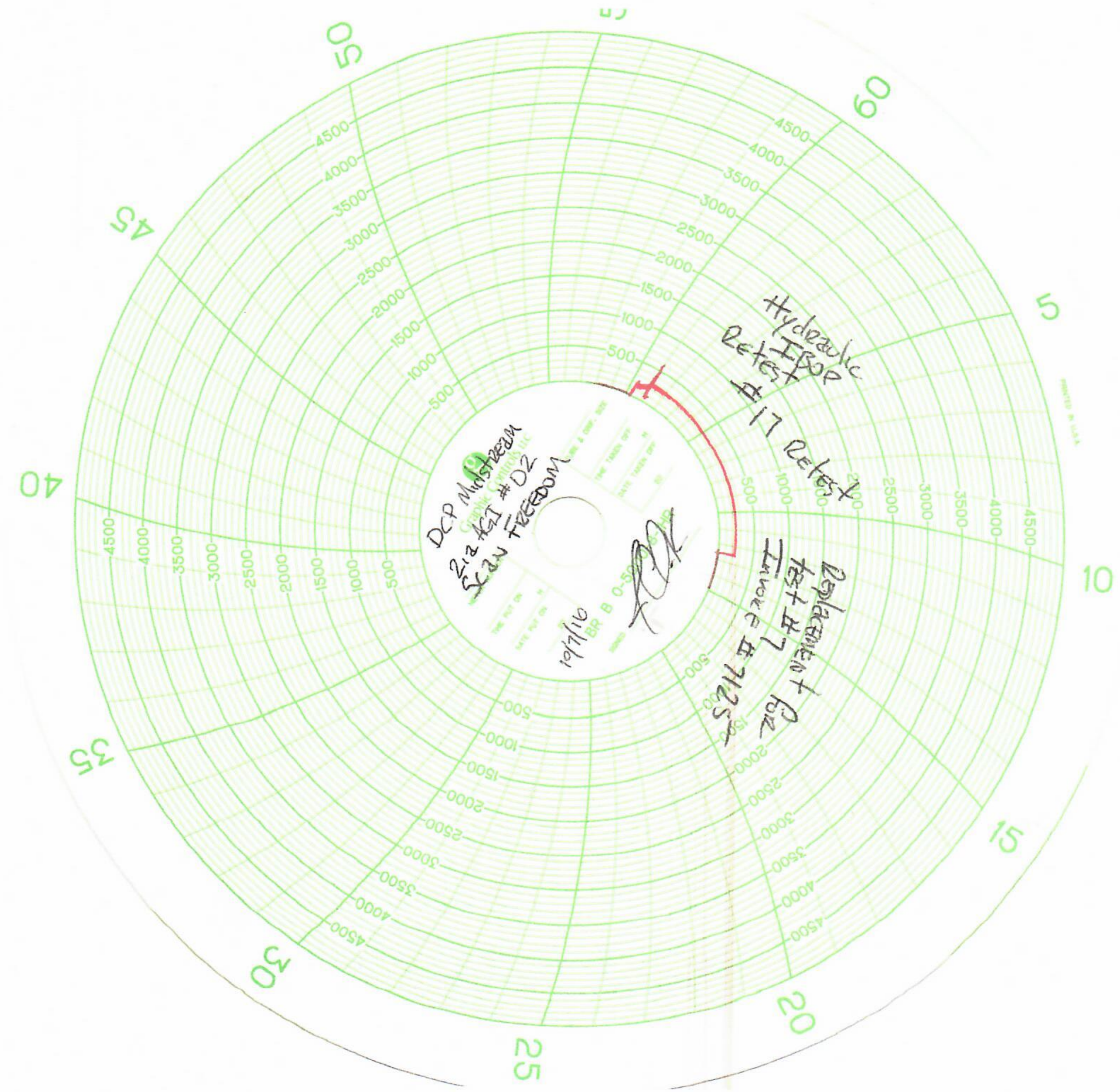
Test #	Items tested	Low Test PSI	Low Test Min.	High Test PSI	High Test Min.	Remarks
1.	Truck	250	10	2,000	10	* All test and pressures per CM.
2	8, 10, 15	250	10	2000	10	* Test 2 failed, had trouble
3	8, 10, 15	250	10	2,000	10	closing annular, worked it and
4	18	250	10	2000	10	it held fine.
5	19	250	10	2000	10	* Test 4 (TIW) bled off.
6	16	250	10	2000	10	pressured back up and it
7	17	250	10	2000	10	held good
8	24	250	10	2000	10	* Had issues getting test #9
9	21, 22, 23, 20	250	10	2000	10	to hold. I believe it had trapped
10	Casing, 11, 15, 16	\	\	1000	30	air or even changing temp, causing
						it to drop in pressure
						* Waited on rig to go in the
						hole to test casing

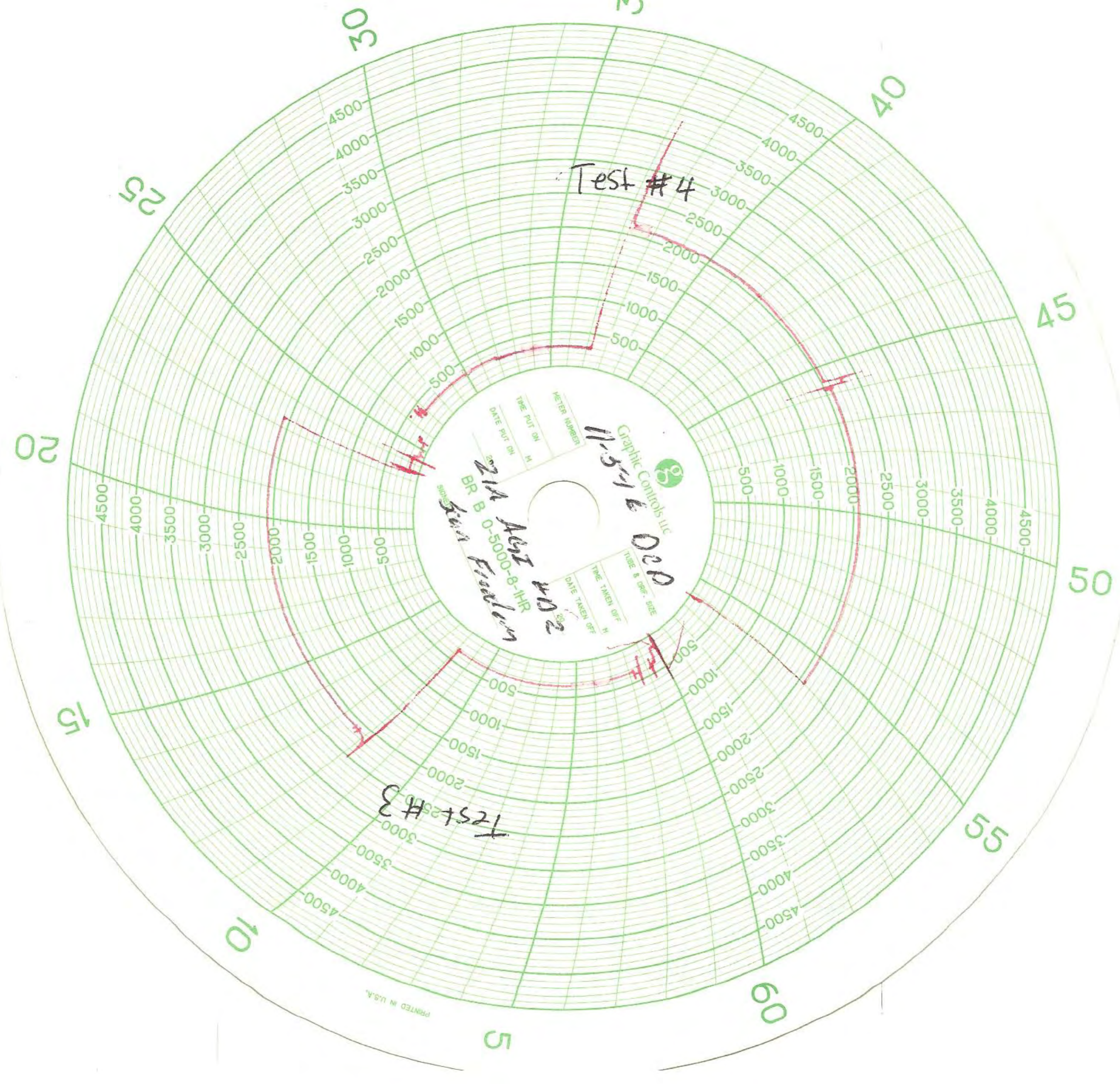
Mileage 80 @ No charge /mile = ______
Methanol ______ = ______
Cup Test ______ = ______
25 HR@ $110.00 = $2750.00
______ @ ______ = ______
20" O-Ring @ $50.00 = $50.00
Subtotal = $3,000.00
Tax = $165.00
TOTAL = $3165.00

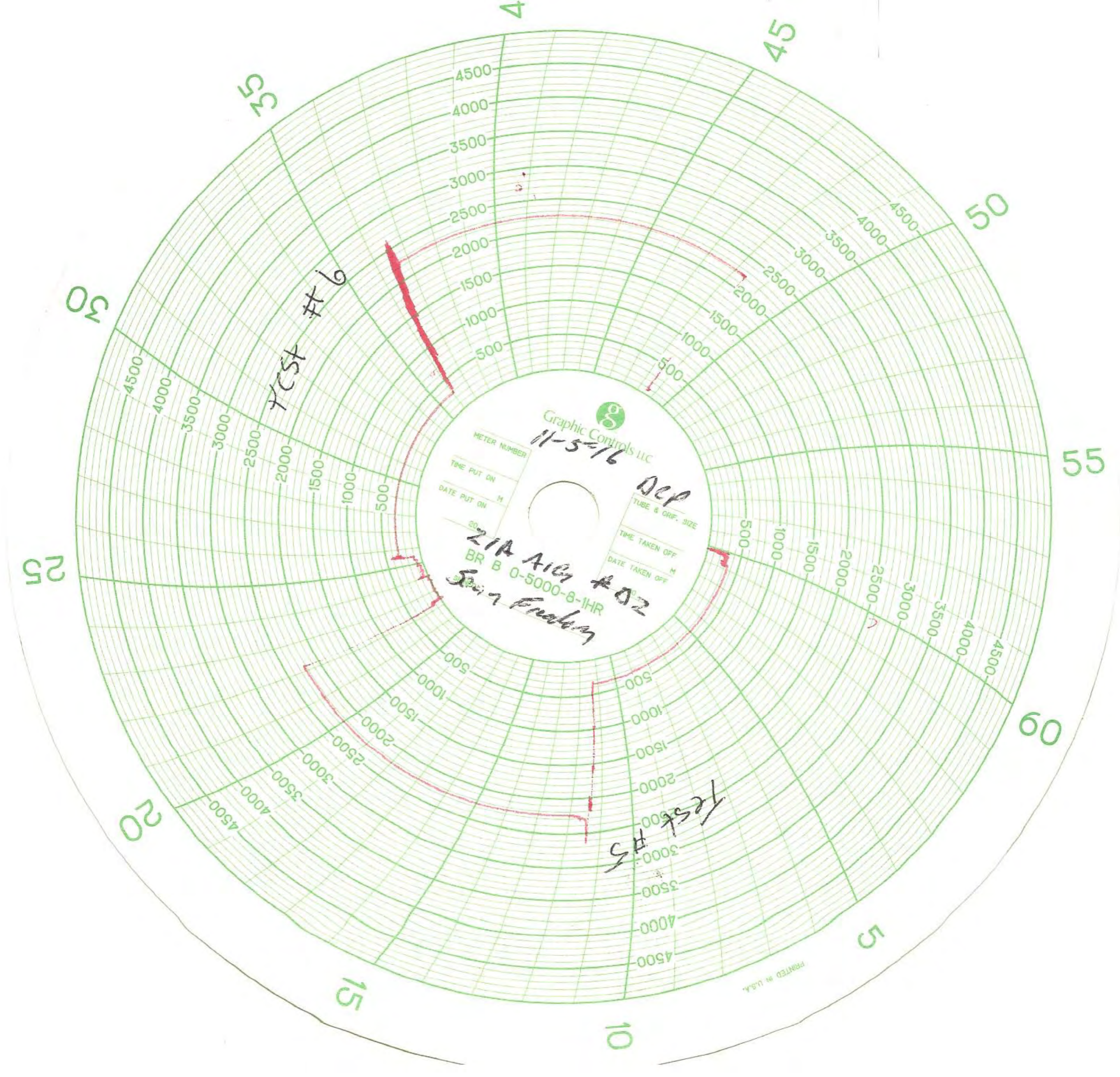
Test accepted by: [signature]

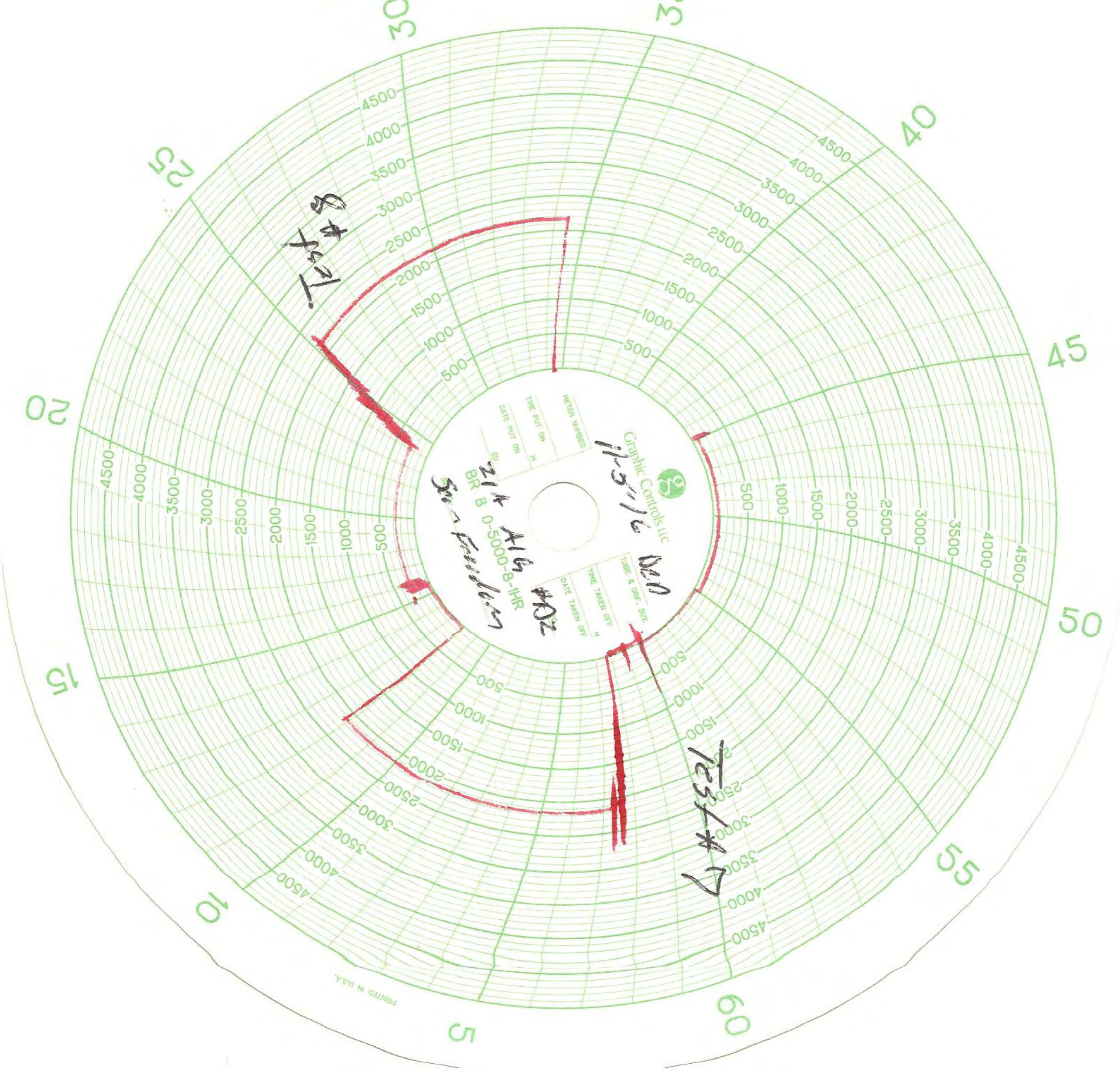

Graphic Controls LLC
METER NUMBER
TIME PUT ON
DATE PUT ON
TUBE & ORF. SIZE
TIME TAKEN OFF
DATE TAKEN OFF
BR B 0-5000-8-1HR
SIGNED
#2 Fail
OCP
Test #1
PRINTED IN U.S.A.

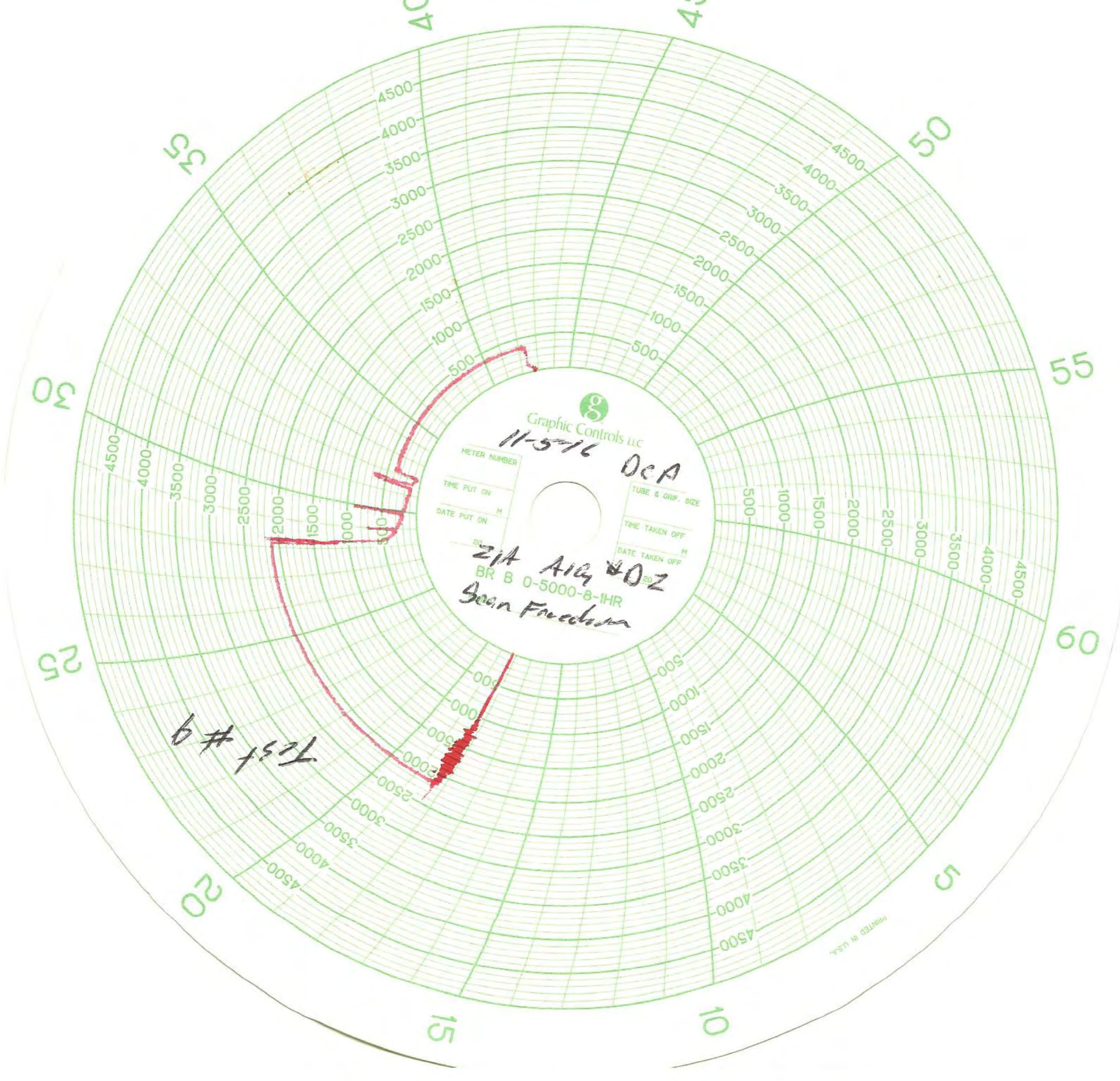

Graphic Controls LLC
METER NUMBER
TIME PUT ON
DATE PUT ON
TUBE & ORIF. SIZE
TIME TAKEN OFF
DATE TAKEN OFF
BR B 0-5000-8-1HR
11-5-16
OCP
ZIA AGI #02
PRINTED IN U.S.A.

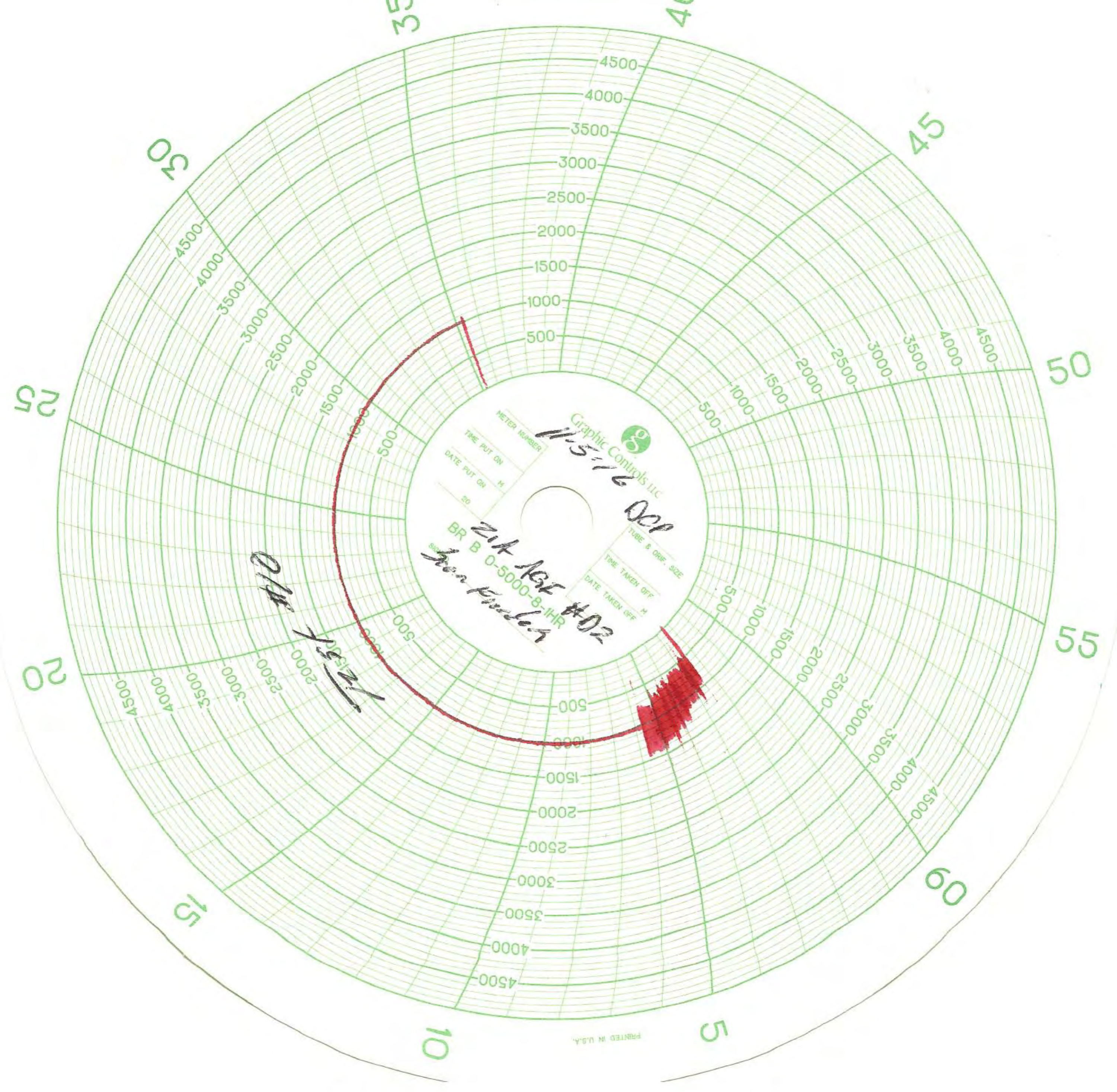

DCP Midstream
212 AGI #D2
Scan Freedom
10/7/10
Hydraulic IBOP Retest
#17 Retest
BR B 0-5000
PRINTED IN U.S.A.


Test #4
Graphic Controls LLC
11-5-16 OCD
21A AGI #02
BR B 0-5000-8-1HR
Test #3
PRINTED IN U.S.A.


Graphic Controls LLC
METER NUMBER
11-5-16
TIME PUT ON
DATE PUT ON
DCP
TUBE & ORIF. SIZE
TIME TAKEN OFF
DATE TAKEN OFF
BR B 0-5000-8-1HR
Test #6
Test #5
PRINTED IN U.S.A.


Graphic Controls LLC
METER NUMBER
TIME PUT ON
DATE PUT ON
TUBE & ORIF. SIZE
TIME TAKEN OFF
DATE TAKEN OFF
BR B 0-5000-8-1HR
PRINTED IN U.S.A.
Test #8
Test #7
11-5-16


Graphic Controls LLC
METER NUMBER
TIME PUT ON
DATE PUT ON
TUBE & ORIF. SIZE
TIME TAKEN OFF
DATE TAKEN OFF
BR B 0-5000-8-1HR
11-5-16
Test #9
PRINTED IN U.S.A.



Graphic Controls LLC
METER NUMBER
TIME PUT ON
DATE PUT ON
TUBE & ORIF. SIZE
TIME TAKEN OFF
DATE TAKEN OFF
BR B 0-5000-8-1HR
PRINTED IN U.S.A.

Second Intermediate and First Intermediate CIT Pressure Testing

BATTLE Energy Services

Test Chart Calibration

Date: 10-13-16

Calibrator: Neil Granath

Signature:

Battle Recorder Number: 4

Model: TechCal

Serial Number: 04314

Maximum Pressure Rating: 5,000 PSI

Certified Gauge Used: L34906

Accuracy of this recorder is +/- 0.5% of indicated range

BATTLE Energy Services

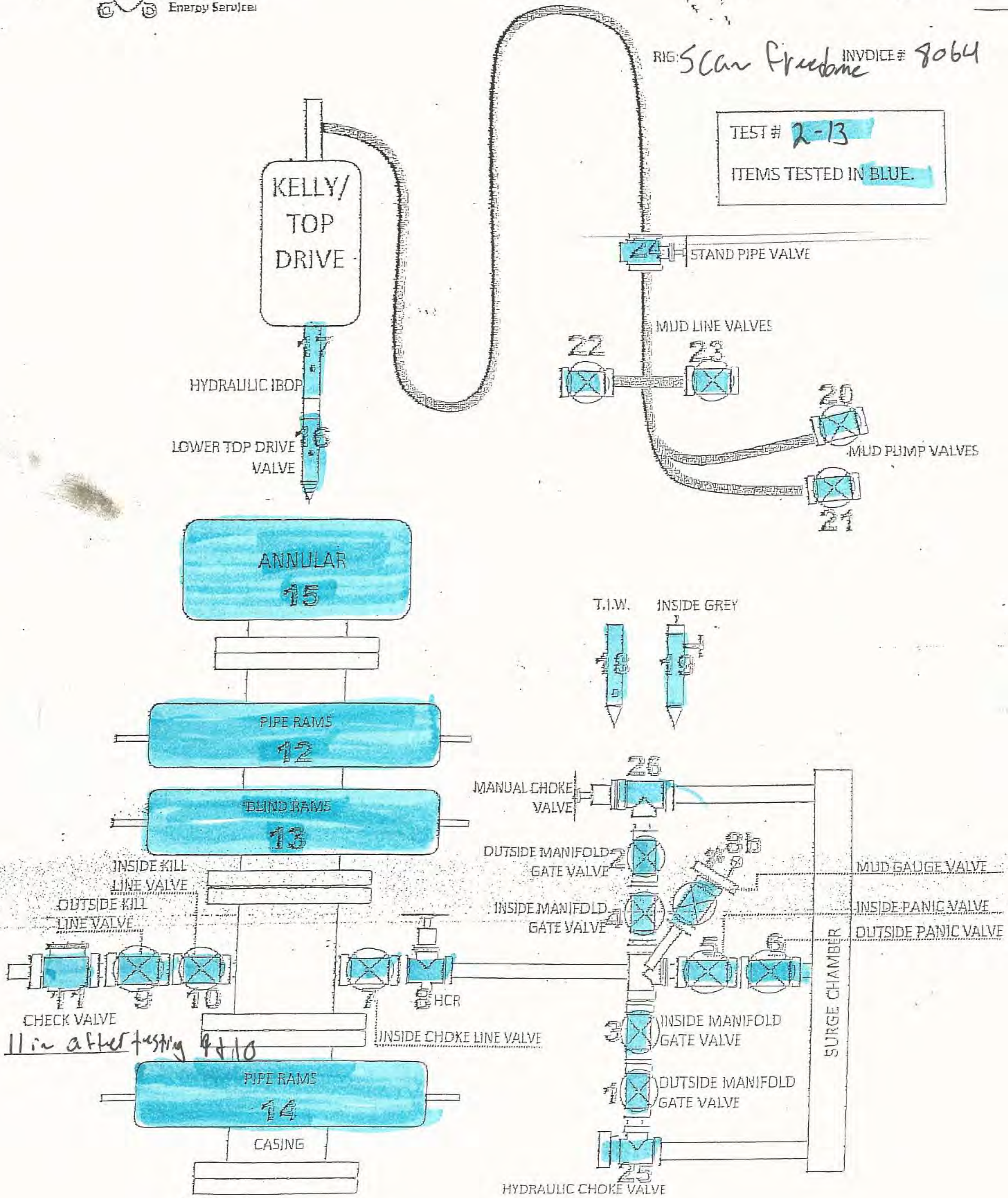
BOP Test Diagram

Date 11-10-16

RIG: Scan Freedome INVOICE # 8064

TEST # 2-13

ITEMS TESTED IN BLUE.



4 1/2 IF

DRILL PIPE & TYPE

13 5/8 C22

PLUG/CUP SIZE AND TYPE

BATTLE Energy Services

INVOICE

B 8064

DATE 11-10-16 START TIME 7:00 pm

COMPANY DCP Midstream COMPANY REP George Smith

LEASE Zia AGI #D2 STATE NM COUNTY Lea

DRILLING CONTRACTOR Scan Freedom TOOL PUSHER

TESTER Art Castro / Michael Petty

TESTING DETAILS

Test Pressures		Test Equipment	
BOP	2,000	Test Plug	13 5/8 C-22
Annular	2,000	Drill Pipe Size	4 1/2 IF
Casing	1,000	Crossovers	n/A
Pumps	2,000		
Manifold	2,000		

TESTING DESCRIPTION

13 5/8 C-22 2,000 PSI Test. All test good ✓

* 15 min safety meeting w/ Rig Crews

Tester	10	Hours @	$110	=	$1100
Additional	n/A	Hours @		=	
Mileage	100	Miles @		=	
Methanol	n/A	@		=	
O-Rings	1	@	50	=	50
Cup Test	n/A	@		=	
		@		=	
		@		=	
		@		=	
				Sub Total	$1,150
				Tax	$65.25
				TOTAL	$1,215.25

G. Smith

PO BOX 7 • LOVINGTON, NM 88260 • 575.942.9472 • battleenergy@gmail.com

BATTLE Energy Services

PO Box 7
Lovington, NM 88260
(575) 224-2345 (575) 942-9472

Company DCP Midstream Date 11-10-16

Lease Z19 A Bl #D2 County Lea County

Drilling Contractor Sam Freedom Plug & Drill Pipe Size 4 1/2 IC ; 13 C 22

Accumulator Function Test - OO&GO#2

To Check - USABLE FLUID IN THE NITROGEN BOTTLES (III.A.2.c.i. or ii or iii)

- Make sure all rams and annular are open and if applicable HCR is closed.
- Ensure accumulator is pumped up to working pressure! **(Shut off all pumps)**

1. Open HCR Valve. (If applicable)
2. Close annular.
3. Close **all** pipe rams.
4. Open one set of the pipe rams to simulate closing the blind ram.
5. For 3 ram stacks, open the annular to achieve the 50+ % safety factor. (5M and greater systems).
6. **Record remaining pressure** 2900 **psi. Test Fails if pressure is lower than required.**

- **a.**{**950** psi for a 1500 psi system} **b.** {**1200** psi for a 2000 & 3000 psi system }

7. If annular is closed, open it at this time and close HCR.

To Check - PRECHARGE ON BOTTLES OR SPHERICAL (III.A.2.d.)

- Start with manifold pressure at, or above, maximum acceptable pre-charge pressure:
  a. {**800** psi for a 1500 psi system} **b.** {**1100** psi for 2000 and 3000 psi system}

1. Open bleed line to the tank, slowly. **(gauge needle will drop at the lowest bottle pressure)**
2. Close bleed line. Barely bump electric pump and see what pressure the needle jumps up to.
3. **Record pressure drop** 1050 **psi. Test fails if pressure drops below minimum.**

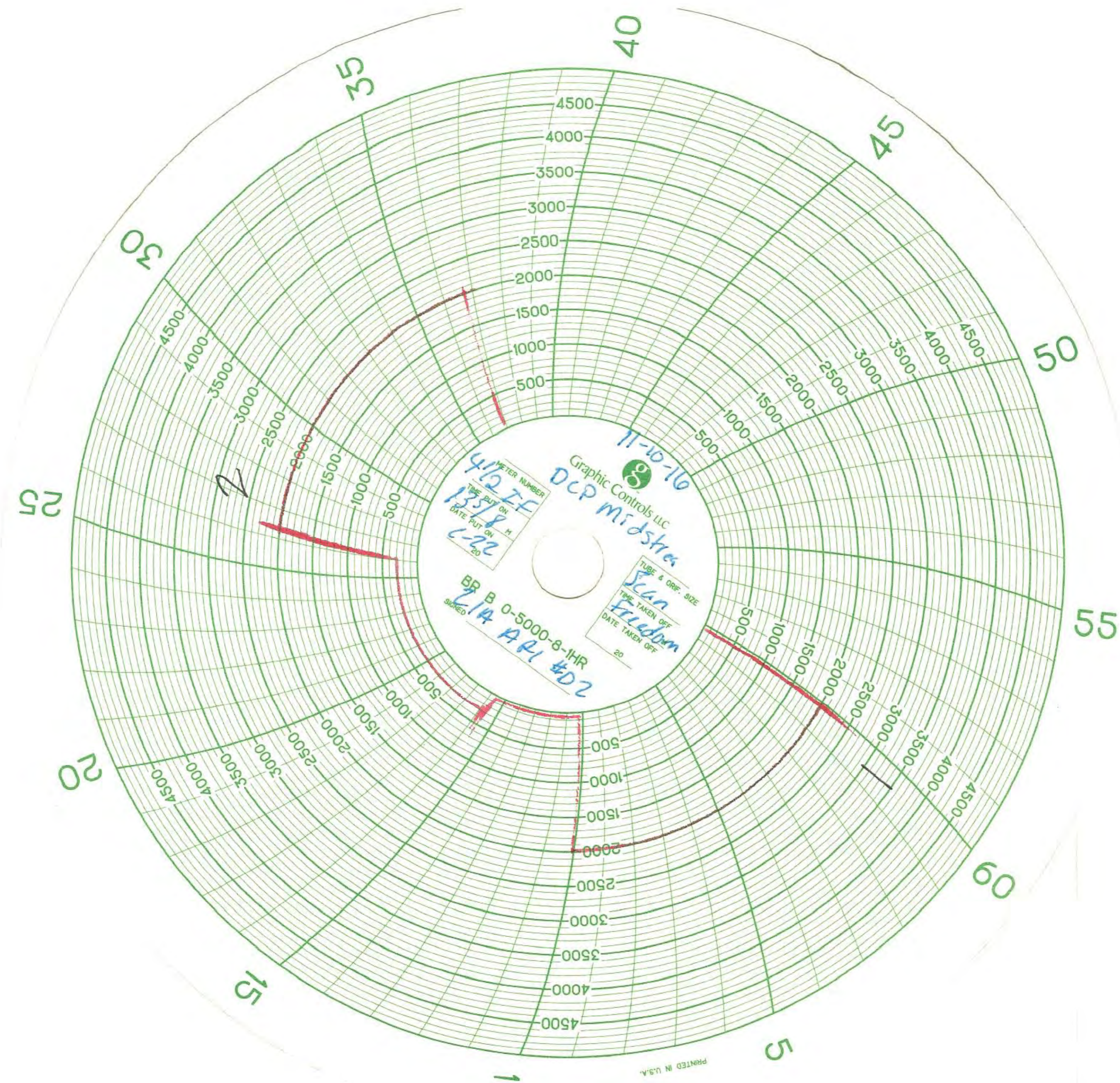
- **Minimum: a.**{**700** psi for a 1500 psi system } b. {**900** psi for a 2000 & 3000 psi system}

To Check - THE CAPACITY OF THE ACCUMULATOR PUMPS (III.A.2.f.)

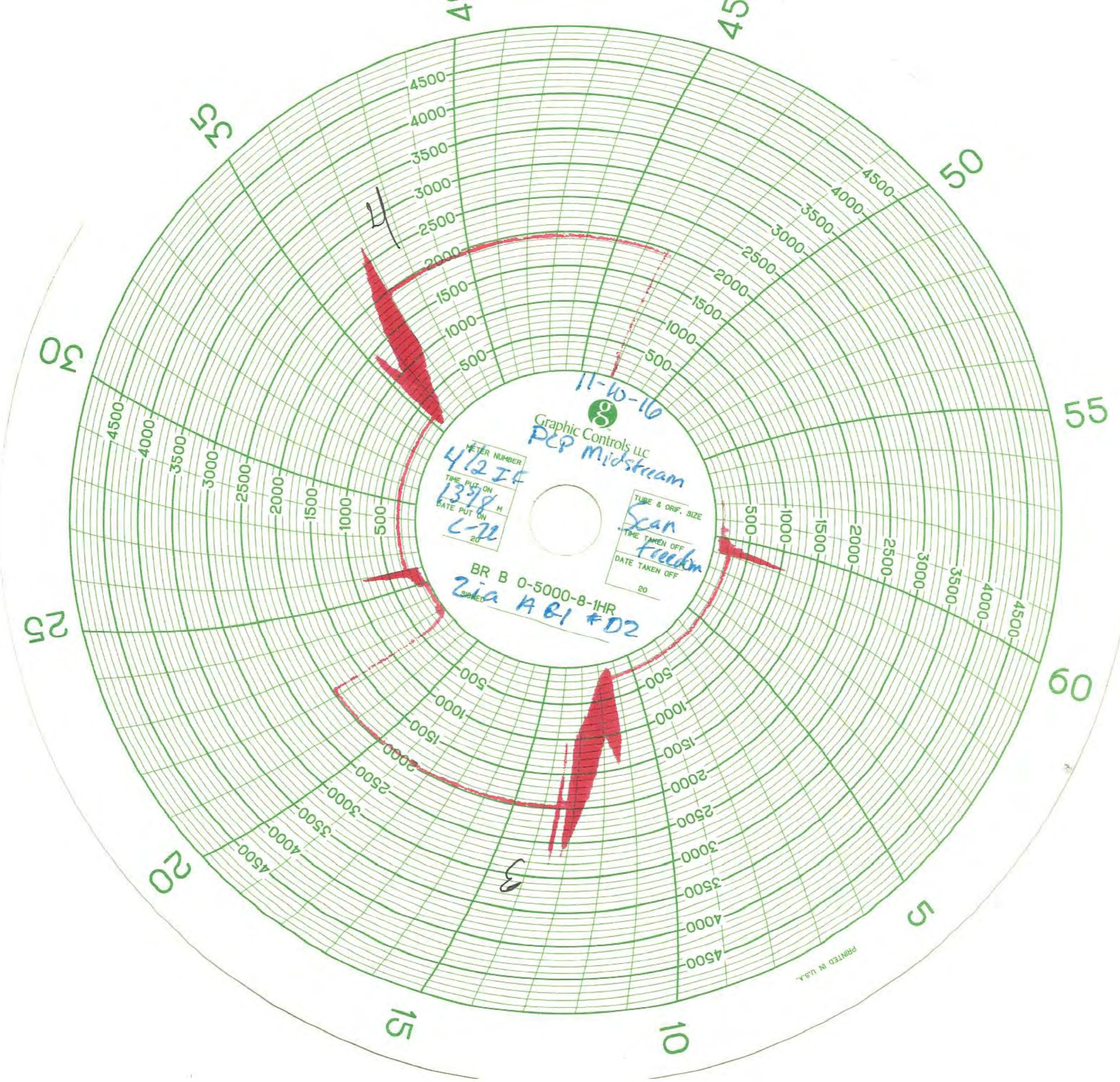
- Isolate the accumulator bottles or spherical from the pumps & manifold.
- Open the bleed off valve to the tank, {manifold psi should go to 0 psi} close bleed valve.

1. Open the HCR valve, {if applicable}
2. Close annular
3. With **pumps** only, time how long it takes to regain the required manifold pressure.
4. **Record elapsed time** 40 sec**. Test fails if it takes over 2 minutes.**

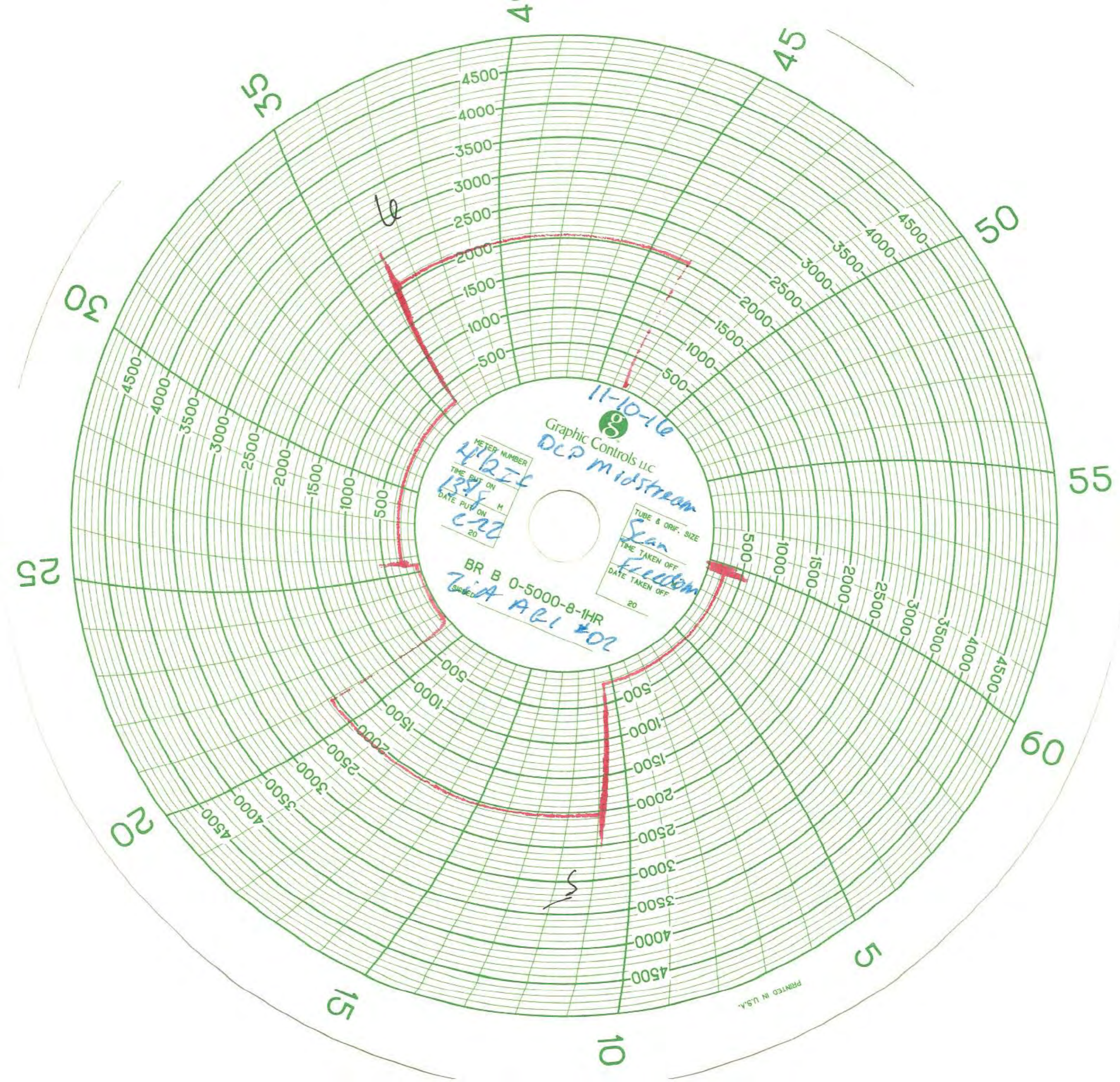
- **a.** {**950** psi for a 1500 psi system} **b.** {**1200** psi for a 2000 & 3000 psi system)



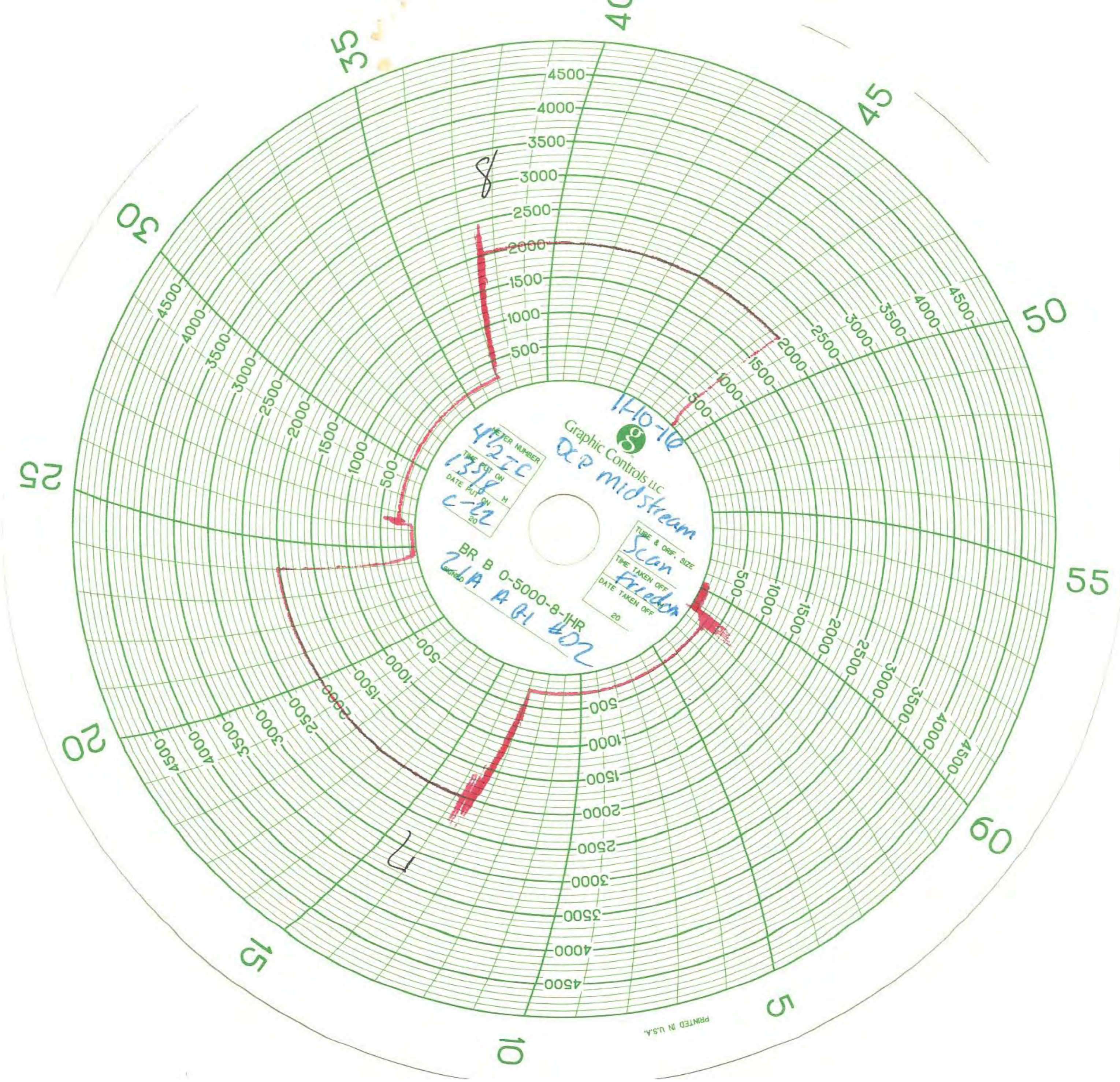
Graphic Controls LLC
BR B 0-5000-8-1HR
METER NUMBER
412 IF
TIME PUT ON
1351 8 M
DATE PUT ON
6-22 20
TUBE & ORF. SIZE
Scan
TIME TAKEN OFF
Freedom
DATE TAKEN OFF
20
SIGNED
214 API #02
DCP Midstrea
11-10-16
PRINTED IN U.S.A.

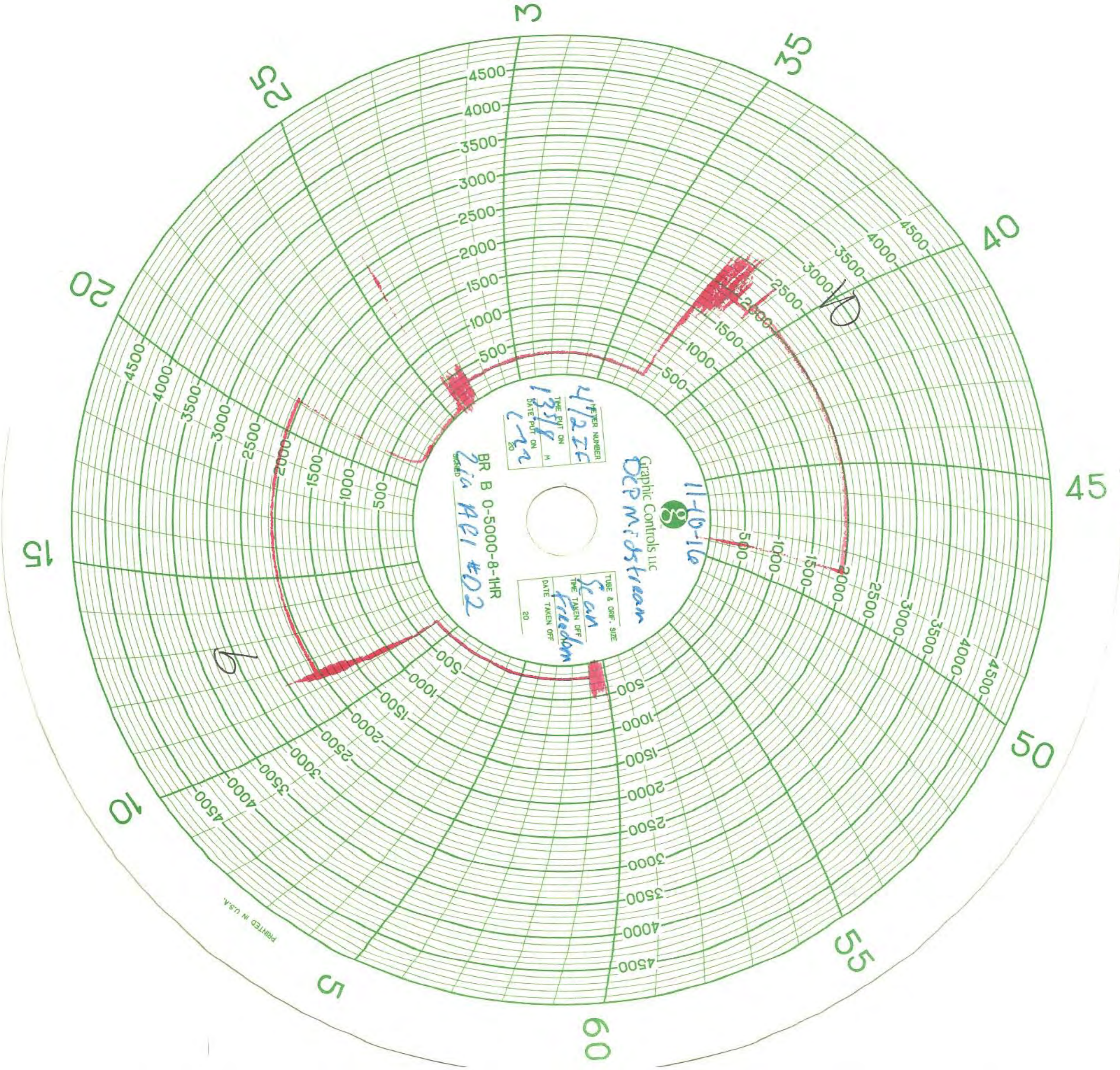


11-10-16
Graphic Controls LLC
PCP Midstream
METER NUMBER
TIME PUT ON
1398
M
DATE PUT ON
20
TUBE & ORIF. SIZE
Scan
TIME TAKEN OFF
Freedom
DATE TAKEN OFF
20
BR B 0-5000-8-1HR
SIGNED
PRINTED IN U.S.A.

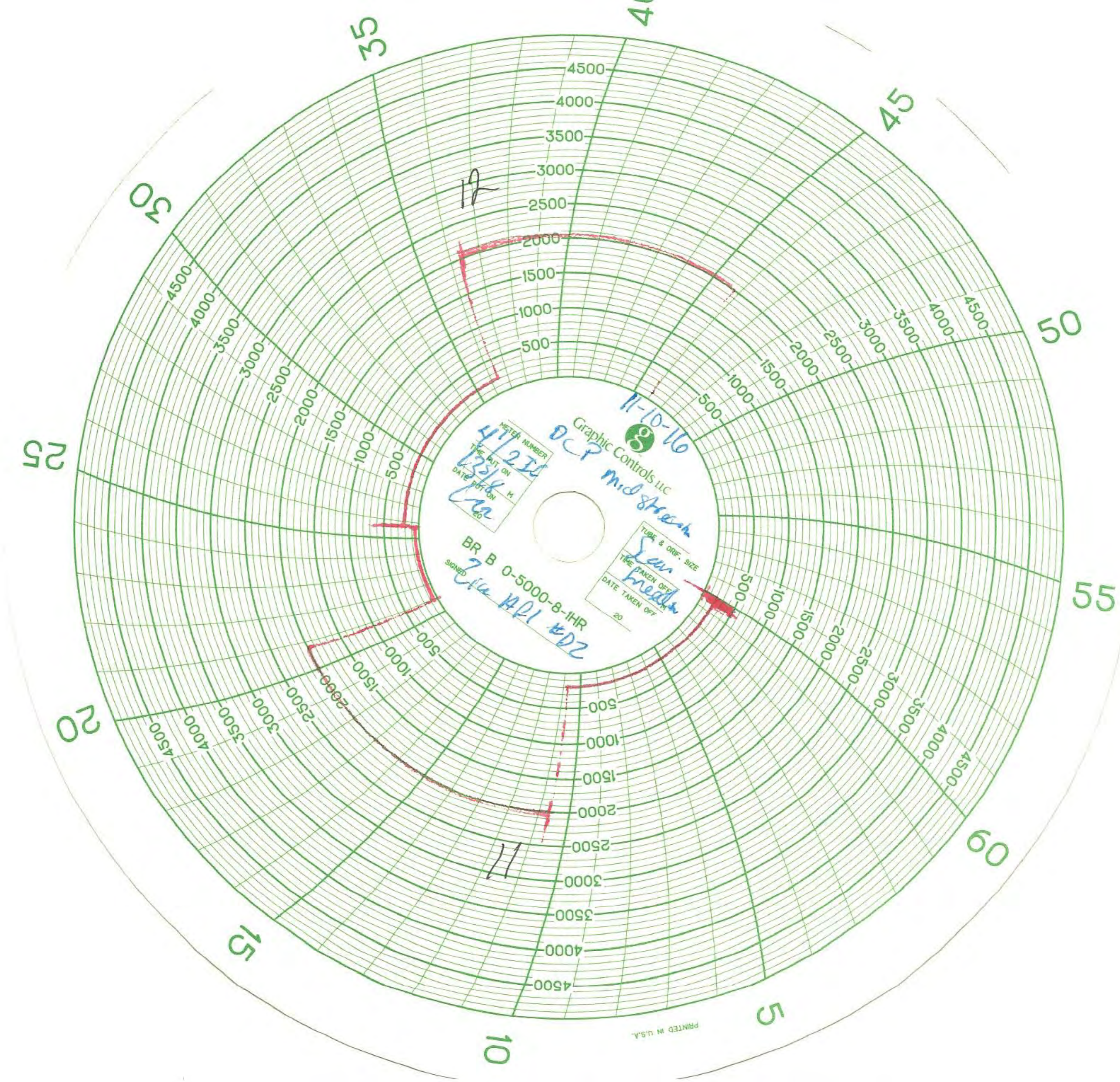


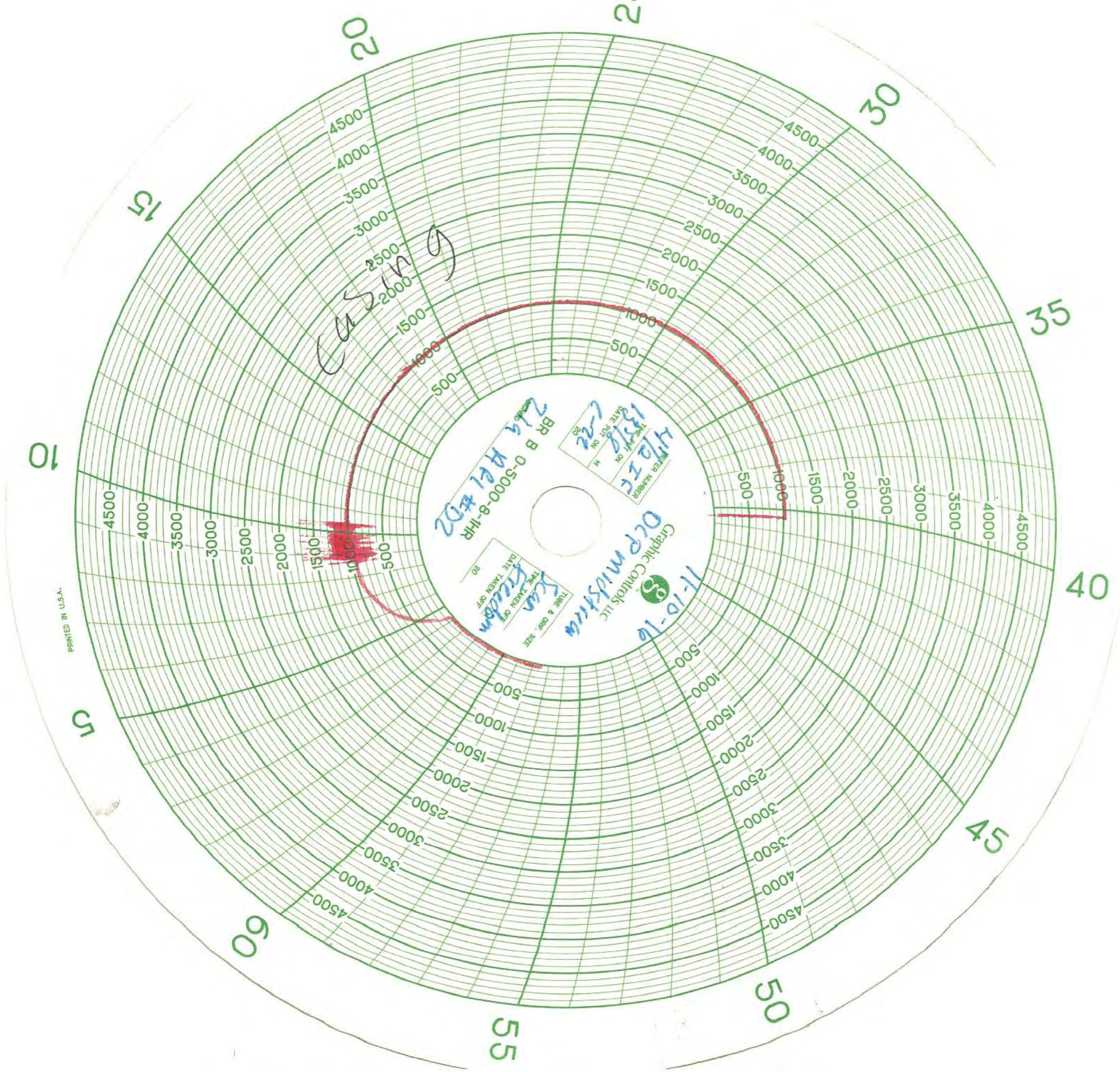
Graphic Controls LLC
METER NUMBER
TIME PUT ON
DATE PUT ON
TUBE & ORIF. SIZE
TIME TAKEN OFF
DATE TAKEN OFF
BR B 0-5000-8-1HR
SIGNED
11-10-16
DCP Midstream
Zia AGI #02
PRINTED IN U.S.A.


Graphic Controls LLC
METER NUMBER
TIME PUT ON
DATE PUT ON
20
TUBE & ORIF. SIZE
TIME TAKEN OFF
DATE TAKEN OFF
20
BR B 0-5000-8-1HR
SIGNED
PRINTED IN U.S.A.
11-10-16
OCP midstream
1318
Scan
Freedom



Graphic Controls LLC
METER NUMBER
TIME PUT ON
DATE PUT ON
TUBE & ORIF. SIZE
TIME TAKEN OFF
DATE TAKEN OFF
BR B 0-5000-8-1HR
11-10-16
DCP Midstream
Zia AGI #02
PRINTED IN U.S.A.


Graphic Controls LLC
BR B 0-5000-8-1HR
METER NUMBER
TIME PUT ON
DATE PUT ON
TUBE & ORIF. SIZE
TIME TAKEN OFF
DATE TAKEN OFF
SIGNED
11-10-16
OCP Midstream
PRINTED IN U.S.A.



Casing
Graphic Controls LLC
BR B 0-5000-8-1HR
OCP midstream
PRINTED IN U.S.A.

Production Casing, Second Intermediate CIT, and FIT Pressure Testing

Test Chart Calibration

Date: 10-13-16

Calibrator: Neil Granath

Signature:

Battle Recorder Number: 3

Model: TechCal

Serial Number: 03457

Maximum Pressure Rating: 5,000 PSI

Certified Gauge Used: L34906

Accuracy of this recorder is +/- 0.5% of indicated range

BATTLE Energy Services

PO Box 7
Lovington, NM 88260
(575) 224-2345 (575) 942-9472

Company DCP Midstream Date 12-5-16

Lease Zia A01 #D2 County Lea NM

Drilling Contractor Scan Freedom Plug & Drill Pipe Size 7"-TC 1XT39

Accumulator Function Test - OO&GO#2

To Check - USABLE FLUID IN THE NITROGEN BOTTLES (III.A.2.c.i. or ii or iii)

- Make sure all rams and annular are open and if applicable HCR is closed.
- Ensure accumulator is pumped up to working pressure! **(Shut off all pumps)**

1. Open HCR Valve. (If applicable)
2. Close annular.
3. Close **all** pipe rams.
4. Open one set of the pipe rams to simulate closing the blind ram.
5. For 3 ram stacks, open the annular to achieve the 50+ % safety factor. (5M and greater systems).
6. **Record remaining pressure** 2900 **psi. Test Fails if pressure is lower than required.**
   - **a.** {**950** psi for a 1500 psi system} **b.** {**1200** psi for a 2000 & 3000 psi system }
7. If annular is closed, open it at this time and close HCR.

To Check - PRECHARGE ON BOTTLES OR SPHERICAL (III.A.2.d.)

- Start with manifold pressure at, or above, maximum acceptable pre-charge pressure:
  a. {**800** psi for a 1500 psi system} **b.** {**1100** psi for 2000 and 3000 psi system}

1. Open bleed line to the tank, slowly. **(gauge needle will drop at the lowest bottle pressure)**
2. Close bleed line. Barely bump electric pump and see what pressure the needle jumps up to.
3. **Record pressure drop** 1080 **psi. Test fails if pressure drops below minimum.**

- **Minimum: a.**{**700** psi for a 1500 psi system } b. {**900** psi for a 2000 & 3000 psi system}

To Check - THE CAPACITY OF THE ACCUMULATOR PUMPS (III.A.2.f.)

- Isolate the accumulator bottles or spherical from the pumps & manifold.
- Open the bleed off valve to the tank, {manifold psi should go to 0 psi} close bleed valve.

1. Open the HCR valve, {if applicable}
2. Close annular
3. With **pumps** only, time how long it takes to regain the required manifold pressure.
4. **Record elapsed time** 40 sec**. Test fails if it takes over 2 minutes.**
   - **a.** {**950** psi for a 1500 psi system} **b.** {**1200** psi for a 2000 & 3000 psi system)

MASTER PRINTERS 575.396.3661

Battle Energy Services

BOP TEST FORM

COMPANY DCP Midstream DATE 12-5-16

LEASE Zia AGI # D2 STATE NM COUNTY Lea

DRILLING CONTRACTOR Scan Freedom TESTER

TESTING DETAILS

Test Pressures		Test Equipment	
BOP		Test Plug	7" C-22
Annular		Drill Pipe Size	XT 39
Casing	n/A per company man	Crossovers	n/A
Pumps			
Manifold			

TEST #	ITEMS TESTED	LOW TEST PSI	LOW TEST MIN.	HIGH TEST PSI	HIGH TEST MIN.	REMARKS
1	Truck				10	testing equipment
2	13, 3, 5, 4, 10	250	10	5,000	10	✓
	12, 0, 1, 6, 2, 8b	250	10	5K	10	✓
	12, 9, 25, 6, 26	——	——	5,000		bumptest * super chokes ✓
5	12, 8, 9	250	10	5K	10	✓
6	12, 7, 11	250	10	5K	10	✓
7	14	250	10	5K	10	✓
8	15, 8, 11	250	10	2500	10	* Hydril
9	16	250	10	5K	10	✓
10	17	250	10	5K	10	✓
11	18	250	10	5K	10	✓
12	19	250	10	5K	10	✓
13	20, 21, 22, 23	250	10	5K	10	* vibrating hose leak (replaced
14	24	250	10	5K	10	by rig crew)

TEST ACCEPTED BY [signature]

PO BOX 7 • LOVINGTON, NM 88260 • 575.942.9472 • battleenergy@gmail.com

BATTLE Energy Services

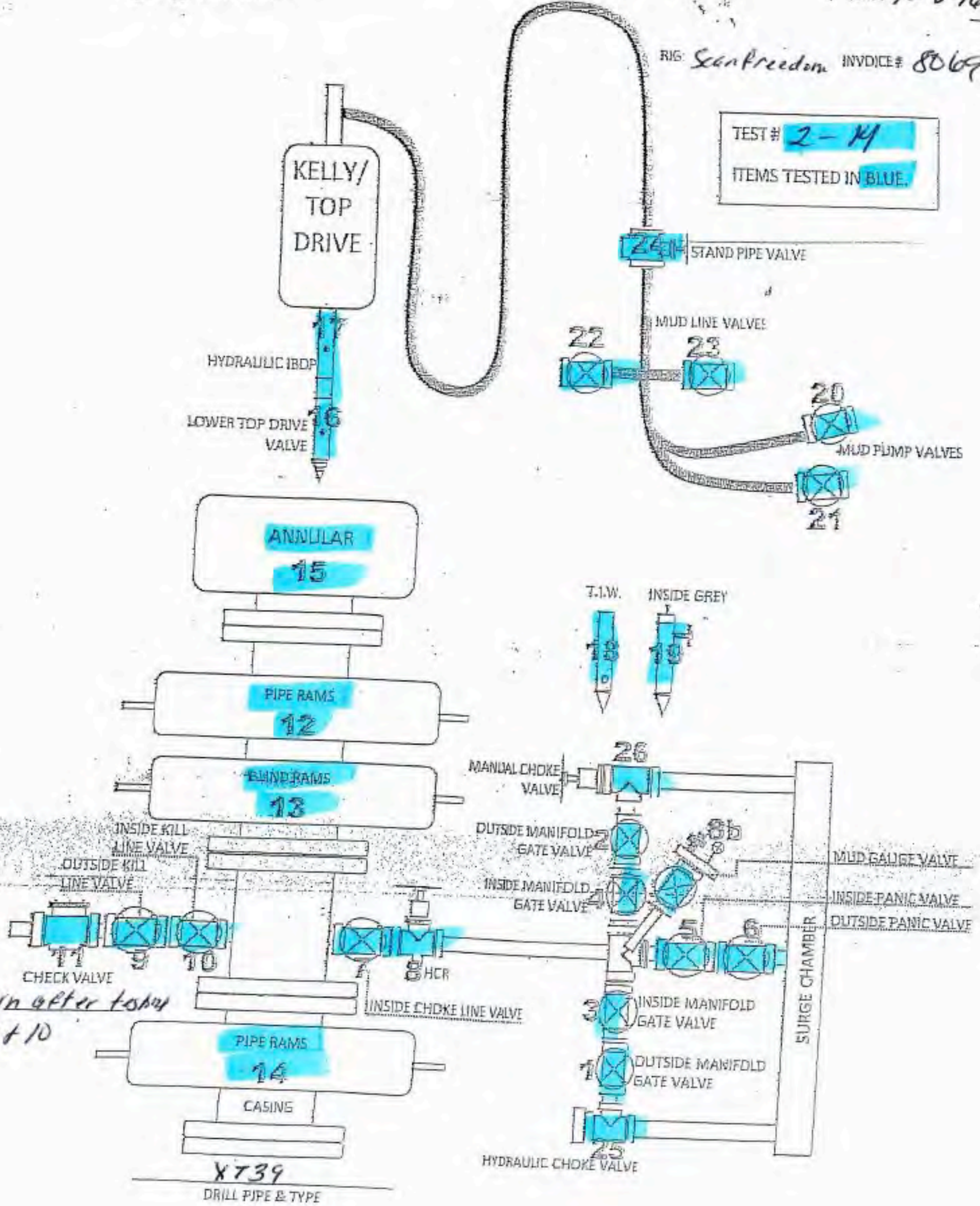
BOP Test Diagram

Date 12-5-16

RIG: Scanfreedom INVOICE# 8069

TEST # 2 - 14

ITEMS TESTED IN BLUE.



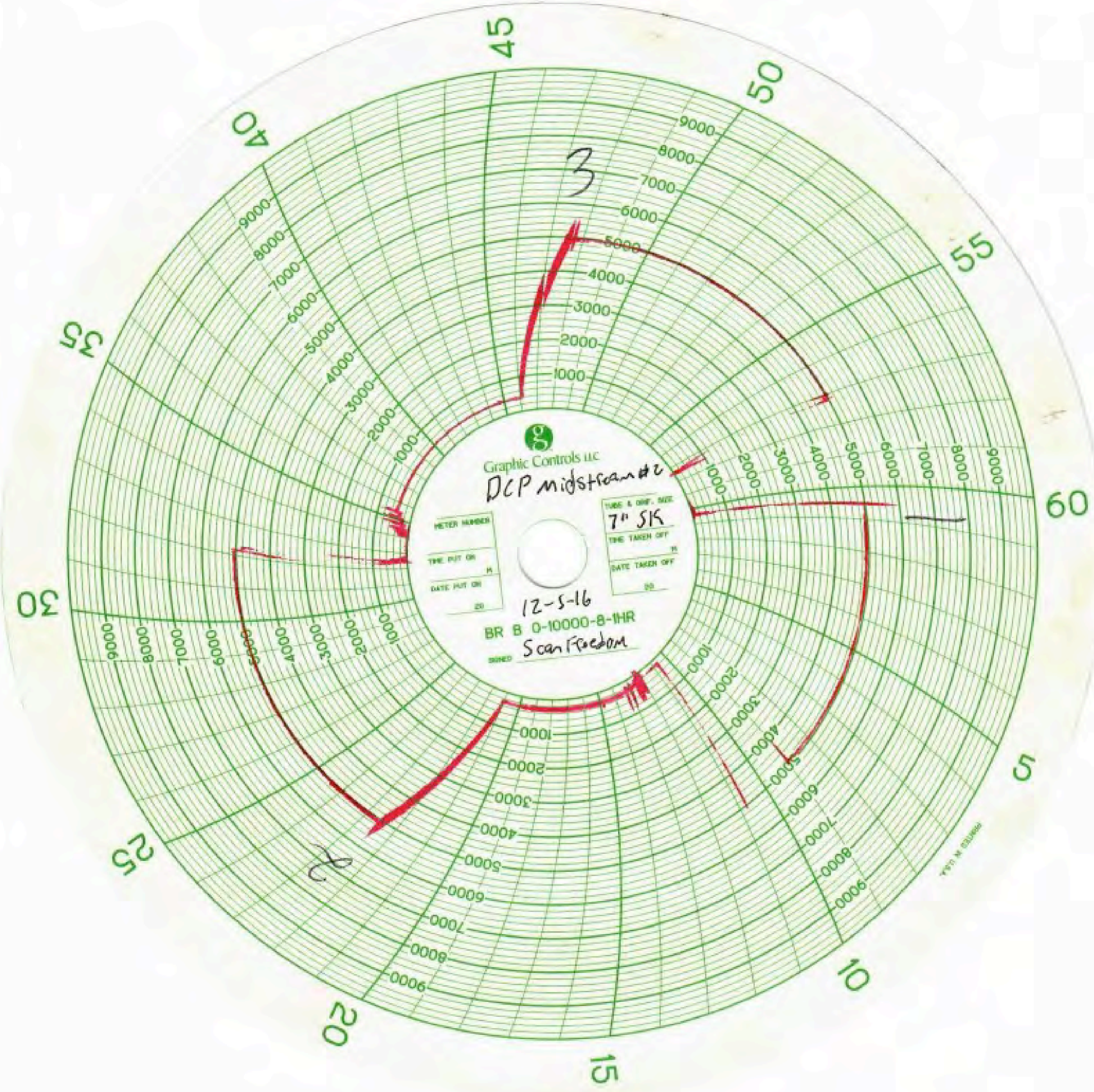
11 in after today 9 + 10

XT39

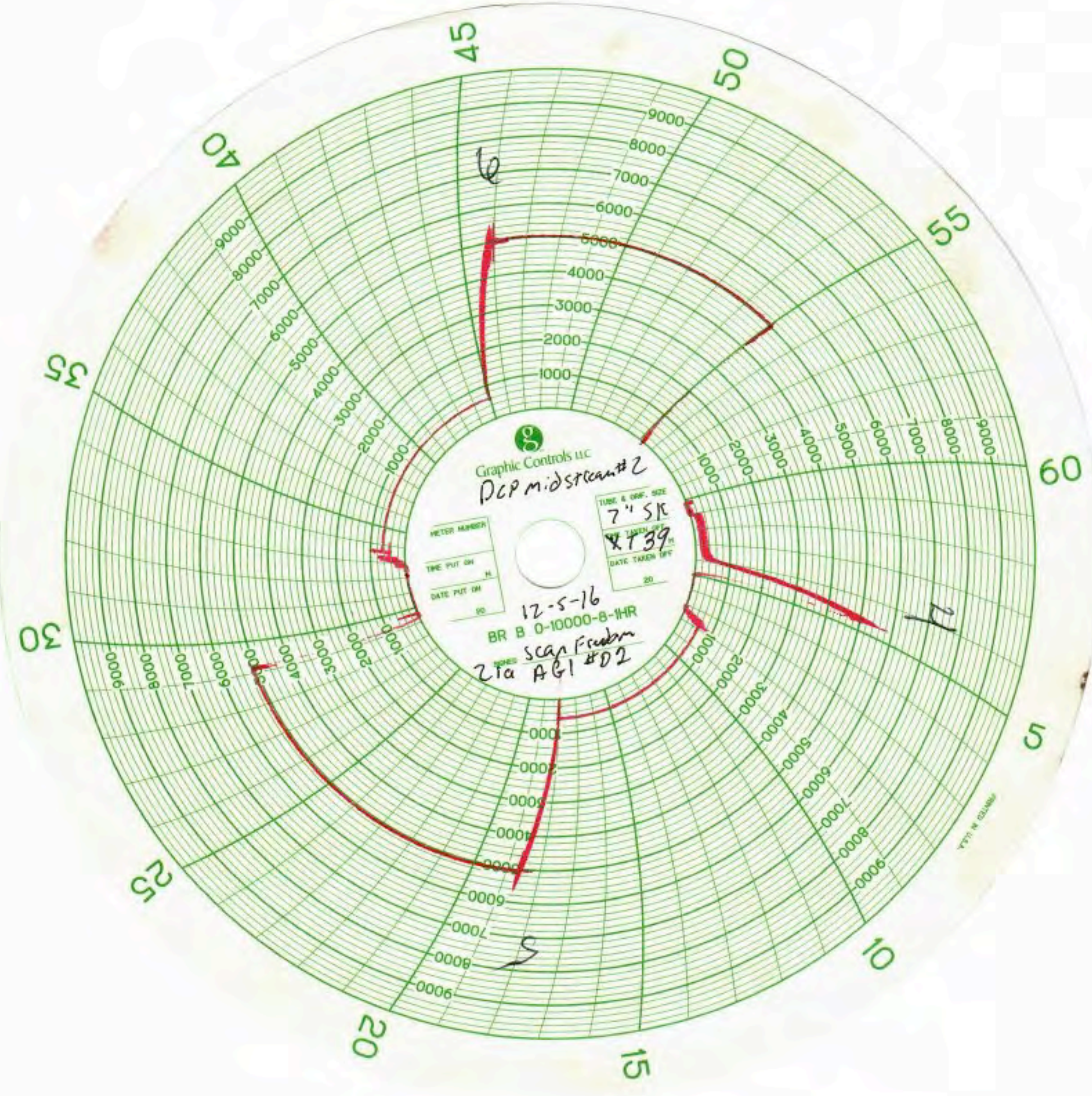
DRILL PIPE & TYPE

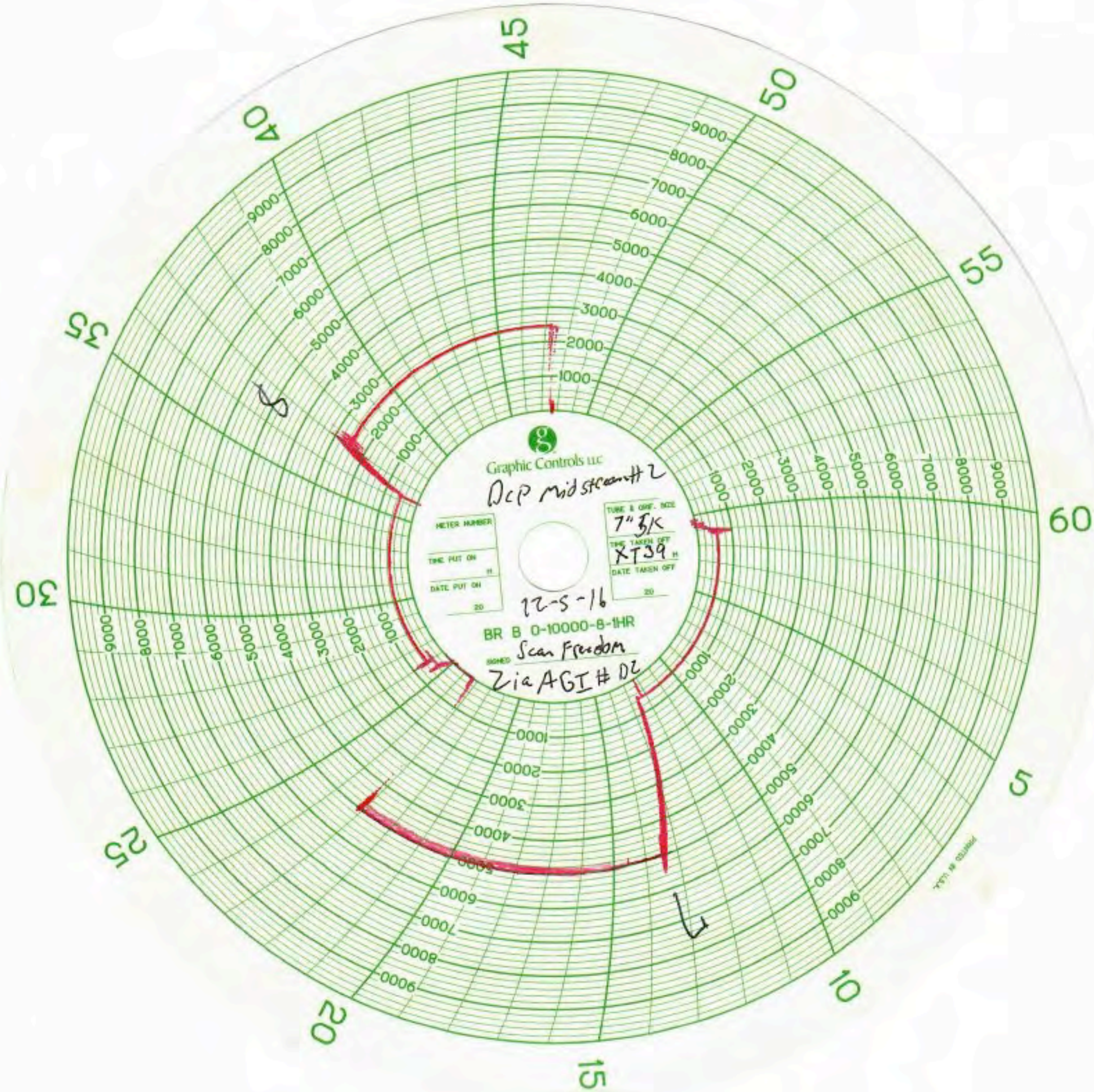
7" K-22

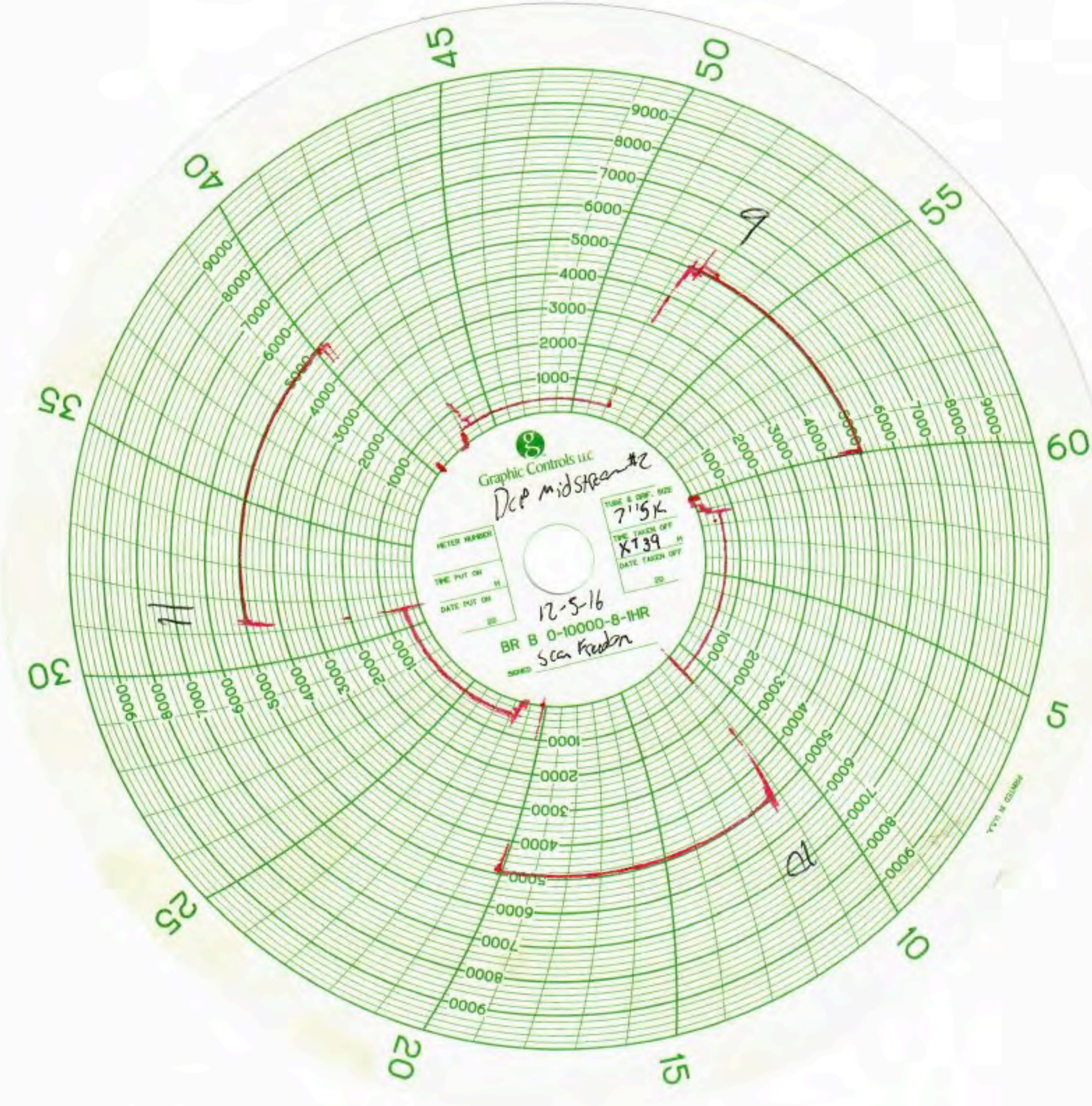
PLUG/CUP SIZE AND TYPE



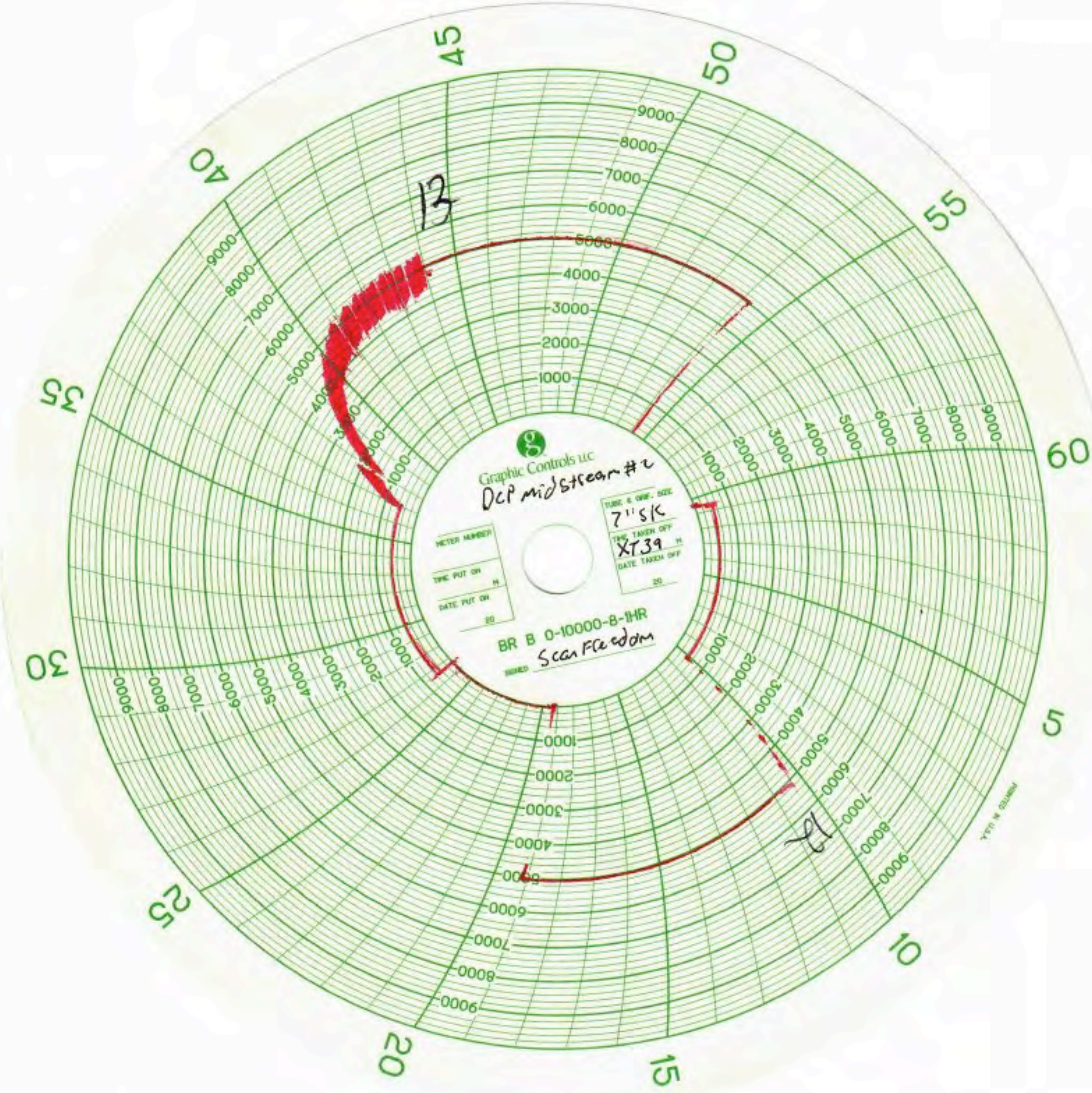
Graphic Controls LLC
DCP midstream #2
METER NUMBER
TUBE & ORIF. SIZE
7" SK
TIME PUT ON
DATE PUT ON
TIME TAKEN OFF
DATE TAKEN OFF
12-5-16
BR B 0-10000-8-1HR
SIGNED Scan Freedom
3


Graphic Controls LLC
DCP midstream #2
TUBE & ORIF. SIZE
METER NUMBER
TIME PUT ON
DATE PUT ON
DATE TAKEN OFF
12-5-16
BR B 0-10000-8-1HR
AGI #D2

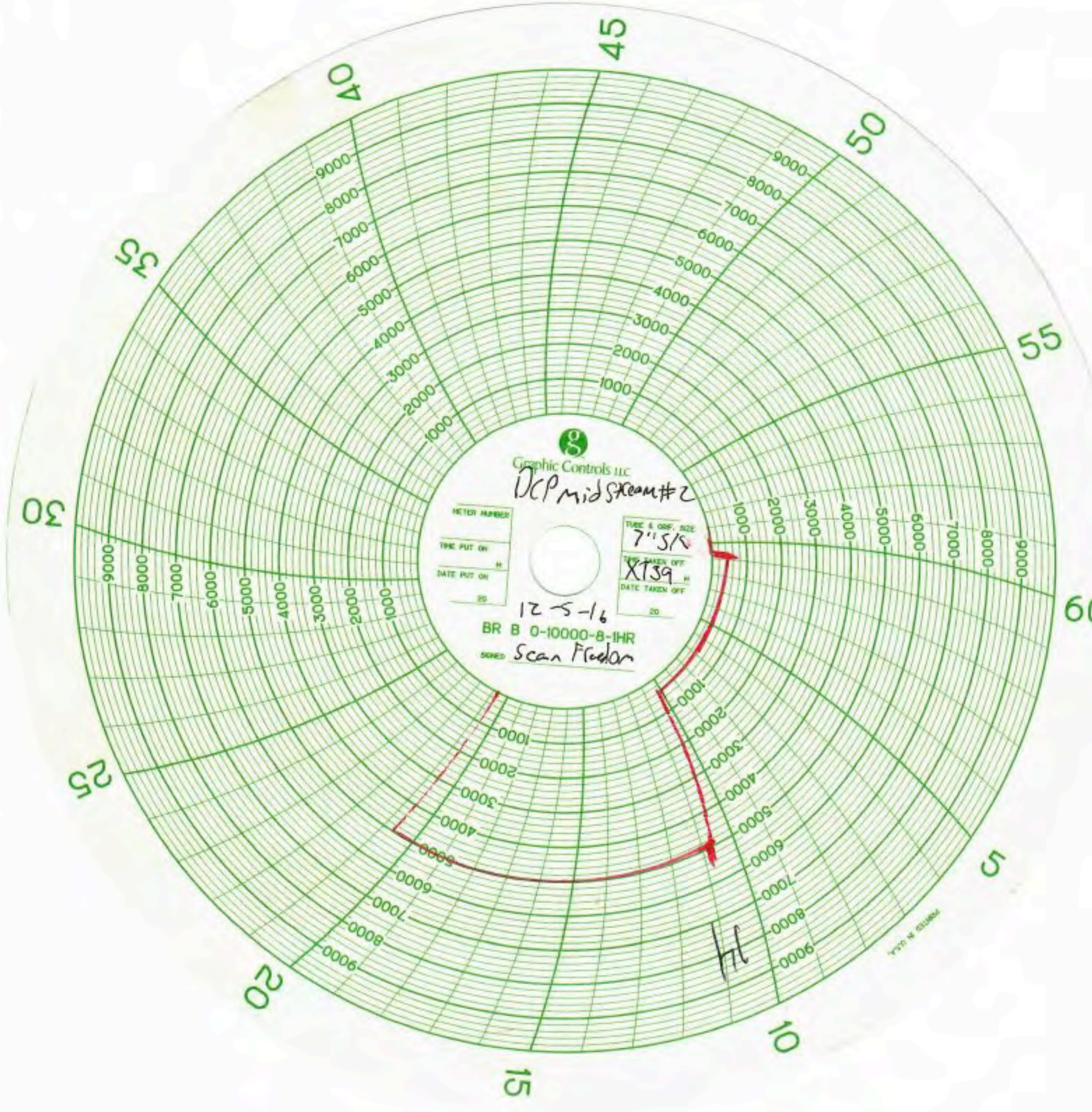

Graphic Controls LLC
Dcp Midstream #2
METER NUMBER
TIME PUT ON
DATE PUT ON
TUBE & ORIF. SIZE
7"
TIME TAKEN OFF
DATE TAKEN OFF
12-5-16
BR B 0-10000-8-1HR
SIGNED
Sean Freedom
Zia AGI # D2



Graphic Controls LLC
DCP Midstream #2
TUBE & ORIF. SIZE
7''5K
TIME TAKEN OFF
X139
M
DATE TAKEN OFF
20
METER NUMBER
TIME PUT ON
M
DATE PUT ON
20
12-5-16
BR B 0-10000-8-1HR
SIGNED
45
50
55
60
5
10
15
20
25
30
35
40



Graphic Controls LLC
DCP Midstream #2
TUBE & ORIF. SIZE
7" S/K
TIME TAKEN OFF
XT39
DATE TAKEN OFF
METER NUMBER
TIME PUT ON
DATE PUT ON
BR B 0-10000-8-1HR
SIGNED Scan Freedom
13



Graphic Controls LLC
DCP Midstream #2
METER NUMBER
TIME PUT ON
DATE PUT ON
TUBE & ORF. SIZE
TIME TAKEN OFF
DATE TAKEN OFF
12-5-16
BR B 0-10000-8-1HR
SIGNED

BATTLE Energy Services

BOP TEST FORM

COMPANY DCP Midstream DATE 12/9/16

LEASE 21a AGI #D2 STATE NM COUNTY Lea

DRILLING CONTRACTOR Scan Freedom TESTER Josh

TESTING DETAILS

Test Pressures

BOP n/a

Annular n/a

Casing 1000psi

Pumps n/a

Manifold n/a

Test Equipment

Test Plug n/a

Drill Pipe Size XT39

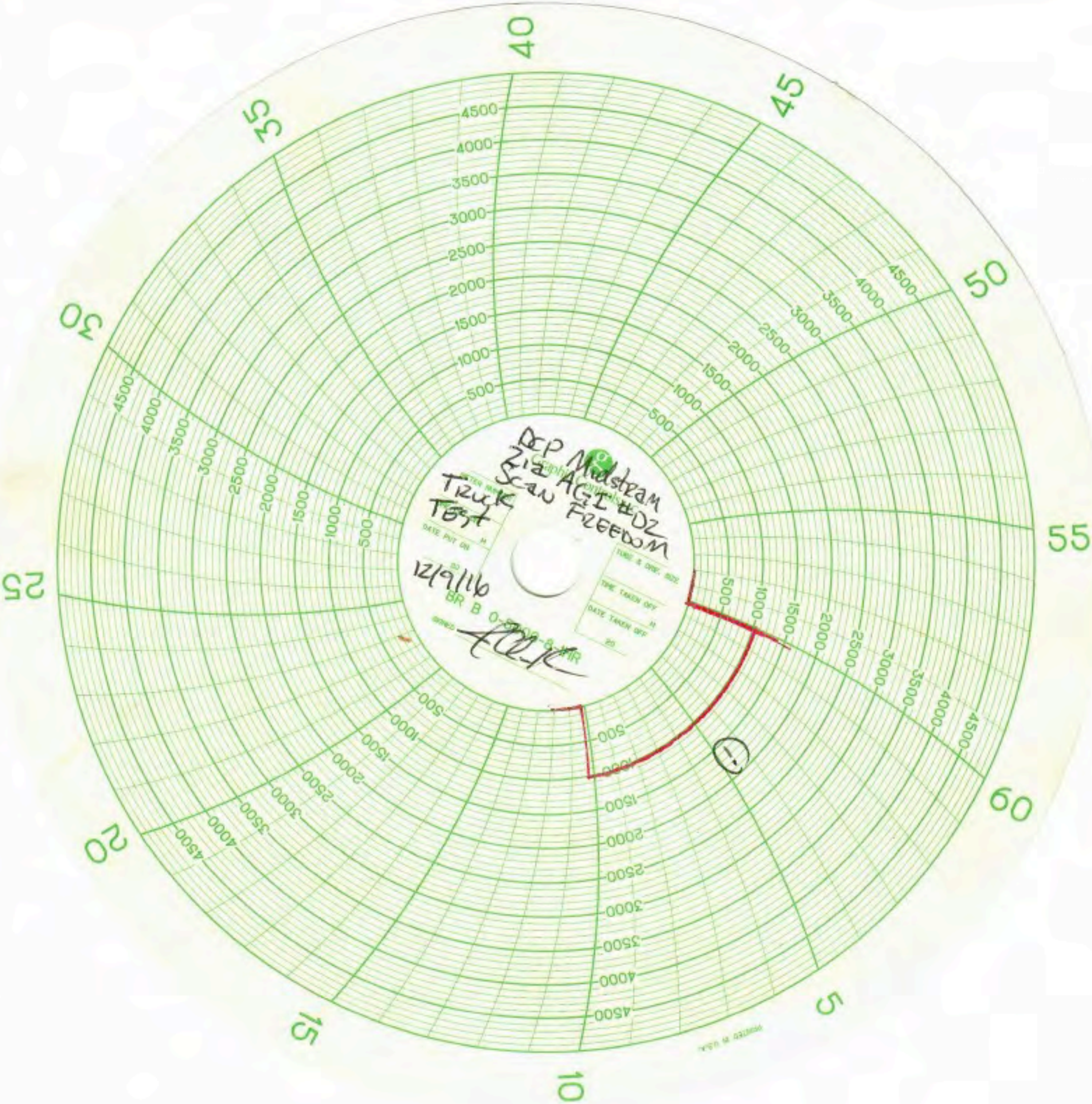
Crossovers n/a

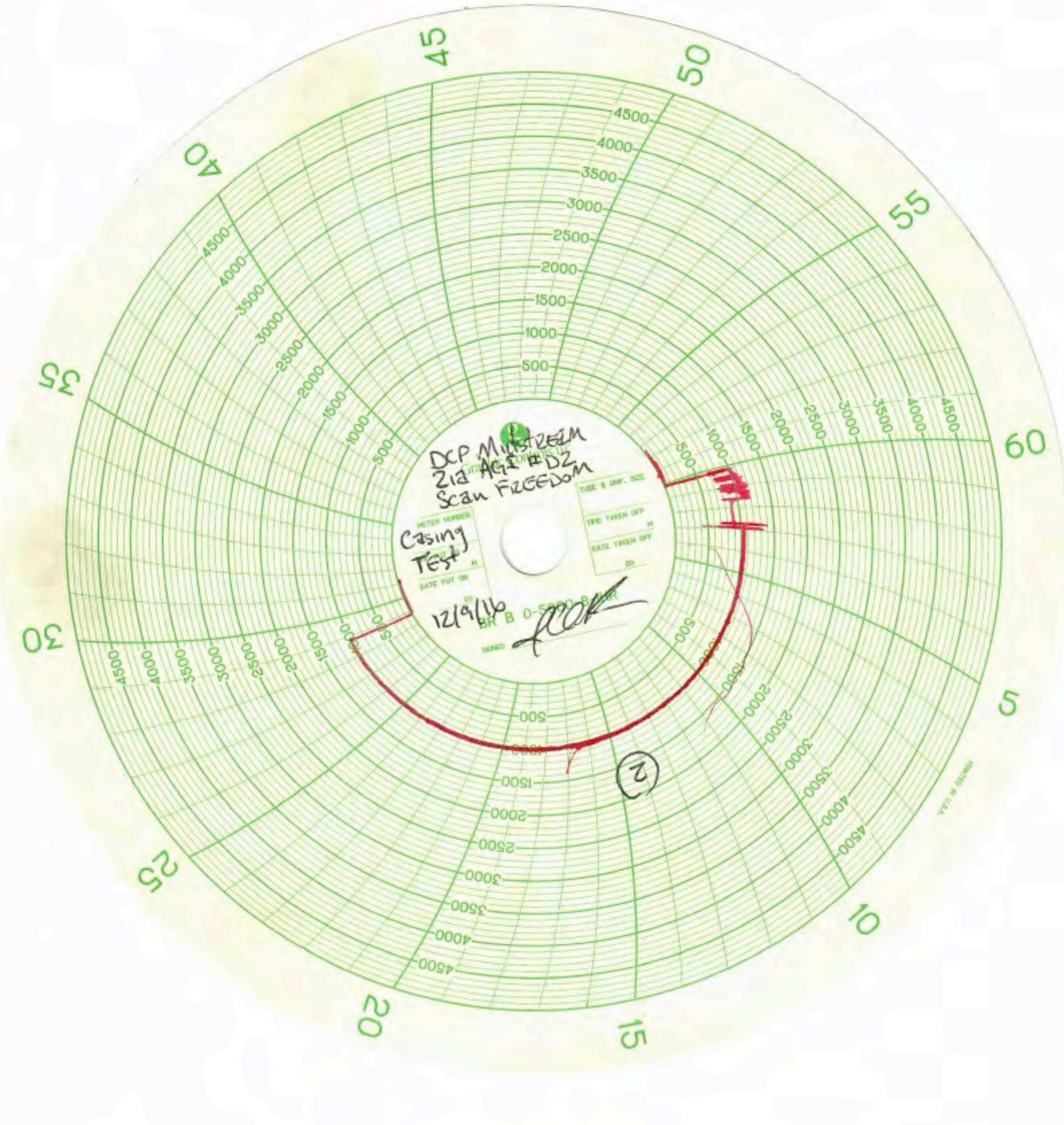
TEST #	ITEMS TESTED	LOW TEST		HIGH TEST		REMARKS
		PSI	MIN.	PSI	MIN.	
1	Unit 48	/	/	1000	10	- All tests went well!
2	Casing, 1, 2, 3, 4, 5, 11	/	/	1000	30	

TEST ACCEPTED BY Victor Hernandez

PO BOX 7 • LOVINGTON, NM 88260 • 575.942.9472 • battleenergy@gmail.com

MASTER PRINTERS 575.396.3661

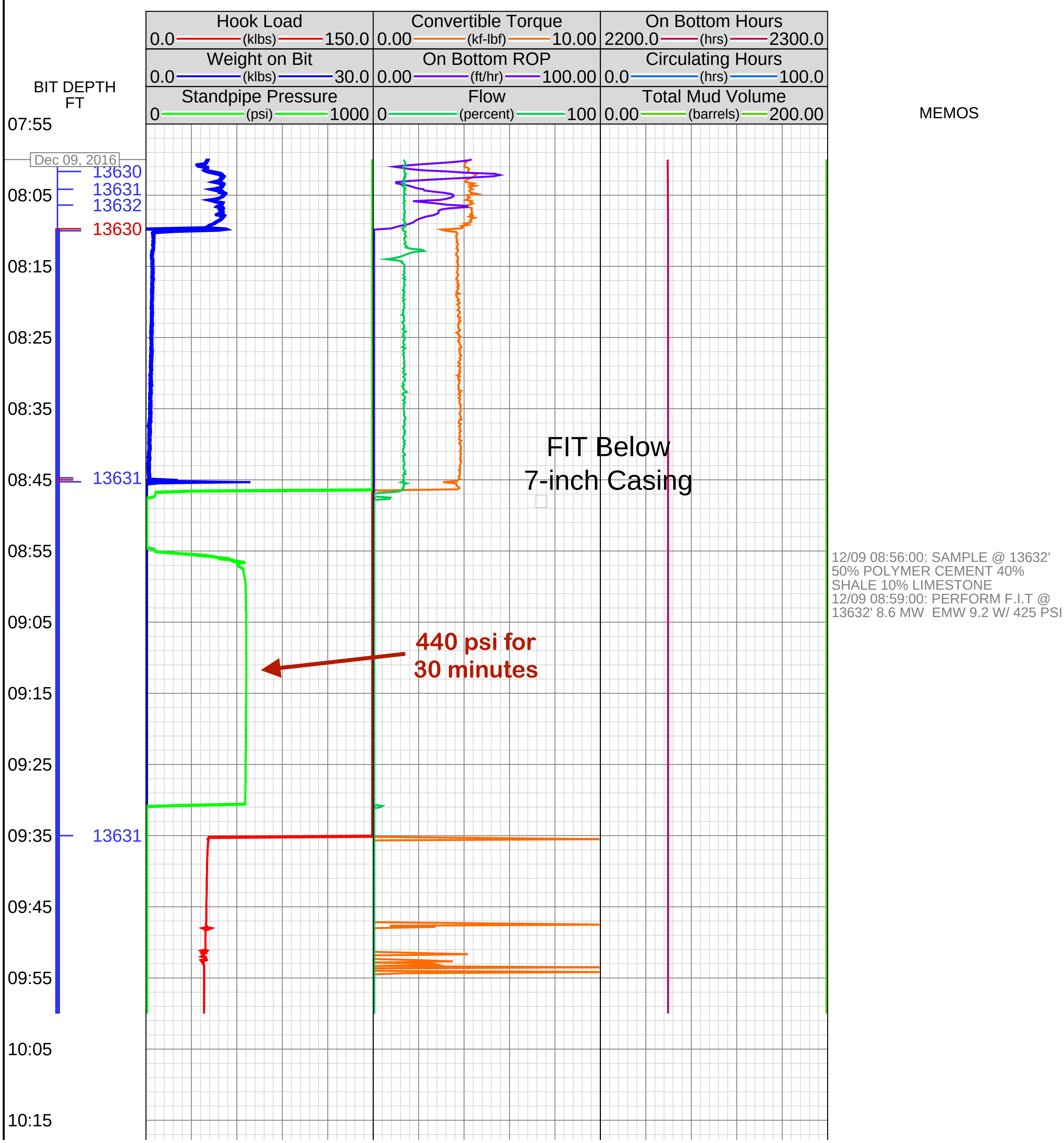

DCP Midstream
Zia AGI #02
Scan Freedom
Truck Test
12/9/16
BR B 0-5000-8-HR
DATE PUT ON
TIME TAKEN OFF
DATE TAKEN OFF


DCP Midstream
Zia AGI #D2
Scan Freedom
TUBE & ORIF. SIZE
METER NUMBER
Casing Test
TIME TAKEN OFF
DATE TAKEN OFF
DATE PUT ON
12/9/16
SIGNED
(2)
45
50
55
60
5
10
15
20
25
30
35
40
500
1000
1500
2000
2500
3000
3500
4000
4500

DataHub EDR Log

Fri Dec 09, 2016 09:08:06
Well Dossier 1477948546
Dale Littlejohn

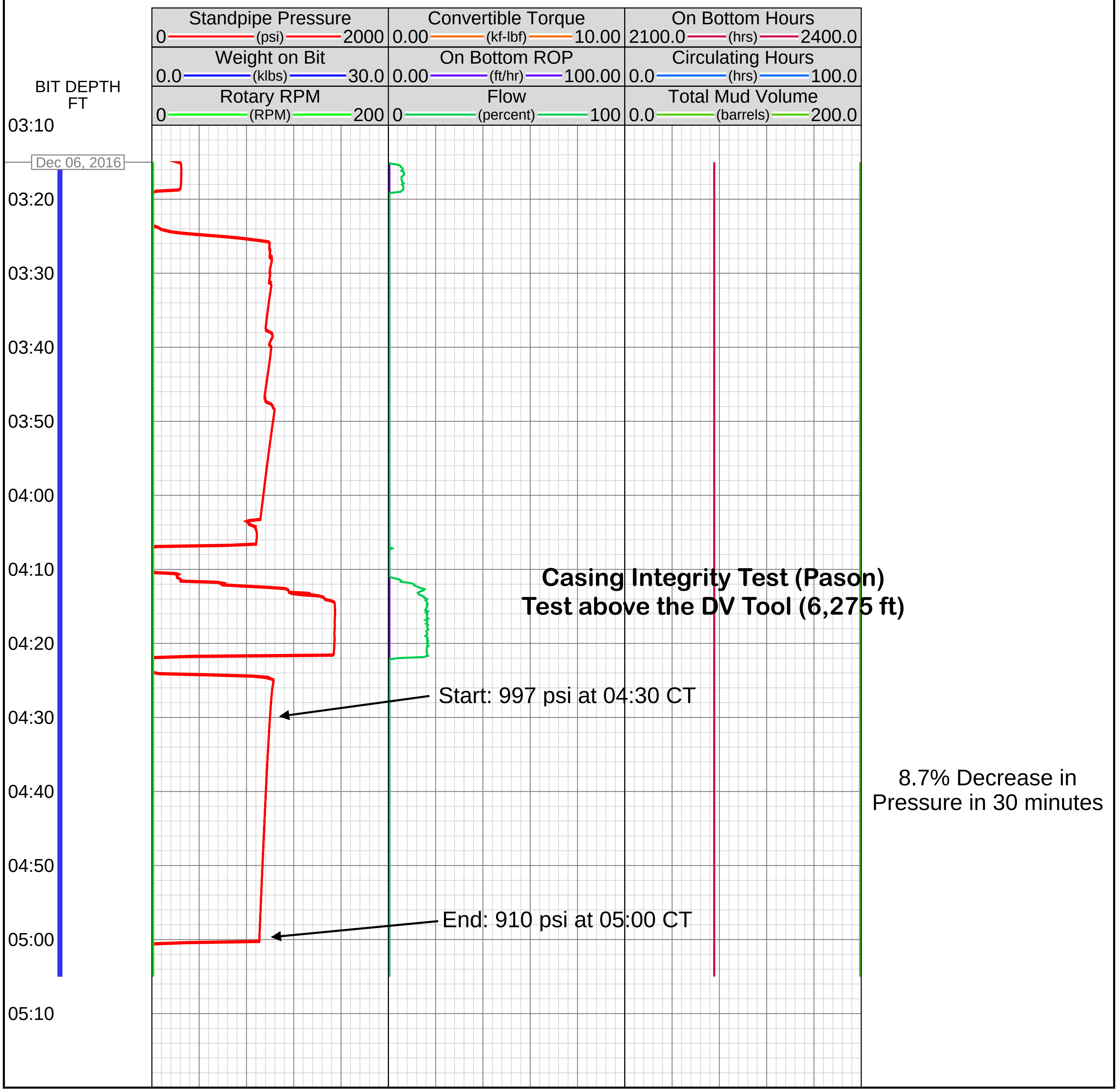
OPERATOR:	DCP Midstream, LLC	**CONTRACTOR:**	Scandrill, Inc.
WELL:	ZIA AGI 2D	**UNIQUE WELL ID:**	30-025-42207
FIELD:		**SPUD DATE:**	Nov 02, 2016 03:00
LOCATION:	SEC 19-T19S-R32E	**RELEASE DATE:**	
COUNTRY:	USA	**FROM DATE:**	Dec 09, 2016 08:00
RIG:	Scan Freedom	**TO DATE:**	Dec 09, 2016 10:00



DataHub EDR Log

Tue Dec 06, 2016 08:24:44
Well Dossier 1477948546
Dale Littlejohn

OPERATOR:	DCP Midstream, LLC	**CONTRACTOR:**	Scandrill, Inc.
WELL:	ZIA AGI 2D	**UNIQUE WELL ID:**	30-025-42207
FIELD:		**SPUD DATE:**	Nov 02, 2016 03:00
LOCATION:	SEC 19-T19S-R32E	**RELEASE DATE:**	
COUNTRY:	USA	**FROM DATE:**	Dec 06, 2016 03:15
RIG:	Scan Freedom	**TO DATE:**	Dec 06, 2016 05:05



Open-hole Borehole, Production CIT, and FIT Pressure Testing

BATTLE Energy Services

PO Box 7
Lovington, NM 88260
(575) 942-9472

Invoice
B 7137

Date 11-14-16 Start Time 7:00 ☒ am ☐ pm
Company DCP midstream State NM County Lea
Lease Zia AGI D2
Company Man ______ Tester Alex Truck # 35
Tool Pusher ______ Plug Size 11"
Drilling Contractor Scan Freedom Rig # ______ Pipe Thread Size 4½ IF

Test Pressures
BOP: 5000
Annular: 2500
Casing: N/A
Pumps: 5000

Test #	Items tested	Low Test PSI	Low Test Min.	High Test PSI	High Test Min.	Remarks
1	Truck	—	—	5000	10	Bop test 250 low 10 min
2	6,10,13,25,26	250	10	5000	10	5000 High 10 min
3	1,2,5,9,13	250	10	5000	10	
4	3,4,5,8b,11,12	250	10	5000	10	Annular 250 low 10 min
5	8,11,12	250	10	5000	10	2500 High 10 min
6	7,11,12	250	10	5000	10	
7	14	250	10	5000	10	pumps ~~[illegible]~~ 5000
8	7,11,15	250	10	2500	10	High 30 min
9	18	250	10	5000	10	
10	19	250	10	5000	10	no Casing test
11	16	250	10	5000	10	
12	17	250	10	5000	10	no Accumulator test
13	20,21,22,23,	—	—	5000	30	
14	24	—	—	5000	30	Per Company Man Request

Mileage — @ — /mile = —
Methanol ______ = ______
Cup Test ______ = ______
13 HR@ $110.00 = $1430.00
O-ring's @ $50.00 = $50.00
______ @ ______ = ______
Subtotal = $1,480.00
Tax = $81.00
TOTAL = $1,561.00

Test accepted by: ______

[signature]

BATTLE Energy Services

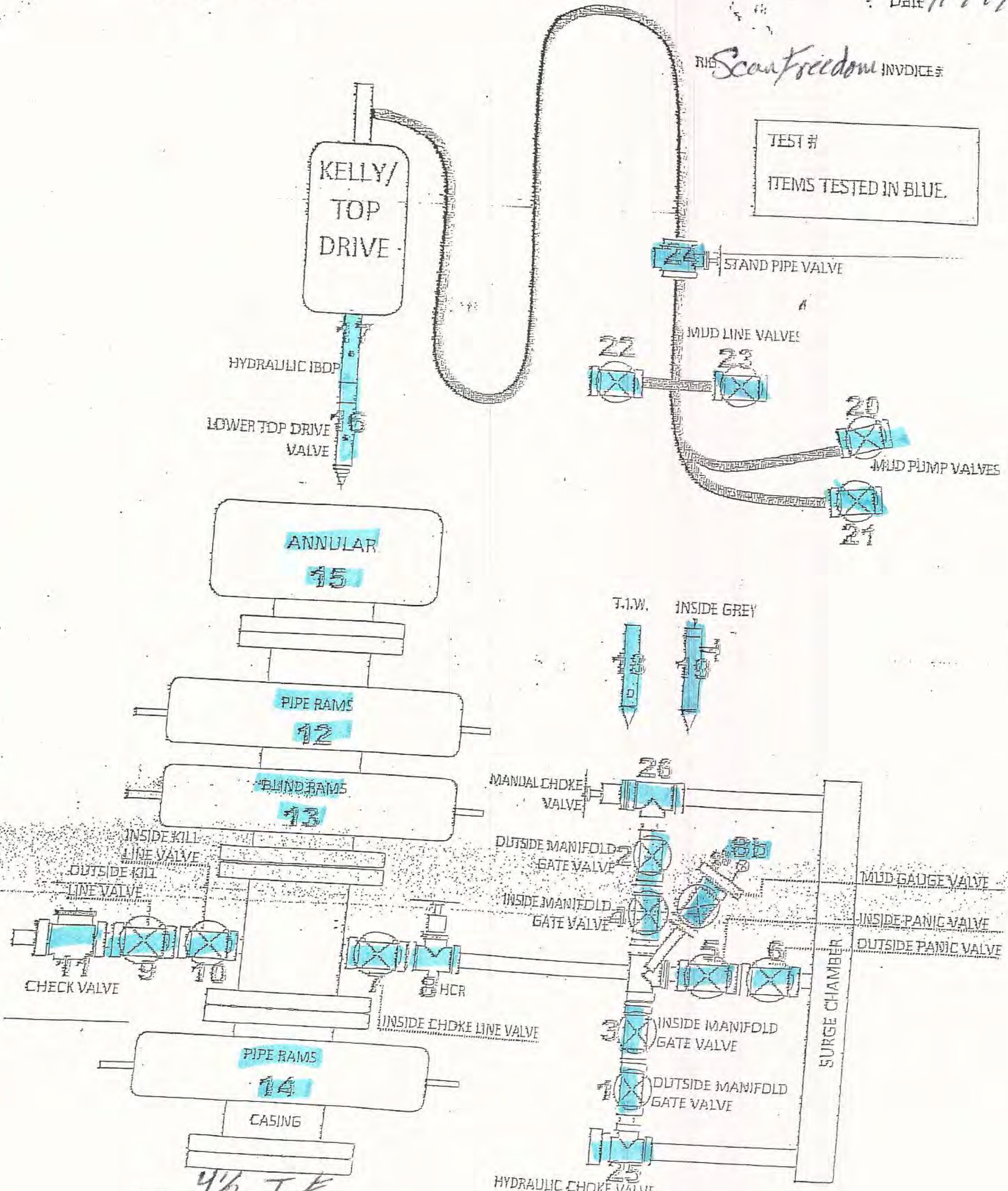
BOP Test Diagram

Date 11-14-16

RIG: Scan Freedom INVOICE #

TEST #

ITEMS TESTED IN BLUE.

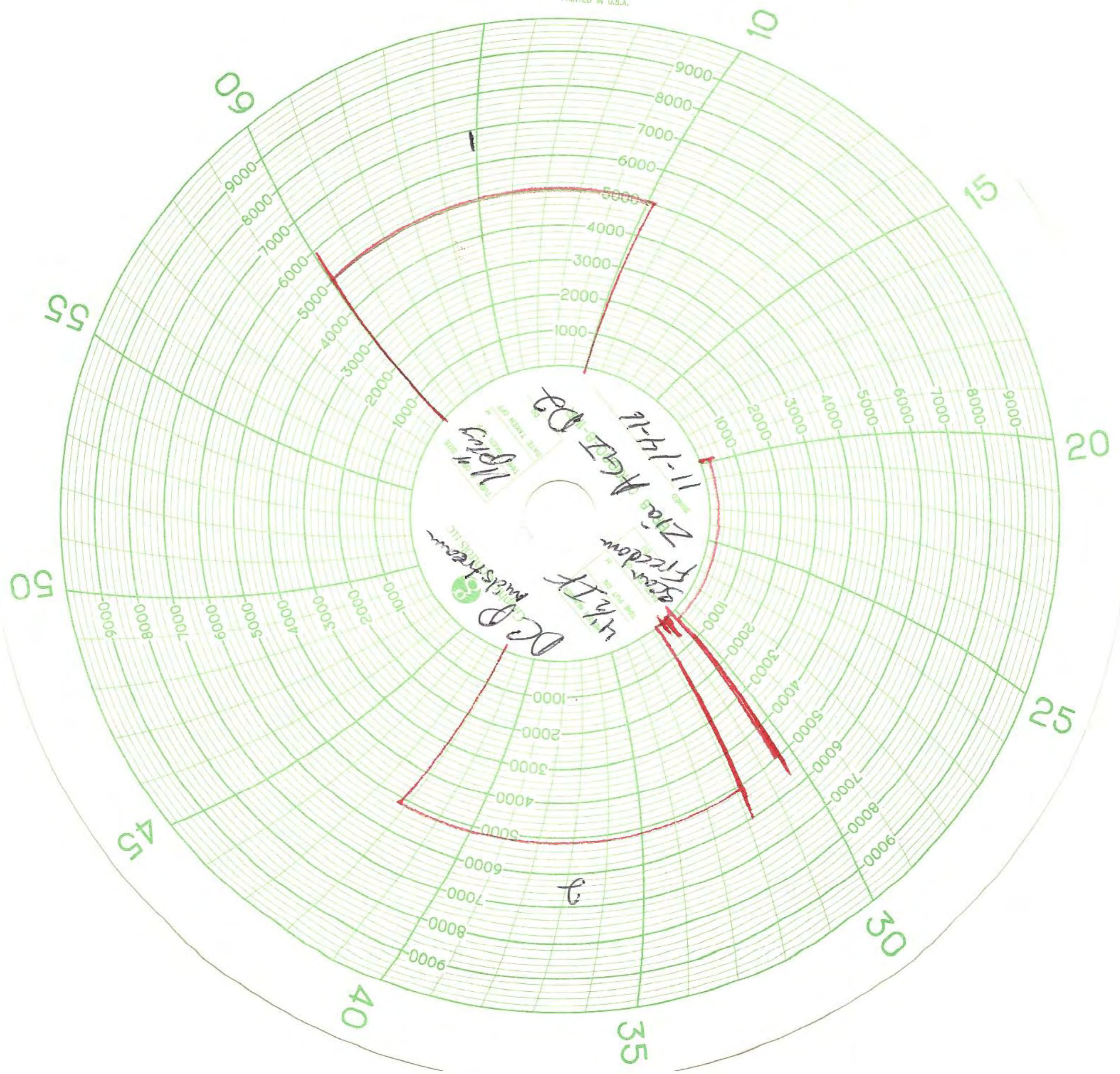


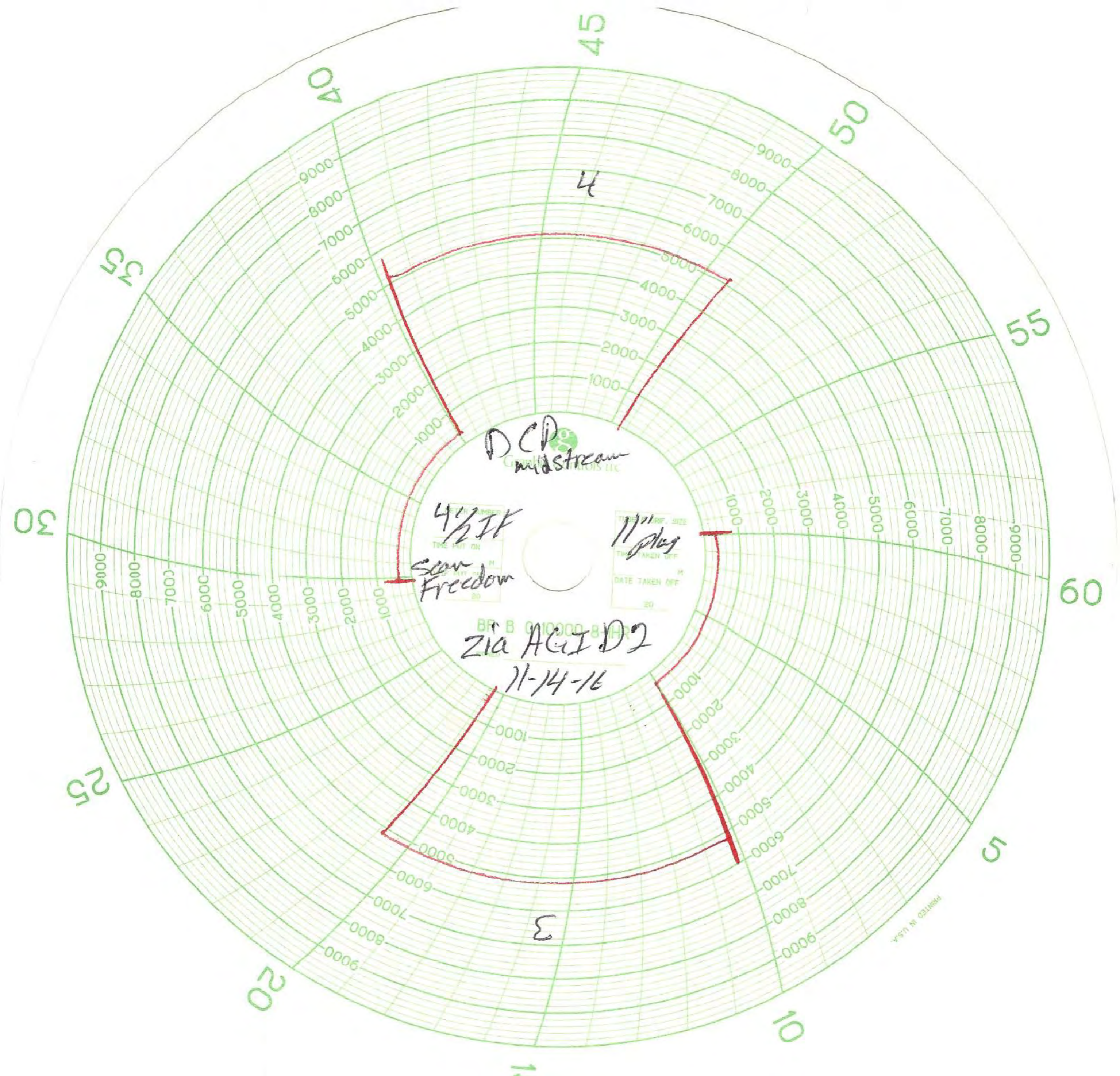
4½ IF

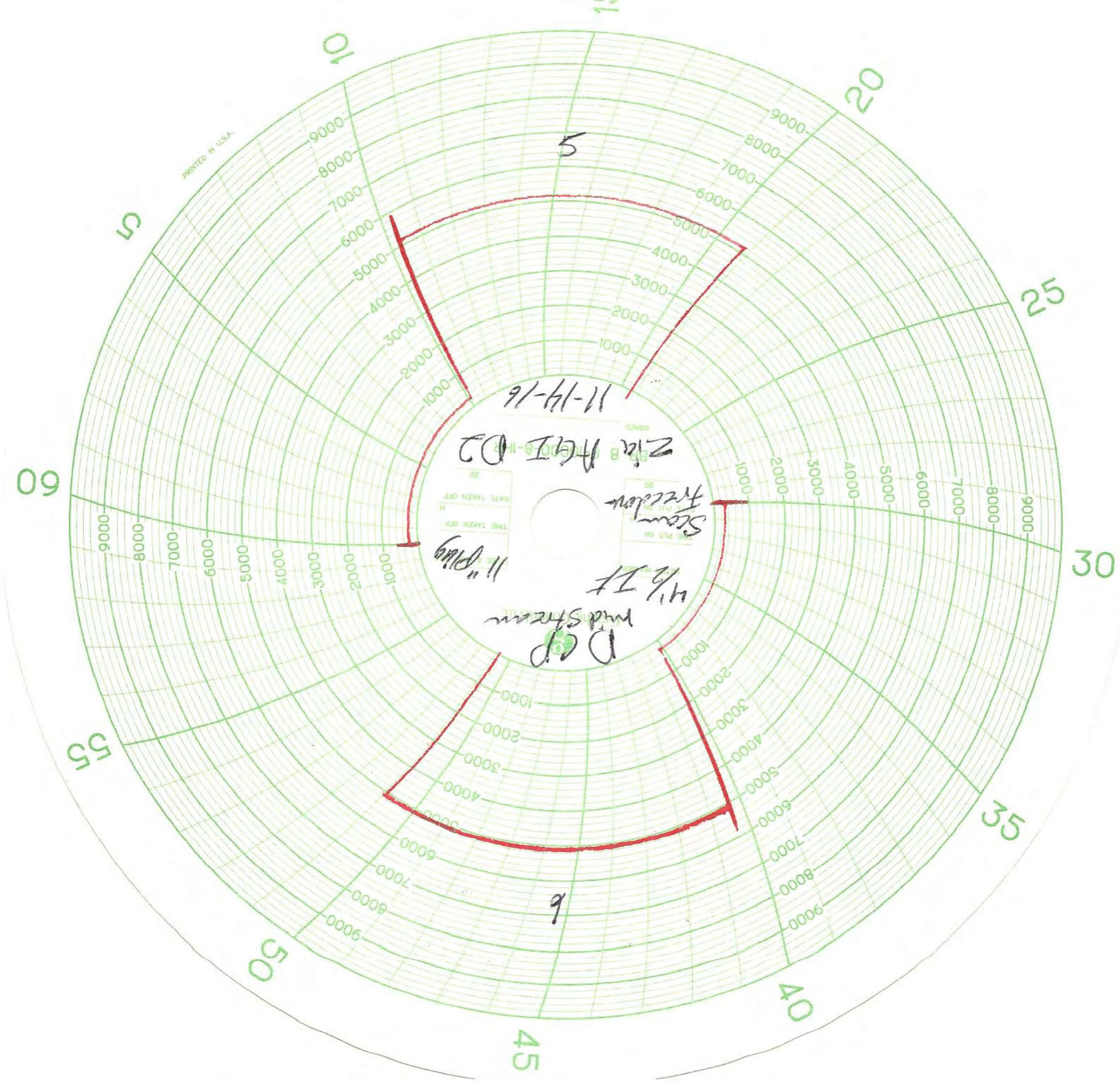
DRILL PIPE & TYPE

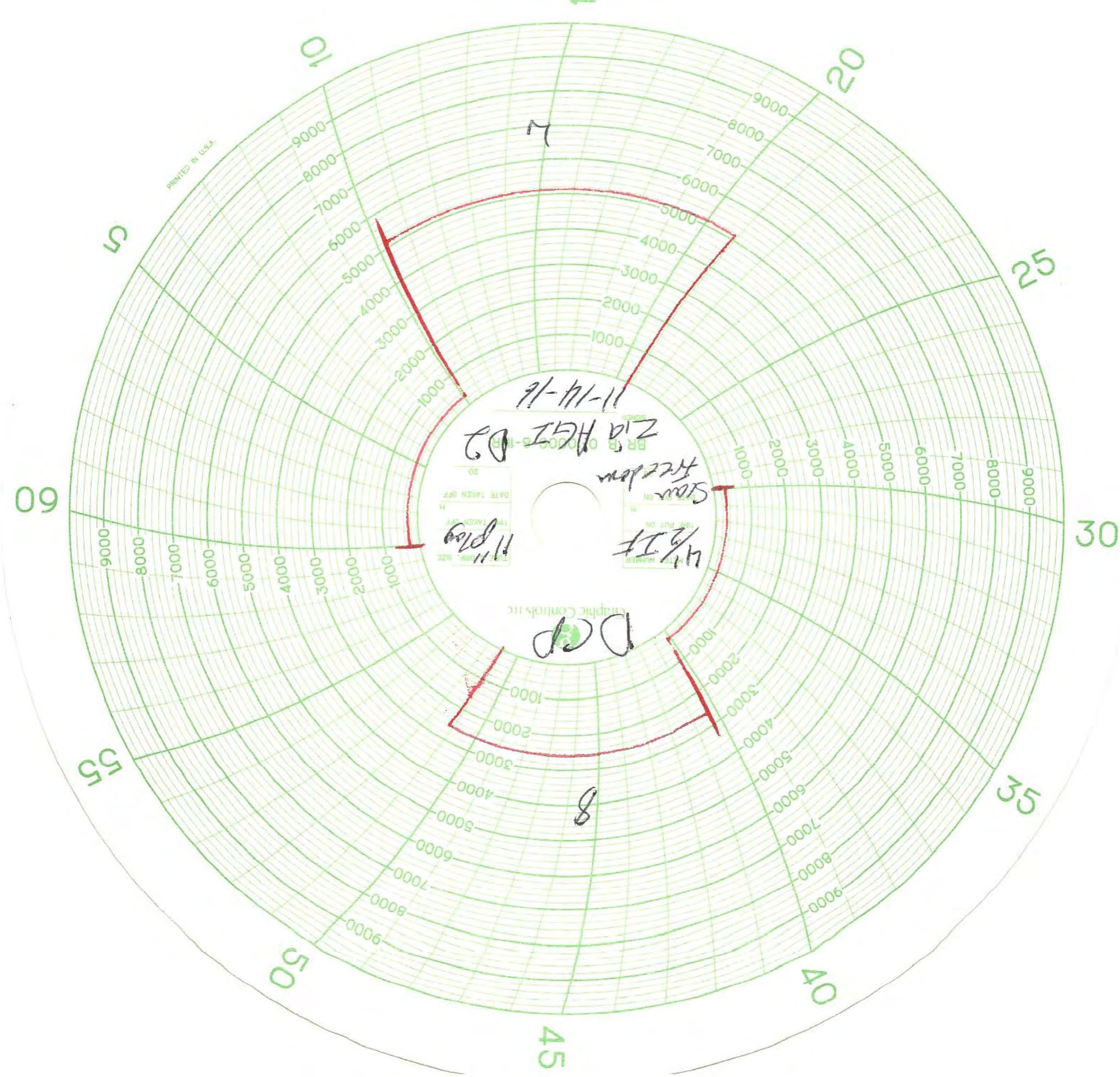
11" plug C 22

PLUG/CUP SIZE AND TYPE

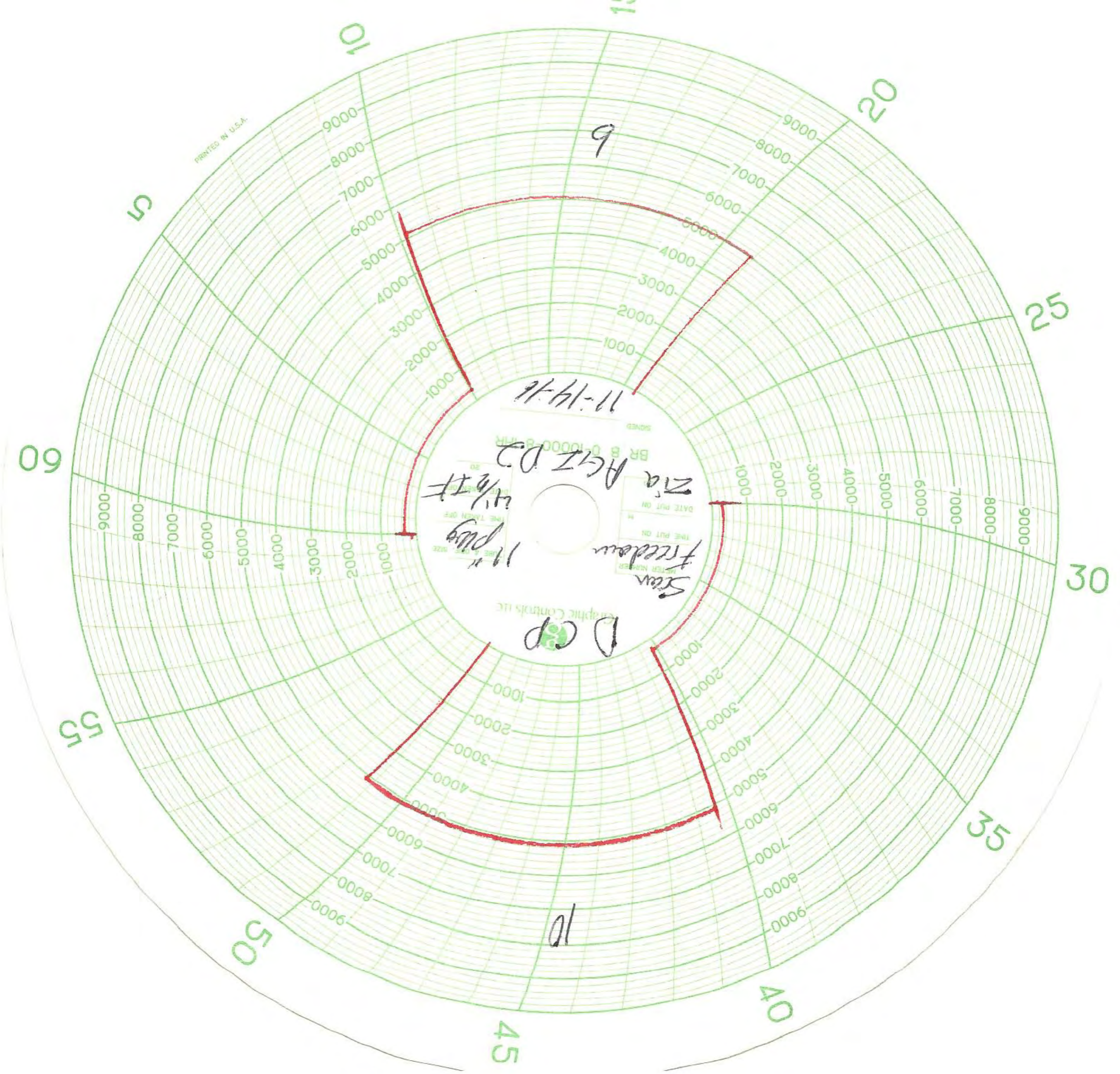

DCP Midstream
4½ IF
Scan Freedom
Zia AGI D2
11-14-16


4
DCP midstream
4½ IF
Scan Freedom
11" plug
Zia AGI D2
11-14-16
3

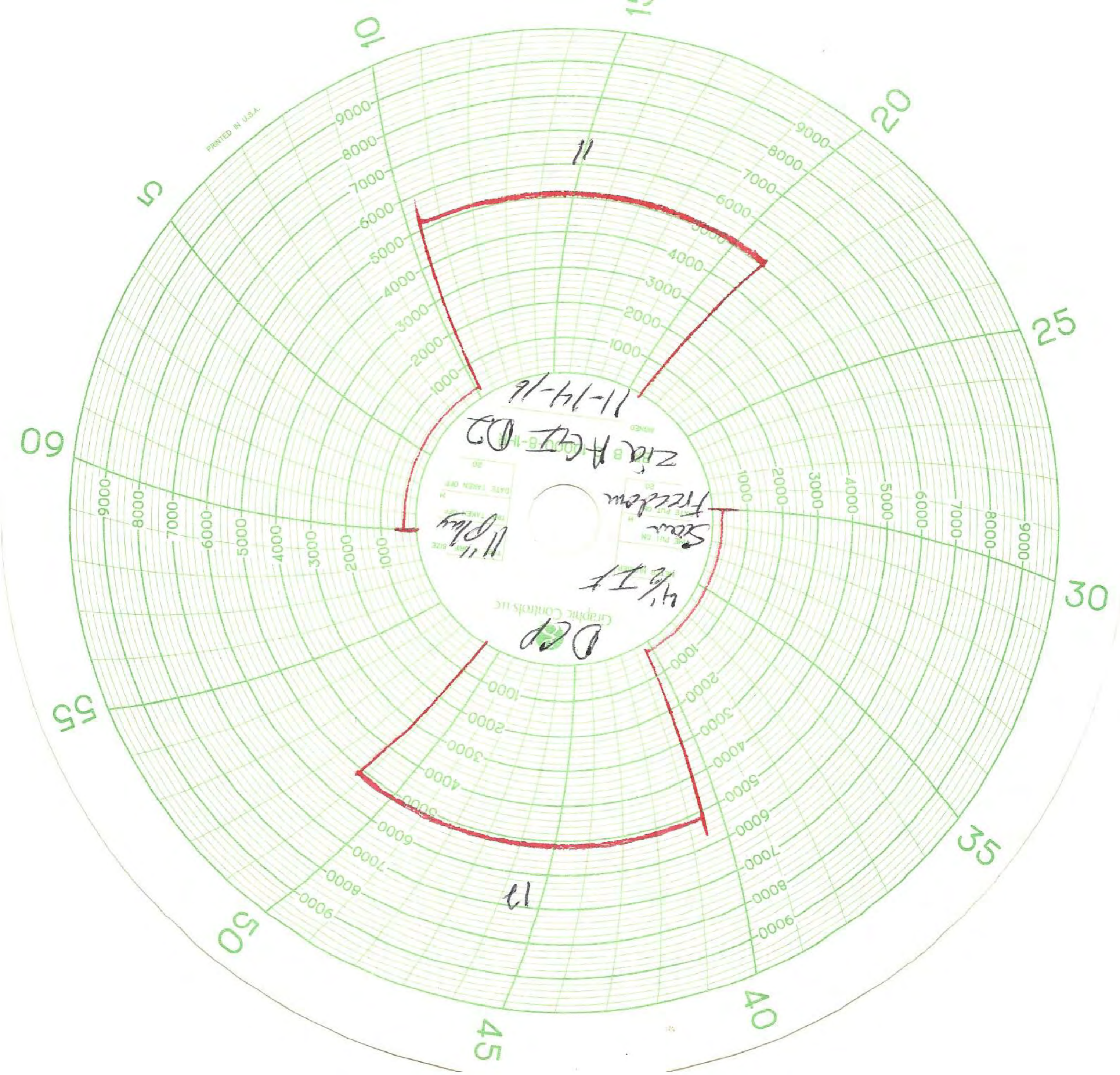

PRINTED IN U.S.A.
11-14-16
11" Plug

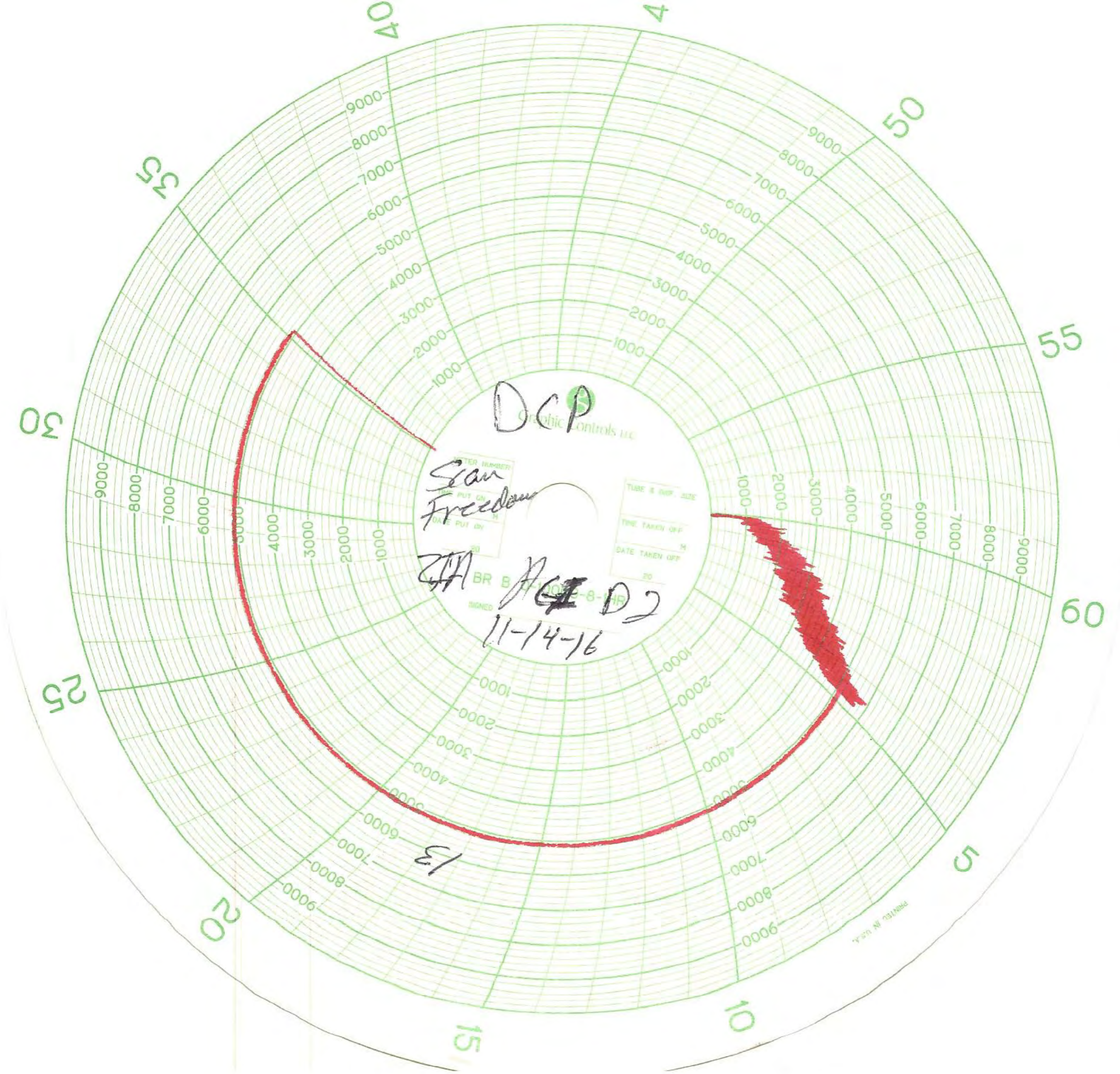


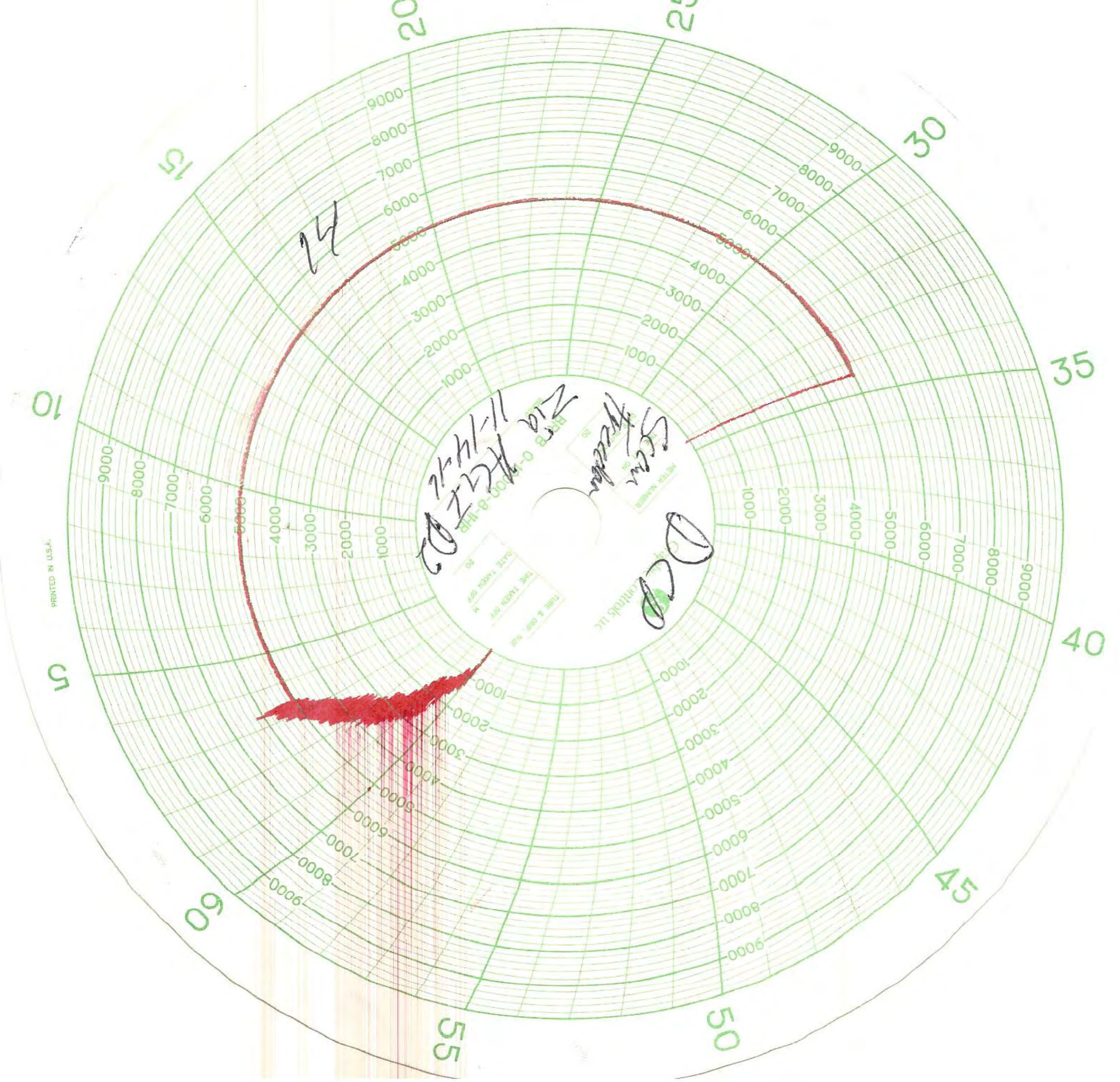
PRINTED IN U.S.A.
5
10
20
25
30
35
40
45
50
55
60
1000
2000
3000
4000
5000
6000
7000
8000
9000
7
8
11-14-16
Graphic Controls LLC
DATE TAKEN OFF
TIME PUT ON



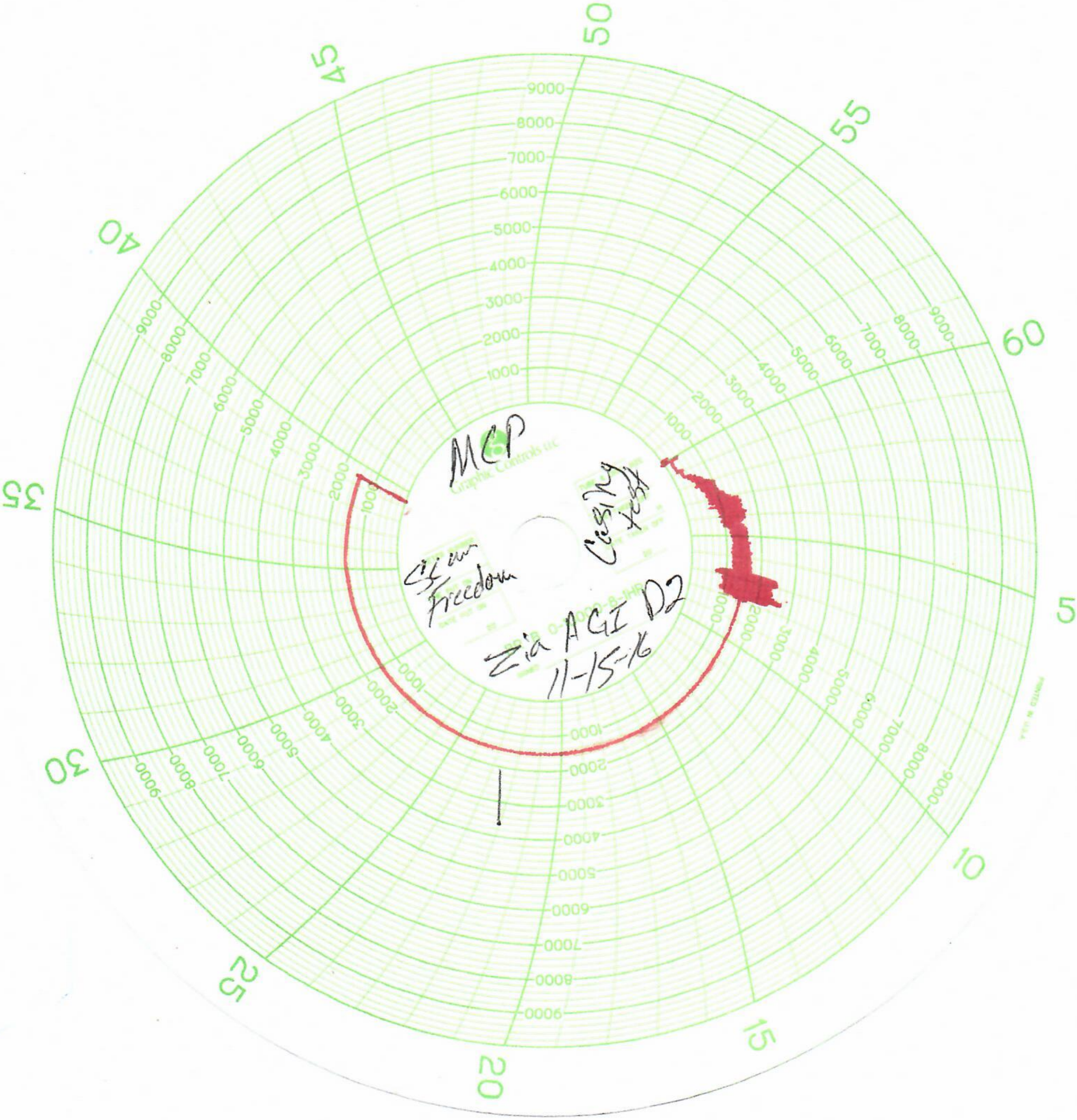
11-14-16
BR B 0-10000-8-NR
Zia AGI D2
Stan
Freedom
11" plug
4 1/2 IF
Graphic Controls LLC
PRINTED IN U.S.A.


PRINTED IN U.S.A.
Graphic Controls


DCP
Graphic Controls LLC
METER NUMBER
Sean Freedom
TIME PUT ON
DATE PUT ON
TUBE & ORIF. SIZE
TIME TAKEN OFF
DATE TAKEN OFF
SIGNED
11-14-16
13
PRINTED IN U.S.A.



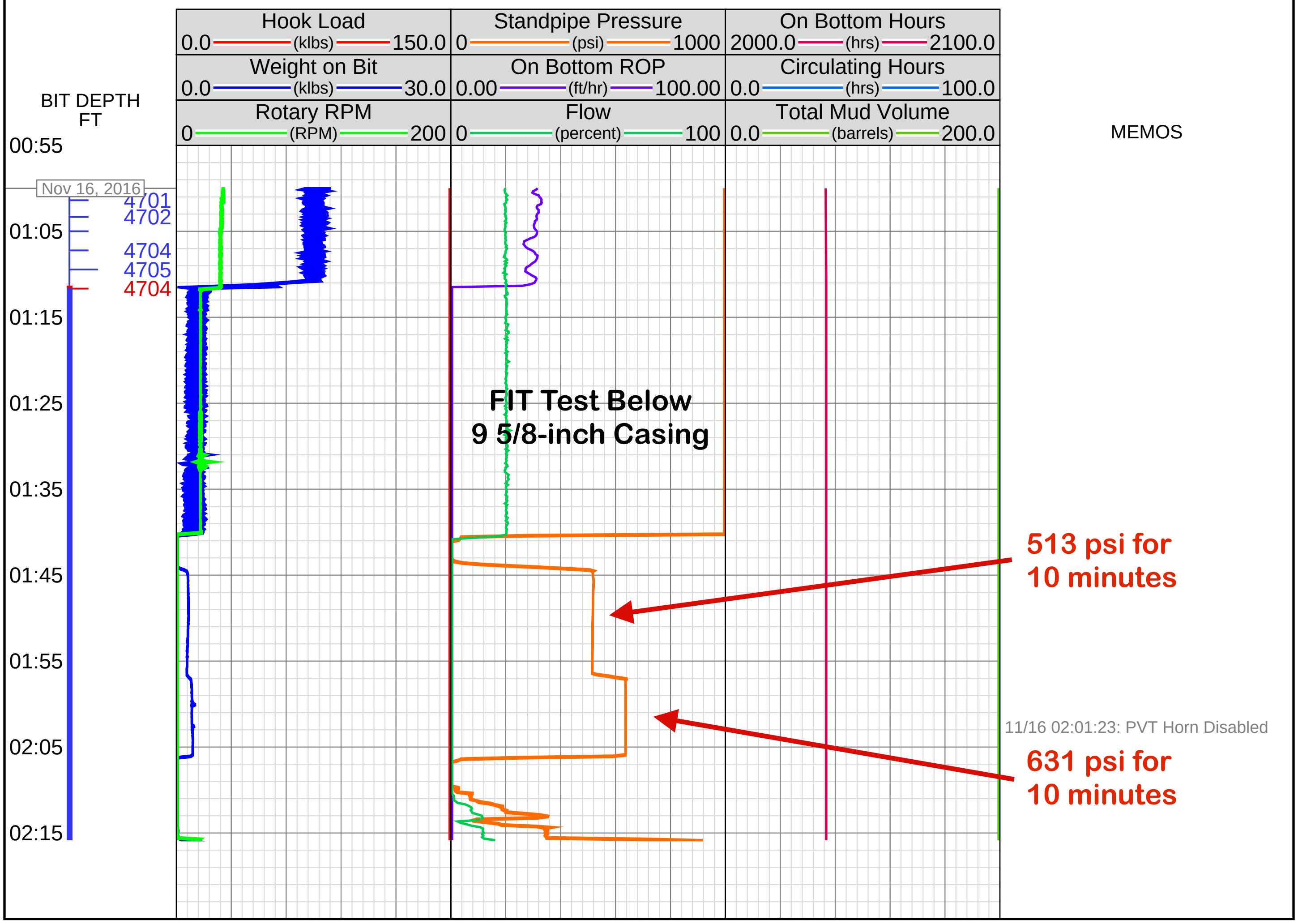
14
PRINTED IN U.S.A.


MCP
Graphic Controls LLC
Zia AGI D2
11-15-16
Freedom

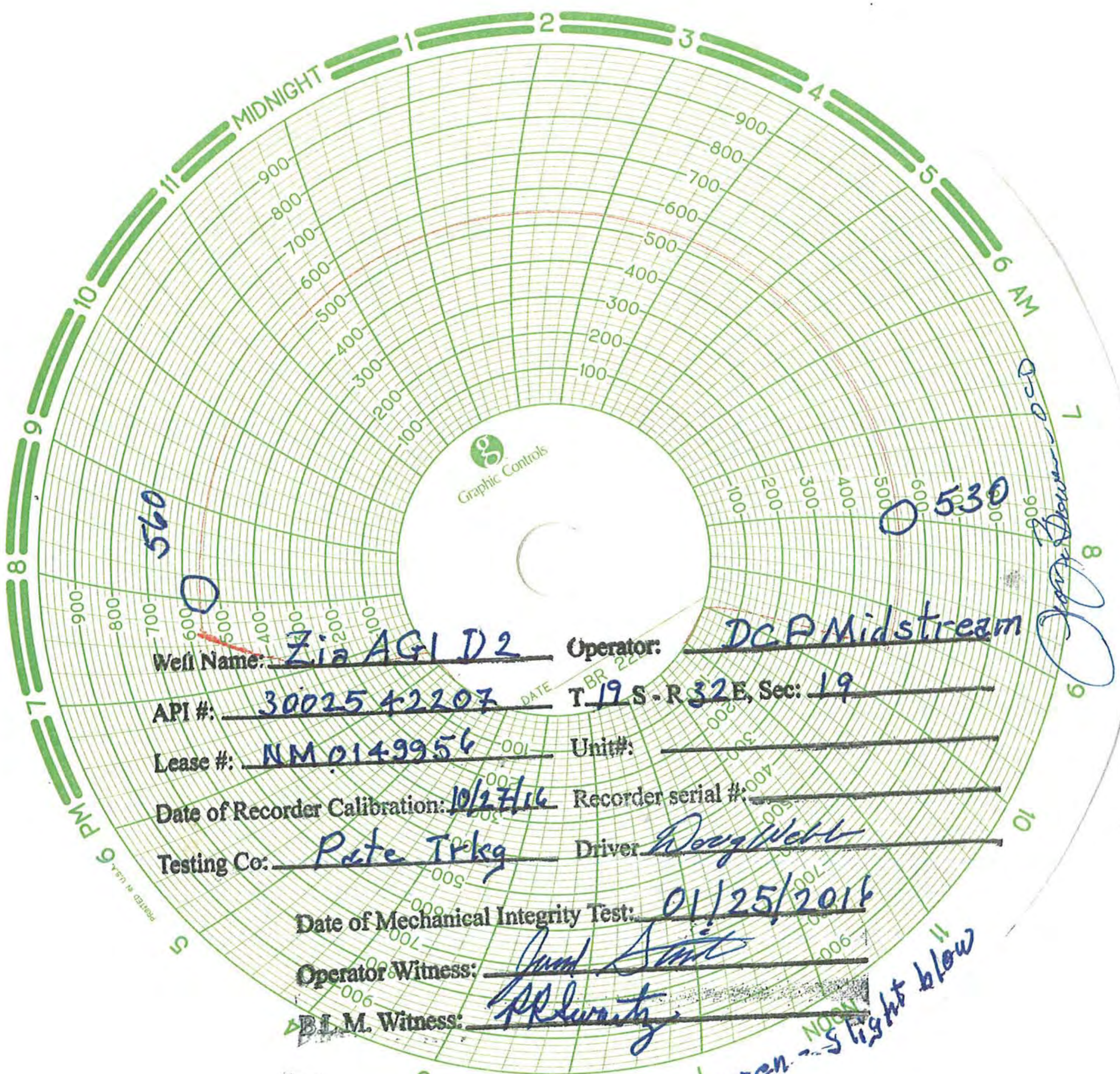
Wed Nov 16, 2016 01:17:25
Well Dossier 1477948546
Dale Littlejohn

DataHub EDR Log

OPERATOR:	DCP Midstream, LLC	**CONTRACTOR:**	Scandrill, Inc.
WELL:	ZIA AGI 2D	**UNIQUE WELL ID:**	30-025-42207
FIELD:		**SPUD DATE:**	Nov 02, 2016 03:00
LOCATION:	SEC 19-T19S-R32E	**RELEASE DATE:**	
COUNTRY:	USA	**FROM DATE:**	Nov 16, 2016 01:00
RIG:	Scan Freedom	**TO DATE:**	Nov 16, 2016 02:30



Mechanical Integrity Test Chart



Well Name: Zia AGI D2 Operator: DCP Midstream

API #: 30025 42207 T 19 S - R 32 E, Sec: 19

Lease #: NM 0149956 Unit#:

Date of Recorder Calibration: 10/27/16 Recorder serial #:

Testing Co: Pate Trkg Driver: Doug Webb

Date of Mechanical Integrity Test: 01/25/2016

Operator Witness:

B.L.M. Witness:

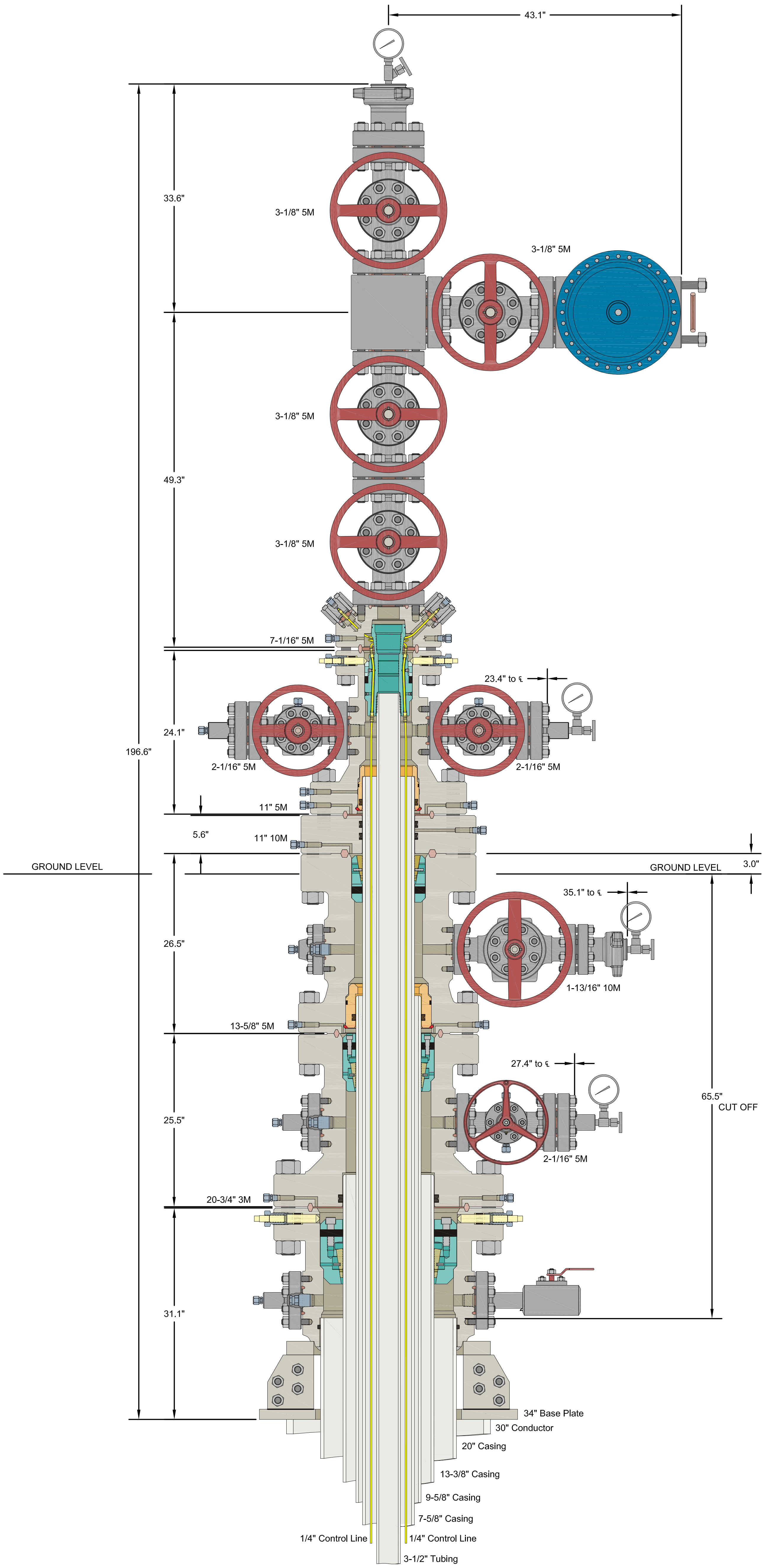
Surface open - slight blow

OCD

APPENDIX N

WELL TREE SCHEMATIC

GE Oil & Gas



ALL DIMENSIONS ARE APPROXIMATE

This drawing is the property of GE Oil & Gas Pressure Control LP and is considered confidential. Unless otherwise approved in writing, neither it nor its contents may be used, copied, transmitted or reproduced except for the sole purpose of GE Oil & Gas Pressure Control LP.	DCP MIDSTREAM ZIA AGI #2/LEA COUNTY, NM		
20" x 13-3/8" x 9-5/8" x 7-5/8" x 3-1/2" 5M Conventional Wellhead Assembly, With T-EBS-F Tubing Head, T-M40-CCL Tubing Hanger and Adapter Flange	DRAWN	CR	25OCT16
	APPRV	KN	25OCT16
	FOR REFERENCE ONLY DRAWING NO.	10012278-A	

APPENDIX O

OIL AND GAS WELLS IN THE DCP ZIA AGI D #2 AREA OF REVIEW AND VICINITY

APPENDIX O

OIL AND GAS WELLS IN THE DCP ZIA AGI D #2 AREA OF REVIEW AND VICINITY

Table A1: Identified Wells within Two Miles of Proposed Zia AGI #2D

Table A1: Identified Wells Within Two Miles of Proposed Zia AGI #2D

API	OPERATOR	PLUG_DATE	RANGE	SECTION	SPUD_DATE	TOWNSHIP	TVD_DEPTH	WELL_NAME	WELL_TYPE	COMPL_STATUS	COUNTY	LATITUDE	LONGITUDE	Distance from AGI #2 (mi)
3002542207	DCP MIDSTREAM, LP		32E	19		19.0S	0	ZIA AGI 002	I	New (Not drilled or compl)	Lea	32.643964	-103.811117	0.00
3002542208	DCP MIDSTREAM, LP		32E	19	12/23/2014	19.0S	6192	ZIA AGI 001	I	Active	Lea	32.644514	-103.811117	0.04
3002500911	SIMMS & REESE OIL CO	12/30/1959	32E	19	12/7/1959	19.0S	2640	GULF 001	O	Plugged	Lea	32.64509902	-103.810947	0.09
3002500904	CARPER DRILLING CO	3/1/1943	32E	19	12/19/1942	19.0S	2862	MILLER 002	O	Plugged	Lea	32.64418191	-103.8077117	0.17
3002520247	EL PASO NATURAL GAS	10/25/1971	32E	19	12/10/1963	19.0S	11432	LUSK DEEP UNIT 006	O	Plugged	Lea	32.640567	-103.8120069	0.24
3002535291	COG OPERATING LLC		32E	19	4/24/2001	19.0S	12718	LUSK DEEP UNIT A 021	G	Active	Lea	32.64055593	-103.8084486	0.26
3001505790	PLAINS PROD CO	8/18/1947	31E	24	1/20/1946	19.0S	2876	JONES 007	O	Plugged	Eddy	32.64510755	-103.815256	0.28
3002500902	REMNANT OIL PROPERTIES, LLC		32E	19	10/12/1942	19.0S	2634	MILLER FEDERAL 001	O	Active	Lea	32.64783008	-103.8120347	0.29
3002500909	TOM R CONE		32E	19	8/31/1958	19.0S	2490	GULF FEDERAL 001	O	Active	Lea	32.64781923	-103.8088029	0.29
3001542914	COG OPERATING LLC		31E	24	2/2/2015	19.0S	9210	SCREWDRIVER 24 FEDERAL COM 002H	O	Active	Eddy	32.64114974	-103.8149193	0.31
3002542750	COG OPERATING LLC	9/25/2015	32E	19	9/1/2015	19.0S	4370	LUSK DEEP UNIT A 026H	O	Plugged	Lea	32.63959695	-103.8084933	0.32
3002542858	COG OPERATING LLC		32E	19	10/22/2015	19.0S	9241	LUSK DEEP UNIT A 026Y	O	Active	Lea	32.63959719	-103.8083954	0.32
3002534573	COG OPERATING LLC		32E	19	12/17/1999	19.0S	12540	LUSK DEEP UNIT A 014	G	Active	Lea	32.64873355	-103.810961	0.34
3002520876	TOM R CONE		32E	19	11/6/1964	19.0S	11223	GULF FEDERAL 003	O	Active	Lea	32.648726	-103.808715	0.35
3002500910	TOM R CONE		32E	19	8/3/1961	19.0S	2500	GULF FEDERAL 002	O	Active	Lea	32.64781197	-103.8066484	0.36
3002500907	KELLY G STOUT	3/24/1958	32E	19	10/1/1957	19.0S	2552	SOUTHERN CALIFORNIA 002	O	Plugged	Lea	32.64507877	-103.8044838	0.37
3001510382	PHILLIPS PETROLEUM CO	10/17/1994	31E	24	4/26/1964	19.0S	11540	LUSK DEEP UNIT 008	O	Plugged	Eddy	32.64329061	-103.8174035	0.40
3002520122	COG OPERATING LLC		32E	19	4/16/1963	19.0S	12554	LUSK DEEP UNIT A 005	G	Active	Lea	32.64416813	-103.8034042	0.42
3001505785	REMNANT OIL PROPERTIES, LLC		31E	24	10/8/1941	19.0S	2470	OHIO JONES 001	O	Active	Eddy	32.64783473	-103.8163437	0.43
3002500906	TOM R CONE		32E	19	1/2/1957	19.0S	2715	SOUTHERN CALIFORNIA PET FEDERAL 001	O	Active	Lea	32.64780036	-103.8034133	0.50
3002520025	CHISOS, LTD		32E	30	2/2/1963	19.0S	11286	DELHI FEDERAL 001	O	Active	Lea	32.6369253	-103.8076849	0.51
3002500903	CARPER DRILLING CO	1/1/1900	32E	19	1/1/1900	19.0S	2710	MILLER 001	O	Plugged	Lea	32.65145839	-103.8120487	0.53
3002539441	COG OPERATING LLC		32E	30	9/15/2009	19.0S	9580	SL DEEP FEDERAL 003	O	Active	Lea	32.63596771	-103.8088936	0.55
3002500908	KELLY G STOUT	1/1/1900	32E	19	1/1/1900	19.0S	2695	SOUTHERN CALIFORNIA 003	O	Plugged	Lea	32.65052557	-103.8044972	0.58
3002540863	COG OPERATING LLC		32E	19	12/19/2012	19.0S	9276	LUSK DEEP UNIT A 024H	O	Active	Lea	32.65233971	-103.8121096	0.59
3001510393	FINA OIL & CHEMICAL	1/1/1900	31E	24	1/1/1900	19.0S	11515	JONES G FED COM 001	O	Plugged	Eddy	32.64783012	-103.8199998	0.61
3001505788	**PLAINS PROD CO**	**1/1/1901**	**31E**	**24**	**1/1/1900**	**19.0S**	**0**	**JONES 005**	**O**	**Plugged**	**Eddy**	**32.65146297**	**-103.8163576**	**0.62**
3001505786	REMNANT OIL PROPERTIES, LLC		31E	24	3/11/1942	19.0S	2654	OHIO JONES 002	O	Active	Eddy	32.64782928	-103.8206527	0.65
3002536257	COG OPERATING LLC		32E	30	4/29/2003	19.0S	12640	SL DEEP FEDERAL 002	G	Active	Lea	32.63379175	-103.8076729	0.71
3002532678	OXY USA INC	3/20/2012	32E	30	10/8/1994	19.0S	7280	GECKO FEDERAL 001	O	Plugged	Lea	32.63331037	-103.8119794	0.73
3002542524	COG OPERATING LLC		32E	19	1/1/2016	19.0S	9250	SL EAST 30 FEDERAL COM 002H	O	Active	Lea	32.64014303	-103.7987492	0.74
3002541291	COG OPERATING LLC		32E	18	10/23/2013	19.0S	9247	LUSK DEEP UNIT A 028H	O	Active	Lea	32.65442921	-103.8132834	0.75
3002540260	COG OPERATING LLC		32E	19	9/9/2011	19.0S	9217	LUSK DEEP UNIT A 023H	O	Active	Lea	32.63962198	-103.7982592	0.78
3001505789	MACK ENERGY CORP	1/1/1900	31E	24	1/1/1900	19.0S	2515	OHIO JONES FED 006	O	Plugged	Eddy	32.65145751	-103.8206666	0.79
3002542525	COG OPERATING LLC		32E	19		19.0S	0	LUSK DEEP UNIT A 034H	O	New (Not drilled or compl)	Lea	32.63962254	-103.7980307	0.79
3002539538	COG OPERATING LLC		32E	30	12/14/2009	19.0S	10858	SL DEEP FEDERAL 004H	O	Active	Lea	32.63233163	-103.812088	0.80
3002535053	COG OPERATING LLC	8/23/2014	32E	18	6/15/2000	19.0S	12780	LUSK DEEP UNIT A 016	S	Plugged	Lea	32.65543028	-103.8120636	0.80
3002520104	OXY USA INC		32E	30		19.0S	12475	ELLIOTT HALL A 001	O	Active	Lea	32.63689725	-103.7990797	0.83
3001510277	DOWDCO INC	1/27/2006	31E	24		19.0S	11530	JONES C FEDERAL 001	O	Plugged	Eddy	32.64350063	-103.8248911	0.83
3001505787	**PLAINS PROD CO**	**1/1/1901**	**31E**	**24**	**1/1/1900**	**19.0S**	**0**	**JONES 003**	**O**	**Plugged**	**Eddy**	**32.64418779**	**-103.8248936**	**0.83**
3001510189	FINA OIL & CHEMICAL	1/10/1994	31E	25		19.0S	12775	JONES FEDERAL 002	O	Plugged	Eddy	32.63421717	-103.8195223	0.84
3002500905	COG OPERATING LLC		32E	19	5/21/1975	19.0S	12453	LUSK DEEP UNIT A 001	G	Active	Lea	32.65141269	-103.7991132	0.85
3002542210	COG OPERATING LLC		32E	20	12/17/2014	19.0S	9295	LUSK DEEP UNIT A 032H	O	Active	Lea	32.64415901	-103.7957156	0.87
3002500900	EL PASO NATURAL GAS	9/4/1971	32E	18	10/16/1960	19.0S	13974	LUSK DEEP UNIT 002	O	Plugged	Lea	32.65505697	-103.8034324	0.88
3002540193	COG OPERATING LLC		32E	20	8/2/2011	19.0S	9320	LUSK DEEP UNIT A 025H	O	Active	Lea	32.64829167	-103.7959464	0.91
3002541513	COG OPERATING LLC		32E	20	12/27/2013	19.0S	9332	LUSK DEEP UNIT A 030H	O	Active	Lea	32.63962381	-103.7958436	0.91
3001510119	H N SWEENY	1/1/1900	31E	13	1/1/1900	19.0S	2650	MALONE FED 001	O	Plugged	Eddy	32.65417868	-103.8206781	0.92
3001510279	DOWDCO INC	2/26/2006	31E	25		19.0S	11550	JONES B FEDERAL 002	O	Plugged	Eddy	32.63693132	-103.8248677	0.96
3001510357	PHILLIPS PETROLEUM CO	8/19/1994	31E	13	2/16/1965	19.0S	11600	SIMON A 001	O	Plugged	Eddy	32.65508573	-103.8206816	0.97
3002500913	EL PASO NATURAL GAS	1/1/1900	32E	20	1/1/1900	19.0S	12621	LUSK DEEP UNIT 003	O	Plugged	Lea	32.64867884	-103.7947975	0.98
3001531357	DEVON ENERGY PRODUCTION COMPANY, LP	4/7/2014	31E	24	10/4/2000	19.0S	12750	RADAR 24 FEDERAL 001	O	Plugged	Eddy	32.65145212	-103.82492	0.98
3002520874	SHACKELFORD OIL CO		32E	20	2/11/1964	19.0S	11467	LUSK WEST DELAWARE UNIT 012	W	Active	Lea	32.64323155	-103.7937066	0.99
3002520035	OXY USA INC	3/15/2012	32E	30		19.0S	11325	ELLIOTT HALL B 002	O	Plugged	Lea	32.62966655	-103.8076015	0.99
3002535095	COG OPERATING LLC		32E	20	9/15/2000	19.0S	12750	LUSK DEEP UNIT A 017	G	Active	Lea	32.64051116	-103.7940263	0.99
3001531730	COG OPERATING LLC		31E	13	8/26/2001	19.0S	12725	MARGARET 13 FEDERAL COM 001	O	Active	Eddy	32.65563546	-103.8206837	1.00
3001510056	LYNX PETROLEUM CONSULTANTS INC	5/7/1997	31E	25	1/22/1964	19.0S	11535	JONES B FEDERAL 001	O	Plugged	Eddy	32.62967911	-103.8162737	1.03
3002524974	COG OPERATING LLC		32E	18		19.0S	12520	LUSK DEEP UNIT A 013	G	Active	Lea	32.65870052	-103.8077664	1.04
3002542209	COG OPERATING LLC		32E	18	10/30/2014	19.0S	9269	LUSK DEEP UNIT A 027H	O	Active	Lea	32.65868979	-103.8136472	1.04
3002531039	OXY USA INC		32E	30		19.0S	7300	FEDERAL 30 001	O	Active	Lea	32.62876958	-103.8119619	1.04
3002532448	COG OPERATING LLC		32E	30	7/12/1994	19.0S	7200	FEDERAL USA J 004	O	Active	Lea	32.62965519	-103.8033817	1.06
3002535088	COG OPERATING LLC		32E	30		19.0S	12474	SL DEEP FEDERAL COM 001	G	Active	Lea	32.62965188	-103.8023046	1.09
3002530500	FRED POOL DRLG INC	1/1/1900	32E	18	1/1/1900	19.0S	2820	LUSK FEDERAL 001	O	Plugged	Lea	32.65868527	-103.8034418	1.10
3001510278	DEVON ENERGY PRODUCTION COMPANY, LP	8/25/2014	31E	24		19.0S	11550	JONES D FEDERAL 001	O	Plugged	Eddy	32.64781843	-103.8292158	1.12
3002520156	EL PASO NATURAL GAS	1/1/1900	32E	29	1/1/1900	19.0S	11407	SOUTHERN CALIFORNIA 002	O	Plugged	Lea	32.635975	-103.7936935	1.13
3002539853	CIMAREX ENERGY CO. OF COLORADO		32E	29	10/19/2010	19.0S	9211	SOUTHERN CALIFORNIA 29 FEDERAL 016H	O	Active	Lea	32.63327432	-103.795788	1.13
3001536562	LYNX PETROLEUM CONSULTANTS INC		31E	25		19.0S	0	HOT LIPS 25 FEDERAL 001D	G	New (Not drilled or compl)	Eddy	32.6368649	-103.828388	1.14
3002534173	SHACKELFORD OIL CO		32E	20	11/10/1997	19.0S	6630	LUSK FEDERAL A 011	O	Plugged	Lea	32.64413051	-103.7904772	1.17
3002534032	SHACKELFORD OIL CO		32E	20	9/3/1997	19.0S	7165	LUSK WEST DELAWARE UNIT 006	O	Active	Lea	32.64867077	-103.791076	1.19
3002500927	PAUL E HASKINS	1/1/1900	32E	30	1/1/1900	19.0S	2768	SHELL FEDERAL 001	O	Plugged	Lea	32.62964186	-103.7990734	1.19
3002500901	P B ENGLISH	1/1/1900	32E	18	1/1/1900	19.0S	4016	MILLER 001	O	Plugged	Lea	32.65866928	-103.799132	1.22
3002532447	COG OPERATING LLC		32E	30	6/26/1994	19.0S	7200	FEDERAL USA J 003	O	Active	Lea	32.62963851	-103.7979963	1.22
3001540947	DEVON ENERGY PRODUCTION COMPANY, LP		31E	24	7/14/2013	19.0S	9278	MIMOSA 24 FEDERAL COM 002H	O	Active	Eddy	32.65027953	-103.8308764	1.26
3002534172	CIMAREX ENERGY CO. OF COLORADO	12/3/2011	32E	29	12/12/1997	19.0S	6635	LUSK WEST DELAWARE UNIT 903	I	Plugged	Lea	32.63596771	-103.7907887	1.28
3002531639	MARBOB ENERGY CORP	1/26/2005	32E	18	9/12/1992	19.0S	12650	CRAZY HORSE 18 FEDERAL 001	G	Plugged	Lea	32.66235004	-103.8120901	1.28
3001540626	DEVON ENERGY PRODUCTION COMPANY, LP		31E	24	12/25/2012	19.0S	9272	MIMOSA 24 FEDERAL COM 001H	O	Active	Eddy	32.65155382	-103.8305956	1.28

3001523781	LYNX PETROLEUM CONSULTANTS INC		31E	13	6/13/1981	19.0S	12697	HJ FEDERAL 001	O	Active	Eddy	32.65870991	-103.8238684	1.28
3002530944	YATES PETROLEUM CORPORATION		32E	30	7/16/1990	19.0S	7270	FLOOD AFN FEDERAL 001	O	Active	Lea	32.62514128	-103.811948	1.29
3002539888	CIMAREX ENERGY CO. OF COLORADO		32E	29	11/5/2010	19.0S	9294	SOUTHERN CALIFORNIA 29 FEDERAL 017	O	Active	Lea	32.62959977	-103.7959306	1.30
3001510397	LYNX PETROLEUM CONSULTANTS INC	3/10/2009	31E	13	12/13/1964	19.0S	11,472	SWEENY FEDERAL COM 001	O	Plugged	Eddy	32.65507531	-103.8289155	1.32
3002541390	COG OPERATING LLC		32E	18	12/4/2013	19.0S	9185	CRAZY HORSE FEDERAL COM 002H	O	Active	Lea	32.663	-103.812901	1.33
3001510238	DELHI TAYLOR OIL	2/4/1964	31E	23	7/30/1963	19.0S	2460	JONES FED 2 003	O	Plugged	Eddy	32.64417663	-103.8335116	1.34
3001540099	DEVON ENERGY PRODUCTION COMPANY, LP		31E	26	6/3/2012	19.0S	9266	SPICA 25 FEDERAL 001H	O	Active	Eddy	32.63764168	-103.8324394	1.34
3002520367	COG OPERATING LLC		32E	30		19.0S	11296	FEDERAL USA J 001	O	Active	Lea	32.62692065	-103.7990709	1.35
3002533461	SHACKELFORD OIL CO		32E	29	7/21/1996	19.0S	7210	SOUTHERN CALIFORNIA FEDERAL 912	O	Active	Lea	32.62962901	-103.7947651	1.35
3002535244	COG OPERATING LLC		32E	17	1/1/2001	19.0S	12754	LUSK DEEP UNIT A 019	S	Active	Lea	32.65502131	-103.7915807	1.35
3001540098	DEVON ENERGY PRODUCTION COMPANY, LP		31E	26	4/23/2012	19.0S	9156	REGULUS 26 FEDERAL 001H	O	Active	Eddy	32.63764222	-103.8326026	1.35
3001510394	DEVON ENERGY PRODUCTION COMPANY, LP		31E	23	9/4/1964	19.0S	9800	JONES FEDERAL B 003	O	TA	Eddy	32.6405484	-103.8334983	1.35
3001510395	TENNECO OIL CO	8/15/1972	31E	23	11/14/1964	19.0S	11513	JONES FED E 001	O	Plugged	Eddy	32.64781287	-103.8335248	1.36
3001540222	DEVON ENERGY PRODUCTION COMPANY, LP		31E	25	11/1/2012	19.0S	9264	SPICA 25 FEDERAL 002H	O	Active	Eddy	32.63324027	-103.8304107	1.37
3002521042	EL PASO NATURAL GAS	1/1/1900	32E	17	1/1/1900	19.0S	11470	LUSK DEEP UNIT 011	O	Plugged	Lea	32.65774718	-103.7937425	1.37
3002540154	COG OPERATING LLC		32E	30	6/29/2011	19.0S	13540	SL EAST 30 FEDERAL COM 001H	O	Active	Lea	32.62509867	-103.8024531	1.38
3002532449	TEXACO EXPLORATION & PRODUCTION INC	10/31/1995	32E	30		19.0S	7300	FEDERAL USA J 005	O	Plugged	Lea	32.62511656	-103.8023103	1.38
3002543070	CIMAREX ENERGY CO. OF COLORADO		32E	29		19.0S	0	SOUTHERN CALIFORNIA 29 FEDERAL 019H	O	New (Not drilled or compl)	Lea	32.62797803	-103.7960005	1.39
3002524869	SHACKELFORD OIL CO		32E	20	11/2/1974	19.0S	12759	LUSK FEDERAL A 012	O	Active	Lea	32.64863504	-103.7872798	1.40
3001531362	MARBOB ENERGY CORP	12/29/2000	31E	13	11/15/2000	19.0S	12722	TRAPPER 13 STATE COM 001	G	Plugged	Eddy	32.66234978	-103.8207095	1.40
3002508104	SHELL OIL CO	1/1/1900	32E	18	1/1/1900	19.0S	12505	MIDDELTON A FEDERAL 001	O	Plugged	Lea	32.66230915	-103.8002189	1.41
3001510584	FINA OIL & CHEMICAL	4/20/1994	31E	26		19.0S	11570	JONES FEDERAL 003	O	Plugged	Eddy	32.63692016	-103.8334843	1.42
3001542489	DEVON ENERGY PRODUCTION COMPANY, LP		31E	26	11/25/2014	19.0S	8348	REGULUS 26 FEDERAL 005H	O	Active	Eddy	32.63737102	-103.8337022	1.42
3002521488	SHACKELFORD OIL CO		32E	20	10/5/1962	19.0S	11550	LUSK FEDERAL A 010	O	Active	Lea	32.6441198	-103.7862217	1.42
3002532051	COG OPERATING LLC		32E	30		19.0S	7229	FEDERAL USA J 002	O	Active	Lea	32.62601078	-103.7981726	1.43
3001505784	THREE STATES NAT'L	4/8/1957	31E	23	3/8/1957	19.0S	2561	ANGEL WELCH 001	O	Plugged	Eddy	32.6514411	-103.833538	1.44
3001536750	COG OPERATING LLC		31E	36	6/9/2009	19.0S	8800	WILD CAP STATE 004H	O	Active	Eddy	32.62334788	-103.8155717	1.44
3001540219	DEVON ENERGY PRODUCTION COMPANY, LP		31E	26	9/27/2012	19.0S	9158	REGULUS 26 FEDERAL 002H	O	Active	Eddy	32.63401404	-103.832631	1.45
3002530328	SHACKELFORD OIL CO		32E	29	3/23/1988	19.0S	7204	SOUTHERN CALIFORNIA FEDERAL 007	O	Active	Lea	32.63261117	-103.7895455	1.45
3002530490	SHACKELFORD OIL CO		32E	20	11/2/1988	19.0S	7200	LUSK FEDERAL A 014	O	TA	Lea	32.63958444	-103.7862082	1.45
3002522280	KINCAID & WATSON DRILLING CO	1/1/1900	32E	29	1/1/1900	19.0S	2746	BOWMAN 001	O	Plugged	Lea	32.63233589	-103.7893821	1.47
3002520161	GEORGE A CHASE JR DBA G AND C SERVICE		32E	31	4/8/1963	19.0S	12976	POLEWSKI FEDERAL 001	O	Active	Lea	32.62242005	-103.8119379	1.48
3002530094	SHACKELFORD OIL CO		32E	29	3/23/1988	19.0S	7200	SOUTHERN CALIFORNIA FEDERAL 913	O	Active	Lea	32.6269078	-103.7947626	1.49
3001537265	COG OPERATING LLC		31E	36	6/10/2010	19.0S	10955	WILD CAP STATE 007H	O	Active	Eddy	32.62334417	-103.8196835	1.51
3001538148	COG OPERATING LLC		31E	36		19.0S	0	DIRTY DOZEN STATE COM 001A	O	New (Not drilled or compl)	Eddy	32.62232762	-103.8161291	1.52
3002530165	SHACKELFORD OIL CO		32E	29	1/17/1988	19.0S	6850	LUSK WEST DELAWARE UNIT 911	I	Active	Lea	32.63052202	-103.7898701	1.52
3001510136	MCFARLAND CORP	12/12/1963	31E	13	4/29/1963	19.0S	12693	MALONE FED A 001	O	Plugged	Eddy	32.66234454	-103.8249594	1.52
3002520359	TEXACO EXPLORATION & PRODUCTION INC	1/1/1900	32E	29	1/1/1900	19.0S	11420	SOUTHERN CALIFORNIA 003	O	Plugged	Lea	32.62961665	-103.7904568	1.53
3002535087	COG OPERATING LLC		32E	18	8/1/2000	19.0S	12640	CRAZY HORSE 18 FEDERAL 003	G	Active	Lea	32.66596439	-103.8081208	1.53
3002530329	SHACKELFORD OIL CO		32E	29	4/16/1988	19.0S	7200	LUSK WEST DELAWARE UNIT 902	O	Active	Lea	32.63595549	-103.7859331	1.54
3002535340	TRITEX RESOURCES, L.L.C.	5/22/2009	32E	31	9/11/2002	19.0S	7303	POLEWSKI FEDERAL 002	O	Plugged	Lea	32.62150545	-103.8086776	1.54
3001510495	PHILLIPS PETROLEUM CO & KERR-MCGEE	1/27/1983	31E	14	4/1/1965	19.0S	11575	SIMON FED A 002	O	Plugged	Eddy	32.65506933	-103.8335516	1.54
3002539634	CIMAREX ENERGY CO. OF COLORADO		32E	29	1/22/2010	19.0S	9321	SOUTHERN CALIFORNIA 29 FEDERAL 015H	O	Active	Lea	32.62518814	-103.7959255	1.54
3001540220	DEVON ENERGY PRODUCTION COMPANY, LP		31E	25	9/16/2012	19.0S	9335	SPICA 25 FEDERAL 003H	O	Active	Eddy	32.62891432	-103.8304057	1.55
3001531568	COG OPERATING LLC		31E	13	3/14/2001	19.0S	12875	TRAPPER 13 FEDERAL COM 002	G	Active	Eddy	32.6659826	-103.8170015	1.57
3002539485	COG OPERATING LLC		32E	17		19.0S	0	STEALTH FEDERAL COM 002	O	New (Not drilled or compl)	Lea	32.65413776	-103.7863504	1.58
3002530523	CIMAREX ENERGY CO. OF COLORADO	12/7/2010	32E	20	1/26/1990	19.0S	7220	LUSK WEST DELAWARE UNIT 002	O	Plugged	Lea	32.65232268	-103.7852808	1.59
3002541389	COG OPERATING LLC		32E	18	11/13/2013	19.0S	9220	CRAZY HORSE FEDERAL 001H	O	Active	Lea	32.66690839	-103.8136562	1.60
3002530164	CIMAREX ENERGY CO. OF COLORADO	12/20/2010	32E	29	12/8/1987	19.0S	6850	LUSK WEST DELAWARE UNIT 914	O	Plugged	Lea	32.62689847	-103.791502	1.61
3001537185	COG OPERATING LLC		31E	13	8/28/2009	19.0S	13680	LIBERATOR FEDERAL COM 001H	O	Active	Eddy	32.66690559	-103.8155172	1.61
3001537144	COG OPERATING LLC		31E	36	9/27/2009	19.0S	9280	WILD CAP STATE 005H	O	Active	Eddy	32.62334015	-103.8241467	1.62
3002534031	CIMAREX ENERGY CO. OF COLORADO	6/28/2011	32E	20	10/2/1997	19.0S	6600	LUSK WEST DELAWARE UNIT 016	O	Plugged	Lea	32.64139047	-103.7829818	1.62
3002520813	COG OPERATING LLC		32E	31	9/4/1987	19.0S	11385	FEDERAL USA I 001	O	Active	Lea	32.62238532	-103.7990742	1.62
3002541977	COG OPERATING LLC		32E	32	10/12/2014	19.0S	9397	MAGNUM PRONTO STATE 006H	O	Active	Lea	32.62363513	-103.7959236	1.63
3001540221	DEVON ENERGY PRODUCTION COMPANY, LP		31E	26	12/7/2012	19.0S	9202	REGULUS 26 FEDERAL 003H	O	Active	Eddy	32.62891605	-103.8326251	1.64
3002535750	APACHE CORP		32E	31	5/6/2002	19.0S	12550	TRES ELO FEDERAL COM 001	G	Active	Lea	32.62148161	-103.8001542	1.66
3002530771	ASPEN OIL INC	2/14/1994	32E	31		19.0S	7150	PRINCESS D 002	O	Plugged	Lea	32.61969136	-103.8086967	1.67
3002530524	CIMAREX ENERGY CO. OF COLORADO	6/17/2009	32E	20	3/17/1990	19.0S	7230	LUSK WEST DELAWARE UNIT 009	I	Plugged	Lea	32.64501603	-103.7819154	1.68
3002534132	CIMAREX ENERGY CO. OF COLORADO	4/27/2012	32E	29	11/27/1997	19.0S	6630	LUSK WEST DELAWARE UNIT 907	I	Plugged	Lea	32.6326275	-103.7851045	1.68
3001534038	COG OPERATING LLC		31E	14	6/30/2005	19.0S	12765	CHAPARRAL 14 FEDERAL COM 001	G	Active	Eddy	32.65869755	-103.8335652	1.68
3002500912	CULBERTSON,IRWIN &	1/1/1900	32E	20	1/1/1900	19.0S	2820	LYNCH 004	O	Plugged	Lea	32.64048067	-103.7819019	1.69
3001540105	DEVON ENERGY PRODUCTION COMPANY, LP		31E	25	8/10/2012	19.0S	9305	SPICA 25 FEDERAL 004H	O	Active	Eddy	32.62534104	-103.8304015	1.72
3002530093	CIMAREX ENERGY CO. OF COLORADO	3/22/2011	32E	29	12/5/1987	19.0S	7200	LUSK WEST DELAWARE UNIT 910	O	Plugged	Lea	32.62960429	-103.7861702	1.73
3002520563	MARBOB ENERGY CORP	8/8/2003	32E	32		19.0S	11495	NEW MEXICO CR STATE 001	O	Plugged	Lea	32.62237247	-103.7947666	1.74
3001534784	COG OPERATING LLC		31E	12	12/9/2006	19.0S	10875	MALIBU FEDERAL 001	O	Active	Eddy	32.66871426	-103.8164293	1.75
3001538149	COG OPERATING LLC		31E	36		19.0S	0	DIRTY DOZEN STATE COM 002H	O	New (Not drilled or compl)	Eddy	32.61880913	-103.816323	1.76
3002530494	CIMAREX ENERGY CO. OF COLORADO	3/16/2011	32E	20	11/21/1988	19.0S	7220	LUSK WEST DELAWARE UNIT 008	O	Plugged	Lea	32.64864576	-103.780849	1.77
3002542211	COG OPERATING LLC		32E	20	11/22/2014	19.0S	8544	LUSK DEEP UNIT A 035H	O	Active	Lea	32.64778306	-103.7804543	1.78
3002534131	SHACKELFORD OIL CO		32E	29	10/24/1997	19.0S	6927	LUSK WEST DELAWARE UNIT 901	I	Active	Lea	32.63775673	-103.7808156	1.79
3002500926	TEXACO EXPLORATION & PRODUCTION INC	1/1/1900	32E	29	1/1/1900	19.0S	2770	BOWMAN FEDERAL 001	O	Plugged	Lea	32.62507818	-103.7893756	1.79
3002530133	TEXACO EXPLORATION & PRODUCTION INC	1/1/1900	32E	32	1/1/1900	19.0S	6863	NEW MEXICO CR STATE 004	O	Plugged	Lea	32.62327017	-103.7914938	1.80
3001540041	DEVON ENERGY PRODUCTION COMPANY, LP		31E	26	4/13/2012	19.0S	9247	REGULUS 26 FEDERAL 004H	O	Active	Eddy	32.62534275	-103.8326209	1.81
3002520875	EL PASO NATURAL GAS	1/1/1900	32E	17	1/1/1900	19.0S	11510	LUSK DEEP UNIT 009	O	Plugged	Lea	32.66591922	-103.7937636	1.81
3002539484	COG OPERATING LLC		32E	17	12/18/2009	19.0S	8528	STEALTH FEDERAL COM 001H	O	Active	Lea	32.65413374	-103.7818448	1.82
3002541563	COG OPERATING LLC		32E	17	1/17/2014	19.0S	9244	LUSK DEEP UNIT A 029H	O	Active	Lea	32.66673844	-103.7948863	1.82
3002539889	CIMAREX ENERGY CO. OF COLORADO		32E	29	12/6/2010	19.0S	9316	SOUTHERN CALIFORNIA 29 FEDERAL 018H	O	Active	Lea	32.63557003	-103.7808348	1.83
3002500925	CIMAREX ENERGY CO. OF COLORADO	6/19/2011	32E	29	3/23/1962	19.0S	12833	LUSK WEST DELAWARE UNIT 908	O	Plugged	Lea	32.63322408	-103.7818755	1.83

3002530518	SHACKELFORD OIL CO		32E	20	11/15/1989	19.0S	7500	LUSK WEST DELAWARE UNIT 001	I	Active	Lea	32.65227679	-103.7808598	1.83
3002536157	COG OPERATING LLC		32E	32	3/19/2003	19.0S	12700	MAGNUM PRONTO STATE COM 001	O	Active	Lea	32.62146235	-103.7936928	1.83
3001535754	APACHE CORP		31E	12		19.0S	0	APACHE FEDERAL 003C	O	New (Not drilled or compl)	Eddy	32.66938203	-103.8196596	1.84
3002538736	COG OPERATING LLC		32E	32	4/10/2008	19.0S	9282	MAGNUM PRONTO STATE 003H	O	Active	Lea	32.62325158	-103.7905376	1.84
3002543124	COG OPERATING LLC		32E	20		19.0S	0	LUSK DEEP UNIT A 031H	O	New (Not drilled or compl)	Lea	32.65185113	-103.7804908	1.84
3001510114	H N SWEENY	8/15/1963	31E	14	6/30/1963	19.0S	625	ROSS 001	O	Plugged	Eddy	32.66233422	-103.8335788	1.85
3001505783	RAY WESTALL OPERATING, INC.		31E	23	7/25/1957	19.0S	12775	JONES FEDERAL 002	O	Active	Eddy	32.64780187	-103.8420902	1.86
3001523159	COG OPERATING LLC		31E	13	3/10/1980	19.0S	13060	TRAPPER 13 FEDERAL COM 003	G	Active	Eddy	32.66572008	-103.8292817	1.86
3002530694	SHACKELFORD OIL CO	10/8/2012	32E	21	7/15/2011	19.0S	7240	MOBIL FEDERAL 003	O	Plugged	Lea	32.64500802	-103.7786836	1.86
3002533548	SHACKELFORD OIL CO		32E	21	7/29/1996	19.0S	5070	MOBIL FEDERAL 007	O	Active	Lea	32.64528289	-103.7786845	1.86
3002530597	ENDURANCE RESOURCES LLC		32E	17	7/1/1999	19.0S	7205	PIPELINE FEDERAL 001	O	Active	Lea	32.65409092	-103.7808649	1.87
3001542412	COG OPERATING LLC		31E	12	6/29/2015	19.0S	9136	AIRBUS 12 FEDERAL 003H	O	Active	Eddy	32.66827766	-103.8250493	1.88
3002530439	CIMAREX ENERGY CO. OF COLORADO	12/13/2010	32E	21	6/14/1988	19.0S	6700	LUSK WEST DELAWARE UNIT 105	I	Plugged	Lea	32.6486433	-103.7786945	1.89
3002534283	CIMAREX ENERGY CO. OF COLORADO	5/16/2013	32E	29	2/16/1998	19.0S	6630	LUSK WEST DELAWARE UNIT 909	I	Plugged	Lea	32.62959455	-103.7827758	1.90
3001510045	LYNX PETROLEUM CONSULTANTS INC	6/27/1997	31E	23		19.0S	12853	JONES FEDERAL 001	S	Plugged	Eddy	32.64325734	-103.8431511	1.90
3002534269	CIMAREX ENERGY CO. OF COLORADO	9/1/2012	32E	29	5/15/1998	19.0S	6630	LUSK WEST DELAWARE UNIT 915Y	I	Plugged	Lea	32.62539941	-103.786383	1.90
3002534130	PIONEER NATURAL RESOURCES USA INC	1/13/1998	32E	29	12/31/1997	19.0S	4210	LUSK WEST DELAWARE UNIT 915	I	Plugged	Lea	32.62539894	-103.7862198	1.91
3001505781	DON ANGLE	6/25/1972	31E	23	1/15/1958	19.0S	2452	ANGLE FED 001	O	Plugged	Eddy	32.65143011	-103.8421032	1.91
3001535526	COG OPERATING LLC		31E	36	4/18/2007	19.0S	12950	WILD CAP STATE COM 002	O	Active	Eddy	32.61880398	-103.8250771	1.92
3002520877	CIMAREX ENERGY CO. OF COLORADO		32E	29	3/8/1964	19.0S	11449	SOUTHERN CALIFORNIA FEDERAL 004	O	Active	Lea	32.62868794	-103.7829356	1.92
3002542200	COG OPERATING LLC		32E	8	1/16/2015	19.0S	9234	KING AIR 8 FEDERAL COM 004H	O	Active	Lea	32.66787978	-103.7938367	1.92
3002520323	PAN AMERICAN PETROLEUM CORP	1/1/1900	32E	21	1/1/1900	19.0S	11517	PLAINS UNIT 004	O	Plugged	Lea	32.64396096	-103.7776033	1.92
3002500915	CULBERTSON & IRWIN	1/1/1900	32E	21	1/1/1900	19.0S	2820	LYNCH 002	O	Plugged	Lea	32.6440984	-103.7776037	1.92
3001510704	TENNECO OIL CO	1/2/1966	31E	23	2/2/1965	19.0S	11330	JONES FED COM 001	O	Plugged	Eddy	32.65142969	-103.8424297	1.93
3002530496	SHACKELFORD OIL CO		32E	21	9/23/1988	19.0S	6650	LUSK WEST DELAWARE UNIT 104	O	Active	Lea	32.65136451	-103.7787026	1.93
3002520518	CIMAREX ENERGY CO. OF COLORADO	9/21/2004	32E	21	1/4/1964	19.0S	11514	PLAINS UNIT FEDERAL 004Y	O	Plugged	Lea	32.64060755	-103.7775933	1.94
3002500914	SHACKELFORD OIL CO	12/12/1946	32E	21	10/4/1946	19.0S	2886	LYNCH 001	O	Plugged	Lea	32.64047012	-103.7775928	1.94
3002533317	SHACKELFORD OIL CO		32E	21	7/17/1996	19.0S	2798	MOBIL FEDERAL 006	O	Active	Lea	32.64025297	-103.7775922	1.94
3002520769	SHACKELFORD OIL CO		32E	21		19.0S	11690	PLAINS 006	O	Active	Lea	32.6477334	-103.7776145	1.94
3002540705	COG OPERATING LLC		32E	17	9/18/2012	19.0S	13670	LUSK DEEP UNIT A 022H	O	Active	Lea	32.6668283	-103.7912624	1.94
3002541476	COG OPERATING LLC		32E	17		19.0S	0	KING AIR 8 FEDERAL COM 003H	O	New (Not drilled or compl)	Lea	32.66661203	-103.7906418	1.95
3002539953	CIMAREX ENERGY CO. OF COLORADO		32E	32		19.0S	0	SOUTH LUSK 32 STATE COM 002	O	New (Not drilled or compl)	Lea	32.62325233	-103.7873146	1.96
3001536032	COG OPERATING LLC		31E	36	2/9/2008	19.0S	9354	WILD CAP STATE 003H	O	Active	Eddy	32.6160758	-103.8195489	1.98
3002500923	SHACKELFORD OIL CO	12/12/1946	32E	28	1/28/1942	19.0S	2811	BOWMAN FEDERAL 001	O	Plugged	Lea	32.63682541	-103.7776135	1.98
3002500917	KERSEY & COMPANY	1/1/1900	32E	21	1/1/1900	19.0S	2710	ATLANTIC 001	O	Plugged	Lea	32.64318877	-103.7765237	1.99
3002534217	CIMAREX ENERGY CO. OF COLORADO	2/28/2011	32E	29	1/30/1998	19.0S	6630	LUSK WEST DELAWARE UNIT 916	O	Plugged	Lea	32.62638042	-103.7834166	1.99
3001540714	BOPCO, L.P.		31E	35	1/26/2013	19.0S	9230	BIG EDDY UNIT 248H	O	Active	Eddy	32.62101119	-103.8315631	1.99
3002535296	COG OPERATING LLC	8/16/2015	32E	8	1/19/2001	19.0S	12710	WBP FEDERAL 001	O	Plugged	Lea	32.6695499	-103.7948492	2.00
3001540715	BOPCO, L.P.		31E	35	12/14/2012	19.0S	9220	BIG EDDY UNIT 249H	O	Active	Eddy	32.62090124	-103.8315635	2.00
3001533062	COG OPERATING LLC		31E	36	5/16/2006	19.0S	12941	WILD CAP STATE COM 001	O	Active	Eddy	32.61516131	-103.8162177	2.00

Note: No data is available in NMOCD files for Jones 003 (3001505787) and Jones 005 (3001505788)

Figure A1: Wells within Two Miles of Proposed Zia AGI #2D

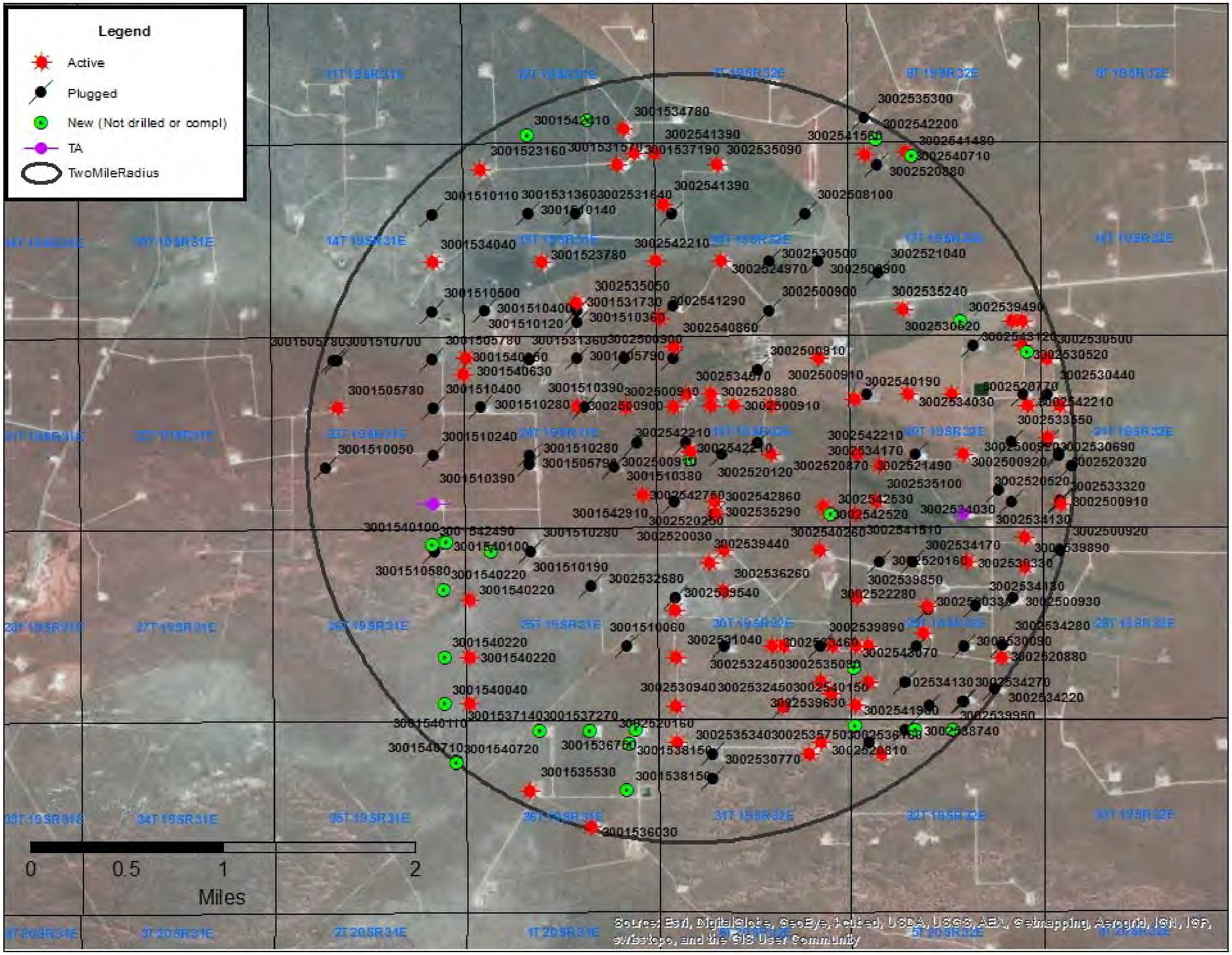


Figure A1: Wells Within Two Miles of Proposed Zia AGI #2D

Exhibit A1: Plugging Records and Drilling Logs, Lusk Deep Unit #2

Form 9-331
(May 1963)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN TRIPLICATE*
(Other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R1424.

5. LEASE DESIGNATION AND SERIAL NO.
LC 064198A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME

SUNDRY NOTICES AND REPORTS ON WELLS

(Do not use this form for proposals to drill or to deepen or plug back to a different reservoir.
Use "APPLICATION FOR PERMIT—" for such proposals.)

1. OIL WELL [X] GAS WELL [ ] OTHER

7. UNIT AGREEMENT NAME
Lusk Deep Unit

2. NAME OF OPERATOR
El Paso Products

8. FARM OR LEASE NAME
Lusk Deep Unit

3. ADDRESS OF OPERATOR
c/o Hobbs Pipe & Supply Co., Box 2010, Hobbs, N.M.

9. WELL NO.
2

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface

660' FSL & 1980' FEL

10. FIELD AND POOL, OR WILDCAT
Lusk Strawn/Morrow

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
Sec.18,T19S,R32E

14. PERMIT NO.

15. ELEVATIONS (Show whether DF, RT, GR, etc.)
3585'

12. COUNTY OR PARISH
Lea

13. STATE
N.M.

16. **Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data**

NOTICE OF INTENTION TO:

TEST WATER SHUT-OFF	[ ]	PULL OR ALTER CASING	[ ]
FRACTURE TREAT	[ ]	MULTIPLE COMPLETE	[ ]
SHOOT OR ACIDIZE	[ ]	ABANDON*	[ ]
REPAIR WELL	[ ]	CHANGE PLANS	[ ]
(Other)			

SUBSEQUENT REPORT OF:

WATER SHUT-OFF	[ ]	REPAIRING WELL	[ ]
FRACTURE TREATMENT	[ ]	ALTERING CASING	[ ]
SHOOTING OR ACIDIZING	[ ]	ABANDONMENT*	[X]
(Other)			

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

1 - Spotted 30 sx cement plug @ 12,350'.
2 - Spotted 35 sx cement plug @ 11,200'.
3 - Spotted 35 sx cement plug @ 7,000' at Bone Springs.
4 - Spotted 50 sx cement plug @ base of 13 3/8" and 9 5/8" csg. stub at 4462'.
5 - Spotted 35 sx cement plug @ 2900'.
6 - Spotted 10 sx cement plug at surface with marker.
7 - Hole was loaded with mud-laden fluids.
8 - Well was plugged and abandoned on 9/4/71.

18. I hereby certify that the foregoing is true and correct

SIGNED [signature] TITLE Agent DATE 9/9/71

(This space for Federal or State office use)

APPROVED BY ______ TITLE ______ DATE ______
CONDITIONS OF APPROVAL, IF ANY:

4 72

*See Instructions on Reverse Side

J L C
ACTING DISTRICT ENGINEER

Form 9-330

Budget Bureau No. 42-R355.4.
Approval expires 12-31-60.

U. S. LAND OFFICE New Mexico

SERIAL NUMBER LC 064198 A

LEASE OR PERMIT TO PROSPECT Lusk Deep Unit

Sec. 18

x

R-32-E

LOCATE WELL CORRECTLY

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

LOG OF OIL OR GAS WELL

Company El Paso Natural Gas Company Address 2005 Wilco Building, Midland, Texas

Lessor or Tract Lusk Deep Unit Field Lusk - Strawn (Lusk-Morrow Undesignated) State New Mexico

Well No. 2 Sec. 18 T-19-S R.-32-E Meridian NMPM County Lea

Location 660' ft. S. of S Line and 1980 ft. E. of E Line of Sec. 18 Elevation 3585 GL (Derrick floor relative to sea level)

The information given herewith is a complete and correct record of the well and all work done thereon so far as can be determined from all available records.

Signed

Date April 14, 1961 Title

The summary on this page is for the condition of the well at above date.

Commenced drilling October 16, 1960 Finished drilling March 13, 1961

OIL OR GAS SANDS OR ZONES

(Denote gas by G)

No. 1, from 11,220 to 11,250' No. 4, from to

No. 2, from 12,380 to 12,398' No. 5, from to

No. 3, from to No. 6, from to

IMPORTANT WATER SANDS

No. 1, from to No. 3, from to

No. 2, from to No. 4, from to

CASING RECORD

Size casing	Weight per foot	Threads per inch	Make	Amount	Kind of shoe	Cut and pulled from	Perforated From—	Perforated To—	Purpose
13 3/8	72#	8 round	new	4462'	Halliburton				Surface
9 5/8	53.5#; 47#; 43.5#	Buttress	"	11400'	"		11,220	11,250	Intermediate
5" liner	18#	8 round	"	13551' (bottom) 11299' (top)			12380	12,398	Production

MUDDING AND CEMENTING RECORD

Size casing	Where set	Number sacks of cement	Method used	Mud gravity	Amount of mud used
13 3/8	4462'	3400	pump & plug		
9 5/8	11400'	525	"		
5	13551' (bottom) 11299' (top)	717 cubic ft.	"		

FOLD | MARK

PLUGS AND ADAPTERS

Heaving plug—Material Length Depth set

Adapters—Material Size

SHOOTING RECORD

Size	Shell used	Explosive used	Quantity	Date	Depth shot	Depth cleaned out

TOOLS USED

Rotary tools were used from 0 feet to 13,974 feet, and from feet to feet

Cable tools were used from feet to feet, and from feet to feet

DATES

Dually Completed 3/31, 1961 Put to producing (Strawn) 4/1, 1961

The production for the first 24 hours was 640.6 barrels of fluid of which 100 % was oil; 0 % emulsion; % water; and % sediment. Gravity, °Bé.

If gas well, cu. ft. per 24 hours Gallons gasoline per 1,000 cu. ft. of gas

Rock pressure, lbs. per sq. in. 5799 (BHP - Strawn - datum point -7585)
(Morrow zone shut-in awaiting gas line)

EMPLOYEES

, Driller , Driller

, Driller , Driller

FORMATION RECORD

FROM—	TO—	TOTAL FEET	FORMATION
0	733	733	redbed
733	1044	311	anhydrite, dolo
1044	2290	1246	salt
2290	2563	273	dolo, anhydrite
2563	2945	382	anhydrite, sand
2945	4515	1570	anhydrite, dolo
4515	6985	2470	dolo, sand, anhydrite
6985	10280	3295	lime, sand
10280	11070	790	lime, sand
11070	11505	435	lime
11505	12510	1005	shale, sand, lime
12510	12605	95	lime
12605	12755	150	shale
12755	13300	545	lime
13300	13414	114	shale
13414	13974	560	lime, dolo, chert

FROM—	TO—	TOTAL FEET	FORMATION

TOPS

Anhydrite	733
Salt	1044
Tansill	2290
Yates	2563
Seven Rivers	2945
Delaware Mountain	4515
Bone Springs	6985
Wolfcamp	10280
Strawn	11070
Atoka	11505
Barnett	12605
Mississippian	12755
Woodford	13300
Devonian	13414

16—43094-2 U. S. GOVERNMENT PRINTING OFFICE

HISTORY OF OIL OR GAS WELL

It is of the greatest importance to have a complete history of the well. Please state in detail the dates of redrilling, together with the reasons for the work and its results. If there were any changes made in the casing, state fully, and if any casing was "sidetracked" or left in the well, give its size and location. If the well has been dynamited, give date, size, position, and number of shots. If plugs or bridges were put in to test for water, state kind of material used, position, and results of pumping or bailing.

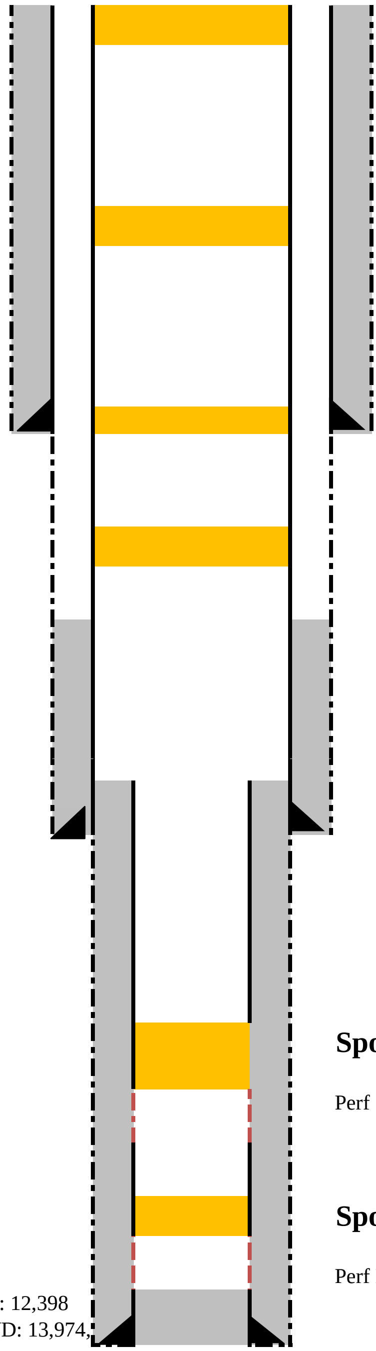
This well is a dual completion, but at the present time only the upper zone (Strawn) is being produced.
The lower zone (Morrow) will be shut-in until a gas pipeline is available to this area.
There are two strings of tubing in this well. The No. 1 string of 2 3/8" EUE is landed @ 12,416' with a packer set @ 12,280'. The No. 2 string of 2 3/8" EUE is landed @ 11,164' with a packer set @ 11,069'.

Figure A2: Plugging Diagram for Lusk Deep Unit #2

Figure A-2

Plugging Diagram for Lusk Deep Unit

Location: Lusk Deep Unit 02
STR Section 18, T19S-R32E
County, St.: LEA COUNTY, NEW MEXICO



Spotted w/10 Sx @ Surface

Spotted w/35 Sx @ 2,900'

SURFACE CASING
13 3/8", 72.00#/ft, at 4,462'
Cmt Circulated to Surface

Spotted w/50 Sx @ 4,462 (Base of Srf Csg)

Spotted w/35 Sx @ 7,000' (Bone Springs)

INTERMEDIATE CASING:
9 5/8", 53.5 #/ft, at 11,400
TOC 8,990'

LINER
5" from 11,299 - 13,551
Cmt to top liner

Spotted w/35 Sx @ 11,200'

Perf Strawn 11,220 - 11,250'

Spotted w/30 Sx @ 12,350'

Perf Morrow 12,380' - 12,398'

PB: 12,398
TVD: 13,974,

NOT TO SCALE

APPENDIX P

CONCHO DRILLING AND COMPLETION PROGNOSES

Concho Drilling Prognosis

ZIA AGI #2D

DRILLING PROGRAM

API: 30-025-42207

LEA COUNTY, NM

CONCHO SIGNATURES:

TIM D. SMITH – DRLILLING ENGINEER

Timothy D Smith 10/18/16

DAVID GIFFIN – DRILLING ENGINEERING LEAD

David Giffin 10/17/16

SETH WILD – DRILLING SUPERINTENDENT

10-24-16

JOHN COFFMAN – DRILLING OPERATIONS MANAGER

John Coffman

DCP MIDSTREAM, LP SIGNATURES:

TONY CANFIELD – PROJECT ENGINEERING MANAGER

10-25-16

Lea County, NM
Section 19 T19S R32E

SHL
1893' FSL
950' FWL

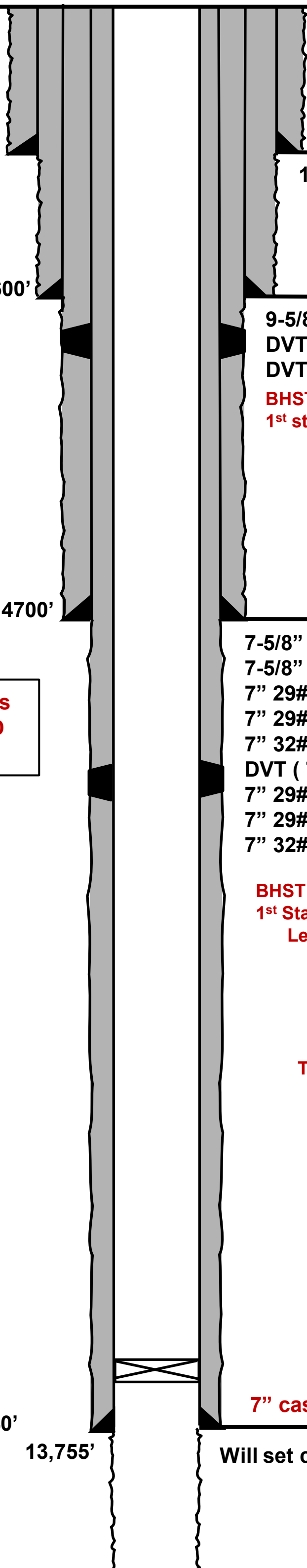
KB: 3572' GL: 3547'

Zia AGI #2D
API: 30-025-42207
Lat/Long: 32°38'38.29"N / 103°46'40.02"W

Well Type: Devonian AGI
DCP Midstream, LP

Rig:	Scan Freedom
Cmt:	Halliburton
Mud:	Nova
Dir Drlg:	Integrity
Wellhead:	GE Oil & Gas
Casing:	CRA / JD Rush
Float Equip:	DL / HES

AFE Cost:	$4,586,167
AFE Days:	47



Rustler @ 740'
Top of Salt @ 889'
Base of Salt @ 2353'
Yates @ 2426'
7 Rivers @ 2652'
Reef @ 2760'
Base of Reef @ 4436'
Delaware @ 4718'
Bone Spring @ 7046'
Wolfcamp @ 10,270'
Strawn @ 11,120'
Atoka @ 11,549'
Morrow @ 12,075'
Mississippian @ 12,665'
Miss Lime @ 13,065'
Woodford @ 13,615'
Devonian/Silurian @ 13,740'
Fusselman @ 14,031'
Montoya @ 14,511'

Offset Acid Gas Injections
F/ 5400' TVD – 6100' TVD
DVT @ ~ 6,350'

20" 106.5# J-55 BTC @ 800'

Lead: 1175 sx
Class C + 4%Gel
13.5 ppg 1.75 ft^3/sx

Tail: 250 sx
Class C + 1% $CaCl_2$
14.8 ppg 1.34 ft^3/sx

Bit Size: 26"
Surface Mud:
FW Spud Mud
8.4 ppg
FV 28-29
WL NC

13-3/8" 61# J-55 BTC @ 2,600'

Lead: 1700 sx
Class C + 4%Gel
13.5 ppg 1.75 ft^3/sx
100% excess

Tail: 250 sx
Class C + 1% $CaCl_2$
14.8 ppg 1.34 ft^3/sx

Bit Size: 17-1/2"
Intrmd Mud:
Brine
10 ppg,
FV @ 28-29
WL NC

9-5/8" 40# L80 BTC @ 4,700'
DVT/ECP 100' above Reef.
DVT/ECP min 50' below 13-3/8" shoe.

BHST @ 4700' is 115° F
1st stg: Lead: 525 sx
35:65:6 C Blend
12.7 ppg 2 ft^3/sx
TT: 4:30+
Tail: 250 sx
Class C
14.8 ppg 1.34 ft^3/sx
TT: 3:00

BHST @ 2650' is 95° F
2nd stg: Lead: 650 sx
Class C + 4% Gel
13.5 ppg 1.75 ft^3/sx
TT: 4:30
Tail: 100 sx
Class C + 1% CaCl2
14.8 ppg 1.34 ft^3/sx
TT: 3:00

Bit Size: 12-1/4"
Intrmd 2 Mud:
FW
8.4 ppg
FV 28-29
WL NC

7-5/8" 33.7# HCP110 LTC 0 – 300'
7-5/8" 33.7# LTC Box X 7" 29# LTC Pin (XO)
7" 29# HCP110 LTC f/ 300' – 5000'
7" 29# LTC Box X 7" 32# VAM TOP Pin (XO)
7" 32# SM2035-110 VAM TOP f/ 5000' – 6350'
DVT (7" 32# VAM TOP box X 7" 29# LTC pin)
7" 29# HCP110 LTC f/ 6350' – 13,455'
7" 29# LTC Box X 7" 32# VAM TOP Pin (XO)
7" 32# SM2035-110 VAM TOP f/ 13,455' – 13,755' (FE to match)

BHST @ 13,755' is 200° F
1st Stage
Lead: 650 sx
50:50:10 H Blend
11.9 ppg 2.5 ft^3/sx
TT: 5:30+
40% Excess + 100 sx
Tail: 40 BBLs
WellLock Resin
12.5 ppg
TT: 4:00+

BHST @ 6350' is 130° F
2nd stage
Lead: 350 sx
50:50:10 C Blend
11.9 ppg 2.51 ft^3/sx
TT: 3:00+
Tail: 80 BBLs
WellLock Resin
12.5 ppg
TT: 3:00+

Bit Size: 8-3/4"
Prod Mud:
WBM
9.0 – 11 ppg
See
Mud Program

7" casing pt to be picked by mud loggers. 15' into the Devonian.

Will set comp bridge plug inside the 7" before installing disposal head

Formation Evaluation

- Gyro @ TD
- Mud log out from 9-5/8" intermediate
- Open Hole logs – see log prog

Bit Size: 6"
OH Mud:
Fresh
8.4 – 9.2 ppg

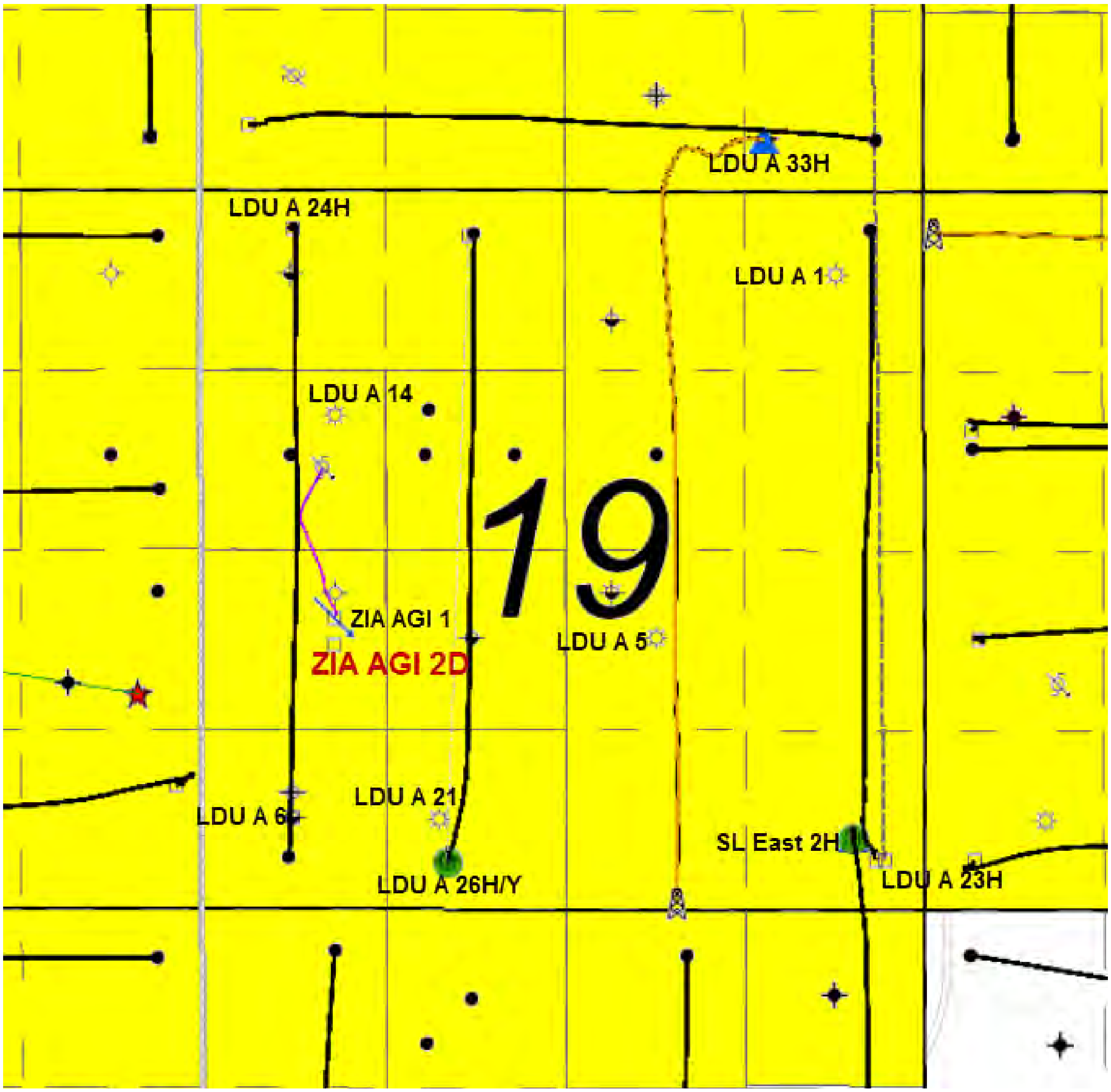
Smith: 10/12/16

Pre Spud

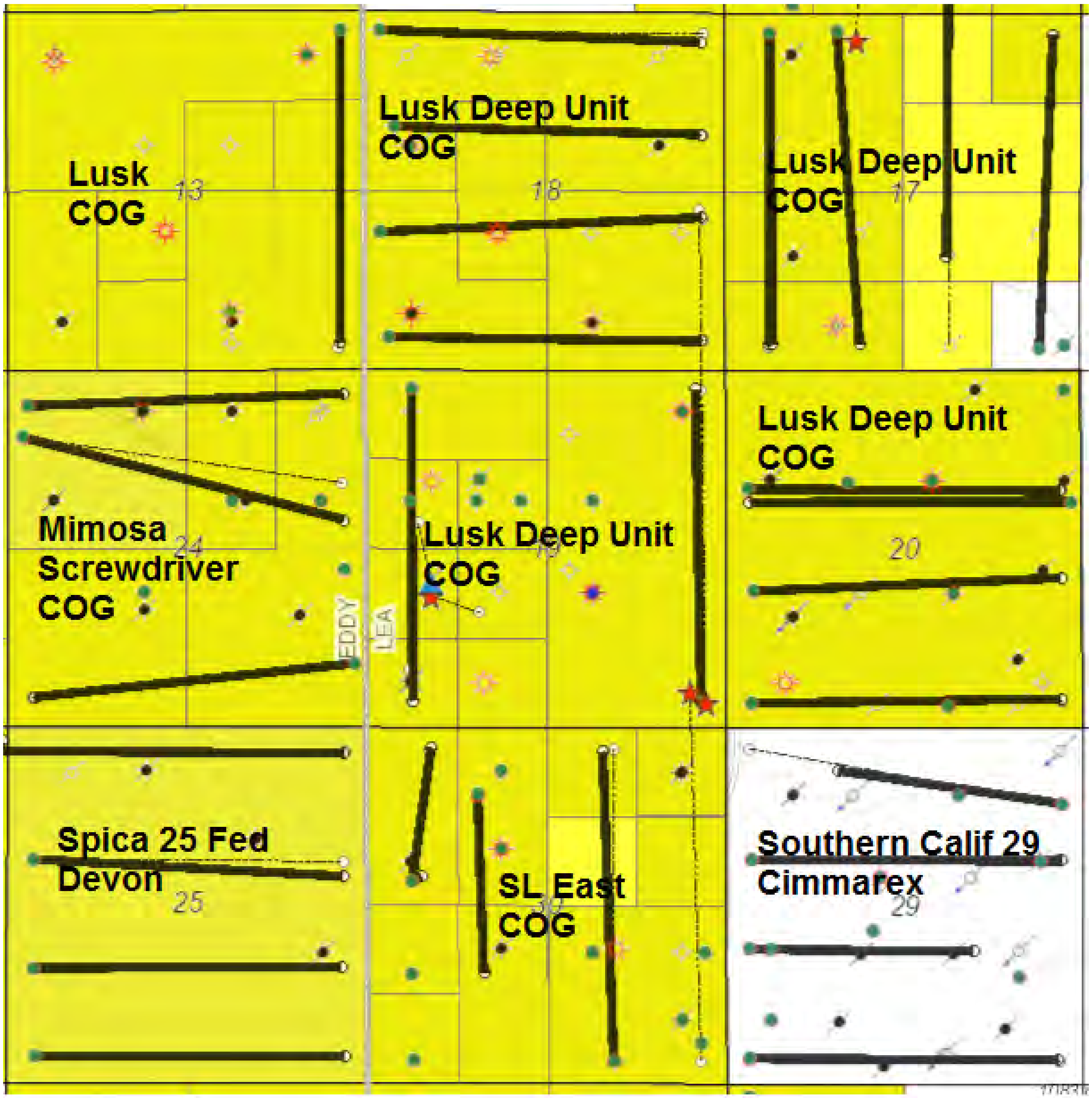
1. Set 120’ of 30” conductor and drill MH.
2. MIRU drilling rig, surface rentals
3. Contact Assistant Drlg Supt for frac pond use. If not water will have to be trucked.
4. Weld on 30” Conductor pipe (with 2” connection on bottom for fill up and flush line).
5. Rig up all safety equipment.
6. Perform pre-spud inspection (email in rig inspection report)
7. **Notify regulatory agency (BLM & OCD) 4 hours prior to spud, cementing any casing string, and all BOP tests. Document notifications on the IADC report and the daily drilling report.**
8. **We will follow the DCP safety guidelines for this well along with our own safety rules. Please see attached DCP presentation for safety information.**
9. **Please Read all Federal permits and COA’s.**
10. **ALL CHARGES FOR THE ZIA AGI #2D WILL GO TO DCP MIDSTREAM, LP. NOTHING WILL BE CHARGED TO CONCHO. Have sign on the door stating this.**
11. **Torque Turn will be utilized on all casing jobs to ensure proper running is recorded. Please attach the torque turn filse to Well View for the ZIA AGI #2D.**

Section Offset Map:

Section 19 / Township 19 South / Range 32 East



Large Scale Offset Map:



26" Surface 120' - 800'

Objective: Drill a 26" hole to ~800' and set 20" casing to protect usable water intervals and unstable intervals above the Rustler. The COA states we need to set below the Magenta Dolomite (this could be as deep as 840'). Cement must be circulated to surface.

Notes: All casing strings will be circulated to surface and have a 360° CBL run on them. Gamma Ray will be logged in all intervals, also. We will run a fluid caliper before TOOH to run casing to conifrm cmt volume.

Procedure:

1) PU BHA with Gamma Ray.
2) Drill to TD
   - Take surveys every 100' and at TD, if angle increases survey as hole dictates
   - Run both pumps while drilling this section
3) Run a fluid caliper to confirm we will circulate cmt with the planned volume on location.
4) Spot 50 bbl ~65 FV pill on btm
5) TOH to run casing
6) RU casing crew and run the surface casing (see casing/cement section)
7) Circulate at least 1 bottom's up or 1-1/2 casing volumes prior to pumping cement. (RD csg crew/RU cmtrs)
8) Hold PJSM. Mix and pump cement as per the cementing program (see casing/cement section).
   - Do not over displace. If floats fail, maintain pressure on the casing for ±4 hours. If cement does not circulate, contact Asst Drlg Supt, Drlg Supt or Drlg Eng for remedial instructions. Report PD time and date, if the floats held and how much cmt was circulated on daily drlg report in activity summary.
9) WOC with casing in tension.
10) Run SLB 360° cement bond log.
    - Halliburton will supply SLB with a UCA plot for each cmt blend to get an exact CBL WOC time (for this surface blend it will be roughly 16 hrs)
    - Geolex & BLM will have to approve the CBL before we cut off.
    - After CBL has been approved make rough cut.
11) Make final cut and install 20-3/4" 3M x 20" SOW w/ Base Plate. (See attached GE documentation for wellhead info)
12) NUBOP 20" 2M annular, RU H_2S Equipment & gas buster
13) Pressure test the wellhead, BOP Equipment after the lead and tail cement have 500 psi comp strength.
14) Can drill out after successful tests have been completed and CBL has been run.

Mud:

MW	Visc.	PV	YP	FL	pH	% Solids	Cl^-
8.4 – 8.8	28 - 34	4-12	4-20	NC	9-10	3-8%	FW
• See Nova mud recommendation							

Surveys:
Take surveys every 100' and then at TD, if hole angle increases survey as hole dictates.

CASING & CEMENTING – 20” Section

CASING						
Size	**Wt./ft.**	**Grade**	**Conn**	**Top**	**Bottom**	**Length**
20”	106.5#	J-55	BTC	0’	800’	800’

Casing Details					
ID:	19	In	**Collapse Rating:**	770	Psi
Drift:	18.813	In	**Burst Rating:**	2410	Psi
Connection OD:	21.00	In	**Body Yield:**	1685	Mlbs
MU Torques:	Δ		**Joint Strength:**	1596	Mlbs

- **Make up max for BTC is 25 RPM**
- **Torque turn will be utilized to ensure proper rng procedures**

Float Equipment & Accessories			
Item	**Model**	**Depth**	**Remarks**
Guide Nose Shoe	Davis Lynch	800	
1 joint of Casing			
Float Collar	Davis Lynch	755	
Casing			
		Quantity	
Centralizers	Davis Lynch	10	Cents on btm 3 jts starting with shoe joint & one centralizer every other joint until gone.
Latch-on stop ring		1	Use stop collar with set screws. 1 required on shoe joint.

Cement	
Spacer:	30 bbls fresh water
Lead:	1175 sx Class C + 4% gel @ 13.5 ppg, 1.75 cuft/sx
Tail:	250 sx Class C + 1% $CaCl_2$ @ 14.8 ppg, 1.35 cuft/sx
Displacement:	.3507 bbl/ft = 20” 106.5# csg

Component	High Test Pressure	Low Test Pressure	Duration
Annular Preventer	2000 psi	250 psi	10 min
Manifold	2000 psi	250 psi	10 min
Upper / Lower / Kelly valves	2000 psi	250 psi	10 min
TIW safety valves / Dart	2000 psi	250 psi	10 min
Mud hose, standpipe, and mud line to pumps	2000 psi	-	30 min
Casing (with 10.0 ppg fluid)	1000 psi	-	30 min

17-1/2” Intermediate 800’ – 2,600’

Objective: Drill a 17-1/2” hole to ~2600’ and set 13-3/8” casing to isolate the salt sections before drilling the Capitan Reef. Cement will be circulated to surface.

Notes: There is potential for crooked hole in the salt section, we will use directional tools for SHC. This entire section needs to be drilled on brine to prevent washout. We will run an OH caliper log to confirm cmt volume.

Procedure:

1. PU directional BHA w/ Gamma Ray.
2. Drill out and Drill ahead to TD
   - Run both pumps while drlg this section
   - Take surveys every 200’ with MWD. Monitor inclination as needed for deviation. Watch the BOS closely for deviation.
3. Sweep to ensure hole is clean.
4. TOH (LD tools not needed for next hole section)
5. Run SLB OH Caliper to confirm cement volumes.
6. RU casing crew and run casing. Run csg fluid filled per COA. (see casing/cement section)
7. Circulate at least 1 bottom’s up. (RD csg crew/RU cmtrs)
8. Hold PJSM. Mix and pump cement as per the cementing program (see casing/cement section).
   - Do not over displace. If floats fail, maintain pressure on the casing for ±4 hours. If cement does not circulate, contact Asst Drlg Supt, Drlg Supt or Drlg Eng for remedial instructions. Report PD time and date, if the floats held and how much cmt was circulated on daily drlg report in activity summary.
9. Lift stack and set slips ASAP (do not allow cement to set up and keep pipe from being centered)
10. WOC for 4 hours before making rough cut
11. Make final cut and install 20-3/4” 3M x 13-5/8” 5M well head. (See attached GE documentation for well head info)
12. NU BOP stack
13. Pressure test the wellhead, BOP Equipment and casing after 8 hrs or tail cement has reached 500 psi. Whichever is longer.
14. Run SLB 360° cement bond log.
    - Halliburton will supply SLB with a UCA plot for each cmt blend to get an exact CBL WOC time (for this intermediate blend it will be roughly 16 hrs)
15. Geolex & BLM have to approve the CBL before we drill out.
16. Can drill out after successful tests and approved CBL.

Mud:

Interval	MW	Visc.	PV	YP	FL	pH	% Solids	Cl^-
Intermediate	10.0	28 - 29	-	-	NC	9-10	1%	180,000+
• See Nova mud recomendation for brine section.								

Surveys:
Take a survey 200’ below casing shoe then every 200’ to TD. If hole angle increases, survey every as hole dictates. Watch BOS transition closely for deviation.

CASING & CEMENTING 13-3/8” Section

CASING						
Size	**Wt./ft.**	**Grade**	**Conn**	**Top**	**Bottom**	**Length**
13-3/8”	61	J-55	BTC	0’	2600’	2600’

Casing Details					
ID:	12.515	In	**Collapse Rating:**	1540	Psi
Drift:	12.359	In	**Burst Rating:**	3090	Psi
Connection OD:	14.375	In	**Body Yield:**	962	Mlbs
MU Torques:		**Δ**	**Joint Strength:**	1025	Mlbs

- **Make up max for BTC is 25 RPM**
- **Torque turn will be utilized to ensure proper rng procedures**
- **Have 2 pump trucks on location since this a large cement job. Have back up truck ready to go.**

Float Equipment & Accessories			
Item	**Model**	**Depth**	**Remarks**
Guide Nose Shoe	Davis Lynch	2,600	
1 joint of Casing			
Float Collar	Davis Lynch	2,555’	
		Quantity	
Centralizers	Davis Lynch	20	One 10’ above the shoe, one on 1st & 2nd collar, & one centralizer every 3rd joint until gone.
Latch-on stop ring		1	Use stop collar with set screws. 1 required on shoe joint.

Cement					
Pump Schedule					
Lead:	Class C + 4% Gel				
Tail:	Class C + 1% CaCl2				
Disp:	.1522 bbl/ft = 13-3/8” 61# csg				
BHST:	90°F				
Slurry Properties					
Lead Slurry			**Tail Slurry**		
Estimated Volume:	1700	sacks	**Estimated Volume:**	250	sacks
Density:	13.5	ppg	**Density:**	14.8	ppg
Yield:	1.75	ft^3/sack	**Yield:**	1.34	ft^3/sack
Thickening Time:	4:30+	hrs:min	**Thickening Time:**	2:45+	hrs:min

Component	High Test Pressure	Low Test Pressure	Duration
Annular Preventer	2000 psi	250 psi	10 min
Manifold	2000 psi	250 psi	10 min
Upper / Lower / Kelly valves	2000 psi	250 psi	10 min
TIW safety valves / Dart	2000 psi	250 psi	10 min
Mud hose, standpipe, and mud line to pumps	2000 psi	-	30 min
Casing (with 8.4 ppg fluid)	1000 psi	-	30 min

12-1/4” Intermediate 2600’ – 4700’

Objective: Drill a 12-1/4” hole to ~4700’ and set 9-5/8” casing. Cement will be circulated to surface in 2 stages.

Notes: This section will be drilled on fresh water. Prepare for total losses in the Capitan Reef. Ensure hole is clean before entering the Capitan Reef. **The DVT/ECP tool needs to be a minimum of 50’below the 13-3/8” csg shoe and 100’ above intial losses in the reef.** See special requirements for Capitan Reef in Drilling COA’s. A fluid caliper will be run to ensure enough cement volume is on location.

Procedure:

17. PU bit, BHA and TIH w/ Gamma Ray tool.
18. Drill out and Drill ahead to TD
    - Run both pumps while drlg this section
    - Take surveys 200’ below shoe, then every 200’. If hole angle increases survey as hole dictates.
    - Ensure hole is clean before entering reef.
    - Follow Capitan Reef guidelines (Keep AV’s up and sweep regularly)
19. Sweep to ensure hole is clean
20. Run Fluid Caliper at TD.
21. TOH (LD tools not needed for next hole section)
22. RU casing crew and run casing. Run csg fluid filled per COA. (see casing/cement section)
23. Circulate at least 1 bottom’s up or 1-1/2 casing volumes prior to pumping cement. (RD csg crew/RU cmtrs)
24. Hold PJSM. Mix and pump cement as per the cementing program (see casing/cement section).
    - Do not over displace. If floats fail, maintain pressure on the casing for ±4 hours. If cement does not circulate, contact Asst Drlg Supt, Drlg Supt or Drlg Eng for remedial instructions. Report PD time and date, if the floats held and how much cmt was circulated on daily drlg report in activity summary.
25. Lift stack and set slips ASAP (do not allow cement to set up and keep pipe from being centered)
26. WOC for 4 hours before making rough cut
27. Make final cut and install 13-5/8” 5M x 11” 10M well head. (See attached GE documentation for well head info)
28. **NU 10M BOP stack. Please refer to COA’s and Onshore Orders to ensure we are obeying all 10M regulations. Remote kill line needs to be installed prior to testing and tested to 10M also.**
29. Pressure test the wellhead, BOP Equipment and casing after 8 hours or tail have reached 500 psi. Whichever is longer.
30. Run SLB 360° cement bond log.
    - Halliburton will supply SLB with a UCA plot for each cmt blend to get an exact CBL WOC time (for this intermediate blend it will be roughly 18 hrs)
31. Will need Geolex & BLM to approve CBL before drill out. Can drill out after successful csg test & approved CBL.

Mud: Fresh water. See Nova Mud Recommendation.

Surveys:
Take a survey 200’ below casing shoe then every 200’ to TD. If hole angle increases, survey every as hole dictates.

CASING & CEMENTING – 9-5/8” Section

CASING						
Size	**Wt./ft.**	**Grade**	**Conn**	**Top**	**Bottom**	**Length**
9-5/8”	40	L-80	BTC	0’	4700	4700

Casing Details (HCL80 / HCP110)					
ID:	8.835	In	**Collapse Rating:**	3090	Psi
Drift:	8.75	In	**Burst Rating:**	5750	Psi
Connection OD:	10.625	In	**Body Yield:**	916	Mlbs
MU Torques:		**Δ**	**Joint Strength:**	947	Mlbs

- **<u>Make up max for BTC is 25 RPM</u>**
- **Torque turn will be utilized to ensure proper rng procedures**

Float Equipment & Accessories			
Item	**Model**	**Depth**	**Remarks**
Guide Nose Shoe	Davis Lynch	4700	
1 joint of Casing			
Float Collar	Davis Lynch	4655	
DVT/ECP	Davis Lynch	2650	~100’ above reef in competent rock. Min 50’ below casing shoe,
		Quantity	
Centralizers	Davis Lynch		One 10’ above the shoe, one on 1st & 2nd collar, & one centralizer every 3rd joint until gone. If we take partial losses have semi rigid centralizer on every joint in reef.
Latch-on stop ring		1	Use stop collar with set screws. 1 required on shoe joint.

Cement					
1st Stage Pump Schedule					
Lead:	35:65:6 C Blend				
Tail:	Class C				
Disp:	.0758 bbl/ft = 9-5/8” 40#				
BHST:	115°F				
1st Stage Slurry Properties					
Lead Slurry			**Tail Slurry**		
Estimated Volume:	525	sacks	**Estimated Volume:**	250	sacks
Density:	12.7	ppg	**Density:**	14.8	ppg
Yield:	2	ft^3/sack	**Yield:**	1.34	ft^3/sack
Thickening Time:	4:30+	hrs:min	**Thickening Time:**	3:00 +	hrs:min
2nd Stage Pump Schedule					
Lead:	Class C + 4% Gel				
Tail:	Class C				
Disp:	.0758 bbl/ft = 9-5/8” 40#				
BHST:	95°F				
2nd Stage Slurry Properties					
Lead Slurry			**Tail Slurry**		
Estimated Volume:	650	sacks	**Estimated Volume:**	100	sacks
Density:	13.5	ppg	**Density:**	14.8	ppg
Yield:	1.75	ft^3/sack	**Yield:**	1.34	ft^3/sack
Thickening Time:	4:30+	hrs:min	**Thickening Time:**	3:00+	hrs:min

- 15,000 psi chart for the 10M Test

Component	High Test Pressure	Low Test Pressure	Duration
Annular Preventer	5,000 psi	250 psi	10 min
Rams	10,000 psi	250 psi	10 min
Manifold	10,000 psi	250 psi	10 min
Upper / Lower / Kelly valves	10,000 psi	250 psi	10 min
TIW safety valves / Dart	10,000 psi	250 psi	10 min
Remote Kill Line	10,000 psi	250 psi	10 min
Mud hose, standpipe, and mud line to pumps	5,000 psi	-	30 min
Casing (with 9.0 ppg fluid)	1500 psi	-	30 min
FIT Test	11.0 ppg EMW minimum FIT Test		

Vertical 8-3/4" Hole 4700' – 13,755'

Notes: The Delware intervals have potential for lost circulation, water flows and gas. This interval also allows the oppurtunity to drill fast while staying relatively straight. **There is an acid gas well that is a direct offset to us. They are currently injecting acid gas from 5400' – 6100' into the DLWR. We will need to be prepared for Acid Gas through this interval. A rotating head with a flow line valve will be needed through this interval.**

Exec Summary:
Drill a 8-3/4" hole 15' below the Woodford shale into the top of Devonian. This will isolate the higher pressured, fluid sensitive formations from the WC to the Mississipian prior to drilling into the disposal interval. Please pay close attention to the casing and cement being used in this interval. Both are deisgned to withstand the corrosive enviroment of Acid Gas.

Drill out with cut brine fluid. We will maintain clear fluid into the Wolfcamp. As we start getting through the lower intevals of the Wolfcamp we need to start mudding up. Please be completely mudded up before we enter the Strawn. See attached mud recommendation from Nova Mud. Make sure to have WL below 6 before we get into the Woodford Shale.

If we make a trip close to TD we will pick up near bit GR logging tools and strap out of the hole to confirm depth. Once withing 100' of top Devonian it may be necessary to make a trip to PU the near bit GR to help pick T/ Devonian. Make sure to communicate well for this game plan.

The mudloggers and geologist will pick the casing point ~15' into the Devonian. It may be necessary to circulate samples and drill small increments or control drill to succesfully TD this section. If we drill to deep, uncontrollable lost circulation in the Devonian with gassy formations above could jepordize the project entirely. This is the most important part of the well, so we will do it accurate & correct the first time in the most efficient manner we can.

Drilling team indicators for the Devonian pick will be first a decline in ROP once we penetrate the top of Devonian, the 2nd confirmation will be the near bit GR (6' back) will drop once it reads the top. If the GR drops after 6' feet from the ROP break then drill 9' -12' feet for a total of 15' -18' into the Devonian. Wait for the btms up sample to confirm for the 3rd indicator. Cuttings will turn from the black shale to the white dolomite.

OH logs will be run will be run at the 8-3/4" TD. Please refer to SLB logging procedure.

A wiper trip will be needed after logging due to minimum room for error on csg setting depth. We have to completely cover the woodford with the 7-5/8" x 7" casing or the OH disposal will bet will be at risk. Yet we will only have roughly 15' or so rat hole below the Woodford until reaching the Devonian porosity.

We will pick up directional tools if deviation becomes an issue. Notify ofc if we deviate to 3° inc, we will trip for directional tools if it looks we can not keep it under 5° inc.

Bit trips: This area is known to have chert in the 1st & 2nd BSS. Also as we know the Miss Lime can be a challenge. Baker Hughes is already in progress with a Rock Strength Analysis using our offset Devonina SWD's to help with BHA design to increase our efficieinces through the tougher lower sections.

See separate PDF of all collected scout tickets and bit records for references for MW.

Procedure:
1. PU BHA with Gamma Ray.
2. TIH and drill out shoe
3. Drill out 10' and perform FIT to a minimum EMW of 11.0 ppg.
4. Drill ahead w/ cut brine.
    - Survey every 300' or as hole dictates
    - Keep water & hole clean

- Circulate btm's up samples and spot high vis pill on btm before coming off btm

5. Once hole conditions show that we need to mud up. Refer to Nova Mud program.
   - XCD for 34-40 vis/ Pac & white starch for 6-8 WL/ Caustic for 10 PH / Barite for weight as needed
   - Before entering the Woodford Shale we need to tighten our WL to below 6.
6. We will have several bit trips through this interval, especially below the Morrow. Consult with office about picking up near bit GR if we have trip towards the btm of the hole.
   - If we are pumping LCM make sure to communicate that with OFC so we do not restrict LCM usage if there is another way to get the job done.
7. Consult closely with mud loggers. Make sure the top of Woodford is picked accurately which will help pick the Devonian more accurately.
8. When within ~100' from T/ Devonian begin monitor returns closely. If necessary we can trip to get GR closer to bit. If we make a trip near TD strap out of the hole to ensure depth is on.
9. Drill ahead in an accurate manner using the key indicators to TD ~15' into Devonian as stated above in exec summary in an efficient manner.
10. Sweep and ensure hole is clean
11. TOH for OH logs
12. Run SLB OH logs & side wall cores.
    - Will send SLB log prog once received. Geolex prog attached.
13. Make wiper trip to TD.
    - Consult with Asst super / Lead Super about wiper trip.
14. TOOH. Strap out of hole.
15. R/U casing crew and run casing. (See details in casing section)
    - The SM2035-110 VAM TOP Casing will need to be specially handled with bolsters and set on special racks. It cannot come in contact with steel. Please advise with Asst Super / Lead Super/ Drill Eng for special handling procedures
    - Special pipe dope will need to be used on 2035-110 casing
    - VAM TOP will need personnel on location to handle & make up properly
    - All XO's in the casing string will have a 30° - 45° internal taper
    - Only polymer centralizers will be used to ensure there are not steel cents to come into contact with the 2035-110 casing
    - Halliburton will handle all float equipment, DVT/ECP, centralization & cement.
16. Circulate at least 1 bottom up prior to cementing.
17. Hold PJSM. Mix and pump a 2 stage cement job as per the cementing program. We will be using and Acid Gas resistant Epoxy Resin for the tail cmts on both stages (see casing/cement section).
    - Do not over displace. If floats fail, maintain pressure on the casing for ±4 hours. If cement does not circulate, contact Asst Drlg Supt, Drlg Supt or Drlg Eng for remedial instructions. Report PD time and date, if the floats held and how much cmt was circulated on daily drlg report in activity summary.
18. Lift stack and set slips ASAP (do not allow cement to set up and keep pipe from being centered)
19. WOC for 4 hours before making rough cut
20. Make final cut on 7-5/8" and install 11" 10M x 7-1/16" 5M Tubing Head Assembly.
    - 11" 10M x 11" 5M Double Studdded Packoff Adaptor
    - 11" 5M x 7-1/16" 5M Tubing Head Assembly
    - See attached GE wellhead schematic
21. NU 5M BOP stack
22. Test BOP.
23. Run **Halliburton** 360° CBL to pick up the WellLock Resin. Halliburton will take a resin sample from both tails on location and send to the lab for UCA tracking. This will be real time decision on CBL timing (this will be roughly 48 hours for the resin to sit before we can get a successful CBL)
24. Total WOC before testing is 8 hours or when tail slurry reaches 500 psi whichever is greater, can drill out after successful casing test and approved CBL from Geolex & the BLM.

Mud: See attached mud program.

Surveys: Survey every 300' after 9-5/8" shoe or as hole dictates.

CASING & CEMENTING – 7-5/8” x 7” Section

CASING						
Size	**Wt./ft.**	**Grade**	**Conn**	**Top**	**Bottom**	**Length**
7-5/8”	33.7	HCP-110	LTC	0’	300’	300’
7”	29	HCP-110	LTC	300’	5000’	4700’
7”	32	SM2035-110	VAM TOP	5000’	6350’	1350’
7”	29	HCP-110	LTC	6350’	13,455’	7105’
7”	32	SM2035-110	VAM TOP	13,455	13,755	300’

Casing Details for 7-5/8” 33.7# HCP110 LTC					
ID:	6.765	In	**Collapse Rating:**	9110	Psi
Drift:	6.640	In	**Burst Rating:**	10,850	Psi
Connection OD:	8.125	In (Spc Clr Coup)	**Body Yield:**	1069	Mlbs
MU Torques:	See JD Rush spec sheet.		**Joint Strength:**	901	Mlbs
Casing Details for 7” 29# HCP110 LTC					
ID:	6.184	In	**Collapse Rating:**	9750	Psi
Drift:	6.125	In	**Burst Rating:**	11,220	Psi
Connection OD:	7.875	In	**Body Yield:**	929	Mlbs
MU Torques:	See JD Rush spec sheet.		**Joint Strength:**	797	Mlbs
Casing Details for 7” 32# SM2035-110 VAM TOP					
ID:	6.094	In	**Collapse Rating:**	10,780	Psi
Drift:	6.00	In	**Burst Rating:**	12,460	Psi
Connection OD:	7.875	In	**Body Yield:**	1,025	Mlbs
MU Torques:	VAM TOP Reps will advise		**Joint Strength:**	Vam Top	

Float Equipment & Accessories			
Item	**Model**	**Depth**	**Remarks**
Float Shoe	Halliburton	13,755’	32# Vam Top 25/125 CR (Chrome)
2 joints of Casing	CRA		32# SM2035-110
Float Collar	Halliburton	13,665’	32# Vam Top 25/125CR (Chrome)
Casing	CRA		32# SM2035-110
XO	CRA	13,455’	7” 29# LTC Box by 7” 32# VAM Top Pin
Casing	JD Rush		7”29# HCP110
DVT/ECP	Halliburton	6350’	7” 32# Vam Top box by 29# LTC pin. This will act as a XO with casing subs attached for contingency for cross threading.
Casing	CRA		32# SM2035-110
XO	CRA	5000’	7” 29# LTC Box by 7” 32# VAM Top Pin
Casing	JD Rush		7”29# HCP110
XO	JD Rush	300’	7-5/8” 33.7# LTC by 7” 29# LTC Pin
Casing	JD Rush		7-5/8” 33.7# HCP110
		Quantity	
Centralizers	Halliburton	55	One 10’ above the shoe, one on 1st & 2nd collar, & one centralizer every 5th joint until gone. Polymer 7” csg x 8-1/2” OD

- **Torque turn will be utilized to ensure proper rng procedures for this casing string**
- **Have 2 pump trucks on location since this a large cement job. Ensure the backup is ready to go if needed.**

Cement					
1st Stage Pump Schedule					
Lead:	50:50:10 H Blend				
Tail:	Halliburton WellLock Resin				
Disp:	7-5/8”= .0445 bbl/ft > 7” 29# = .0371 bbl/ft > 7” 32# = .0361 bbl/ft				
BHST:	200°F				
1st Stage Slurry Properties					
Lead Slurry			Tail Slurry		
Estimated Volume:	650	sacks	**Estimated Volume:**	40	BBLS
Density:	11.9	ppg	**Density:**	12.5	ppg
Yield:	2.5	ft^3/sack	**Yield:**	40	BBLS
Thickening Time:	5:30+	hrs:min	**Thickening Time:**	4:00 +	hrs:min
2nd Stage Pump Schedule					
Lead:	50:50:10 C Blend				
Tail:	Halliburton WellLock Resin				
Disp:	7-5/8”= .0445 bbl/ft > 7” 29# = .0371 bbl/ft > 7” 32# = .0361 bbl/ft				
BHST:	135°F				
2nd Stage Slurry Properties					
Lead Slurry			Tail Slurry		
Estimated Volume:	350	sacks	**Estimated Volume:**	80	BBLS
Density:	11.9	ppg	**Density:**	12.5	ppg
Yield:	2.5	ft^3/sack	**Yield:**	80	BBLS
Thickening Time:	4:00+	hrs:min	**Thickening Time:**	3:00+	hrs:min

Component	High Test Pressure	Low Test Pressure	Duration
Annular Preventer	5,000 psi	250 psi	10 min
Rams	5,000 psi	250 psi	10 min
Manifold	5,000 psi	250 psi	10 min
Upper / Lower / Kelly valves	5,000 psi	250 psi	10 min
TIW safety valves / Dart	5,000 psi	250 psi	10 min
Mud hose, standpipe, and mud line to pumps	5,000 psi	-	30 min
Casing (with 8.4ppg fluid)	1000 psi	-	30 min

6” Disposal Interval 13,755’ MD – 14,750’ MD

Notes:
Drill 6” hole no deeper than 14,750’ (max depth approved for OH disposal) . Lets communicate TD confirmation once starting this interval. These are deep depths and can change once we confirm Devonian top.

Drill out with fresh water weight up with brine if needed. See mud program.

This interval will be logged, but it will not be cased.

After running OH logs we will run a 7” composite bridge plug inside the 7” casing before we install disposal head and rig down.

Procedure:

1. PU slim hole drill pipe, bit, BHA & TIH w/ Gamma Ray
2. Drill ahead to TD.
    - Confirm TD depth after drilling out.
    - Take surveys every 300’ or as hole dictates.
3. TOOH
4. RU and run OH logs
5. RU set WL bridge plug approx. 200’ inside casing shoe.
6. If we left anything other than fresh water above bridge plug we may need to TIH to circ fresh water around
7. LDDP.
8. Install well head cap.
9. Clean pits, RD, release rig.

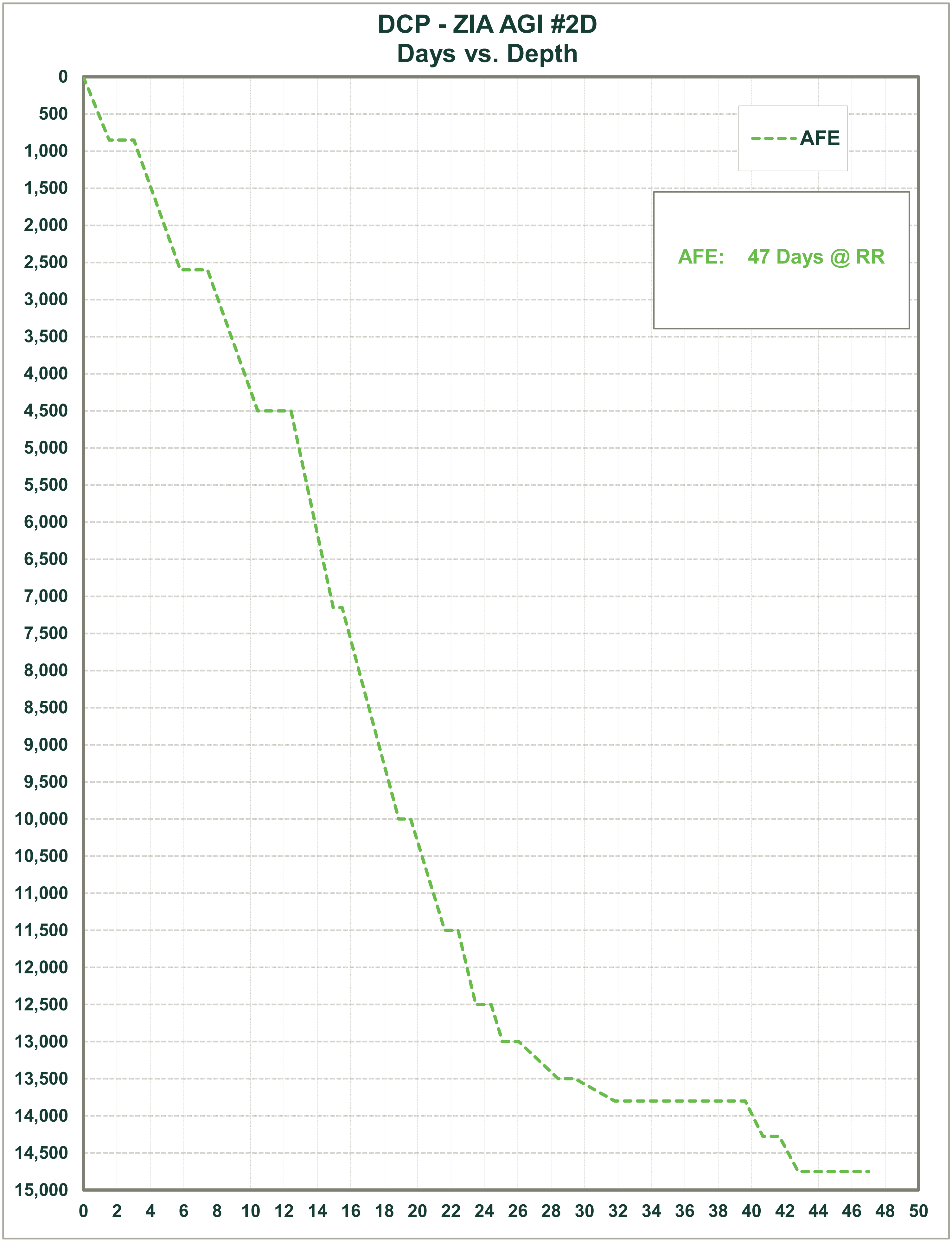
Mud:

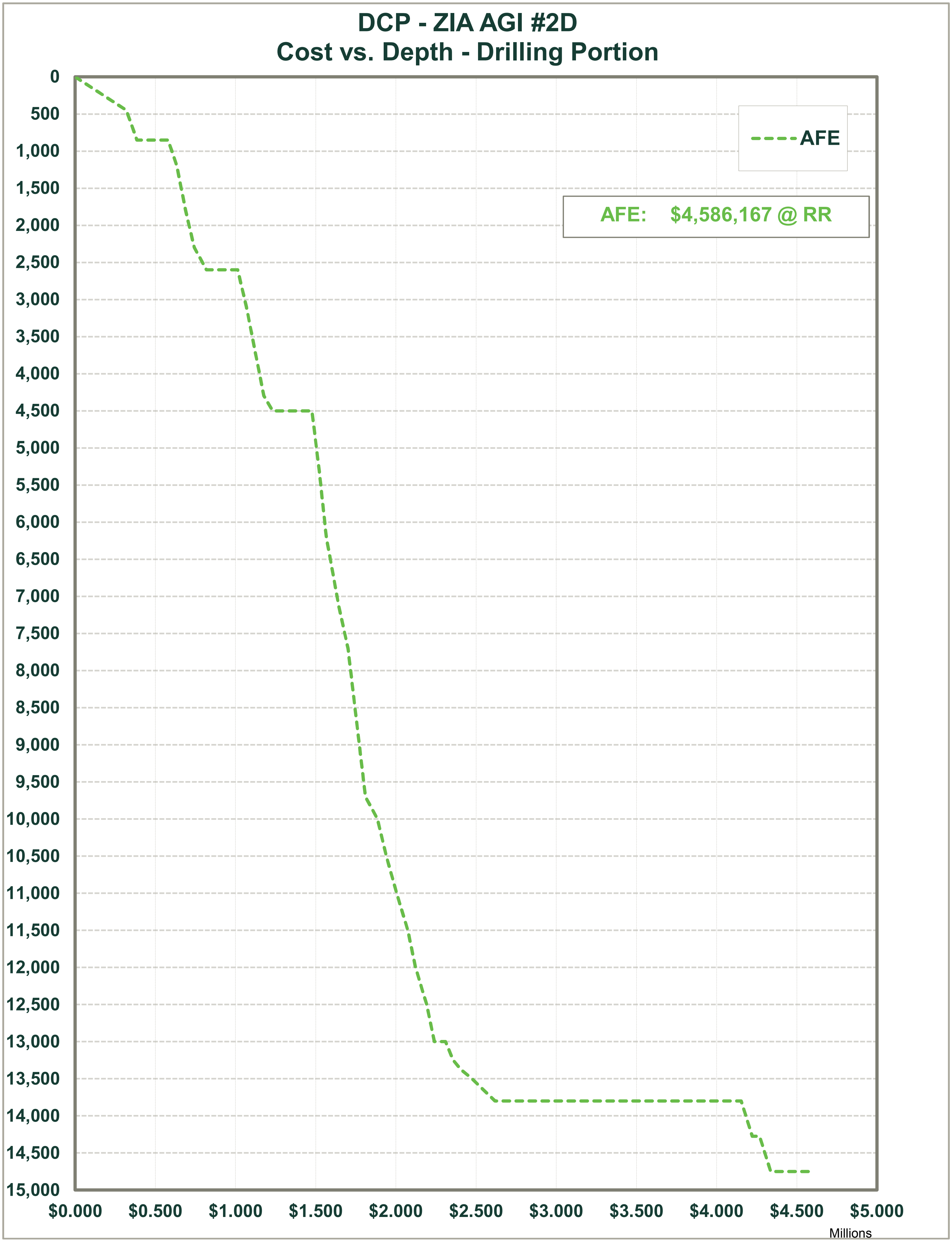
Interval	MW	Visc.	PV	YP	FL	pH	% Solids	Cl^-
Disposal	8.4	Fresh water						

Logging Prognosis

- **SLB will send out logging prognosis also along with bid.**

Casing String	Log Interval	Open-hole Logs Planned	Closed-hole Logs Planned
Surface	0-800	1) Gamma ray (behind bit) 2) Fluid volume caliper	1) 360 Cement Bond Log
1st Intermediate	800-2600	1) Gamma ray (behind bit) 2) Mechanical caliper	1) 360 Cement Bond Log
2nd Intermediate	2600-4700	1) Gamma ray (behind bit) 2) Fluid caliper	1) 360 Cement Bond Log
Production	4700-14750	Mudlogging will commence with this hole 1) Gamma ray (behind bit) 2) Borehole Compensated Sonic/ Gamma Ray 3) Borehole Image Interpretation 4) Borehole Profile / IHV / ICV Gamma Ray 5) Fracture Density Log with Image Fracture Analysis 6) Full-bore Formation Micro Imager 7) Hostile Natural Gamma Ray 8) Platform Express / Compensated Neutron Log / Three Detector Litho-Density 9) Platform Express / High Resolution Laterolog Array / Micro-CFL/HNGS 10) PEX ELAN Log Analysis 11) Isotropic Mechanical Properties 12) Best-DT* Compressional and Shear	1) 360 Cement Bond Log 2) Ultrasonic Imager


DCP - ZIA AGI #2D
Days vs. Depth
AFE
AFE: 47 Days @ RR
0
500
1,000
1,500
2,000
2,500
3,000
3,500
4,000
4,500
5,000
5,500
6,000
6,500
7,000
7,500
8,000
8,500
9,000
9,500
10,000
10,500
11,000
11,500
12,000
12,500
13,000
13,500
14,000
14,500
15,000
0 2 4 6 8 10 12 14 16 18 20 22 24 26 28 30 32 34 36 38 40 42 44 46 48 50


DCP - ZIA AGI #2D
Cost vs. Depth - Drilling Portion
AFE
AFE: $4,586,167 @ RR
0
500
1,000
1,500
2,000
2,500
3,000
3,500
4,000
4,500
5,000
5,500
6,000
6,500
7,000
7,500
8,000
8,500
9,000
9,500
10,000
10,500
11,000
11,500
12,000
12,500
13,000
13,500
14,000
14,500
15,000
$0.000
$0.500
$1.000
$1.500
$2.000
$2.500
$3.000
$3.500
$4.000
$4.500
$5.000
Millions

COG OPERATING LLC Pre-Drill Geological Prognosis
Devonian SWD

SWD	

DCP ZIA AGI #2D
300254220700

Rig: TBD

Regular section		FNL	FSL	FEL	FWL	Unit
§-T-R (SHL)	19-T19S-R32E		1900		950	L
§-T-R (BHL)						

GL:	3545	actual
KB:	3570	actual

PROPOSED WELL						REFERENCE WELL
COG OPERATING LLC		<------------------------~1475'------------------------->				COG OPERATING LLC
DCP ZIA AGI #2D		Est. VS:		Chicken:	Yes	Lusk Deep Unit A 21
19-T19S-R32E		Trt. Lat:		Potash:	No	19-T19S-R32E
Lea Co., NM		PH-TD:		Lizard:	Yes	Lea Co., NM
KB: 3570	Est. MD: 14900	AFE type:	Devonian SWD			KB: 3573

Formations	TVD	Subsea	Iso to Tgt	Lith	Hazards/Misc	TVD	Subsea	Iso
Rustler	740	2830		Mixed lithologies		754	2819	149
TOS	889	2681		Salt/Evaporites		903	2670	1464
BOS	2353	1217		Salt/Evaporites		2367	1206	73
Yates	2426	1144		Sand/Anhydrite		2440	1133	226
Seven Rivers	2652	918		Dolo/Silt/Anhydrite		2666	907	108
Capitan Reef	2760	810		Limestone		2774	799	1676
Base of reef	4436	-866		Sand & Dolomite		4450	-877	282
Delaware	4718	-1148		Limestone & Sand		4732	-1159	2328
Bone Sprg (BSGL)	7046	**-3476**		Limestone		7060	-3487	1250
FBSG_sand	8296	-4726		Fine Sand & Carb		8310	-4737	715
SBSG_sand	9011	-5441		Fine Sand & Carb		9025	-5452	835
TBSG_sand	9846	-6276		Fine Sand & Carb		9860	-6287	372
Wolfcamp	10270	-6700		Silt, Shale & Carb		10232	-6659	878
Strawn	11120	-7550		Limestone		11110	-7537	429
Atoka	11549	-7979		Sand/Shale/Lime		11539	-7966	526
Morrow	12075	-8505		Sand & Shale		12065	-8492	590
Mississippian*	12665	-9095		Shale w/ Lime	Est. from isopach	12655	-9082	400
Mississippian Lime*	13065	-9495		Limestone	Est. from isopach	*13055*	-9482	550
Woodford*	13615	-10045		Organic Shale	Est. from isopach	*13605*	-10032	125
Devonian/Silurian*	13740	-10170		Dolomite	Est. from isopach	*13730*	-10157	291
Fusselman*	14031	-10461		Dolomite	Est. from isopach	*14021*	-10448	480
Montoya*	14511	-10941		Cherty Dolomite	Est. from isopach	*14501*	-10928	
☆ Total Depth	14750	-11180						

Comments Reference well - Lusk Deep Unit A 21 TD'd before the top of the Mississippian
*Tops from Mississippian to TD are isopached from Lusk North 32 State SWD 1 in SW 32-18S-32E which is
~4 miles to the NE of the reference well and Magnum Pronto 32 State SWD 1 (32-19S-32E) which is ~2 miles SE.

Wireline Evaluation

Log Bone Spring and deeper intervals with Triple Combo or PEX

Coring and Testing

None

Mudlogging

Log out from intermediate casing to TD with a 2-man unit keeping 1 set of 20' samples & capturing 1' drill time.
Critical to accurately pick top of Woodford to determine wireline logging point

Land (obligations and deadlines)

Version/Geologist

v1 **Jason Hanzel** **DATE:** **6/3/2016**

Concho Completion Prognosis

Revision V2.3

Zia AGI #D2
1893' fsl, 950' fwl
L-19-19s-32e
Lea, NM
API 30-025-42207
Lat N 32.643951, Long W 103.811116

Acid Gas Injection Well Completion Procedure
16 December 2016

<u>Basic Data (Well Bore Schematic Attached):</u>

GL Elev: 3548' survey plat, 3547' used for drilling phase and logs
KB Elev: 3574' logs
Reference: 27' AGL logs

<u>Conductor:</u> 30" conductor set at 80'.

<u>Surface:</u> 26" hole to 826'.
20"/106.5/J55/BTC surface casing @ 826'.
Cemented with 1175 sx Class C + 4% gel plus 250 sx Class C + 1% CaCl2. Circulated 487 sx to surface.

<u>Intermediate 1:</u> 17-1/2" hole to 2555'.
13-3/8"/61 & 68/J55/BTC intermediate casing (salt) @ 2555'.
Cemented with 1700 sx Class C + 4% gel plus 250 sx Class C + 1% CaCl2. Circulated 428 sx to surface.

<u>Intermediate 2:</u> 12-1/4" hole to 4696'.
9-5/8"/40/L80/BTC intermediate casing (reef) @ 4696'.
DV/ECP @ 2612'.
Stage 1 cemented with 450 sx Class 35:65:6 C blend plus 50 sx Class C + 4% gel plus 250 sx Class C.
Circulated 144 sx to surface.
Stage 2 cemented with 600 sx Class C + 4% gel plus 100 sx Class C + 1% CaCl2. Circulated 107 sx to surface.

<u>Injection String:</u> 8-3/4" hole to 13622'.
7-5/8" x 7" injection casing @ 13622' drillers, 13635' logs.

7-5/8"/33.7/HCP110/LTC	0-306'
7"/29/HCP110/LTC	306' - 4955'
7"/32/SM2035-110/VAM TOP	4955'- 6317'
7"/29/HCP110/LTC	6317' - 13298'
7"/32/SM2035-110/VAM TOP	13298'- 13622' (shoe at 13635' on logs, 13' deeper)

DV @ 6346'.
Stage 1 cemented with 770 sx Class 50:50:10 H blend plus 20 bbls Well Lock Resin. Circulated 128 sx to surface.
Stage 2 cemented with 420 sx Class 50:50:10 C blend plus 80 bbls Well Lock Resin. Circulated 93 sx to surface.

<u>Devonian Open Hole Injection Zone:</u> 6" open hole 13622'- 14750' (13635' – 14770' logs).

Halliburton composite bridge plug left at 13016' when drilling rig moved off. Casing filled with fresh water.

Capacity Factors:

7-5/8"/33.7ppf 0.0444 B/F
7-5/8"/33.7ppf x 3-1/2" 0.0326 B/F

7"/29ppf 0.0371 B/F
7"/29ppf x 3-1/2" 0.0252 B/F

7"/32ppf 0.0360 B/F
7"/32ppf x 3-1/2" 0.0242 B/F

3-1/2"/9.3ppf 0.00870 B/F

6" OH 0.0350 B/F
6-1/2" OH 0.0410 B/F

Objective: Complete well as Devonian/Silurian acid gas injection well 13622' – 14750' open hole. See wellbore schematic. Give NMOCD Hobbs and BLM Hobbs 24 hrs notice to witness MIT. Permitted injection interval 13755-14750', actual injection interval 13622-14750' (13635-14770' from logs), injection pressure limit = 5028 psi. Case No. 15528, Order No. R-14207.

Note:

Well was left with 7" composite bridge plug at 13016'.

Procedure is written to use fresh water as the completion/well control fluid in the expectation that the reservoir pressure gradient is less than that of fresh water. If the well tries to flow when using fresh water, cut brine will be used as the well control fluid. We can discuss what density of cut brine to use if necessary.

Use contractors on DCP-approved list. Will need to contact Matt Ivy if we need to use someone who's not on the approved list (mlivy@dcpmidstream.com, 303.446.4145 office, 713.305.3729 cell).

Procedure:

1. Clean location, set and test anchors, set two frac tanks for swabbing, set two lined acid frac tanks, set five fresh water frac tanks, set a brine water tank and MIRU Aries WSU. RU Alliance Safety.

2. NU 7-1/16" 5000 psi WP double ram hydraulic BOP with pipe rams for 3-1/2" tubing and blind rams. Install 5000 psi WP choke manifold and kill line onto the tubing head side outlets. See attached schematic for manifold configuration. The kill and choke manifolds will have a BLM 2M configuration using 5M components. RU BOP testers and test BOPs, choke manifold and kill line inlet assembly to 250 psi for 10 minutes and 5000 psi for 10 minutes.

BLM conditions of approval for BOPE: 5000 (5M) Blow Out Prevention Equipment to be used. All BOPE and workover procedures shall establish fail safe well control. Blind ram(s) and pipe ram(s) designed to close on all workstring diameters used is required equipment. A manual BOP closure system (hand wheels) shall be available for use regardless of BOP design. Function test the installed BOPE to 500psig when well conditions allow. Related equipment, (choke manifolds, kill trucks, gas vent or flare lines, etc.) shall be employed when needed for reasonable well control requirements.

3. RU power swivel and reverse unit package. Take delivery of approximately 12800' of 3-1/2"/9.3/P110/EUE Sp Cl plus approximately 2000' of 3-1/2"/9.3/L80/EUE Sp Cl work string. Pick up 6" bit and DCs. Install rotating head and drill out composite bridge plug set at 13016' using fresh water. Expect possible lost circulation after drilling plug.

   Make up torque 9.3ppf/L80: Optimum 3130 lb-ft Minimum 2350 lb-ft Maximum 3910 lb-ft
   Make up torque 9.3ppf/P110: Optimum 4230 lb-ft Minimum 3170 lb-ft Maximum 5290 lb-ft

4. Push remnant of plug down to at least 14700' if possible (open hole TD is 14750' drillers, 14770' loggers). Try to keep pipe moving as much as possible to minimize chance of differential sticking in the open hole. Recommend using fresh water to minimize differential sticking. If differential sticking occurs, stop pumps (if pumping water), let fluid level fall then try to free the pipe. POOH and lay down enough work string to leave approx. 10000' of tubing in the derrick.

5. RIH with Kenco 7" retrievable packer with profile nipple in on/off tool above packer to stop/catch swab cups and wireline reentry guide on bottom (packer will pass through 32ppf casing, set in 29ppf casing) on 3-1/2" work string to 10000'. Space out to put 15-20 points compression on the packer and set packer.

6. Hang tubing in the tubing head on a carbon steel tubing hanger with GE two-way BPV pre-installed in the tubing hanger. Tighten hold down screws to activate packoff in tubing hanger. Test tubing x casing annulus to 1000 psi. ND BOP.

7. Install rental 5M 3-1/8" x 7-1/16" tubing head adaptor and 5M 3-1/8" rental tree consisting of master valve, tee, wing valve, crown valve and crown cap. Pressure test the tree assembly above the tubing hanger to 250 psi for 10 minutes followed by 5000 psi for 10 minutes. Install BPV removal/installation equipment and have GE remove the two-way BPV.

   Note: Leave kill and choke manifolds installed on the tubing head side outlets for the duration of completion operations.

8. Leave well static and shut-in overnight prior to collecting initial static bottom hole pressure and temperature data. RU Schlumberger Opticall fiber optic slick line, install lubricator and RIH with tandem BHP gauges to approximately 14650' (approximately 100' from TD). Let gauges stay static for a few hours to collect static BHP and a baseline temperature profile. If baseline temperature profile is mostly static after a couple of hours on bottom, POOH with gauges.

9. RU to swab well to the frac tanks previously set for the swab test. Make sure the tanks are clean and free of oil prior to starting swab test. Swab at least 500 bbls of fluid into the swab tanks while checking for presence of hydrocarbons in the tanks and at the bleeder while swabbing. If the water doesn't appear to be formation water after swabbing 500 bbls, continue swabbing until formation water is being swabbed.

   Note: It is anticipated that the Devonian will feed fluid quickly into the well when swabbing. If, however, well swabs down to packer without giving up significant fluid, decision will likely be made to 1) pump a small breakdown acid job, 2) lower packer further down the well or 3) contact BLM and see if well swabbing dry with no hydrocarbon show meets the well testing requirement—let's discuss.

BLM conditions of approval for swabbing: A minimum of 500 barrels is to be withdrawn from the proposed disposal formation after any recent stimulation load volumes have been recovered. A composite report of ten samples from the last 100bbls analyzed for hydrocarbons and insitu salinity by a reputable laboratory. The procedure is to be witnessed by BLM. Notify pswartz@blm.gov, 575-200-7902 24 hours prior to the 10 samples being taken.

10. Catch ten water samples throughout the last 100 bbls of the swab test and have them delivered to Cardinal Labs in Hobbs for detailed analysis. Give BLM results of swab test via phone call.

    Note: Have Cardinal Labs contact Alberto Gutierrez with Geolex prior to doing the water analysis.

11. Give the BLM Hobbs and NMOCD Hobbs 24 hrs notice to witness the step rate test that will be performed the day after the acid job is pumped.

12. Load acid into coated frac tanks, fill the five fresh water tanks with fresh water, RU Halliburton and tie into 3-1/8" 5M wing valve for acid job.

13. Acidize Devonian open hole 13622' – 14750' with 40,000 gals **double inhibited** NE Fe 20% HCl acid (inhibited for 220 deg F BHST) plus graded rock salt in gelled brine at 7-10 BPM while limiting treating pressure to 5000 psi and holding 1000 psi on annulus as follows. Flush acid with two frac tanks (1000 bbls) of fresh water. Shut well in and record bleed off data until well goes on a vacuum or the surface pressure stabilizes.

    15,000 gals acid
    2,000 lbs graded rock salt in gelled brine
    15,000 gals acid
    2,000 lbs graded rock salt in gelled brine
    10,000 gals acid

    40,000 gals acid total
    4,000 lbs rock salt total

14. Leave the well shut-in overnight then prepare to pump a step rate test. RU Schlumberger slick line, install lubricator and make a dummy run to approximately 14550' (approx. 200' above TD) with sinker bars and jars. Be very cautious when tools are in the open hole section.

15. Run tandem BHP memory gauges to approximately 14550' on Schlumberger OPTICall optic fiber slick line and leave hanging for step rate test and 10 day fall off test to follow. Memory gauges will need to collect data for at least 11 days.

16. Measure the density or specific gravity of the water in each of the 5 frac tanks filled with fresh water for this step rate test. RU to record accurate surface injection pressure data. Perform the step rate test with fresh water as shown below.

    Record initial surface pressure.

Pump at 0.25 bpm for 30 minutes after tubing loads up.	(7.5 bbls fluid)
Pump at 0.50 bpm for 30 minutes	(15 bbls fluid)
Pump at 1.00 bpm for 30 minutes.	(30 bbls fluid)
Pump at 1.50 bpm for 30 minutes.	(45 bbls fluid)
Pump at 2.00 bpm for 30 minutes.	(60 bbls fluid)
Pump at 3.00 bpm for 30 minutes.	(90 bbls fluid)

Pump at 4.00 bpm for 30 minutes.	(120 bbls fluid)
Pump at 5.00 bpm for 30 minutes.	(150 bbls fluid)
Pump at 6.00 bpm for 30 minutes.	(180 bbls fluid)
Pump at 7.00 bpm for 30 minutes.	(210 bbls fluid)
	907.5 bbls total fluid

Note: It is possible that parting pressure will not be reached on this test due to the permeability-thickness of the Devonian/Silurian section.

BLM conditions of approval for step rate test (injection potential test): The proposed Step 8 (Step Rate Test) is to be conducted as an "Injection Potential Test" to provide data to the operator and NMOCD. The data collected by Step 8. is not be used to request a pressure increase.

Step 8 is to be BLM witnessed and conducted with a fluid of consistent density. The peak rate is to be selected to achieve the peak formation pressure anticipated to meet the well's acid gas disposal volume requirements.

The Step Rate Test flow rates of the fluid (fresh water or brine) are to be controlled with a constant flow regulator and measured with a turbine flow meter calibrated within 0.1 bbl/min.

A down hole transmitting pressure device and a surface pressure device with accuracies of ±10psig are required for the Step Rate Test.

Step Rate Test formation and surface pressures are to be synchronized with BLM approved rate changes.

17. When step rate test finished, shut pump down and close wing valve. Remove handles from crown valve, wing valve and master valve and put tag on well head stating that there is slick line in the well and that the master and crown valves are to remain in the open position until further notice. Leave valve handles close to well head in case of emergency.

18. Schlumberger slick line operators will stay on location for the duration of the fall off test to make sure all equipment is operating properly.

19. RDMO WSU and leave the well shut-in for 10 days for an extended fall off test.

20. When fall off test is finished, pull BHP gauges out of the well and RDMO. Schlumberger will analyze the pressure and temperature data from the step rate test and fall off test and produce reports for each.

21. MIRU WSU. If well has surface pressure, bleed off as/if necessary. Kill well with fresh water or cut brine water if necessary. Install BPV installation equipment and have GE install two-way BPV into the tubing hanger to allow testing of the BOP.

22. Nipple down the rental tree and THA and NU the 5M hydraulic double ram BOP, 7-1/16" 5M x 7-1/16" 3M adaptor and place a 7-1/16" 3M Torus annular BOP on top of the BOP stack (3000 psi WP is the maximum for Torus BOPs which are designed to close on external control lines outside the tubing without crushing them).

23. Close the blind rams and pressure test the blind rams and BOP connection to tubing head to 250 psi for 10 minutes followed by 5000 psi for 10 minutes. Screw 3-1/2" EUE sub into tubing hanger, close pipe

rams and test to 250 psi for 10 minutes followed by 5000 psi for 10 minutes. Open pipe rams, close Torus and test to 250 psi for 10 minutes followed by 3000 psi for 10 minutes.

24. Remove 3-1/2" sub from tubing hanger. Install BPV removal/installation equipment and have GE remove the two-way BPV from the tubing hanger. Screw lift sub into tubing hanger.

25. Unseat treating packer and TOOH with work string. Inspect packer to ensure all the rubber elements and the rest of the packer is intact.

26. RIH with a bit and scraper (7"/29 and 32 ppf casing) on the work string to approx. 13600' (7" casing shoe at 13622' drillers/13635' loggers). Run scraper up and down a few times from 13500-13600'. TOOH laying the work string down.

27. Refer to attached Halliburton Design of Service Installation Procedure and attached packer/tubing schematic. RU Halliburton wireline, install lubricator and run a junk basket/gauge ring to approximately 13600' inside the 7"/29 and 32ppf casing (7" shoe @ 13622' drillers/13635' wireline).

28. Pick up Incoloy 925 permanent packer assembly shown below and on attached Haliburton installation diagram, attach to packer setting tool/GR/CCL assembly and RIH very slowly <u>(no more than 100 ft/min, suggest slower than this)</u> with the packer assembly on wireline.

29. Be very cautious when approaching transitions from 7-5/8" to 7" casing, transitions from 7"/29 ppf to 7"/32 ppf casing and the fluid level inside the casing if it's not at surface.

30. The target packer setting depth is approximately 13565' (approximately 70' above 7" casing shoe at 13635' loggers depth). Section of neutron density open hole log with casing connection depths annotated from the casing tally is attached. <u>Collars are hard to detect on the CCL in the CRA casing at bottom so the packer will have to be correlated into place using the Gamma Ray log</u>.

31. Set packer, POOH with wireline and RDMO wireline services.

    <u>Packer assembly from top to bottom (estimated length = 31.93'):</u>

    a) Halliburton 7" 26-32 ppf 4" bore BWD permanent packer Incoloy 925

    b) Seal bore extension 4" x 12' Incoloy 925

    c) Seal bore extension crossover 4.75" 8UN box x 3-1/2"/9.2 VAM TOP pin Incoloy 925

    d) 6' pup joint 3-1/2"/9.2 VAM TOP box x pin Incoloy 925

    e) Halliburton 2.562" R nipple 3-1/2"/9.2 VAM TOP box x pin Incoloy 925

    f) 6' pup joint 3-1/2"/9.2 VAM TOP box x pin Incoloy 925

    g) Halliburton 2.562" R nipple 3-1/2"/9.2 VAM TOP box x pin Incoloy 925

    h) Wireline reentry guide 3-1/2"/9.2 VAM TOP box Incoloy 925 machined for aluminum pump off plug and associated shear pins

32. RU Franks casing crew with calibrated tongs and handling equipment for 3-1/2" Inconel G3 CRA tubing with VAM TOP connections and 3-1/2" L80 tubing with BTS-8 connections. RU catwalk and vee door

assembly and/or a pick up/lay down machine. RU Halliburton spooler trailers for running the ¼" armored data line for the pressure/temperature sensor and the ¼" SSSV control line. RU specialty slips for running lines outside the tubing string.

Note: Special handling precautions will be necessary for the injection tubing, particularly the CRA tubing on bottom. Precaution guidelines are attached.

33. RIH with the injection tubing string as shown below and on the attached Halliburton installation diagram. <u>Maximum running speed is 30 ft/min</u>. RU NOV Gator Hawk and externally hydrotest the tubing connections to 5000 psi with fresh water while TIH.

    Make up torque 3-1/2"/9.2/Inconel G-3/VAM TOP: Opt 3360 lb-ft/Min 3030 lb-ft/Max 3690 lb-ft

    Make up torque 3-1/2"/9.2/L80/BTS-8: Opt 3375 lb-ft/Min 3000 lb-ft/Max 3750 lb-ft

    <u>Packer seal assembly and tubing from top down</u>:

    a) 3-1/2"/9.2/L80/BTS-8 pin x pin crossover sub (pre-installed and pressure tested by GE) into the Inconel 718 tubing hanger

    b) 3-1/2"/9.2/L80/BTS-8 box x pin space out subs as needed

    c) 3-1/2"/9.2/L80/BTS-8 tubing as needed to SSSV depth of approximately 250' with ¼" control line clamped outside the tubing to surface

    d) 3-1/2"/9.2/L80/BTS-8 box x 3-1/2"/9.2/L80/AB TC-II pin crossover sub

    e) Halliburton SSSV w/2.813" R profile w/ AB TC-II box x pin Incoloy 925

    f) 3-1/2"/9.2/L80/AB TC-II box x 3-1/2"/9.2/L80/BTS-8 pin crossover sub

    g) 3-1/2"/9.2/L80/BTS-8 tubing as needed to approximately 300' above the seal assembly

    h) 3-1/2"/9.2/L80/BTS-8 box x 3-1/2"/9.2/L80/VAM TOP pin crossover sub

    i) 3-1/2"/9.2/Inconel G-3/VAM TOP tubing bottom 300' of tubing string

    j) Halliburton 2.562" R nipple 3-1/2"/9.2 VAM TOP box x pin Incoloy 925

    k) 6' pup joint 3-1/2"/9.2 VAM TOP box x pin Incoloy 925

    l) HAL ROC pressure temperature sensor 3-1/2"/9.2/VAM TOP box x pin Incoloy 925 with ¼" armored data cable clamped outside the tubing to surface

    m) 4' pup joint 3-1/2"/9.2 VAM TOP box x pin Incoloy 925

    n) Straight slot locator sub 3-1/2"/9.2/VAM TOP box x 3-1/2"/10.2/VAMINSIDE pin Incoloy 925

    o) 8' 3-1/2"/10.2/VAMINSIDE two seal unit extension Incoloy 925

    p) 4" x 3-1/2"/10.2/VAMINSIDE two seal units Incoloy 925 (moulded AFLAS/Flourel seals)

q) 4" x 3-1/2"/10.2/VAMINSIDE three seal units Incoloy 925 (moulded AFLAS/Flourel seals)

r) 3-1/2"/10.2/VAMINSIDE mule shoe guide Incoloy 925

34. Sting into packer, use subs to space out to put 20,000 lbs compression on packer, install 7-1/16" x 3-1/2" BTS-8 Inconel 718 tubing hanger machined for two ¼" lines and connect ¼" armored data line and ¼" SSSV control line to the tubing hanger.

35. Tie onto 3-1/2" injection tubing string with bottom of seal assembly just above the packer. RU Halliburton pump truck, mix 20 bbl WG-19 gel spacer mixed with red dye and place diesel packer fluid into tubing x casing annulus as follows:

   - Pump 20 bbl dyed gel spacer down tubing

   - Pump 500 bbls diesel packer fluid mixed with 1% (5 bbls) Baker CRO 381 corrosion inhibitor down the tubing at a maximum rate of 3 BPM. The CRO 381 corrosion inhibitor contains quaternary amines which also function as a biocide.

   - Stop pumping diesel when the dyed gel spacer circulates out of the tubing x casing annulus and clean diesel appears at the surface. The tubing and tubing x casing annulus will be full of diesel packer fluid when finished. The capacity of the tubing is approx. 120 bbls. The capacity of the tubing x casing annulus above the packer is approx. 350 bbls for a total of 470 bbls.

   - Diesel can be delivered to Baker Chemical facility in Hobbs where they can mix the CRO 381 into the diesel to make the packer fluid.

36. Sting into packer, land tubing hanger into tubing head, tighten packoff screws, install internally nickel plated tubing head adaptor and connect to the two ¼" lines. Install GE two-way BPV into tubing hanger. Install the internally nickel plated injection tree and plumb all casing and casing x tubing annuli to surface.

37. Pressure test the injection tree assembly from the tubing hanger up to 250 psi for 10 minutes followed by 5000 psi for 10 minutes. Install BPV removal/installation equipment and have GE remove the two-way BPV from the tubing hanger.

38. Give NMOCD Hobbs and BLM Hobbs 24 hrs notice for MIT. Top the annulus off with inhibited diesel packer fluid if necessary. Test tubing x casing annulus to 500 psi for 30 minutes. Use a one hour full rotation chart scaled from 0 to 1000 psi.

BLM conditions of approval for MIT: The proposed Mechanical Integrity Test of the NOI Step 18 is to be conducted after the wellbore equipment intended for acid gas injection/disposal is installed. Notify pswartz@blm.gov, 575-200-7902 24 hours prior to the MIT.

The minimum test pressure is 500 psig for 30 minutes with a minimum 200 psig differential between tubing and casing pressure (at test time) but no more than 70% of casing burst pressure as described by Onshore Order 2.III.B.1.h. Verify all annular casing vents are plumbed to surface and those valves open to the surface during this pressure test.

Document the pressure test on a one hour full rotation chart recorder (calibrated within the last 6 months) registering within 35 to 75 per cent of its full range. Greater than 10% pressure leakoff will be viewed as a failed MIT. Less than 10% pressure leakoff will be evaluated site specifically and may restrict injection approval.

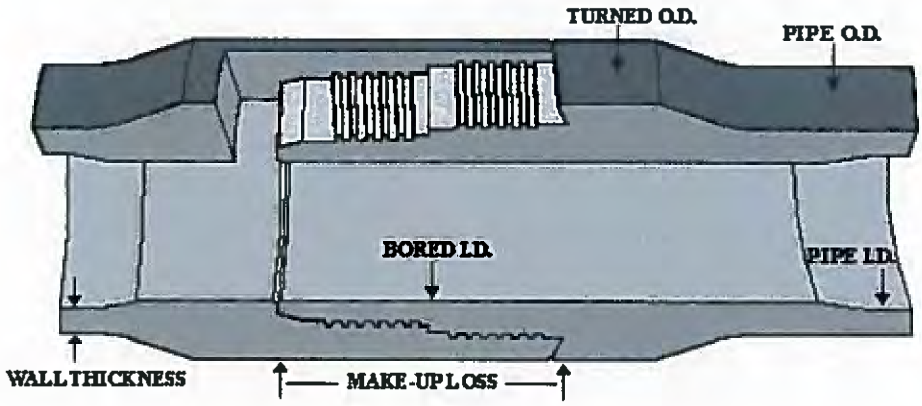
39. RU kill truck to tree and pump off the pump out plug located on the bottom of the packer tail pipe. Use fresh water and limit pressure to 5000 psi. If plug hasn't pumped off by the time 3500 psi surface pressure has been reached, may need to pressurize annulus to 1000 psi before pressurizing above 3500 psi—let's discuss.

40. Flow small amount of fluid back (slowly) into a tub or open top pit to ensure diesel is at surface. If any water flows into tub or pit, continue to flow until diesel is at surface inside the tubing and leave the tubing full of diesel packer fluid. RDMO all completion equipment and turn well over to DCP.

Kbc/dcp zia agi d2 compl proc v2.3 16 dec 16

Injection Tubing Data

Consistently Exceeding Customer Expectations



BTS-8 | **3 1/2** *in* | **9.30** *lb/ft* | **L-80**

PIPE DATA

TUBE O.D.	3.500	*in*
TUBE I.D.	2.992	*in*
WALL	.254	*in*
DRIFT DIA.	2.867	*in*
TENSILE YLD. STRENGTH	207,000	*lbs*
MAX STRING LGTH. (1.6 S/F)	13,910	*ft*
INTERNAL YLD.	10,160	*psi*
COLLAPSE YLD.	10,540	*psi*
TORSIONAL YLD.	15,089	*ft/lbs*
MAX BENDING	104.80	*°/100'*

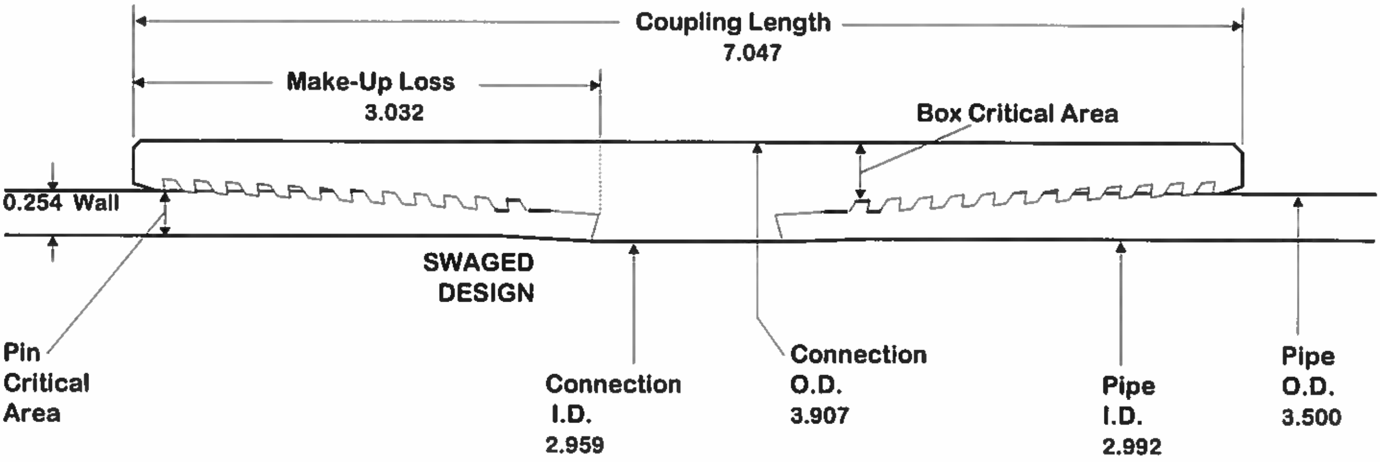
CONNECTION DATA

			% eff
CONNECTION O.D.	3.915	*in*	
CONNECTION I.D.	2.920	*in*	
S/C O.D.	3.859	*in*	
MAKE-UP LOSS	2.84	*in*	
TENSILE EFF.	106	*% eff*	
INTERNAL YLD.	100	*%*	
COLLAPSE YLD.	100	*%*	
TORSION YLD.	6,200	*ft/lbs*	41.1
MAX BENDING	77.70	*°/100'*	74.2
MAX BENDING - PR	61.80	*°/100'*	59.0
COMPRESSION	139,627	*lbs*	67.4
COMPRESSION - PR	102,947	*lbs*	49.7

MAKE-UP TORQ

MIN.	3,000	*ft/lbs*
OPT.	3,375	*ft/lbs*
MAX.	3,750	*ft/lbs*

VAM TOP



O.D.	WEIGHT	WALL	GRADE	DRIFT
3.500	9.20	0.254	G3-125	2.867

PIPE BODY PROPERTIES

Material Grade	G3-125	
Min. Yield Strength	125	ksi
Min. Tensile Strength	130	ksi
Outside Diameter	3.500	in
Inside Diameter	2.992	in
NOMINAL AREA	2.590	sq.in.
YIELD STRENGTH	324	kips
ULTIMATE STRENGTH	337	kips
MIN INTERNAL YIELD	15,880	psi
COLLAPSE	14,890	psi

CONNECTION PROPERTIES

CONNECTION OD	3.907	in
CONNECTION ID	2.959	in
MAKE UP LOSS	3.032	in
COUPLING LENGTH	7.047	in
BOX CRITICAL AREA	2.643	sq.in.
%PB Section Area	102.0%	
PIN CRITICAL AREA	2.590	sq.in.
%PB Section Area	100.0%	
YIELD STRENGTH	324	kips
PARTING LOAD	337	kips
MIN INTERNAL YIELD	15,880	psi
EXT PRESSURE	14,890	psi
WK COMPRESSION	259	kips
MAX PURE BENDING	30	deg/100

Questions? Contact Tech Services (281) 821-5510
Ref. Drawing: SI-PD 7534 Rev.D
Date: 11-Aug-10
Time: 6:35 PM

TORQUE DATA ft-lb

min	opt	max
3,030	3,360	3,690

Generated by:

Dave Herrmann

VAM USA

Tubing Handling Guidelines

CRA

1.0 Purpose

1.1 The purpose of this document is to specify the proper handling, storage and packaging methods to avoid detrimental damage and contamination from iron and other aggressive species/compounds.

2.0 Scope

2.1 This procedure applies to any steel alloy with a minimum of 9% Cr to include stainless steels, nickel alloys and titanium alloys.

3.0 Definition

- cra: corrosion resistant material
- CRA: Corrosion Resistant Alloys, Houston, Texas 77043

4.0 Safety/Housekeeping

4.1 Employees will wear protective gloves at all times when handling material. Cut resistant gloves must be worn when handling any materials.

5.0 Responsibility and Authority

5.1 All personnel handling, storing, machining, inspecting, packaging or transporting cra material are expected to conform to this procedure.

6.0 Procedure

6.1 Handling and processing

6.1.1 Lifting equipment: No metal-to-metal contact is allowed

6.1.1.1 Overhead cranes:

No chains, dogs, cables or metal tools are to contact the material.
Spreader bars with fabric slings are the preferred method

6.1.1.2 Forklifts

Forks and exposed lift frame vertical surfaces are to be covered.
Fork sleeves are the preferred means to cover this component.

6.1.2 Conveyors, machines, tables, and other such equipment

6.1.2.1 Uncovered work surfaces are to be hardened alloy steel, aluminum, brass or other non-marking material or otherwise covered.

6.1.2.2 Devices used to drive, lift, kick or hold material in an automated system need to have the contact surface covered with non-marking material.

6.1.3 Care should be taken to avoid severe contact between joints.

6.1.4 Any fluids or other substances that may be aggressive shall be removed from the material before further handling or release.

6.2 Marking

6.2.1 Material Traceability by Etching or Stamping

Permanent marking of the Heat/tube number and item serial number, if present, by vibro-etch or low stress intensity stamping is required. Use of other than low-stress intensity stamping is forbidden.

6.2.2 Marking

Other identity information is to be applied by stencil or paint pen. Inks or paints must be free of low melting temperature metals or chlorides.

6.3 Storage

6.3.1 Racks

6.3.1.1 Material will not be stored on steel, dirt or concrete surfaces.

6.3.1.2 Pipe racks or pallet\s with plastic liners are the contact surface for material.

6.3.1.3 No metal to metal contact is allowed between tubes or bars.

6.3.1.4 All wood surfaces must have protruding nails and other imbedded iron removed before use

6.3.1.5 When material is stacked in layers; each layer must use 4 X 4 or larger size lumber with plastic stripping as needed for access between layers and to avoid moisture entrapment into material. Plastic stripping applies to 9%, 13%, and 15% Chrome grades and below.

6.3.1.6 Dirt, mud and other foreign material must be removed from the ID when racked.

6.3.1.7 Plastic wrapping and other causes for trapped moisture will be removed as part of the racking procedure.

6.3.1.8 Care will be taken to avoid contact between tubes when handling material. Bumper rings or cardboard will be used for bars and tubes to avoid metal to metal contact.

6.3.1.9 All material must be identified by stock/job #, description and heat/tube # as a minimum.

6.3.2 Bolsters and Bumper Rings

6.3.2.1 All casing and production tube material will have a minimum of 2 bumper rings applied to isolate each tube joint. For R2 and under- 2 rings (staggered) and for R3- 3 rings (staggered).

6.3.2.2 Coupling stock and tube hollows intended for use where OD turning will be performed on the material. On-size material needs rings.

6.3.2.3 Bolsters with only plastic contact surfaces are permitted for storage and shipment without limitation. Other types must be individually evaluated.

6.3.3 Thread Protectors

6.3.3.1 All thread connections suitable for use will have the appropriate plastic pin or box thread protection applied. No metal protectors are permitted.

6.3.3.2 Kendex or similar product will be applied to useable thread surfaces.

6.3.4 Preservation

6.3.4.1 9CR, 13 CR, 15 CR or any grade so indicated, will not be stored on wooden surfaces without plastic lining. This material will be routinely checked for any pitting or crevice corrosion at the contact points. Any such attack will require remediation, coating and restacking.

6.3.4.2 Threaded ends should be checked annually for conditions and the need to clean and reapply protective substance.

6.3.4.3 Any product found to be deteriorating will be cleaned and remediated as determined on a by case basis.

6.4 Packaging and loading out

6.4.1 No metal-to-metal contact, especially with steel surface.

6.4.2 Trailer pipe stakes must be covered with non-metallic metals.

6.4.3 Tubing, casing and on-size tube hollows will have bumper rings applied.

6.4.4 Product other than tubing should be boxed, crated or put on a skid for protection and to avoid potential loss if the item size or fragility to warrant this extra care. Machined products with critical dimensions will be wrapped or crated.

6.4.5 Pyramid stacking is not permitted. If the product is layered, 4X4 wooden stripping minimum will be used between layers.

6.4.6 Overwrapping or tarp should be used for interstate trucking.

7.0 Related and Support Documentation

None

8.0 Revision History

Rev.	Section	NDCR#	Description of Change	Date	Authorized by
A	All	0284	Initial Release	3/12/14	Ricardo Mendiola
B	2.1, 6.3.1.5, 6.3.4.1	353	Changed wording	2/25/2015	Justin Bouis

Approval: Date

Acid Recommendation

HALLIBURTON

COG OPERATING LLC - EBUS
DONOTMAIL - 600 W ILLINOIS AVE
MIDLAND, TX, 79701
US

ZIA AGI 2
AGI
LEA County, NM, US
API/UWI 30-025-42207-00
SEC: 19,TWP: 19,RNG: 32

Acid Job Proposal

Proposal 224899 - Version 1.0
November 08, 2016

Submitted by:
Julio Sanchez
2311 S First
Artesia, NM - 88210
USA

HALLIBURTON

Contents

Halliburton appreciates the opportunity to present this cost estimate and looks forward to being of service to you.

1 Foreword

MIDLAND SALES OFFICE
1-800-844-8451

ODESSA DISTRICT
1-800-417-5096

CEMENTING:
Steve Luscombe / Joe Briseno
Teddy Johnson / Mike Kilgore
STIMULATION:
Robert Rodriguez / Justin Carrasco
John Perez / Juan Jimenez
LOGGING & PERFORATING
Xaviere Emiliano / Raul Gutierrez
COILED TUBING & NITROGEN
Quincy Cole

TOOLS & TESTING, PROD. SVCS., TCP, COMPL. PRODUCTS
Steve Engleman / Kevin Warren

BAROID
Clint McCoy / Elijio Vela

SPERRY
David Oakley / David Carroll

HOBBS DISTRICT
1-800-416-6081

CEMENTING
Louis Sosa / Jaime Gonzales
Andrew Dennis / Clay Erwin
STIMULATION:
Robert Rodriguez / Justin Carrasco
John Perez / Juan Jimenez
LOGGING & PERFORATING
Daniel Heitz / John Harrison
DRILL BITS:
Whit McWilliams / Kellan Zindel

TOOLS & TESTING, PROD. SVCS., TCP, COMPL. PRODUCTS
Jim Tillman / Doak Shannon

ARTIFICIAL LIFT
John Wright / Jeff Wilhelm

2 Service Center Contacts

3 Acid Job Proposal

3.1 Executive Summary

Job Summary

Number of Treatment Intervals	1	
Casing Treating Pressure Calculated:	2679.3	psig
Casing Treatment Rate	10.0	bbl/min
Hydraulic Horsepower Casing (recommended)	534.13	hp
Total Estimated Pumping Time	2.24	hr
BH Rate	10.0	bbl/min

Total System Requirement

20 % NE Acid	40000	Gal
20# Gel w/ Diverter	4000	Gal
Fresh Water	8026	Gal

Total Customer Supplied

FRESH WATER	12026	Gal

3.2 Well Details

3.2.1 Formations

Name / Depth (ft)	Pore Press. (psig)	BHST (degF)	Frac Gradient (psi/ft)
Devonian / 13750 - 14750		200.0	0.000

3.3 Procedure

3.3.1 Job Fluids

20# Gel w/ Diverter
Job Volume: 4000.0 (Gal)

Base Fluid	FRESH WATER 1000.00 (gal/Mgal)	4000 (Gal)	**Diverter**	TBA(TM)-110 500.00 (lbm/Mgal)	4000.00 (lbm)
Gelling Agent	WG-17 20.00 (lbm/Mgal)	80.00 (lbm)			

Fresh Water
Job Volume: 8026.0 (Gal)

Base Fluid	FRESH WATER 1000.00 (gal/Mgal)	8026 (Gal)

20 % NE Acid
Job Volume: 40000.0 (Gal)

Base Fluid	HCL ACID 1000.00 (gal/Mgal)	40000 (Gal)	**Corrosion Inhibitor**	HAI-OS 2.00 (gal/Mgal)	80.00 (Gal)
Surfactant	LOSURF-360 1.00 (gal/Mgal)	40.00 (Gal)			

3.3.2 Job Totals

Fluids

Diverter	TBA(TM)-110	4000.00(lbm)	**Gelling Agent**	WG-17	80.00(lbm)
Corrosion Inhibitor	HAI-OS	80(Gal)	**Surfactant**	LOSURF-360	40(Gal)

Diverters

Name	Volume (Gal)	Conc (lbm/gal)	Mass (lbm)
TBA(TM)-110	4000	1.00	4000.00

Customer Supplied Items

	Designed Qty	Tank Bottom	Requested with Tank Bottom
FRESH WATER	12026 (Gal)	0 (Gal)	12026(Gal)

3.3.3 Treatment Interval 1

Well Name	ZIA AGI/2	20 % NE Acid	40000(Gal)
Job Name	Acid Job Proposal	20# Gel w/ Diverter	4000(Gal)
Mid Perf MD	14253(ft)	Fresh Water	8026(Gal)
No. of Perfs/Jets	0	TBA(TM)-110	4000.00(lbm)
Estimated Pump Time	134.54(min)		
BHST	200.0(degF)		
Frac Gradient	0.500 (psi/ft)		

20# Gel w/ Diverter Additive Tuning

Base Fluid	Diverter (lbm/Mgal)
FRESH WATER	TBA(TM)-110
0 - 4000	1000

CASING Surface Pumping Schedule

Trt-Stage	Stage Desc.	Fluid Desc.	Rate-Liq+Prop (bbl/min)	Clean Vol. (Gal)	Proppant	Proppant Conc. (lbm/gal)	Prop. Mass (lbm)
1-1	Load Well	Fresh Water	10.00	500		0.00	0
1-2	Acid	20 % NE Acid	10.00	15000		0.00	0
1-3	Diverter	20# Gel w/ Diverter	5.00	2000		0.00	0
Note: Drop 2000 lbs diverter							
1-4	Acid	20 % NE Acid	10.00	15000		0.00	0
1-5	Diverter	20# Gel w/ Diverter	5.00	2000		0.00	0
Note: Drop 2000 lbs diverter							
1-6	Acid	20 % NE Acid	10.00	10000		0.00	0
1-7	Flush	Fresh Water	10.00	7526		0.00	0
Note: Please confirm flush							
1-8	Shut-In		0.00	0		0.00	0
Totals				52026			0

Perforation Balls & Diverters

Trt-Stage	Stage Desc.	Clean Vol. (Gal)	Ball Used	Ball Drop Rate	Volume In (Gal)	Diverter Used	Div. Conc.	Div. Qty (lbm)
1-3	Diverter	2000		0	0	TBA(TM)-110	1.00	2000.00
1-5	Diverter	2000		0	0	TBA(TM)-110	1.00	2000.00

3.4 Cost Estimate

Mtrl Nbr	Description	Qty	UOM	Unit Price	Gross Amt	Net Amount
13288	**PE BOM-Acidize Formation w/o CT**	1.00	JOB	0.00	0.00	0.00
Solution pricing line items						
3124	PE MILEAGE FOR FRAC EQUIPMENT *MOBILIZATION CHGS FRAC SOL SVC CHG* Number of Units	340.00 3	MI	USD 1.96/ 1 MI	1,999.20	699.72
3125	PE MILEAGE FOR FRAC CREW *FRACTURING -SOLUTION SERVICE CHARGE* Number of Units	1.00 1	MI	USD 1.15/ 1 MI	1.15	0.40
3128	PE TRANSPORT W/ EQUIPMENT OPERATOR / HR *ADDTL HOURLY PUMPING & PROPORTIONING CHG* NUMBER OF HOURS	2.00 4	EA	USD 56.00/ 1 EA	448.00	156.80
16134	ACID PUMP CHARGE 1ST 2 HOURS PRESSURE UNITS (PSI/MPA/BAR) PRESSURE	2.00 PSI 6000	EA	USD 889.20/ 1 EA	1,778.40	622.44
122598	ACID PUMP CHG FOR ADDITIONAL HR PER PUMP PRESSURE UNITS (PSI/MPA/BAR) PRESSURE NUMBER OF HOURS	2.00 PSI 6000 2	EA	USD 223.00/ 1 EA	892.00	312.20
756562	ACID ON-LOCATION PUMP CHARGE,> 2 HR HR/DAY/WEEK/MTH/YEAR/JOB/RUN TOTAL NUMBER	2.00 H 6	EA	USD 105.00/ 1 EA	1,260.00	441.00
Material line items						
341772	SBM Fe Acid *20 % NE Acid* UNIT OF MEASURE - % PERCENT ACID	40,000.00 % 20	GAL	USD 2.62/ 1 GAL	104,800.00	36,680.00
100003623	CHEM, WG-17-Gelling Agent, 50 lb *WG-17, 50 LB SK (100003623)*	80.00	LB	USD 22.00/ 1 LB	1,760.00	616.00
100001581	CHEM-TBA-110 - 100# SK *TBA(TM)-110, 100 LB SK (100001581)*	4,000.00	LB	USD 0.11/ 1 LB	440.00	154.00
102231312	CHEM,LOSURF-360, 330 GALLON TOTE *LOSURF-360, 330 GALLON TOTE(102231312)*	40.00	GAL	USD 27.50/ 1 GAL	1,100.00	385.00
101366650	Chem-HAI-OS, 260 gal tote tank *HAI-OS, 330 GAL TOTE TANK (101366650)*	80.00	GAL	USD 40.00/ 1 GAL	3,200.00	1,120.00
	Total Gross Amount					**117,678.75**
	Total Item Discounts					**76,491.19**
	Total Net Amount	USD				**41,187.56**

Primary Plant:	Brownfield, TX, USA	**Price Book Ref:**	27 - PERMIAN BASIN
Secondary Plant:	Brownfield, TX, USA	**Price Date:**	5/1/2016

4 Step Rate Test

4.1 Executive Summary

Job Summary

Number of Treatment Intervals	1	
Total Estimated Pumping Time	4.00	hr

Total System Requirement

Fresh Water	37800	Gal

Total Customer Supplied

FRESH WATER	37800	Gal

4.2 Procedure

4.2.1 Job Fluids

Fresh Water
Job Volume: 37800.0 (Gal)

Base Fluid	FRESH WATER 1000.00 (gal/Mgal)	37800 (Gal)

4.2.2 Job Totals

Customer Supplied Items

	Designed Qty	Tank Bottom	Requested with Tank Bottom
FRESH WATER	37800 (Gal)	0 (Gal)	37800(Gal)

4.2.3 Treatment Interval 1

Well Name	ZIA AGI/2	Fresh Water	37800(Gal)
Job Name	Step Rate Test		
Mid Perf MD	0		
No. of Perfs/Jets	0		
Estimated Pump Time	240.00(min)		
Frac Gradient	0.000 (psi/ft)		

CASING Surface Pumping Schedule

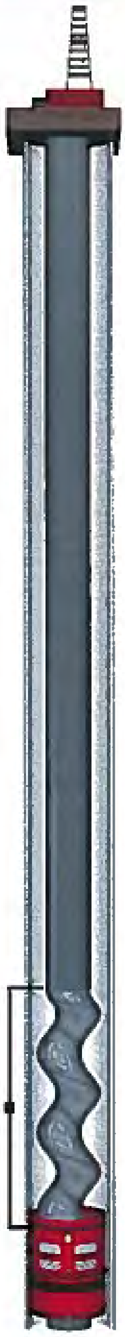
Trt-Stage	Stage Desc.	Fluid Desc.	Rate-Liq+Prop (bbl/min)	Clean Vol. (Gal)	Proppant	Proppant Conc. (lbm/gal)	Prop. Mass (lbm)
1-1	Load Well		0.50	500		0.00	0
1-2	Step Rate Test	Fresh Water	3.75	37800		0.00	0
Note: Rate will increase from .5bpm to 7bpm please confirm with company man on how step will be taken							
Totals				38300			0

Tubing Movement Calculations

Company: DCP	Phone #: 575-748-6924	Contact: Brian Collins	Well #:	Well API#:	Lease Name: Zia AGI #2

OVERVIEW

NO PROBLEMS PREDICTED



Purpose

This Tubing Movements report analyzes the effects of movement, forces, temperatures, and stresses occurring in the tubing string and down-hole tools during the specified operating scenarios. CyberString utilizes Halliburton Completion Tools Algorithms, INSITE® for Well Intervention (IWI) Analysis, as well as WellCat Technology.

Project

Name: Acid Gas Injector
Date: 6/27/2016
Field Location:
Environment: Land

Comments

8' PBR

Summary

	Injection
Maximum Stress psi	37066
Max. Stress Location ft	0

Bottom Packer: BWD

Buckling Length ft	3023.90
Tubing to Packer Force lbf	0.00
Total Seal Movement ft	-3.64

INITIAL CONDITION

BWD: 13700 ft

Bottom Packer: BWD at 13700 ft

Seal Bore Packer – Tubing is free to move			Slackoff at Surface:	0	lbf
Bore Diameter:	4.000	in	Slackoff at Packer:	0	lbf
Max Seal Travel Up:	12.00	ft	Length Change:	0.00	ft
Max Seal Travel Down:	0.00	ft	There is a NOGO at the bottom of the seal		

Measure Depth Tubing

From ft	To ft	OD in	ID in	WT lb/ft	Grade	Min. Yield psi	After SF psi
0	8200	3.500	2.992	9.30	P-105	105000	84000
8200	13700	3.500	2.992	9.30	L-80	80000	64000

Measure Depth Casing

From ft	To ft	OD in	ID in	WT lb/ft	Grade	Min. Yield psi	After SF psi
0	350	7.625	6.765	33.70	P-110	110000	88000
350	13755	7.000	6.184	29.00	P-110	110000	88000

SF: Safety Factor

HALLIBURTON | Completion Tools

CYBERSTRING® SL

Company: DCP	Phone #: 575-748-6924	Contact: Brian Collins	Well #:	Well API#:	Lease Name: Zia AGI #2

INITIAL CONDITION

Deviation		Critical Tubing Data						Critical Annulus Data	
MD	TVD	Pressure	Temp.	Density	Axial Force	Stress	Dogleg	Pressure	Density
ft	ft	psi	°F	lb/gal	lbf	psi	deg/100ft	psi	lb/gal
0	0	0	65.00	8.34	92035	35532	0.00	0	8.34
350	350	152	68.70	8.34	88782	34427	0.00	152	8.34
350	350	152	68.71	8.34	88780	34426	0.00	152	8.34
8200	8200	3553	151.79	8.34	15776	9643	0.00	3553	8.34
8200	8200	3553	151.79	8.34	15776	9643	0.00	3553	8.34
13700	13700	5935	210.00	8.34	-35374	14563	8.96	5935	8.34

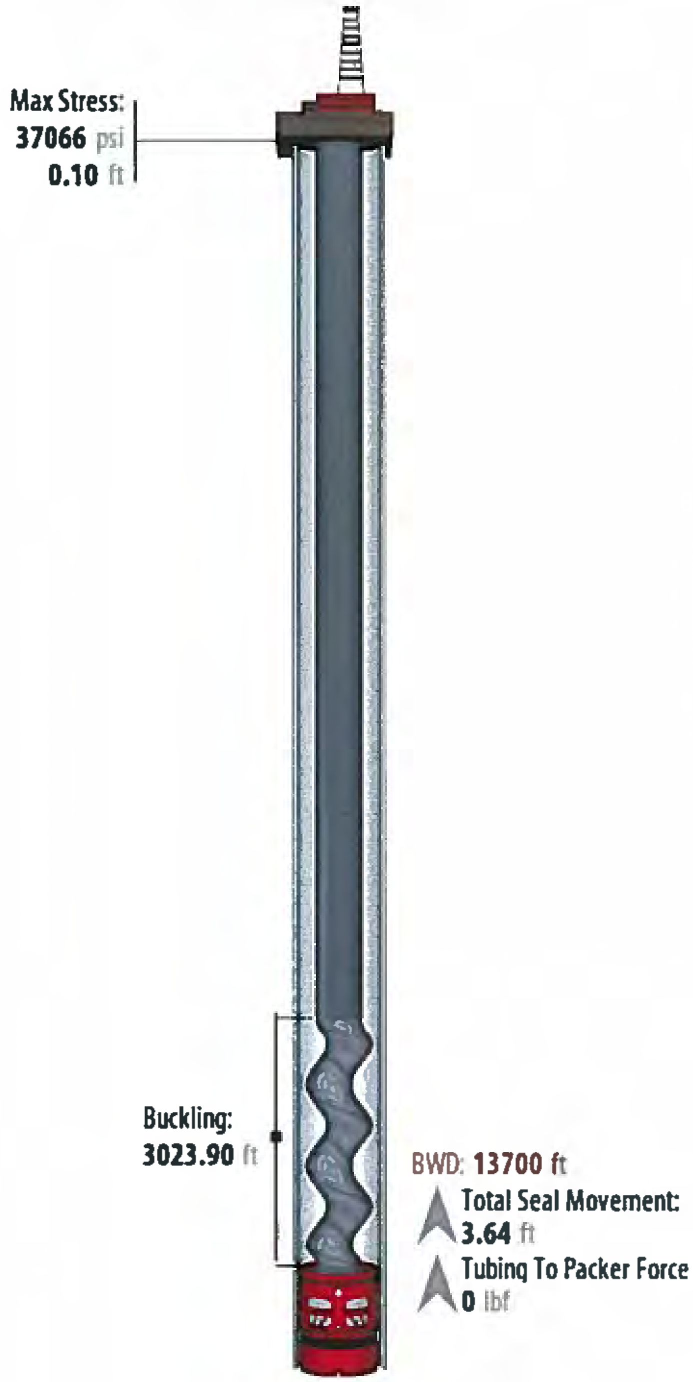
Bottom Packer at 13700.00 ft

Sign Conventions Force: (+)Tension (-)Compression

Company: DCP	Phone #: 575-748-6924	Contact: Brian Collins	Well #:	Well API#:	Lease Name: Zia AGI #2

INJECTION

NO PROBLEMS PREDICTED



Scenario Information

Tubing Fluid			Annulus Fluid		
Fresh	6.40	lb/gal	Diesel:	6.80	lb/gal

Injection Info

Injection Rate:	4.00	bbl/min
Injection Duration:	24.00	hour
Injection Volume:	32340	ft³
Injection Pressure:	2500.00	psi
Injection Temp:	90.00	°F
Surface Pressure:	0.00	psi

Bottom Packer: BWD at 13700 ft

Seal Movement

Piston:	2.12	ft
Ballooning:	-1.80	ft
Thermal:	-3.91	ft
Buckling:	-0.06	ft
Total:	-3.64	ft
Diff. P Across Packer	From Below 1951	psi

Drag Calculation (IWI Torque & Drag)

Slackoff at Packer:	20000	lbf
Slackoff required at Surface:	25728	lbf
Length Change due to Slackoff:	6.96	ft
Resultant Slackoff at Packer:	20000	lbf

INJECTION

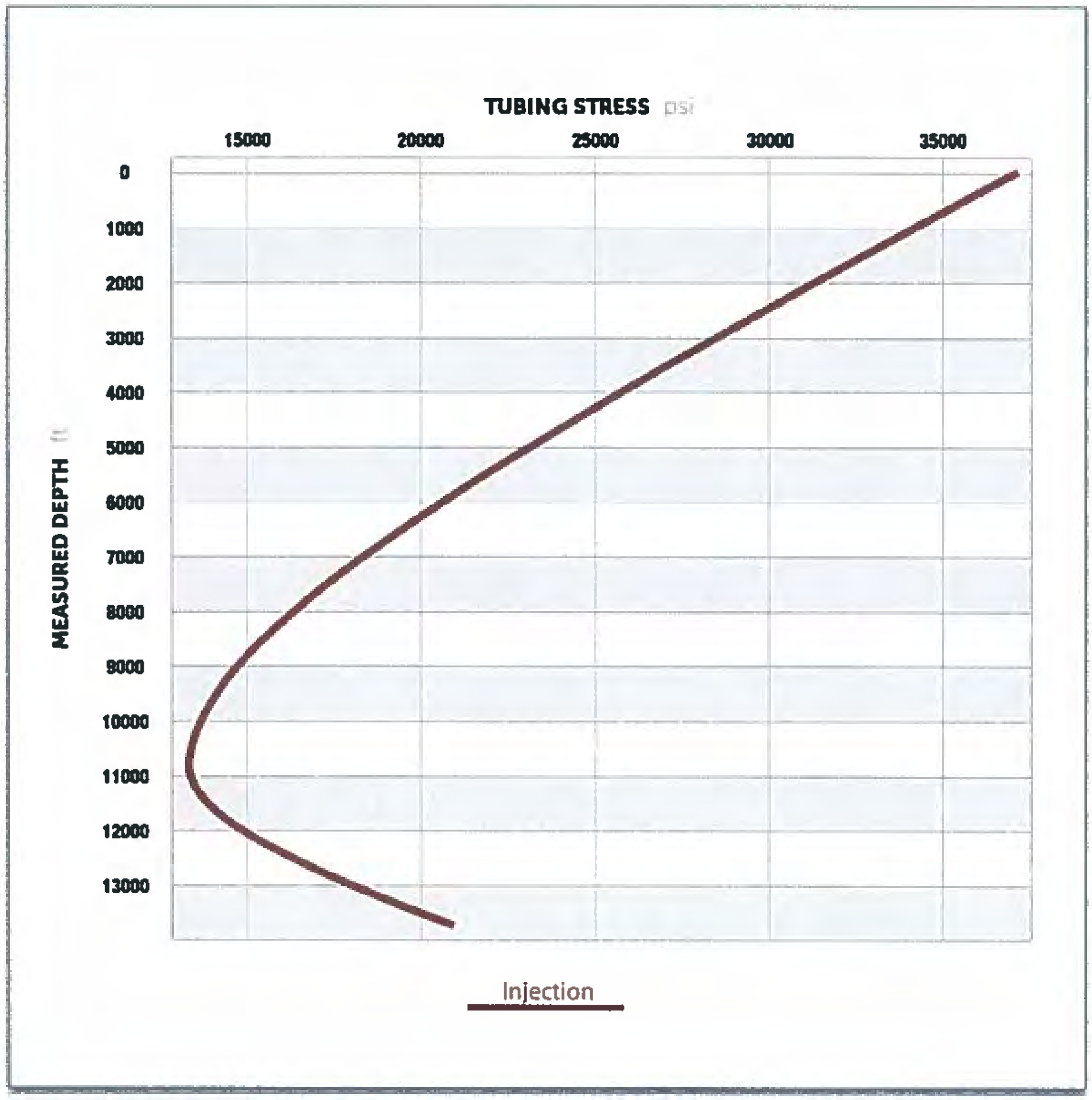
Critical Tubing Data / Critical Annulus Data

MD (ft)	Pressure (psi)	Temp. (°F)	Density (lb/gal)	Axial Force (lbf)	Stress (psi)	Dogleg (deg/100ft)	Annulus Pressure (psi)	Annulus Density (lb/gal)
0	2500	89.95	6.40	104080	37066	0.00	0	6.80
350	2610	89.80	6.40	100820	36043	0.00	124	6.80
350	2610	89.81	6.40	100820	36043	0.00	124	6.80
8200	5066	96.28	6.40	27818	15964	0.00	2897	6.80
8200	5066	96.28	6.40	27818	15964	0.00	2897	6.80
13700	6790	111.81	6.40	-23332	20833	10.98	4839	6.80

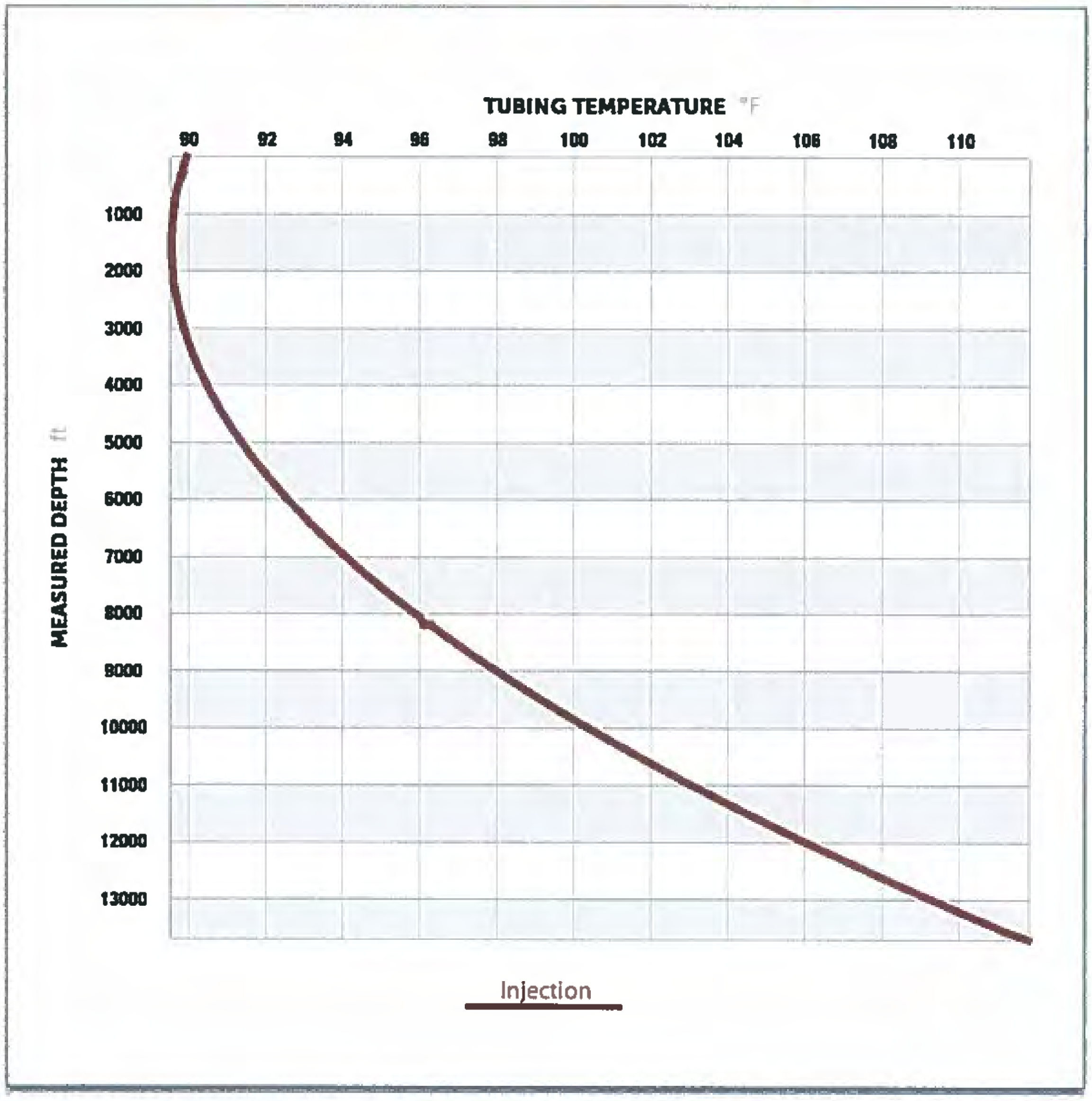
Bottom Packer at 13700.00 ft

Sign Conventions Movement: (+)Elongation (-)Contraction Force: (+)Tension (-)Compression

STRESS GRAPH

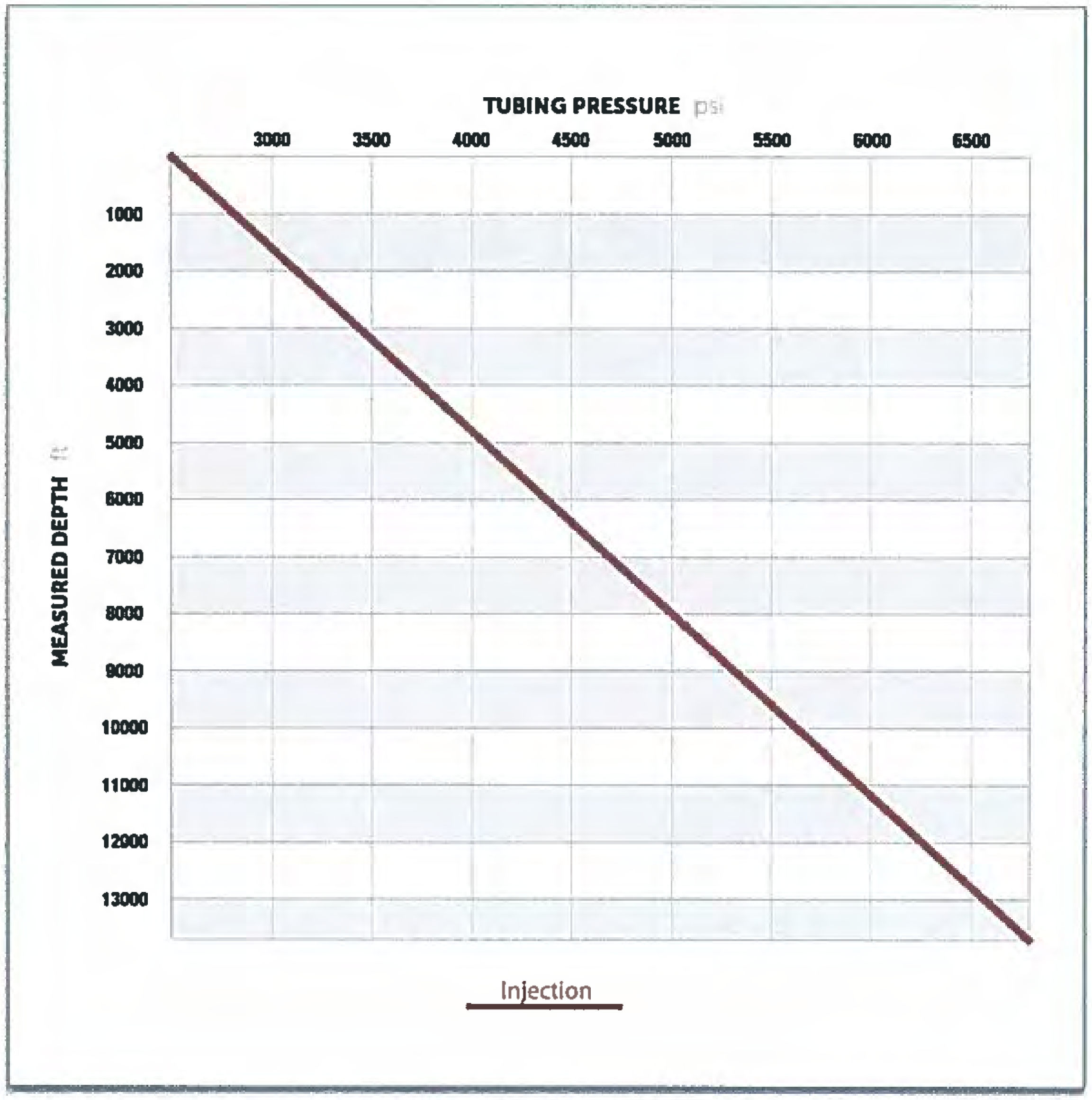


TEMPERATURE GRAPH



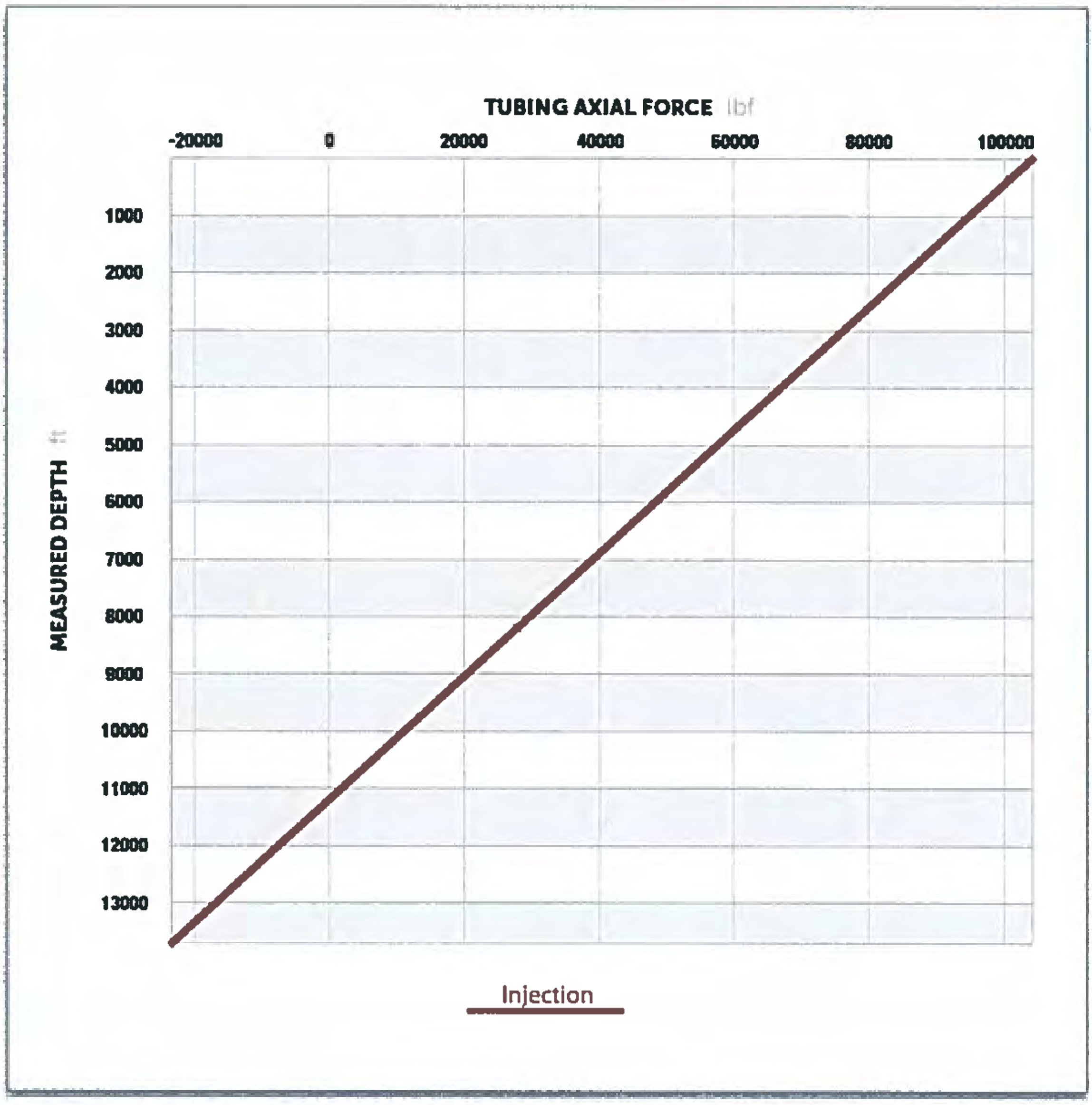
Company: DCP | Phone #: 575-748-6924 | Contact: Brian Collins | Well #: | Well API#: | Lease Name: Zia AGI #2

PRESSURE GRAPH



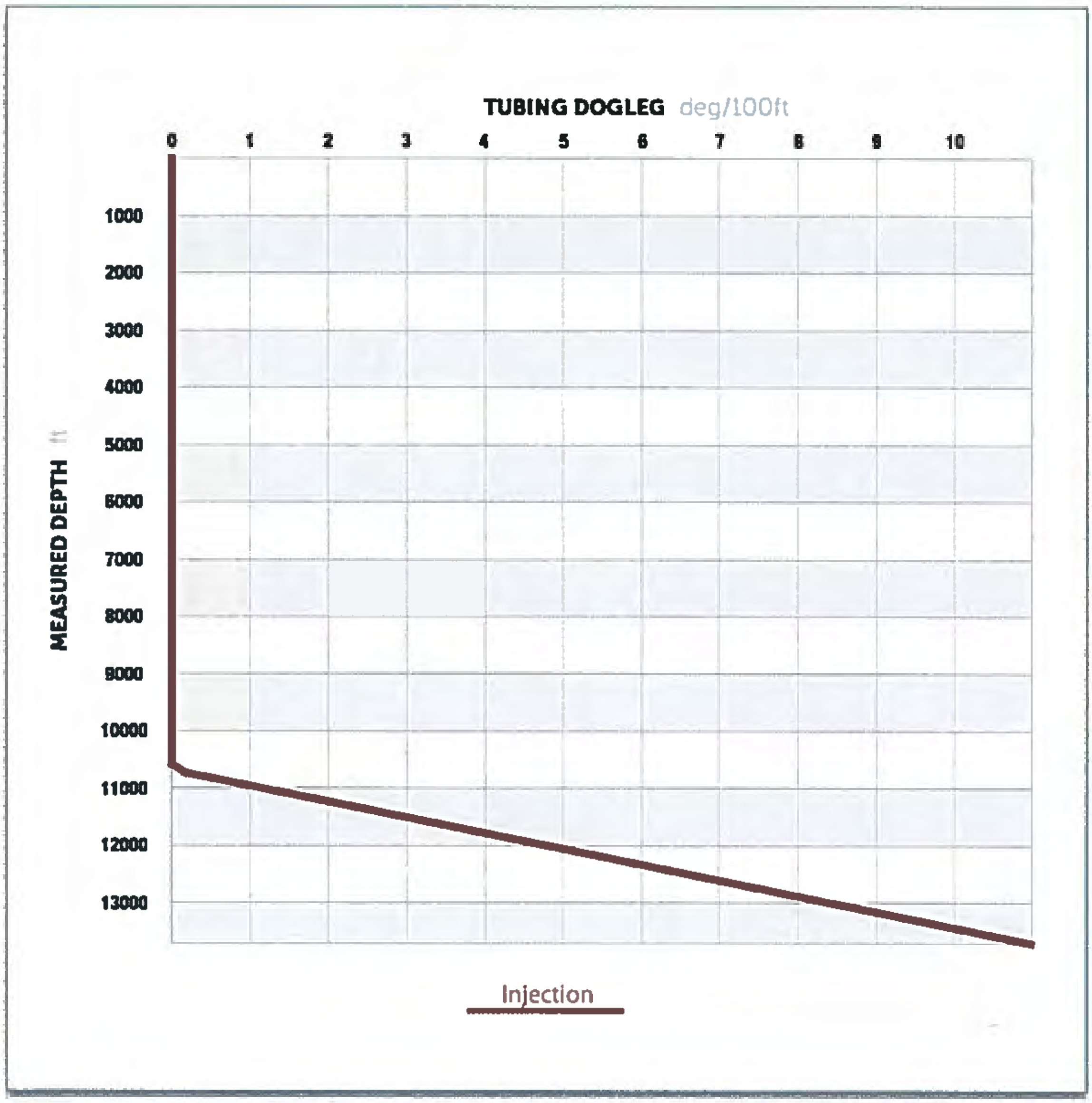
Company: DCP	Phone #: 575-748-6924	Contact: Brian Collins	Well #:	Well API#:	Lease Name: Zia AGI #2

FORCE GRAPH



Company: DCP	Phone #: 575-748-6924	Contact: Brian Collins	Well #:	Well API#:	Lease Name: Zia AGI #2

DOGLEG GRAPH



AFE

COG OPERATING LLC
AUTHORITY FOR EXPENDITURE
DRILLING

WELL NAME:	ZIA AGI #2D	PROSPECT NAME:	4 STRING AREA
SHL:	1893' FSL / 950' FWL	STATE & COUNTY:	New Mexico, Lea
BHL:		OBJECTIVE:	47 DAYS @ RR
FORMATION:	DEVONIAN	DEPTH:	14,500
LEGAL:	S 19 / T19S / R32E	TVD:	14,500

INTANGIBLE COSTS		Drlg - Rig Release(D)		Completion(C)		Tank Btty Constrctn(TB)		Pmpg Equipment(PEQ)	TOTAL
Title/Curative/Permit	201	11.000							11.000
Insurance	202	4.000	302						4.000
Damages/Right of Way	203	5.000	303		351				5.000
Survey/Stake Location	204	6.000			352				6.000
Location/Pits/Road Expense	205	75.000	305	2.500	353		366		77.500
Drilling / Completion Overhead	206	8.400	306						8.400
Turnkey Contract	207	0	307						0
Footage Contract	208	0	308						0
Daywork Contract	209	930.000	309						930.000
Directional Drilling Services	210	200.000	310						200.000
Fuel & Power	211	130.000	311		354		367		130.000
Water	212	75.000	312	15.000			368		90.000
Bits	213	125.000	313	5.000			369		130.000
Mud & Chemicals	214	100.000	314	40.000			370		140.000
Drill Stem Test	215	0	315						0
Coring & Analysis	216	150.000							150.000
Cement Surface	217	25.000							25.000
Cement Intermediate	218	55.000							55.000
Cement 2nd Intermediate/Production	219	340.000							340.000
Cement Squeeze & Other (Kickoff Plug)	220	0					371		0
Float Equipment & Centralizers	221	80.000							80.000
Casing Crews & Equipment	222	35.000							35.000
Fishing Tools & Service	223	0	323				372		0
Geologic/Engineering	224	0	324		355		373		0
Contract Labor	225	8.500	325	10.000	356		374		18.500
Company Supervision	226	85.000	326	10.000	357		375		95.000
Contract Supervision	227	135.000	327		358		376		135.000
Testing Casing/Tubing	228	20.000	328				377		20.000
Mud Logging Unit	229	80.000	329						80.000
Logging	230	100.000					378		100.000
Perforating/Wireline Services	231	4.000	331	35.000			379		39.000
Stimulation/Treating			332	70.000			380		70.000
Completion Unit			333				381		0
Swabbing Unit			334				382		0
Rentals-Surface	235	200.000	335	150.000	359		383		350.000
Rentals-Subsurface	236	125.000	336	125.000			384		250.000
Trucking/Forklift/Rig Mobilization	237	125.000	337	35.000	360		385		160.000
Welding Services	238	2.000	338	2.500	361		386		4.500
Water Disposal	239	0	339	5.000	362		387		5.000
Plug to Abandon	240	0	340						0
Seismic Analysis	241	0	341						0
Miscellaneous	242	0	342				389		0
Contingency 5%	243	128.100	343	45.000	363		390		173.100
Closed Loop & Environmental	244	225.000	344		364		388		225.000
Coil Tubing			346						0
Flowback Crews & Equip			347						0
Offset Directional/Frac	248		348						0
TOTAL INTANGIBLES		3.570.000		550.000		0		0	4.120.000

TANGIBLE COSTS			Drlg - Rig Release(D)		Completion(C)		Tank Btty Constrctn(TB)		Pmpg Equipment(PEQ)	TOTAL
Surface Casing	850' 20" 106.5 J55	401	55.374							55.374
Intermediate Casing	2600' 13 375" 61# / 4700' 9 625" 40#	402	171.450							171.450
Production Casing/L	11850' 7" 29# / 1850' CRA / XO's	403	719.344							719.344
Tubing				504	550.000			530		550.000
Wellhead Equipment		405	60.000	505	250.000			531		310.000
Pumping Unit								506		0
Prime Mover								507		0
Rods								508		0
Pumps-Sub Surface (BH)				509				532		0
Tanks						510				0
Flowlines						511				0
Heater Treater/Separator						512				0
Electrical System						513		533		0
Packers/Anchors/Hangers		414	10.000	514	800.000			534		810.000
Couplings/Fittings/Valves		415	0			515				0
Dehydration						517				0
Injection Plant/CO2 Equipment						518				0
Pumps-Surface						521				0
Instrumentation/SCADA/POC						522		529		0
Miscellaneous		419	0	519		523		535		0
Contingency		420	0	520	100.000	524		536		100.000
Meters/LACT						525				0
Flares/Combusters/Emission						526				0
Gas Lift/Compression				527		516		528		0
TOTAL TANGIBLES			1.016.167		1.700.000		0		0	2.716.167
TOTAL WELL COSTS			4.586.167		2.250.000		0		0	6.836.167
% of Total Well Cost			67%		33%		0%		0%	

COG Operating LLC

Date Prepared: 9.20.2018

COG Operating LLC

By: TIMOTHY D. SMITH BRIAN COLLINS

We approve:
_____% Working Interest

Company:
By:

Printed Name:
Title:
Date:

This AFE is only an estimate. By signing you agree to pay your share of the actual costs incurred.

PRE-COMPLETION MEETING #2 OUTLINE

Zia AGI #D2
1893’ fsl, 950’ fwl
L-19-19s-32e
Lea, NM
API 30-025-42207
Lat N 32.643951, Long W 103.811116

3 January 2017

1. **Introductions, Safety Moment and Administrative Items**

2. **Completion Procedure Basic Outline**

POOH with retrievable packer. RIH with bit and scraper to approx. 13600’. LD work string.

RU wireline and make dummy run with gauge ring/junk basket/simulated packer.

RIH with Halliburton Incoloy 925 BWD packer assembly on wireline being very cautious, particularly at casing size and weight changes, DV tool and baffle assembly.

Set packer at approx. 13550’.

RU Franks Casing crew and special handling equipment for CRA tubing, VAM TOP connections and BTS-8 connections on 3-1/2” injection tubing. RU Gatorhawk to externally hydrotest connections and Halliburton to run ¼” data line and ¼” SSSV control line clamped to outside of tubing.

RIH with Incoloy 925 locator/seal assembly, PT sensor, 300’ 3-1/2”/9.2/Inconel G3/VAM TOP tubing, 3-1/2”/9.2/L80/BTS-8 tubing, Incoloy 925 SSSV at approx. 250’, 3-1/2”/9.2/L80/BTS-8 tubing, space out subs and Inconel 718 dual port tubing hanger with pin x pin sub already made up onto hanger. There will be numerous subs associated with components in tubing string. See attached packer/tubing schematic.

Space out to leave 20,000 lbs tubing compression on packer.

Fill tubing and tubing x casing annulus with approx. 500 bbls diesel with corrosion inhibitor/biocide combo.

Install injection tree, run MIT for BLM and NMOCD then pump plug off end of packer tailpipe. Turn well over to DCP.

3. **<u>DCP Summary of Gas Plant Operations and Flare Operation</u>**

   Basic gas plant operation.

   Acid gas flare operation and potential H2S/SO2

   Main gas flare operation and potential heat issues

   Events requiring evacuation of well site and location of muster points

4. **<u>Define Critical Well Site Operations Where Evacuation Isn't a Good Option</u>**

   Nippling up or nippling down BOPs? (well control concerns)

   Injection tubing running operation until wellhead is installed? (no good time to stop and leave well unattended while running tubing with control lines attached to outside)

5. **<u>Invoices—All invoices go directly to DCP. Don't send them to Concho.</u>**

6. **<u>Safety orientation video required for anyone at the well site or within the gas plant fence.</u>**

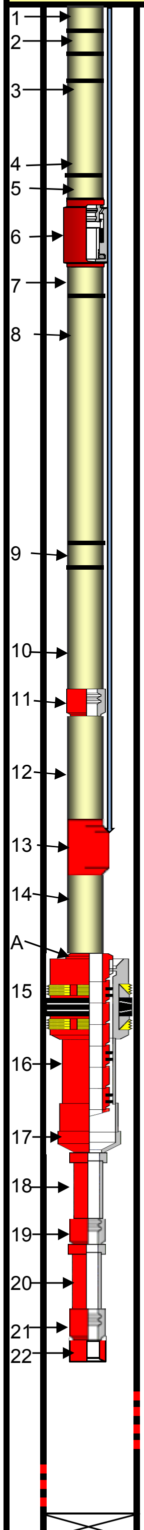
7. **<u>Questions or comments?</u>**

HALLIBURTON

DCP Midstream

ZIA AGI #2	Company Rep.	Brian Collins
Lea County New Mexico	Sales Rep.	Lynn Talley
7/18/16	Office	432-682-4305

Installation



Length	Depth	Description	OD	ID
		KB Correction		
		Tubing Hanger		
		1) 1 joint 3 1/2" 9.3# BTS-8 Tubing Joint Inverted	3.500	2.920
		2) Double Pin Sub (DCP)	3.500	2.920
		3) Tubing Subs (As Required) (DCP)	3.500	2.920
		4) 3 1/2" 9.3# BTS-8 Tubing	3.500	2.920
		5) 3 1/2" 9.3# BTS-8 Box X 3 1/2" 9.2# AB TC-II Pin L-80 Sub (DCP)	3.500	2.959
		6) Halliburton Tubing Retrievable Safety Valve-NE 3 1/2" 9.2# AB TC-II Box X Pin 102588547 SN ###### Nickel Alloy 925 10K Rated 875 Minimum PSI Closing, 2000 PSI Open, 2.813" R Profile	5.300	2.813
		7) 3 1/2" 9.2# AB TC-II Box X 3 1/2" 9.3# BTS-8 Pin L-80 Sub (DCP)	3.907	2.920
		8) 3 1/2" 9.3# BTS-8 L-80 Tubing	3.500	2.920
		9) 3 1/2" 9.3# BTS-8 Box X 3 1/2" 9.2# VAMTOP Pin L-80 Sub (DCP)	3.915	2.920
		10) 3 1/2" 9.2# VAMTOP Inconel G3 Nickel Tubing	3.500	
1.33		11) Halliburton 2.562" R Nipple 3 1/2" 9.2# VAMTOP Box x Pin (102204262) Nickel Alloy 925	3.937	2.562
6.00		12) 6' x 3 1/2" 9.2# VAMTOP BxP Tubing Sub NA 925	3.500	2.992
4.83		13) HAL ROC® PT Gauge Mandrel Assembly 3 1/2 TBG DIAMETER,9.20#,VAMTOP TOP,BOX-PIN Type Nickel Alloy 925 110KSI, 0.75" GAUGE	4.660	2.992
6.00		14) 4' x 3 1/2" 9.2# VAMTOP BxP Tubing Sub NA 925	3.500	2.992
		A) Halliburton Seal Assembly		
1.76		A1) Straight Slot Locator Sub 3 1/2" 9.2# VAMTOP Box X 3 1/2" 10.2# VAMINSIDE Pin Incoloy 925 (102351212)(SN-######)	4.470	2.883
8.00		A2) 2-Seal Unit Ext. 3 1/2" 10.2# VAMINSIDE Nickel Alloy 925 (158726) (SN-#######)	3.860	2.902
1.99		A3) 2-Seal Units 4" X 3 1/2" 10.2 VAMINSIDE Nickel Alloy 925 Molded AFLAS/Flourel Seals 4.07 OD, 8000 PSI	4.050	2.883
3.00		A4) 3-Seal Units 4" X 3 1/2" 10.2 VAMINSIDE Nickel Alloy 925 Molded AFLAS/Flourel Seals 4.07 OD, 8000 PSI (102133617)(SN-########)	4.050	2.883
0.55		A5) Mule Shoe Guide 3 1/2" 10.2# VAMINSIDE Nickel Alloy 925 (102133560)(SN-########)	3.960	2.972
		Land Seals w/~26,000# Compression @ Surface, ~20K @ Packer		
		Pick Up Weight ###### Slack Off #######		
		Halliburton Packer Assembly		
3.11	13,700.00	15) Halliburton 7" 26-32# BWD Permanent Packer 4.00" Bore Incoloy 925 (101303583) (SN #######)	5.875	4.000
12.00	13,703.11	16) Seal Bore Extension 4.00" X 12' Incoloy 925 (120051359) (SN-#######)	5.020	4.000
0.83	13,715.11	17) Seal Bore Ext. Crossover 4 75" 8UN Box X 3 1/2" 9.2# VAMTOP Pin Incoloy 925 (101719647)(SN-######)	5.650	2.992
6.33	13,715.94	18) 6' x 3 1/2" 9.2# VAMTOP Box x Pin Pup Joint Incoloy 925	3.540	2.992
1.33	13,722.27	19) Halliburton 2.562" R Nipple 3 1/2" 9.2# VAMTOP Box x Pin (102204262) (SN-#######) Nickel Alloy 925	3.937	2.562
6.34	13,723.60	20) 6' x 3 1/2" 9.3# VAMTOP Box x Pin Pup Joint Incoloy 925	3.540	2.992
1.33	13,729.94	21) Halliburton 2.562" R Nipple 3 1/2" 9.2# VAMTOP Box x Pin (102204262) (SN-#######) Nickel Alloy 925	3.937	2.562
0.66	13,731.27	22) Wireline Re-entry Guide 3 1/2" 9.2# VAM Incoloy 925	3.960	2.992
	13,731.93	Bottom Of Assembly		

DIESEL USED FOR PACKER FLUID

Filename: