District I
PO Box 1980, Hobbs, NM 88241-1980
District II
PO Drawer DD, Artesia, NM 88211-0719
District III
1000 Rio Brazos Rd., Aztec, NM 87410
District IV
PO Box 2088, Santa Fe, NM 87504-2088

State of New Mexico
Energy, Minerals & Natural Resources Department

OIL CONSERVATION DIVISION
P.O. Box 2088
Santa Fe, NM 87504-2088

Form C-101
Revised February 10, 1994
Instructions on back
Submit to Appropriate District Office
State Lease - 6 Copies
Fee Lease - 5 Copies

☐ **AMENDED REPORT**

APPLICATION FOR PERMIT TO DRILL, RE-ENTER, DEEPEN, PLUGBACK, OR ADD A ZONE

1 Operator name and Address	2 OGRID Number / 3 API Number
Phillips Petroleum Company 5525 Highway 64, NBU 3004 Farmington, NM 87401	017654 30-039-25497

4 Property Code	5 Property Name	6 Well Number
009258	San Juan 30-5 Unit	~~S J 30-5~~ #22A

7 Surface Location

UL or lot no.	Section	Township	Range	Lot. Idn	Feet from the	North/South Line	Feet from the	East/West line	County
P	17	30N	5W		801'	South	793'	East	Rio Arriba

8 Proposed Bottom Hole Location If Different From Surface

UL or lot no.	Section	Township	Range	Lot. Idn	Feet from the	North/South Line	Feet from the	East/West line	County
P									

9 Proposed Pool 1	10 Proposed Pool 2
Basin Dakota - 71599 E/320	Blanco Mesaverde - 72319 E/320

11 Work Type Code	12 Well Type Code	13 Cable/Rotary	14 Lease Type Code	15 Ground Level Elevation
N	~~M~~ G	R	P	6381'
16 Multiple	**17 Proposed Depth**	**18 Formations**	**19 Contractor**	**20 Spud Date**
yes	8050'	Dakota/MV	not contracted	sometime in 1995

21 Proposed Casing and Cement Program

Hole Size	Casing Size	Casing weight/foot	Setting Depth	Sacks of Cement	Estimated TOC
12-1/4"	9-5/8"	36#, J-55	250'	150 sx	surface
8-3/4"	7"	23#, J-55	4000'	500 sx	surface
6-1/4"	5-1/2"	17#, N-80	8050'	800 sx total	* see note below

22 Describe the proposed program. If this application is to DEEPEN or PLUG BACK give the data on the present productive zone and proposed new productive zone. Describe the blowout prevention program, if any. Use additional sheets if necessary

* The 5-1/2" casing's cement is designed to cover openhole section (with 30% excess) and 200' inside 7" shoe (with 10% excess). See details attached in the cement program (see drilling prognosis).

BOP Equipment - See attached.

RECEIVED
MAR 2 3 1995
OIL CON. DIV.
DIST. 3

23 I hereby certify that the information given above is true and complete to the best of my knowledge and belief.		OIL CONSERVATION DIVISION 3-28-95	
Signature: Ed Hasely		Approved by: Ernie Busch	
Printed name: Ed Hasely		Title: DEPUTY OIL & GAS INSPECTOR, DIST. #3	
Title: Environmental/Regulatory Engineer		Approval Date: MAR 2 8 1995	Expiration Date: MAR 2 8 1996
Date: 3-22-95	Phone: 505-599-3454	Conditions of Approval: Attached ☐	

DISTRICT I
P.O. Box 1980, Hobbs, N.M. 88241-1980

DISTRICT II
P.O. Drawer DD, Artesia, N.M. 88211-0719

DISTRICT III
1000 Rio Brazos Rd., Aztec, N.M. 87410

DISTRICT IV
PO Box 2088, Santa Fe, NM 87504-2088

State of New Mexico
Energy, Minerals & Natural Resources Department

Form C-102
Revised Febuary 21, 1994
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Fee Lease - 3 Copies

OIL CONSERVATION DIVISION
P.O. Box 2088
Santa Fe, NM 87504-2088

☐ AMENDED REPORT

WELL LOCATION AND ACREAGE DEDICATION PLAT

[1] API Number	[2] Pool Code	[3] Pool Name
30-039-25497	71599 & 72319	Basin Dakota & Blanco Mesaverde

[4] Property Code	[5] Property Name	[6] Well Number
009258	SAN JUAN 30-5 UNIT	22A
[7] OGRID No.	**[8] Operator Name**	**[9] Elevation**
017654	PHILLIPS PETROLEUM	6381

[10] Surface Location

UL or lot no.	Section	Township	Range	Lot Idn	Feet from the	North/South line	Feet from the	East/West line	County
P	17	T.30 N.	R. 5 W.		801	SOUTH	793	EAST	RIO ARRIBA

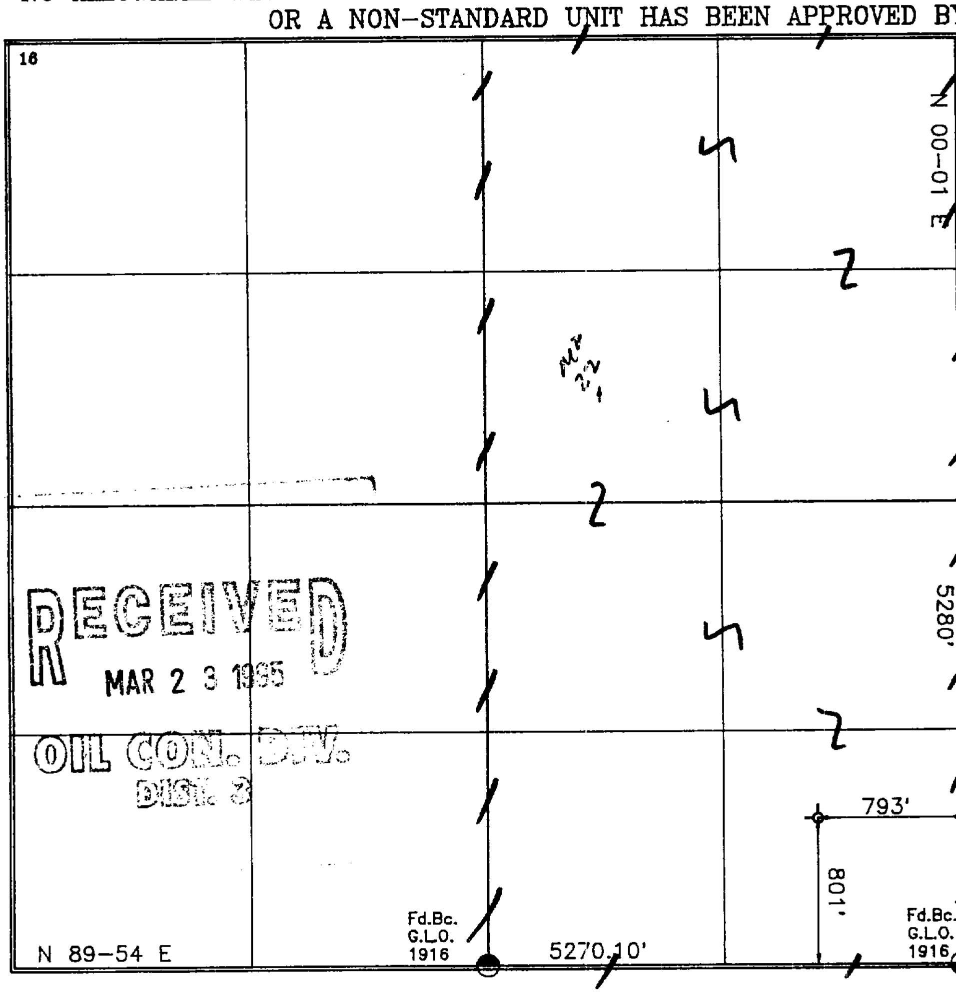
[11] Bottom Hole Location If Different From Surface

UL or lot no.	Section	Township	Range	Lot Idn	Feet from the	North/South line	Feet from the	East/West line	County
P									

[12] Dedicated Acres	[13] Joint or Infill	[14] Consolidation Code	[15] Order No.
MV-E/2 - 320 ac DK-E/2 - 320 ac		Unitized	

NO ALLOWABLE WILL BE ASSIGNED TO THIS COMPLETION UNTIL ALL INTERESTS HAVE BEEN CONSOLIDATED OR A NON-STANDARD UNIT HAS BEEN APPROVED BY THE DIVISION

16



[17] OPERATOR CERTIFICATION

I hereby certify that the information contained herein is true and complete to the best of my knowledge and belief

Signature: Ed Hasely

Printed Name: Ed Hasely

Title: Envir./Regulatory Engineer

Date: 3-22-95

[18] SURVEYOR CERTIFICATION

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

Date of Survey: APRIL 4, 1994

Signature and Seal of Professional Surveyor:

ROY A. RUSH
NEW MEXICO
8894
REGISTERED PROFESSIONAL LAND SURVEYOR

Certificate Number: 8894

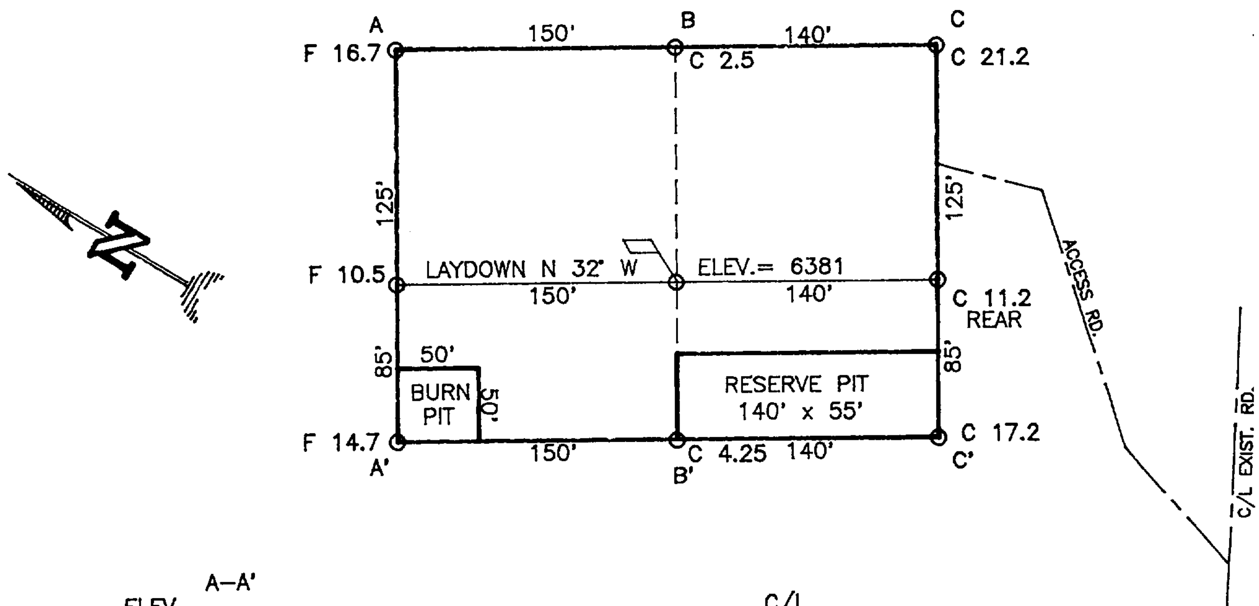
COMPANY: PHILLIPS PETROLEUM Co.

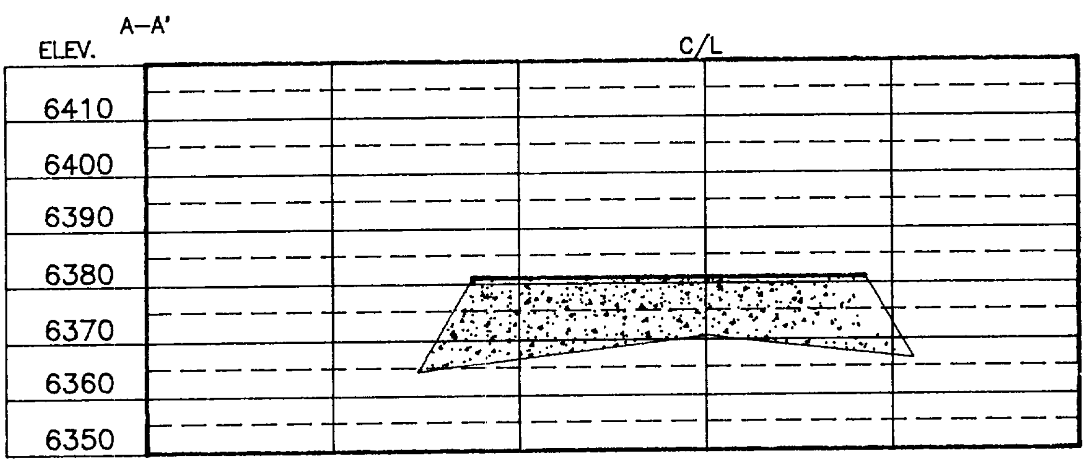
LEASE: SAN JUAN 30-5 UNIT No.22A

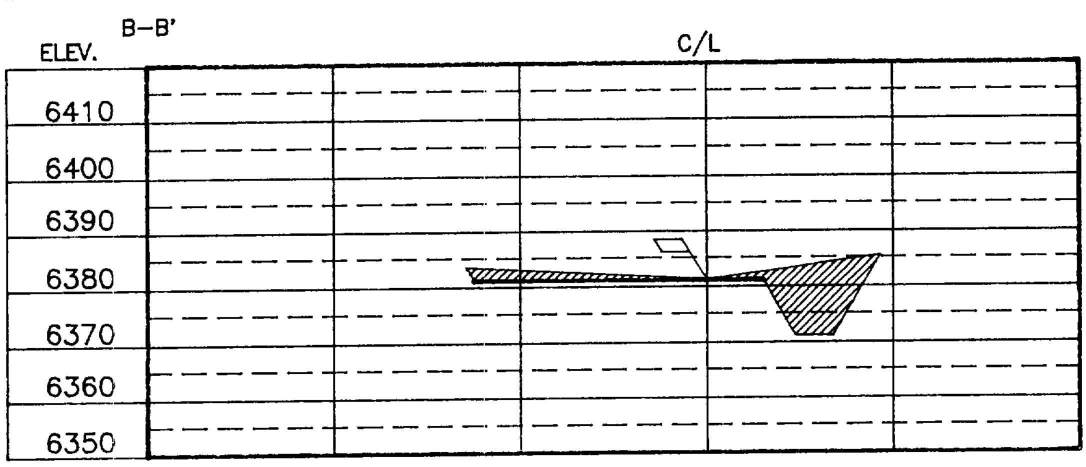
FOOTAGE: 801 FSL, 793 FEL

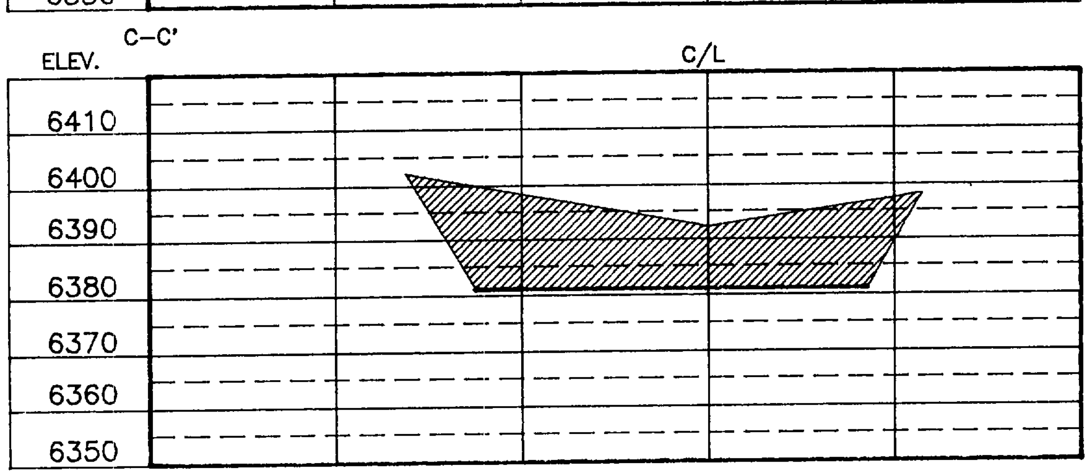
SEC.: 17, TWN: T. 30 N., RNG: R. 5 W., NMPM

ELEVATION: 6381



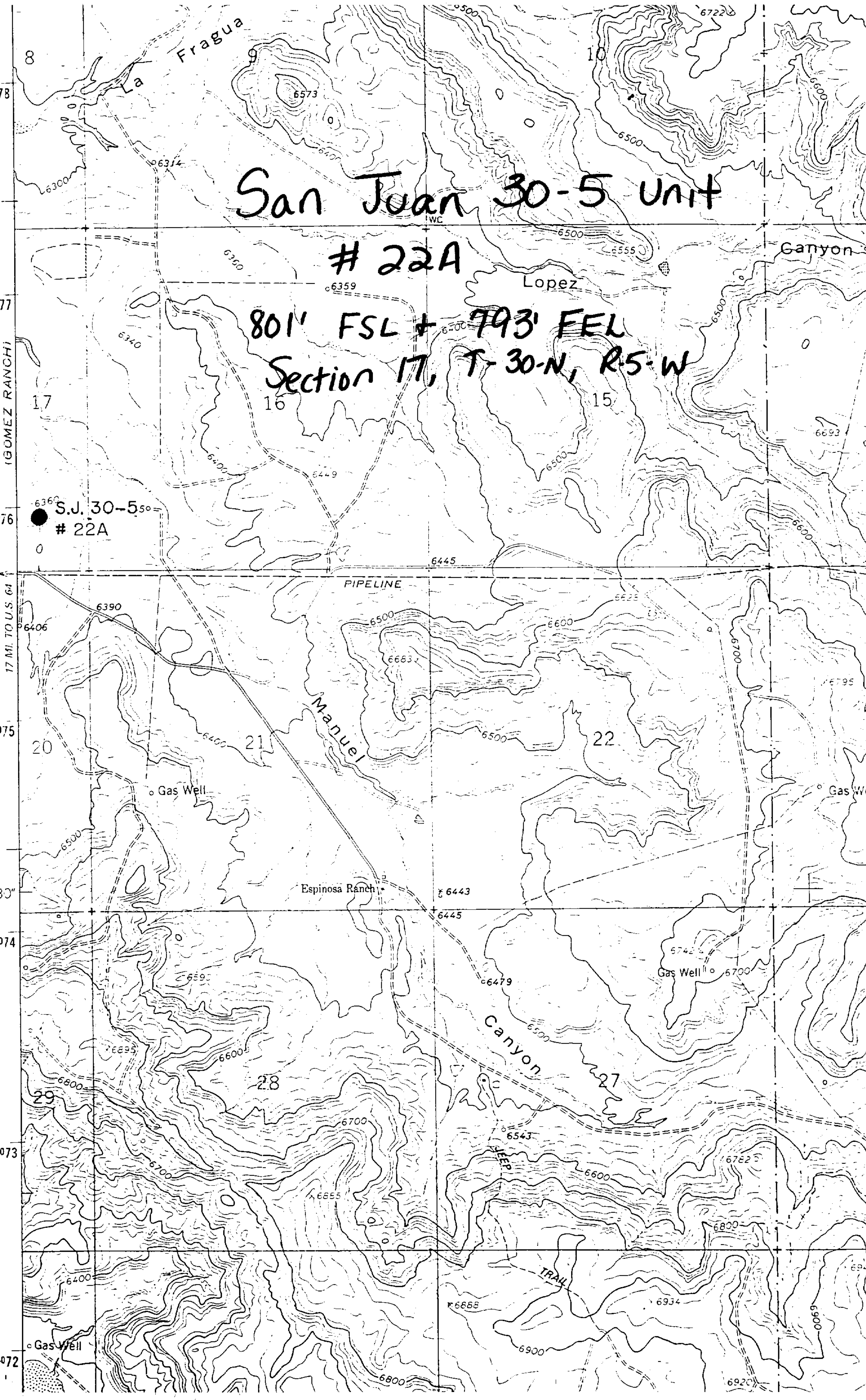






Daggett, Inc.

420 W. Elm Street Ph. (505) 326-1772
Farmington, New Mexico 87401


San Juan 30-5 Unit
22A
801' FSL + 793' FEL
Section 17, T-30-N, R-5-W
S.J. 30-5
22A
La Fragua
Lopez
Canyon
Manuel
Canyon
PIPELINE
Espinosa Ranch
Gas Well
Gas Well
Gas Well
Gas Well
JEEP
TRAIL
4557 I V SW
(GOMEZ RANCH)
17 MI. TO U.S. 64
47'30"
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4075
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6543
6695
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6855
6888
6934
6900
6800
6920
6663
6500
6555
6722
6693
6795
6742
6782
6400

PHILLIPS PETROLEUM COMPANY

Preliminary 11/17/94

Well Name: San Juan 30-5 #22A

DRILLING PROGNOSIS

1. Location of Proposed Well: 801' FSL & 793' FEL, Sec. 17, T-30-N,R-5-W, Rio Arriba County, New Mexico
2. Unprepared Ground Elevation: 6381'.
3. The geologic name of the surface formation is San Jose.
4. Type of drilling tools will be rotary.
5. Proposed drilling depth is 8050'.
6. The estimated tops of important geologic markers are as follows:

Ojo Alamo	2400'	Lewis	3500'	Mancos	6190'
Kirtland	2600'	Cliff House	5225'	Greenhorn	7580'
Fruitland	3050'	Menefee	5315'	Graneros	7640'
Pictured Cliffs	3350'	Pt Lookout	5570'	Dakota	7770'

7. The estimated depths at which anticipated water, oil, gas, or other mineral bearing formations are expected to be encountered are as follow:

Water:	Ojo Alamo - 2400' - 2600'
Gas & Water:	Fruitland - 3050' - 3170'
Gas:	Mesaverde - 5225' - 6050'
Gas:	Dakota - 7700' - 8050'

8. The proposed casing program is as follows:

Surface String	9-5/8", 36#, J-55 @ 250'
Intermediate String	7", 23#, J-5 5 @ 4000'
Production String	5-1/2", 17#, N-80 @ 8050'
Production Tubing	2-3/8", 4.7#, J-55 @ 8000'
	1-1/4", 1.083# HS-70 coil tubing @ 5500'

9. **Cement Program:**

Surface String: 150 sx Cl "B" cement w/2% CaCl2 & 1/4#/sk Cello-Seal; 15.6 ppg @ 1.18 ft3/sx yield; or quantity sufficient to circulate cement to surface.

Intermediate String: Flush: 10 bbls mud flush, then 10 bbls fresh water.

Lead cmt: 350 sx 65/35 POZ w/12% Bentonite, 2% CaCl2 & 1/4#/sk Cello-seal; 12.0 ppg @ 2.18 ft3/sk yield; or quantity sufficient to circulate cement to surface after tail cement added.

Intermediate String (Cont)

Tail: 150 sx Cl "B" Neat Cement; + 1/4#/sx Cello-flake + 2% $caCl_2$; 15.6 ppg @ 1.18 ft3/sx yield; or quantity sufficient to circulate cement to surface.

Production String: Flush: 20 bbls mud flush, then 10 bbls fresh water.

Lead = 650 sx 65/35 POZ+12% gel + 1/4#/sx Flocele + 2% $CaCl_2$, mixed at 12.0 ppg and 2.18 ft3/sx.

Tail = 150 sx Cl "B" + 1/4#/sx Flocele + 2% $CaCl_2$, mixed at 15.6 ppg and 1.18 ft3/sx.

Cement is designed to cover openhole section (with 30% excess) and 200' inside 7" shoe (with 10% 3 excess).

Centralizer Program:

Surface: Centralizer at 10' above shoe. Top of 2nd, 4th and 6th joints.

Intermediate: Centralizer at 10' above shoe. Top of 2nd Jt., Top of 4th Jt. Top of 6th Jt., Top of 8th Jt.

Turbulator at 1 Jt. below Ojo Alamo
Turbulator at top of next joint.
Turbulator at top of next joint.

Production: Centralizer at 10' above shoe. Top of 2nd Jt., Top of 4th Jt. Top of 6th Jt., Top of 8th Jt.

10. Pressure Control Equipment: schematic diagrams showing sizes, pressure ratings (or) API series are enclosed within the APD packet.

11. Drilling Mud Prognosis: Surface to Bottom of 8-3/4" Hole
Low solids, non-dispersed, 9.0 ppg+, fresh water base mud.
6-1/4" Hole Section
Air or Gas Drilled

12. The testing, logging, and coring programs are as follows:
D.S.T.'s or cores: None
Logs: Induction, GR-Density-Neutron, Temperature
Special Tests: None

13. Anticipate no abnormal pressures or temperatures to be encountered or any other potential hazards such as Hydrogen Sulfide Gas. Low risk H_2S equipment will be used.

14. The anticipated starting date will be sometime 1995 with duration of operations for approximately 60 days thereafter.

apd\305#22a.dp

BOP AND RELATED EQUIPMENT CHECK LIST

3M SYSTEM:

Annular preventer, double ram, or two rams with one being blind and one being a pipe ram

Kill line (2-inch minimum)

1 kill line valve (2-inch minimum)

1 Choke line valve

2 Chokes (refer to diagram in Attachment 1) on Choke Manifold

Upper Kelly cock valve in open position with handle available

Safety valve (in open position) and subs to fit all drill strings in use (with handle available)

Pressure gauge on choke manifold

2 inch minimum choke line

Fill-up line above the uppermost preventer

The BOPs will be pressure tested according to Onshore Order #2 III, A 1 and 30% safety factor.

Attachment I

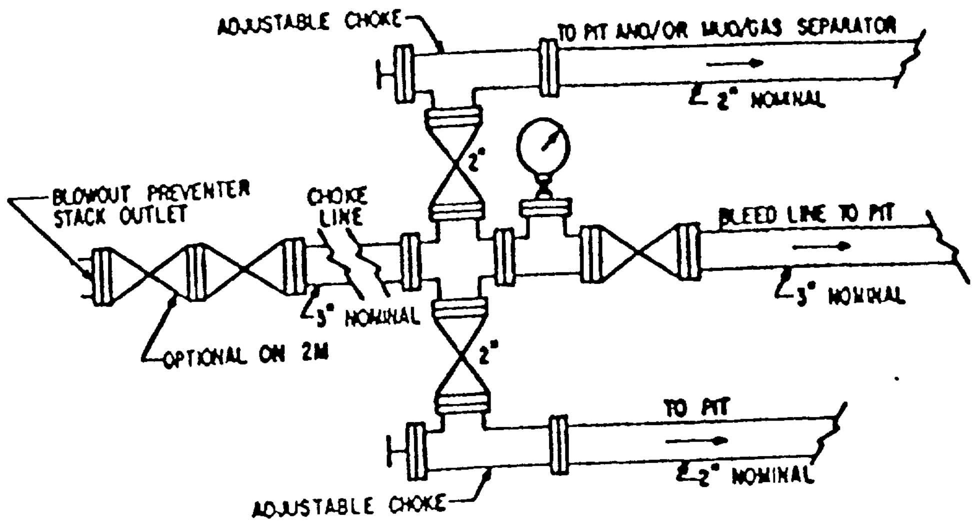
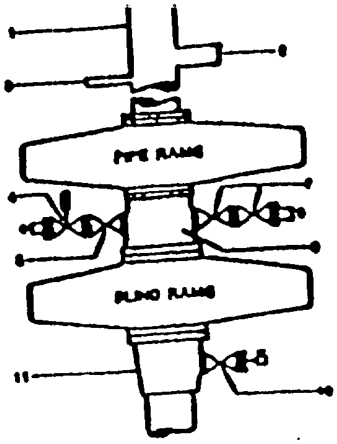


FIG. 3.A.1

TYPICAL CHOKE MANIFOLD ASSEMBLY FOR 2M AND 3M RATED WORKING PRESSURE SERVICE – SURFACE INSTALLATION



NOTE: THE DRILLING SPOOL MAY BE LOCATED BELOW BOTH SETS OF RAMS IF A DOUBLE PREVENTER IS USED AND IT DOES NOT HAVE SUITABLE OUTLETS BETWEEN RAMS

Figure 7-9. Standard Hydraulic Blowout Preventer Assembly
3 M Working Pressure Alternative 1

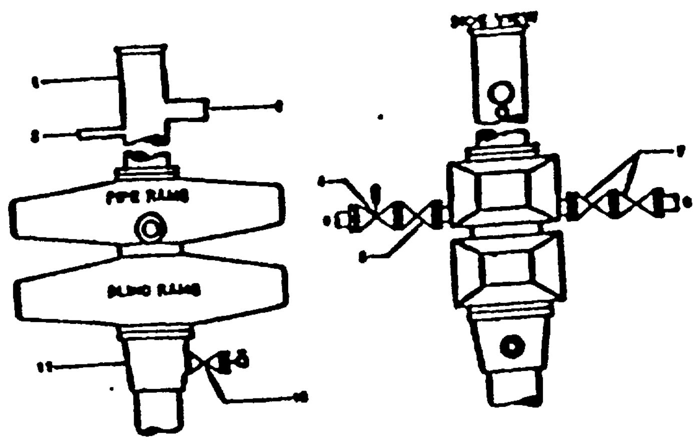


Figure 7-10. Standard Hydraulic Blowout Preventer Assembly
3 M Working Pressure Alternative 3 (without Drilling Spool)

2.8 TESTING BLOWOUT PREVENTER EQUIPMENT

2.8.1 Pressure Test Frequency

All rams, annulars, valves, choke and kill lines, choke manifold, kelly valves, and safety valves should be pressure tested at the following frequencies:

1. On installation of blowout preventers.
2. After setting casing and before drilling cement.
3. Every 7 days or on first trip out of hole after 7 days since previous pressure test.
4. After any component of the blowout preventer assembly is disassembled, replaced, or repaired (this includes lines, valves, or choke manifold). In this case, the component changed may be the only component tested.
5. Any time the Wellsite Supervisor requests testing.

7. In addition to the above tests, subsea BOPs shall be tested on test stump, prior to installation or reinstallation of the blowout preventer assembly. Operating chambers are to be tested in addition to all pipe rams, valves etc.

2.8.2 Function Test Frequency

Surface BOPS

All rams, annulars, valves, and other items specified below, should be function-tested at the following intervals:

1. On initial installation from all control panels.

2. After each trip out of hole alternating between driller's and remote control panel but not more than once every twenty-four (24) hours. Close pipe/blind rams only.

   NOTE: Pipe rams will only be closed with pipe in the hole.

Sub-Surface BOPs

All rams, pipe ram locks, fail-safe valves, or other subsea items specified below should be function-tested at the following intervals:

1. Prior to running the assembled blowout preventer stack, function test all components with both control pods from the drillers and remote control panels.

2. After initial installation of the blowout preventer stack or after any control components have been repaired or replaced. Function test all components, except wellhead connector, using both control pods from the drillers and remote control panels.

3. Blind/shear rams each trip out of the hole alternating between Drillers and remote control panels.

   NOTE: Do not leave blind/shear rams closed while out of the hole.

2.8.3 Test Pressures

The following Tables 2.3 and 2.4 shall be used to identify which test is appropriate and at what pressure shall be applied for surface and subsea BOPs.

Table 2.3
SURFACE BOPE PRESSURE TEST

TEST	INTERVAL
Low Pressure	Test to 200-300 psi prior to each high pressure test.
Initial Installation	Test all rams, annulars, valves, choke manifold, kelly valves, and safety valves to the lesser of the following pressures. • Rated working pressure of the component in the blowout preventer assembly with the exception of annular preventer which is to be tested to 70% of the rated working pressure. • The API rated casing burst pressure of the last casing to be utilized in the well with the BOP assembly being tested. • Rated working pressure of the casing head. • If "Cup Tester" is used, do not exceed 80% of the API rated burst pressure of the casing.
Repair	Repaired or replaced components are to be tested to the same pressures used in the Initial Test.
Weekly and After Setting Casing	Test all rams, annulars, valves, choke and kill lines, choke manifold, kelly valves, and safety valves, to the lesser of the following pressures. • 50% of the rated working pressure of the component to be tested. • 80% of the API rating of the casing burst pressure then in the well. • Test blind rams during internal casing pressure test. (Refer to drilling program for test pressures.)
Accumulator	Test accumulator to the manufacturer's rated working pressure. Test the accumulator for time to pump up to specifications. A accumulator performance test as per Section 2.8.7 should be performed on initial installation and subsequently as deemed necessary.

Table 2.4 *SUBSURFACE BOPE PRESSURE TEST*	
TEST	**INTERVAL**
Low Pressure	Test to 200-300 psi prior to each high pressure test.
Test Stump	Test all rams, annulars, fail-safe valves, operating chambers, choke manifold, kelly valves, and safety valves to the lesser of the following pressures. • Rated working pressure of the component in the blowout preventer assembly with the exception of annular preventer which is to be tested to 70% of the rated working pressure. • The API rated casing burst pressure of the last casing to be utilized in the well with the BOP assembly being tested.
Initial Installation	Test connector seal, choke line, and kill line to that pressure specified for testing the pipe rams during the stump test. Test remainder of the BOP stack to that pressure specified during weekly tests.
Repair Test	Same as Stump Test. Surface component repairs or replacements can be tested separately.
Weekly and After Setting Casing	Test all rams, annulars, fail-safe valves, choke and kill lines, choke manifold, kelly valves, and safety valves, to the lesser of the following pressures: • 50% of the rated working pressure of the component to be tested. • 80% of the API rating of the casing burst pressure then in the well. • Test blind rams during internal casing pressure test. (Refer to drilling program for test pressures).

2.8.4 Blowout Preventer Test Practices

All pressure tests shall be witnessed by Wellsite Supervisor on location. Charts shall be certified by the Wellsite Supervisor. All tests shall be recorded on Phillips' Daily Drilling Report, the IADC Report, and the Phillips BOP Test Form. A reproducible copy of the Phillips BOP Test Forms can be found in Chapter 9.

Drilling Contractor form can be acceptable if comparable to the Phillips BOP form.

Hold all low-pressure tests for three minutes and high pressure tests for five minutes or until the Wellsite Supervisor is satisfied that there are no leaks.

The following items should be addressed:

1. Prior to testing, all lines and valves will be thoroughly flushed to ensure that the system is clear. Test all opening and closing control lines to 1500 psi and inspect for leaks.

2. If necessary, run a stand of drill collars below the test plug to properly seat the test tool.

3. Precautions should be taken to avoid pressuring the casing below the test tool.

4. The running string is to be full of fluid (or antifreeze solution) for immediate indication of test tool leakage.

5. All pipe rams, blind/shear rams, blind rams, annular preventers, valves, fail-safe valves, choke and kill lines are to be tested at the frequencies and pressures outlined in this section.

6. Drillpipe safety valve and lower and upper kelly valves, inside BOP are to be tested from below at pressures and frequencies outlined in this section.

7. Test fluids are to be bled back to pump unit in a safe manner.