DRAFT

HOBBS RMT
CLOSE PROXIMITY OPERATING POLICY
JULY, 2001

BEFORE THE
OIL CONSERVATION DIVISION
Case No. 12722 Exhibit No. 19
Submitted By:
Occidental Permian Ltd

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CLOSE PROXIMITY OPERATING POLICY
JUNE, 2001

I. SCOPE

This document details the operating procedures and practices that will implemented by the Hobbs Reservoir Management Team (RMT) as part of it's Operating Plan for CO2 Injection and Production in Close Proximity Areas Of Hobbs, New Mexico. Variances from this Plan must be approved at the Asset Manager level of the Wasson Business Asset. Employees are expected to understand the requirements of this plan and immediately address or report to their immediate supervisor any non-compliance conditions.

This policy will be distributed to the Production Engineers, Facilities Engineers, Production Coordinators, Team Leaders and Operations personnel responsible for close proximity operations. This document will be reviewed yearly for changes and redistributed accordingly. The RMT Team Leader or his designate will be responsible for coordinating policy revisions, policy distribution and the yearly meetings to review compliance.

II. INTRODUCTION

1.0 CO2 Flood Description

Oxy Permian (and its predecessors) has been engaged in active CO2 flooding for tertiary recovery in the Permian Basin for over 15 years. Oxy Permian currently operates a large CO2 flood operation near Denver City, Texas. The CO2 flood in Denver City has been operational since early 1991 with operations being conducted in both populated and remote areas.

The experience in operating the Denver Unit CO2 flood in and near populated areas has demonstrated that CO2 flooding can be safely operated and has validated the use of properly designed equipment in and near populated areas. However, because of the close proximity to the public, special monitoring and testing of the Hobbs area wells and facilities are justified. The facility and well designs specified in this plan meet or exceed the all regulatory requirements.

2.0 Safety Concerns

Safety has and will continue to be the top priority in the operation of the Hobbs RMT CO2 flood. The CO2 flood injection and production equipment is designed and installed to safely handle H2S and increased amounts of CO_2. Safety devices (e.g., automatic shut down devices, vibration switches) are installed to protect both people and equipment. The Cprox Operating Plan is intended to be an additional tool that will be used to help safely manage the continually changing challenges involved in operating oil and gas production operations in areas where public exposure exist. The plan is supplemented by existing emergency action plans which are vital part of the Hobbs RMT operations.

3.0 Oil Producer and Injector Close Proximity Definition

The plan defined close proximity using the applicable elements of API 6A, OSHA and air dispersion modeling. NMOCD Rule 118 also establishes operating rules for H2S environments. The API 6A 17th Edition "Specification for Wellhead and Christmas Tree Equipment" uses the classification of close proximity to determine the level of quality control, which should be utilized in the construction of wellhead components. The API concerns are primarily exposure to H2S releases and fire hazards. Combining these two sets of specifications with OSHA requirements and dispersion modeling for injector releases has resulted in the table below for classifying the Hobbs RMT oil producer and injector well locations as close proximity or remote.

Well Type	Close Proximity Locations	Distance	Source
All CO2 Injectors	Public Area	200 feet	OSHA
All CO2 Injectors	Pubic Road	50 feet	API 6A
Produced Gas Injector	Public Road	466 feet	H2S 100 PPM Dispersion Model
Produced Gas Injector	Public Area	1171 feet	H2S 500 PPM Dispersion Model
CO2 Producer	Public Area	308 feet	H2S 100 PPM Dispersion Model
CO2 Producer	Public Road	30 feet	H2S 500 PPM Dispersion Model
CO2 Producer	Public Road	350 feet	API 6A

To summarize in words, a close proximity well is:

1. Any injector which has a public area within 200 feet or a public road within 50 feet.
2. Produced gas injectors which have a public area within 1171 feet or a public road within 466'
3. Any CO2 producers which have a public area with 308' or a public road within 350' .

A <u>public area</u> is a dwelling, business, church, school, bus stop, government building, park, or part of a city. To be modified by the new Rule 118.
A <u>public road</u> is a federal, state, county or municipal street or road owned or maintained for public use. To be modified by the new Rule 118.

A map defining the close proximity area is included as Figure 1. Tables 1, 2 and 3 list close proximity oil producers, injectors.

III. POLICY COMPLIANCE

1.0 Definitions

Failure: Improper performance of a device or equipment item that prevents completion of its design function.

Test Tolerances:

Safety Relief Valve (PSV): PSV set pressure tolerances are plus or minus 2 psi for pressure up to and including 70 psi, and 3 percent for pressure above 70 psi.
High and Low Pressure Sensor (PSHL): PSHL set pressure tolerance for set pressures greater than 5 psi is plus or minus 5 percent or 5 psi, whichever is greater, however, the trip pressure should not exceed the pressure rating of the equipment protected. A PSHL with a set pressure of 5 psi or less must function properly within the service range for which it is installed.

2.0 Testing Frequency

Safety devices will be tested at specified regular intervals dictated by field experience, Oxy policy and Government regulations where applicable. The testing frequencies listed within this document are maximum intervals; actual testing frequencies may be more frequent than the maximum interval as indicated by field experience. The testing frequency will be determined by the Reservoir Management Team and reviewed at the Close Proximity yearly meetings.

2.1 Testing and Facilities HAZOP Review

In xxxx a hazard analysis was performed on several alarms and shutdowns associated with our close proximity injection facilities. (this section could be replaced by the OXY Risk Screening/Ranking process and by the upcoming PHA's.)

3.0 Compliance Responsibility and Audits

MAXIMO will be the platform to handle the required testing of facilities and wellbores. Preventative Maintenance (PM's) will be scheduled and documented using this program. In daily operations, the Lease Operator is responsible for understanding this policy and to operate the wells and facilities accordingly. The lease operator should do a drive by inspection a minimum of every other day during the 5-day work week. The safety devices should be set and operated per this policy. Any repair or replacement of equipment in the close proximity area should be done per this policy. To ensure that we are in compliance with the testing requirements, a meeting will be held yearly to audit testing activities. The engineer designated to coordinate close proximity activities will call this meeting.

IV. INJECTION EQUIPMENT

1.0 Injector Wellbore Equipment

Casing Packer: Hookwall retrievable packers capable of being set in tension or compression are used in close proximity injectors. The mandrel is constructed of 9 Cr. 1 Mo. metal alloy. The entire packer is internally and externally plastic coated. In wells with fiberglass liners, a cup packer is set within the liner. In wells with full ID fiberglass casing, hydraulic packers are used.

On/off tool: An on/off tool assembly with a profile receptacle is run above the casing packer. The seal bores of the on/off tool and the profile receptacle are constructed from 316 SS. The washover shoe and J slot are plastic coated 4140 steel. A downhole shutoff valve will not be run in injectors

Tubing: 2 3/8" or 2 7/8" 8rd EUE J-55 tubing, internally coated or fiberglass lined using current best technology should be used. (2 7/8" and 3 ½" tubing will be used at NHU)

Tubing/casing annulus: The tubing/casing annulus should be filled with inhibited water

1.1 Casing/Tubing Annulus Testing

Injector annular testing will default to the testing requirements of the State of New Mexico. The time interval of the test is dependent on the injector permit.

2.0 Injector Wellhead Equipment

Attachment I gives the diagram and detailed specifications for the injector wellheads. The following are additional requirements:

The production casing is hung in a standard API casing head. The production casing/tubing annulus pressure is monitored with an alarm and a high pressure shutdown.

Tubing spool: The tubing spool is rated to a minimum of 3000 psi with flanged or studded outlets, and is suitable for H2S and C02 Service.

Tubing hanger: The tubing hanger has an extended neck with back pressure valve threads and is constructed from Inconel 718 or 625.

Master valves: Flanged double master valves are used. The valves are 3000 psi 316 SS gate valves rated to ANSI 1500. The drive bushing is constructed from AISI 660 material with a stem of K-500 Monel material.

Wing valves: The wing valves are 3000 psi, 316 SS gate valves rated to ANSI 1500 trimmed the same as the master valve. The wing valve has an actuator to act as an ESD in the event of high casing pressure. The valve will fail safe in the closed position. The tubing bonnet and cross are constructed of 316 SS.

Crown valve: The crown valve is a 3000 psi, 316 SS gate valve trimmed the same as the master valve.

3.0 Injection Facilities

3.1 Injection Lines

There is a single injection line that connects each injection well to its water-alternating-gas (WAG) manifold. WAG manifolds, located at the injection satellites, consist of water and gas switching valves, flow measurement, pressure and temperature monitoring, and pressure / flow control.

Individual well injection lines are constructed of a thermoplastic polymer lined carbon steel pipe buried a minimum of three feet deep and externally wrapped for corrosion protection. Those servicing water / CO2 injection wells are constructed per ANSI B31.4, to a design pressure of 1800 psig (ANSI 900). Those servicing water / produced gas injection wells are constructed per ANSI B31.4, to a design pressure of 2600 psig (ANSI 1500). Surface marker signs for the lines are ~~not~~ installed.

Water trunk lines are constructed per ANSI B31.4 to a design pressure of 1800 psig (ANSI 900). The water injection lines are internally polyethylene lined carbon steel. Water lines are buried a minimum of three feet deep and externally wrapped for corrosion protection.

CO_2 trunk lines are internally bare carbon steel, constructed to ANSI B31.4 to a design pressure of 1800 psig (ANSI 900). CO_2 lines are buried a minimum of three feet deep and externally wrapped for corrosion protection.

Produced gas trunk lines are internally bare carbon steel, constructed to ANSI B31.8 to a design pressure of 2600 psig (ANSI 1500). Produced gas lines are buried a minimum of three feet deep and externally wrapped for corrosion protection.

3.2 Injection Control Equipment

The injection wells are monitored and controlled by Supervisory Injection Control (SINC) Remote Terminal Units (RTU) installed at each injection satellite. The CO2 or produced gas, and the water piping of the SINC unit is built to standards referenced in paragraph 3.1. CO2 and produced gas isolation valves, control valves, utility vent and drain valves, and instrumentation hardware are stainless steel.

The SINC RTUs collect and transmit operating data and alarms to central computers located at the Hobbs Production Office. Based on either pressure or rate, the RTUs control injection via a control valve. Information monitored by the RTU includes flowline pressure, tubing and casing pressure, and flow rates. The RTUs will alarm or shutdown injection when operating parameters (e.g. pressure) reach preprogrammed setpoints. If a shutdown setpoint is reached, the RTU is programmed to close the control valve and close the (actuated wing) SDV. The alarm and shutdown points are as follows:

Wells on Water Injection:

Action	Set-Point	Units
High Injection Rate Shutdown	TBD	mcfd
High Injection Rate Alarm	TBD	mcfd
High Injection Pressure Shutdown	TBD	Psig
High Injection Pressure Alarm	TBD	Psig
Low Injection Pressure Alarm	TBD	Psig
Low Injection Pressure Shutdown	TBD	Psig
High Flowline Pressure Alarm	TBD	Psig
Low Flowline Pressure Alarm	TBD	Psig
Low Flowline Pressure Shutdown	TBD	Psig
High Casing Pressure Shutdown	TBD	Psig
High Casing Pressure Alarm	TBD	Psig
High Bradenhead Pressure Alarm	TBD	Psig
High RTU Battery Voltage Alarm	TBD	Volts
Low RTU Battery Voltage Alarm	TBD	Volts

Wells on CO2 Injection

Action	Set-Point	Units
High Injection Rate Shutdown	TBD	mcfd
High Injection Rate Alarm	TBD	mcfd
High Injection Pressure Shutdown	TBD	Psig
High Injection Pressure Alarm	TBD	Psig
Low Injection Pressure Alarm	TBD	Psig
Low Injection Pressure Shutdown	TBD	Psig
High Flowline Pressure Alarm	TBD	Psig
Low Flowline Pressure Alarm	TBD	Psig
Low Flowline Pressure Shutdown	TBD	Psig
High Casing Pressure Shutdown	TBD	Psig
High Casing Pressure Alarm	TBD	Psig
High Bradenhead Pressure Alarm	TBD	Psig

High RTU Battery Voltage Alarm	TBD	Psig
Low RTU Battery Voltage Alarm	TBD	Psig

Wells on Produced Gas Injection

Action	Set-Point	Units
High Injection Rate Shutdown	TBD	**mcfd**
High Injection Rate Alarm	TBD	**mcfd**
High Injection Pressure Shutdown	TBD	Psig
High Injection Pressure Alarm	TBD	Psig
Low Injection Pressure Alarm	TBD	Psig
Low Injection Pressure Shutdown	TBD	Psig
High Flowline Pressure Alarm	TBD	Psig
Low Flowline Pressure Alarm	TBD	Psig
Low Flowline Pressure Shutdown	TBD	Psig
High Casing Pressure Shutdown	TBD	Psig
High Casing Pressure Alarm	TBD	Psig
High Bradenhead Pressure Alarm	TBD	Psig
High RTU Battery Voltage Alarm	TBD	Psig
Low RTU Battery Voltage Alarm	TBD	Psig

TEST	Frequency (Maximum)	Max. Set Pressure
SDV	**Semi-annual**	--
Transmitters, Logic Circuits	**Semi-annual**	--
Hi/Low Shutdowns	**Semi-annual**	--
Thermal Relief Valves	**Every 5 years**	TBD

Records of all tests shall be filed or kept in tabular data base form at the Production office and retained for the life of the equipment. Note these are maximum test frequencies as stated in Section III. Policy Compliance, 2.0 Testing Frequency.
(Will we have to establish a history at Hobbs?)

3.3 Injection Pump Facilities

The water injection pump stations are located outside the Close Proximity Areas.

3.4 Perimeter Fences

All injection wells in close proximity will have chain linked fences with top guards and posted warning signs constructed along the perimeter of the location. The fence will be locked when unattended. The sign will include warning to the public concerning the potential presence of H2S as well as any other appropriate warnings. Additionally, emergency contact information will be posted at the entrance to the site.

V. PRODUCTION EQUIPMENT

1.0 Beam Pumped Wells

1.1 Beam Pumped Downhole Equipment

The standard production tubing is 2 7/8" or 2 3/8" 8rd EUE J-55 tubing. A hookwall anchor is used. Rod strings are typically KD rods or Norris 97 rods. The pumps are constructed of special corrosion and wear resistant alloys.

1.2 Beam Pumped Wellhead Equipment

Standard low alloy NACE materials, designed for H2S service, are used within the wellhead.

Tubing spool: The tubing spool has a minimum working pressure of 2000 psi and has flanged or studded side outlets. The tubing is hung in slips within the bonnet with a wrap-around bushing/seal installed around the tubing below the slips to provide an improved annular seal. Material must be suitable for NACE MR01-75 service and constructed to meet API PSL I PR1 recommendations. Figure 2 shows a typical pumping unit installation.

Rod BOP/Stuffing Box/Polished Rod BOP: Ram-type rod BOPs are installed below the pumping tee. An additional rod BOP is installed between the stuffing box and the pumping tee. A high pressure (2500 psi) double stuffing box equipped with a leak detector (shuts down the unit if there is leak) is installed above the pumping tee. Operator intervention is required to restart the unit. A polished rod BOP is installed or included in the design of the stuffing box. All elastomers should be CO_2 compatible.

Polished rod liners are not used because their presence blocks the performance of the polished rod BOP.

Vibration Switch: A vibration switch is installed on the walking beam. It Is switch wired to trip the pumping unit motor if a vibration is apparent. It requires an operator to reset the motor manually prior to restarting.

Computer Assisted Operations: Beam pumped wells are equipped with pump-off controllers (POCS) to permit remote starting and stopping. The CAO system will indicate the well to be in alarm but a lease operator must visit the location to determine the cause of the alarm.

1.3 Beam Pumped Well Testing

Stuffing box leak detector and vibration switch:
The stuffing box leak detector and vibration switch will be tested yearly with a visual inspections as determined by schedule.

Casing test: There are no additional requirements for the testing of Close Proximity producers besides those of normal operating procedures.

2.0 Submersible Pumped (ESP) Producers

2.1 ESP Downhole Equipment

The following equipment is run:

- Standard pump housing.
- Floating impellers with proper design.
- 4" Diameter pumps in most cases
- Rotary gas separators where free gas exceeds 10%.
- Single section motors with special alloy housings.
- The tubing is either ~~2-3/8"~~ or 2 7/8" EUE 8-RD J-55. ~~The 2 3/8" tubing provides sufficient capacity for rates below 1000 BPD.~~ **Leave 2-3/8" in**

2.2 ESP Wellhead Equipment

The wellhead assembly has at least a 2000 psi working pressure. Figure 3 shows a submersible wellhead assembly.

Tubing spool: The tubing spool has flanged or studded outlets. Material must be suitable for NACE MR0I-75 service and the spool must be constructed to API, PSL 1, PR1 recommendations.

Tubing hanger The tubing hanger has a mandrel hanger with an electric connector system. The tubing hanger and adapter are made of low alloy steel and certified for NACE service.
MasterValve: For 2 3/8" tubing a flanged 2 1/16" 3000 psi API gate valve is used as the master valve. A flanged 2 9/16" 3000 psi API gate valve is used when the production tubing is 2 7/8". The body is made of low alloy 4130 materials with 410 stainless steel

for the gate and seat. Within the rest of the wellhead, screwed connections are acceptable.

Computer Assisted Operations: Submersible wells are equipped with submersible pump monitoring (SPM) RTUs to permit the wells to be monitored for status and alarms and to permit them to be remotely started and stopped.

2.3 ESP Well Testing

Casing test: There are no additional requirements for the testing of Close Proximity producers besides those of normal operating procedures.

3.0 Flowing Wells

As the CO_2 flood matures, some wells are expected to flow. Producers are individually reviewed for conversion to flowing status based on flow potential.
This review should include the WAG cycle, convert to flow and other actions to reduce the flow up the backside.

3.1 Flowing Well Downhole Equipment

Casing Packer: For flowing producers use a hookwall retrievable packer capable of being set in tension or compression with the mandrel constructed of 9 CR 1 Mo. metal alloy. The entire packer should be internally and externally plastic coated.

On/off tool: An on/off tool assembly with a profile receptacle is run above the packer. The seal bore of the on/off tool and the profile receptacles are constructed from 316 SS. The washover shoe and J slot are plastic coated 4140 steel. A DHSOV is not run.

Tubing: Either 2 3/8" or 2 7/8" bare EUE 8-RD J-55 tubing should be used in flowing producers.

Tubing/casing annulus: The tubing/casing annulus should be filled with inhibited water to protect the casing from corrosion.

3.2 Flowing Wellhead Equipment

Attachment 2 gives the diagram and detailed specifications for producers.
The flowing wellhead equipment is designed according to the recommendations in the "Design and Quality Assurance Considerations for Flowing Wellheads in the Denver Unit CO2 Flood" (Reference 2). The tree is 3000 psi working pressure API and NACE certified equipment. The tree has double master valves, swab and wing valves.

Tubing Spool: The tubing spool is rated to a minimum working pressure of 2000 psi and has flanged or studded outlets. The material must be suitable for NACE MR0l-75 service.

Tubing hanger/tubing bonnet/tubing hanger adapter: An extended neck mandrel type hanger with back pressure valve threads is used. The hanger material is Inconel 718 or 625. The tubing hanger is constructed to API 6A Product Specification Level (PSL) 3 with a materials classification of EE and temperature classification of P. The tubing bonnet and valve bodies are AISI 4130. The tubing head adapter is constructed to API PSL 3 recommendations.

Lower master valve: The lower master valve body is constructed of 4130 steel, with the gates and seats constructed of 410 SS. The valve stem and injection fitting is Inconel 718. The drive bushing is AISI 660. The lower master valve is constructed to API PSL 3 recommendations.

Second master valve/ swab valve/actuated wing valve: A second master valve, swab valve, and actuated wing valve should be installed. The valves are constructed of the same materials as the lower master valve. API PSL I quality control is appropriate since the valves can be isolated from wellbore pressure by the lower master valve.

Computer Assisted Operations: Flowing wells are equipped with Flowing Well Control (FWC) RTUs to control the production rate, to help bring high pressure wells on line slowly, to control hydrates, and to monitor pressure (tubing, casing, and flow line). Currently, CAO equipment is being tested and evaluated in the field ??.

3.3 Flowing Well Testing

A. Tubing/casing annulus: Test casing to 500 psi every 5 years.

4.0 Production Facilities

4.1 Production Flowlines

Production flowlines from the wellhead to the satellite are 4" IPC Zaplock pipe. The internal plastic coating should be suitable for CO_2 service as per Chemical Engineering's recommendations **(is this the correct reference?)**. The design pressure is 700 psig. Buried flowlines are buried a minimum of 3' deep and externally wrapped to prevent external corrosion. **(CP system or anodes?)**

All flowlines are equipped with high/low pressure shutdowns that perform the following functions:

Well Type	Action
Wells on Artificial Lift	Artificial lift motor is stopped
Flowing Wells	Shut Down Valve (SDV) is closed

Producing Well Shutdown Guidelines

Action	**Set-Point**	**Units**
High Flowline Pressure Shutdown	TBD	Psig
Low Flowline Pressure Shutdown	TBD	Psig
High Bradenhead Pressure Shutdown	TBD	Psig
High Stuffing Box Pressure Shutdown	TBD	Psig
High Vibration Shutdown (Beam Units)		

The above numbers are guidelines only. Shutdowns may be determined on an individual well basis by recording the pressure in question on a chart recorder for an appropriate length of time (e.g., overnight) and setting the shutdown 15% higher or lower than the highest or lowest pressure encountered within the pressure rating of the piping and within the pressure range of the instruments. Records of the chart test to determine shutdown settings will be kept in the individual well file.

Testing Requirements

Test	**Frequency**	**Duration**	**Test Pressure**
SDV's	Semi-annual		TBD
Hi/Low Shutdowns	Quarterly		TBD

Note these are maximum test frequencies as stated in Section III Policy Compliance, 2.0 Testing Frequency.

Records of all tests shall be filed or kept in tabular data base form in a central location at the Production office and retained for the life of the equipment.

4.2 Tertiary Satellites

Tertiary satellites are primary (liquid/gas) separation facilities. There are no tertiary satellites in the Close Proximity Area (**Is this true?**).

4.3 Remote Header

(there are no remote headers in the project scope ... delete paragraph)

4.4 Emulsion Transfer Lines

Emulsion Transfer lines from the satellites to the batteries are steel and fiberglass reinforced plastic (FRP), buried a minimum of 3' deep. The steel lines have a design pressure of 275 psig. The fiberglass lines have a manufacturer's cyclic pressure rating of at least 125 psig

4.5 Tank Batteries

The tank batteries are not located in the Close Proximity Area.

4.6 Perimeter Fences

All production wells in close proximity have chain link fences with top guards and posted warning signs constructed along the perimeter of the location. The fence will be locked when unattended.

VI. INACTIVE WELLS

1.0 Temporarily Abandoned Wells

All temporarily abandoned (TA'D) wells have a wellhead assembly rated for at least 2000 psi working pressure with a tubing spool with flanged or studded side outlets. The wellbore is filled with an inhibited water to protect the casing above the plug. The casing pressures are monitored and recorded quarterly by the Lease Operator on a form supplied by the CMS Coordinator. The CMS Coordinator will maintain these records. TA'd wells tubing/casing tests: Default to NMOCD requirements.

2.0 Pressure Observation Wells

The pressure observation wells (POW) are potentially subjected to the same operating pressures as flowing wells. All POWs are equipped with downhole and wellhead equipment consistent with the design specification for flowing wells except the actuated wing valve is not required.
Tubing /casing annulus testing: Test casing to 500 psi every 5 years. If these wells are previous injectors and have injection permits, default to the NMOCD requirements.

VII. WELL SERVICING OPERATIONS

Guidelines from the Wasson San Andres Well Servicing Manual (Red Book) are followed during well servicing operations in the close proximity area.

Within the Close Proximity Area, all well servicing operations are performed while maintaining an overbalanced situation of 100 psi with the formation. Sufficient kill fluid volume is available on short notice to handle any emergency situation which might arise during the operation.

A hydraulically actuated blow out preventer (BOP) including an annular BOP, pipe rams, and blind rams are installed on each close proximity well, except submersible pumped wells, on which tubing is to be pulled. Submersible wells are equipped with a hydraulic annular BOP and manual pipe and blind rams to line up and accommodate the cable. The BOP's have an accumulator with Nitrogen back up at all times. The BOP is tested for proper operation prior to installation as per Reference 3 (See Amendment 12).

Prior to moving in the rig, the downhole specialist and the Integrated Solutions Team will discuss potential hazards and emergency procedures. Any hot work will be require completion of a Hot Work Permit. A daily safety meeting is performed during which a detailed review of the day's procedures is performed.

All well servicing operations have OXY Ops and/or Progs reviewed by the Integrated Solutions Team. This information is available at the well location with the rig crew. Deviation from this information requires the concurrence of the downhole specialist.

A downhole specialist is on location for critical stages of the servicing operations of producing wells and injection wells. These stages include cementing, perforating, acidizing, and any well control operations.

Production flowlines and tanks are used for circulating producing wells. The fluids from swabbing/flowback are circulated down the producing flowline. During clean out operations a tank is used to circulate fluids (as deemed appropriate based on location). For operations on new wells, return to production, and return to injection. During production and injection well work, fans are used (i.e., bug blowers) to disperse gas as deemed appropriate. H2S monitors are located on the rig and reverse unit. In addition, for close proximity wells, a portable monitor is placed downwind from the well if tanks are used. A cascade system is required to be on location for all close proximity locations.

For submersible installations on high CO_2 wells, drain valves are sheared with a wireline sinker bar to provide positive indication that paraffin has not prevented the bar from reaching the drain valve.

When pressure is anticipated, all wireline operations are performed using a grease lubricator tested to 1.5 times the expected pressure.

VIII. VARIANCES

A variance process is critical to the continuing development of an operating plan. As conditions change and experiences are gained, adjustment to the Cprox operating plan will be made , however it is vital that management of these changes is controlled and most importantly, documented. Therefore the OXY Permian Management of Change (MOC) **procedure** will be implemented and strictly adhered to when changes to the Hobbs RMT Close Proximity Operating Plan are proposed. The variance request form is included to this plan as Attachment 5.

Figure 1

Close Proximity Map

Needs to be created

Figure 2

Typical Pumping Unit Wellhead Installation
Needs to find copy used in DU plan

Figure 3

Submersible Pump Wellhead Installation
Need to find copy used n DU Plan

TABLE I

ACTIVE PRODUCERS
CLOSE PROXIMITY - (UPDATE

Well Number	Current Lift Method

TABLE 2

ACTIVE INJECTORS
CLOSE PROXIMITY - UPDATE

Well Number

~~39~~ ACTIVE INJECTOR

TABLE 3

TEMPORARILY ABANDONED WELLS
CLOSE PROXIMITY - UPDATE

Well Number

TA'D WELLS

TABLE 4

List of Wells for Fencing Variance

Well Number	Date Variance Approved

TABLE 5

CLOSE PROXIMITY TESTING IN MAXIMO (if Maximo is utilized)

TABLE 6

CPROX CHECKLIST

HAS POTENTIAL HAZARDS AND EMERGENCY PROCEDURES BEEN DISCUSSED? (SAFE WORK PERMIT)

TRIPLE HYDRAULIC IF NECESSARY?

ANNULAR HYDRIL INSTALLED ON TOP?

WORKOVER SPOOL INSTALLED?

MANUAL BOP WITH PIPE AND BLIND RAMS IF WELL IS A SUB?

BOP TIMING CHECKED? (NOT TO EXCEED THIRTY SECONDS).

BOP TESTED PRIOR TO COMMENCING WORK?

HANDLES ON ACCUMULATOR LEFT IN EITHER OPEN OR CLOSED POSITION? (NOT NEUTRAL)

WRAP AROUND LEFT IN WELLHEAD TUBING SPOOL AFTER SHUTDOWN?

IF WIRELINE OPERATIONS IN USE WAS LUBRICATOR TESTED TO 1.5 TIMES EXPECTED PRESSURE?

IS APPROVED WRITTEN PROCEDURE NEEDED?

IS GAS IN WELLBORE CIRCULATED DOWN FLOWLINE?

IS ADDITIONAL H_2S MONITOR AVAILABLE DOWNWIND?

IS KILL FLUID SHORTLY AVAILABLE?

IS A QUALIFIED SUPERVISOR ON LOCATION FOR CRITICAL STAGES OF THE JOB?

WAS A SECURITY CHECK DONE PRIOR TO LEAVING LOCATION FOR THE DAY?

ATTACHMENT 1

CLOSE PROXIMITY CO_2/WATER INJECTION WELL HEAD AND TREE SPECS.

Needs to be created

ATTACHMENT 2

CLOSE PROX. PRODUCER WELLHEAD SPECS.

Needs to be created

ATTACHMENT 3
Facilities HAZOPS

Hazard Analysis for Close Proximity Facilities Equipment

SUBSYSTEM				
EQUIPMENT				
FUNCTION				
OCCURANCE				
EFFECT				
HAZARD SEVERITY				
INDIVIDUAL EVENT FREQUENCY				
RISK ASSESSMENT RANKING				
DECISION				

ATTACHMENT 5

VARIANCE REQUEST (To be completed by Initiator)

ROUTE TO: ____

INITIATOR: ______________________ DATE: ________________

INITIATOR PHONE: _______________E-mail:________________
UNIT: _________________ WELL#(S): __________________

VARIANCE FROM: ____
____

SECTION/PARAGRAPH ______________________________________

REQUIREMENT IN WORDS: ___________________________________
____
____

DESCRIPTION OF Concern:
____
____

ITEM (Attach Additional Data as Required)
____
____
____

ESTIMATED COST OF REPAIR: ____

PROPOSED ACTIONS (S) (Discuss any action (s) that WILL be taken, if any, to address the concern (s). Discuss associated cost/manpower savings and describe how an appropriate degree of safety will be maintained. Use attachments if needed):

____
____
____
____

CONCUR: _________________________ DATE: _________________
Field Team Leader

CONCUR: _________________________ DATE:_________________
Asset Manager

Reference Number to be assigned after approval____________