OCS ORDERS 1 thru 14

Governing

Oil, Gas, And Sulphur Leases

In The Outer Continental Shelf

Gulf Of Mexico Area

UNITED STATES
DEPARTMENT OF THE INTERIOR

GEOLOGICAL SURVEY
CONSERVATION DIVISION

Gulf Of Mexico Area

JANUARY, 1977

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I N D E X

OCS Order		Page
	Filing of Reports	12-4
	Availability of Records Filed Prior to December 1, 1970	12-4
13	PRODUCTION MEASUREMENT AND COMMINGLING	13-1
	Definition of Terms	13-2
	Liquid Sales Meters	13-2
	Sale Tanks	13-8
	Allocation Meter Facilities	13-9
	Gas Measurement	13-9
	Commingling of Production	13-12
	Automatic Custody Transfer	13-13
	Accidents	13-14
14	APPROVAL OF SUSPENSION OF PRODUCTION	14-1
	Suspension of Production to Facilitate Proper Development	14-1
	Suspension of Production Because of Lack of Transportation Facilities	14-2

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION
GULF OF MEXICO AREA

OCS ORDER NO. 1
Effective August 28, 1969

MARKING OF WELLS, PLATFORMS, AND FIXED STRUCTURES

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.37. Section 250.37 provides as follows:

> Well designations. The lessee shall mark promptly each drilling platform or structure in a conspicuous place, showing his name or the name of the operator, the serial number of the lease, the identification of the wells, and shall take all necessary means and precautions to preserve these markings.

The operator shall comply with the following requirements. Any departures from the requirements specified in this Order must be approved pursuant to 30 CFR 250.12(b).

1. Identification of Platforms, Fixed Structures. Platforms and structures, other than individual wellhead structures and small structures, shall be identified at two diagonal corners of the platform or structure by a sign with letters and figures not less than 12 inches in height with the following information: The name of lease operator, the name of the area, the block number of the area in which the platform or structure is located, and the platform or structure designation. The information shall be abbreviated as in the following example:

   "The Blank Oil Company operates 'C' platform in Block 37 of South Timbalier Area."

   The identifying sign on the platform would show:

   "BOC - S.T. - 37 - C."

2. Identification of Single Well Structures and Small Structures. Single well and small structures may be identified with one sign only, with letters and figures not less than 3 inches in

height. The information shall be abbreviated as in the following example:

> *"The Blank Oil Company operates well No. 1 which is equipped with a protective structure, in Block 68 in the East Cameron Area."*

The identifying sign on the protective structure would show:

> *"BOC - E.C. - 68 - No. 1"*

3. *Identification of Wells. The OCS lease and well number shall be painted on, or a sign affixed to, each singly completed well. In multiple completed wells each completion shall be individually identified at the well head. All identifying signs shall be maintained in a legible condition.*

Robert F Evans

Robert F. Evans
Supervisor

Approved: August 28, 1969

Russell G. Wayland

Russell G. Wayland
Chief, Conservation Division

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION
GULF OF MEXICO AREA

OCS ORDER NO. 2
Effective January 1, 1975

DRILLING PROCEDURES

This Order is established pursuant to the authority prescribed in 30 CFR 250.11. All exploratory and development wells drilled for oil and gas shall be drilled in accordance with 30 CFR 250.34, 250.41, 250.91, and the provisions of this Order which shall continue in effect until field drilling rules are issued. When sufficient geologic and engineering information is obtained through exploratory drilling, operators may make application or the Area Supervisor may require an application for the establishment of field drilling rules. After field drilling rules have been established by the Area Supervisor, development wells shall be drilled in accordance with such rules.

All wells drilled under the provisions of this Order shall have been included in an exploratory or development plan for the lease as required under 30 CFR 250.34. Each Application for Permit to Drill (Form 9-331C) shall include all information required under 30 CFR 250.91, and shall include a notation of any proposed departures from the requirements of this Order. All departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b).

The operator shall comply with the following requirements. All applications for approval under the provisions of this Order shall be submitted to the appropriate District Supervisor.

1. *Well Casing and Cementing. All wells shall be cased and cemented in accordance with the requirements of 30 CFR 250.41 (a) (1), and the Application for Permit to Drill shall include the casing design safety factors for collapse, tension, and burst. In cases where cement has filled the annular space back to the Gulf floor, the cement may be washed out or displaced to a depth not exceeding 40 feet below the Gulf floor to facilitate casing removal upon well abandonment. For the purpose of this Order, the several casing strings in order of normal installation are drive or structural, conductor, surface, intermediate, and production casing.*

   The design criteria for all wells shall consider all pertinent factors for well control, including formation fracture gradients *and pressures and casing setting depths such that the well bore could be expected to withstand a pressure equivalent to at least a 0.5-ppg kick. All casing, except drive pipe, shall be new pipe or reconditioned used pipe that has been tested to insure that it will meet API standards for new pipe.*

A. <u>Drive or Structural Casing</u>. This casing shall be set by drilling, driving, or jetting to a minimum depth of 100 feet below the Gulf floor or to such greater depth required to support unconsolidated deposits and to provide hole stability for initial drilling operations. If this portion of the hole is drilled, the drilling fluid shall be of a type that is in compliance with the liquid disposal requirements of OCS Order No. 7, and a quantity of cement sufficient to fill the annular space back to the Gulf floor shall be used.

B. <u>Conductor and Surface Casing</u>. Casing design and setting depths shall be based upon all engineering and geologic factors, including the presence or absence of hydrocarbons or other potential hazards and water depths.

(1) <u>Conductor Casing</u>. This casing shall be set at a depth in accordance with paragraph 1B(3) below. A quantity of cement sufficient to fill the annular space back to the Gulf floor shall be used.

(2) <u>Surface Casing</u>. This casing shall be set at a depth in accordance with paragraph 1B(3) below and cemented in a manner necessary to protect all freshwater sands and provide well control until the next string of casing is set.

This casing shall be cemented with a quantity sufficient to fill the calculated annular space to at least 1,500 feet above the surface casing shoe and at least 100 feet inside the conductor casing or as approved by the District Supervisor. When there are indications of improper cementing, such as lost returns, cement channeling, or mechanical failure of equipment, the operator shall recement or make the necessary repairs. After drilling a maximum of 100 feet below the surface casing shoe, a pressure test shall be obtained to aid in determining a formation fracture gradient either by testing to formation leak-off or by testing to a predetermined equivalent mud weight. The results of this test and any subsequent tests of the formation shall be recorded on the driller's log and used to determine the depth and maximum mud weight of the intermediate hole.

(3) <u>Conductor and Surface Casing Setting Depths</u>. These strings of casing shall be set at the depth specified below, subject to approved variation to permit the

casing to be set in a competent bed, or through formations determined desirable to be isolated from the well by pipe for safer drilling operations, provided, however, that the conductor casing shall be set immediately prior to drilling into formations known to contain oil or gas, or, if unknown, upon encountering such formations. These casing strings shall be run and cemented prior to drilling below the specified setting depths. For those wells which may encounter abnormal pressure conditions, the District Supervisor may prescribe the exact setting depth. Conductor casing setting depths shall be between 500 feet and 1,000 feet (TVD below Gulf floor), and surface casing setting depths shall be between 1,500 feet and 4,500 feet (TVD below Gulf floor).

Engineering and geologic data used to substantiate the proposed setting depths of the conductor and surface casing (such as estimated fracture gradients, pore pressures, shallow hazards, etc.) shall be furnished with the Application for Permit to Drill.

C. *Intermediate Casing. This string of casing shall be set when required by anticipated abnormal pressure, mud weight, sediment, and other well conditions. The proposed setting depth for intermediate casing will be based on the pressure tests of the exposed formation below the surface casing shoe.*

A quantity of cement sufficient to cover and isolate all hydrocarbon zones and to isolate abnormal pressure intervals from normal pressure intervals shall be used. If a liner is used as an intermediate string, the cement shall be tested by a fluid entry or pressure test to determine whether a seal between the liner top and next larger string has been achieved. The test shall be recorded on the driller's log. When such liner is used as production casing, it shall be extended to the surface and cemented to avoid surface casing being used as production casing.

D. *Production Casing. This string of casing shall be set before completing the well for production. It shall be cemented in a manner necessary to cover or isolate all zones which contain hydrocarbons, but in any case, a calculated volume sufficient to fill the annular space at least 500 feet above the uppermost producible hydrocarbon zone must be used. When a liner is used as production casing, the testing of the seal between the liner top and the next larger string shall be conducted as in the case of intermediate liners. The test shall be recorded on the driller's log.*

E. *Pressure Testing. Prior to drilling the plug after cementing, all casing strings, except the drive or structural* *casing, shall be pressure-tested as shown in the table below. The test pressure shall not exceed the internal yield pressure of the casing. The surface casing shall be tested with water in the top 100 feet of the casing. If the pressure declines more than 10 percent in 30 minutes, or if there is other indication of a leak, the casing shall be recemented, repaired, or an additional casing string run, and the casing shall be tested again in the same manner.*

Casing	*Minimum Surface Pressure*
Conductor	*200*
Surface	*1,000*
Intermediate	*1,500 or 0.2 psi/ft., whichever is greater.*
Liner	*1,500 or 0.2 psi/ft., whichever is greater*
Production	*1,500 or 0.2 psi/ft., whichever is greater*

After cementing any of the above strings, drilling shall not be commenced until a time lapse of eight hours under pressure for conductor casing string or 12 hours under pressure for all other strings. Cement is considered under pressure if one or more float valves are employed and are shown to be holding the cement in place or when other means of holding pressure is used. All casing pressure tests shall be recorded on the driller's log.

F. Directional Surveys. Wells are considered vertical if inclination does not exceed an average of three degrees from the vertical. Inclination surveys shall be obtained on all vertical wells at intervals not exceeding 1,000 feet during the normal course of drilling.

Wells are considered directional if inclination exceeds an average of three degrees from the vertical. Directional surveys giving both inclination and azimuth shall be obtained on all directional wells at intervals not exceeding 500 feet during the normal course of drilling and at intervals not exceeding 100 feet in all angle change portions of the hole.

On both vertical and directional wells, directional surveys giving both inclination and azimuth shall be obtained at intervals not exceeding 500 feet prior to, or upon, setting surface or intermediate casing, liners, and at total depth.

Composite directional surveys shall be filed with the District Supervisor. The interval shown will be from the bottom of conductor casing, or, in the absence of conductor casing, from the bottom of drive or structural casing to total depth. In calculating all surveys, a correction from true north to Lambert-Grid north shall be made after making the magnetic to true north correction.

2. Blowout Prevention Equipment. Blowout preventers and related well-control equipment shall be installed, used, and tested in a manner necessary to prevent blowouts. Prior to drilling below the drive pipe or structural casing and until drilling operations are completed, blowout prevention equipment shall be installed and maintained ready for use as follows:

   A. Drive Pipe or Structural Casing. Before drilling below this string, at least one remotely controlled, annular-type blowout preventer or pressure-rotating, pack-off-type head and equipment for circulating the drilling fluid to the drilling structure or vessel shall be installed. When the blowout preventer system is on the Gulf floor, the choke and kill lines or equivalent vent lines, equipped with necessary connections and fittings, shall be used for diversion. An annular preventer or pressure-rotating, pack-off-type head, equipped with suitable diversion lines as described above and installed on top of the marine riser, to permit the diversion of hydrocarbons and other fluids, may be utilized for diversion. A diverter system which provides at least the equivalent of two 4-inch lines (22 square inches internal cross-sectional area) and full-open or butterfly valves shall be installed in order to permit the full diversion of hydrocarbons and other fluids. The diverter system shall be equipped with automatic, remote-controlled valves which open, prior to shutting in the well, at least two lines venting in different directions to accomplish downwind diversion. A schematic diagram and operational procedure for the diverter system shall be submitted with the Application for Permit to Drill (Form 9-331C) to the District Supervisor for approval.

   In drilling operations where a floating drill ship or semisubmersible type of drilling vessel is used, and/or where the placement of the initial structural casing is not operationally feasible to provide adequate formation competence to subsequently safely contain shallow hydrocarbons or other fluids while drilling conductor hole, a program which provides for rig and personnel protection and safety in these operations shall be described and submitted to the District Supervisor for his consideration and approval. This program shall include all known pertinent and relevant information, including seismic and geologic data, water depth, drilling-fluid hydrostatic pressure, schematic *diagram from rotary table to proposed conductor casing seat, and contingency plan for moving off location. In all areas where shallow hazards or hydrocarbons are unknown, seismic data shall be obtained, and a small-diameter initial pilot hole from the bottom of drive or structural casing to proposed conductor casing seat shall be drilled to determine the presence or absence of these hazards.*

B. <u>Conductor Casing</u>. Before drilling below this string, at least one remotely controlled, annular-type blowout preventer and equipment for circulating the drilling fluid to the drilling structure or vessel shall be installed. A diverter system as described in paragraph 2A above shall be installed.

C. <u>Surface Casing</u>. Before drilling below this string, the blowout prevention equipment shall include a minimum of: (1) three remote-controlled, hydraulically operated blowout preventers with a working pressure which exceeds the maximum anticipated surface pressure, including one equipped with pipe rams, one with blind rams, and one annular type; (2) a drilling spool with side outlets, if side outlets are not provided in the blowout preventer body; (3) a choke line and manifold; (4) a kill line separate from choke line; and (5) a fill-up line.

D. <u>Intermediate Casing</u>. Before drilling below this string, the blowout prevention equipment shall include a minimum of: (1) four remote-controlled, hydraulically operated blowout preventers with a working pressure which exceeds the maximum anticipated surface pressure, including at least two equipped with pipe rams, one with blind rams, and one annular type; (2) a drilling spool with side outlets, if side outlets are not provided in the blowout preventer body; (3) a choke line and manifold; (4) a kill line separate from choke line; and (5) a fill-up line.

E. <u>Testing</u>.

(1) <u>Pressure Test</u>. Ram-type blowout preventers and related control equipment shall be tested with water to the rated working pressure of the stack assembly, with the exception of the annular-type preventer, which shall be tested to 70 percent of the rated working pressure. They shall be tested: (a) when installed, (b) before drilling out after each string of casing is set, (c) not less than once each week from each of the control stations, and (d) following repairs that require disconnecting a pressure seal in the assembly.

(2) Actuation. While drill pipe is in use, ram-type blowout preventers shall be actuated to test proper functioning once each trip, but in no event less than once each day. The annular-type blowout preventer shall be actuated on the drill pipe once each week. Accumulators or accumulators and pumps shall maintain a pressure capacity reserve at all times to provide for repeated operation of hydraulic preventers. An operable remote blowout-preventer-control station shall be provided, in addition to the one on the drilling floor.

(3) Drills. A blowout prevention drill shall be conducted weekly for each drilling crew to insure that all equipment is operational and that crews are properly trained to carry out emergency duties.

(4) Records. All blowout preventer tests and crew drills shall be recorded on the driller's log.

F. Other Equipment. An inside blowout-preventer assembly (back-pressure valve) and an essentially full-opening drill-string safety valve in the open position shall be maintained on the rig floor to fit all pipe in the drill string. A kelly cock shall be installed below the swivel, and an essentially full-opening kelly cock of such design that it can be run through the blowout preventers shall be installed at the bottom of the kelly.

3. Mud Program. The characteristics, use, and testing of drilling mud and the conduct of related drilling procedures shall be such as are necessary to prevent the blowout of any well. Quantities of mud materials sufficient to insure well control shall be maintained readily accessible for use at all times.

A. Mud Control. Before starting out of the hole with drill pipe, the mud shall be properly conditioned. Proper conditioning requires either circulation with the drill pipe just off bottom to the extent that the annular volume is displaced, or proper documentation in the driller's log prior to pulling the drill pipe that: (1) there was no indication of influx of formation fluids prior to starting to pull the drill pipe from the hole, (2) the weight of the returning mud is not less than the weight of the mud entering the hole, and (3) other mud properties recorded on the daily drilling log are within the specified ranges at the stage of drilling the hole to perform their required functions. In those cases when the hole is circulated, the driller's log shall be so noted.

When coming out of the hole with drill pipe, the annulus shall be filled with mud before the mud level drops 100 *feet. A mechanical device for measuring the amount of mud required to fill the hole shall be utilized, and any time there is an indication of swabbing, or influx of formation fluids, the necessary safety devices and action shall be employed to control the well. The mud shall not be circulated and conditioned, except on or near bottom, unless well conditions prevent running the drill pipe back to bottom. The mud in the hole shall be circulated or reverse-circulated prior to pulling drill-stem test tools from the hole.*

The hole shall be filled by accurately measured volumes of mud. The number of stands of drill pipe and drill collars that may be pulled between the times of filling the hole shall be calculated and posted. The number of barrels and pump strokes required to fill the hole for this designated number of stands of drill pipe and drill collars shall be posted. For each casing string, the maximum pressure which may be applied to the blowout preventer before controlling excess pressure by bleeding through the choke shall be posted near the driller. Drill pipe pressure shall be monitored during the bleeding procedure for well control.

An operable degasser shall be installed in the mud system prior to the commencement of drilling operations and shall be maintained for use throughout the drilling and completion of the well.

B. Mud Test Equipment. Mud test equipment shall be maintained on the drilling rig at all times, and mud tests shall be performed daily, or more frequently as conditions warrant. The following mud-system monitoring equipment shall be installed (with derrick floor indicators) and used at the point in the drilling operation when mud returns are established and throughout subsequent drilling operations:

(1) Recording mud pit level indicator to determine mud pit volume gains and losses. This indicator shall include a visual and audio warning device.

(2) Mud volume measuring device for accurately determining mud volumes required to fill the hole on trips.

(3) Mud return indicator to determine that returns essentially equal the pump discharge rate.

(4) Gas-detecting equipment to monitor the drilling mud returns.

C. Mud Quantities. Daily inventories of mud materials, including barite, shall be recorded to provide a basis for determining minimum quantities needed for emergency use. Drilling operations shall be suspended in the absence of minimum quantities of mud materials for emergency use.

4. Well Control Surveillance and Training.

   A. Surveillance. From the time drilling operations are initiated and until the well is completed or abandoned, a member of the drilling crew or the toolpusher shall maintain rig floor surveillance at all times, unless the well is secured with blowout preventers or cement plugs.

   B. Training. Company and drilling-contractor supervisory personnel shall be trained in and knowledgeable of present-day well control. The operator shall maintain a record of such training on the facility. Training shall include:

      (1) Abnormal pressure detection methods.

      (2) Well control operations, including kicks, lost circulation, and trips.

5. Hydrogen Sulfide. When drilling operations are undertaken to penetrate reservoirs known or expected to contain hydrogen sulfide (H_2S), or, if unknown, upon encountering H_2S, the following preventive measures shall be taken to control the effects of the toxicity, flammability, and corrosive characteristics of H_2S. Alternative equipment or procedures that achieve the same or greater levels of safety may be approved by the District Supervisor. When sulphur dioxide (SO_2), a product of combustion of H_2S, is present, the procedures outlined in the approved contingency plan required in paragraph 5a(3) of this Order shall be followed.

   A. Personnel Safety and Protection.

      (1) Training Program.

         (a) All personnel, whether regularly assigned, contracted, or employed on an unscheduled basis, shall be informed as to the hazards of H_2S and SO_2. They shall also be instructed in the proper use of personnel safety equipment and informed of H_2S detectors and alarms, ventilation equipment, prevailing winds, briefing areas, warning systems, and evacuation procedures.

         (b) Information relating to these safety measures shall be prominently posted on the drilling facility and on vessels in the immediate vicinity which are serving the drilling facility.

(c) *To promote efficient safety procedures, an on-site H_2S safety program, which includes a weekly drill and training session, shall be established. Records of attendance shall be maintained on the drilling facility.*

(d) *All personnel in the working crew shall have been indoctrinated in basic first-aid procedures applicable to victims of H_2S exposure. During subsequent on-site training sessions and drills, emphasis shall be placed upon rescue and first aid for H_2S victims. Each drilling facility shall have the following equipment, and each crew member shall be thoroughly familiar with the location and use of these items:*

(i) *A first-aid kit.*

(ii) *Resuscitators, complete with face masks, oxygen bottles, and spare oxygen bottles.*

(iii) *A Stokes litter or equivalent.*

(e) *One person, who regularly performs duties on the drilling facility, shall be responsible for the overall operation of the on-site safety and training program.*

(2) *Visible Warning System.* *Wind direction equipment shall be installed at prominent locations to indicate to all personnel, on or in the immediate vicinity of the facility, the wind direction at all times for determining safe upwind areas in the event that H_2S is present in the atmosphere.*

Operational danger signs shall be displayed from each side of the drilling ship or platform, and a number of rectangular red flags shall be hoisted in a manner visible to watercraft and aircraft. Each flag shall be of a minimum width of three feet and a minimum height of two feet. Each sign shall have a minimum width of eight feet and a minimum height of four feet, and shall be painted a high-visibility yellow color with black lettering of a minimum of 12 inches in height, indicating: "DANGER - HYDROGEN SULFIDE - H_2S". All signs and flags shall be illuminated under conditions of poor visibility and at night when in use. These signs and flags shall be displayed to indicate the following operational conditions and requirements:

(a) *Moderate Danger.* *When the threshold limit value of H_2S (10 parts per million) is reached, the signs will be displayed. If the concentration of H_2S*

reaches 20 parts per million, protective breathing apparatus shall be worn by all personnel, and all nonworking personnel shall proceed to the safe briefing areas.

(b) Extreme Danger. When H_2S is determined to have reached the injurious level (50 parts per million), the flags shall be hoisted in addition to the displayed signs. All nonessential personnel or all personnel, as appropriate, shall be evacuated at this time. Radio communications shall be used to alert all known air- and watercraft in the immediate vicinity of the drilling facility.

(3) Contingency Plan. A contingency plan shall be developed prior to the commencement of drilling operations. The plan shall include the following:

(a) General information and physiological response to H_2S and SO_2 exposure.

(b) Safety procedures, equipment, training, and smoking rules.

(c) Procedures for operating conditions:

(i) Moderate danger to life.

(ii) Extreme danger to life.

(d) Responsibilities and duties of personnel for each operating condition.

(e) Designation of briefing areas as locations for assembly of personnel during Extreme Danger condition. At least two briefing areas shall be established on each drilling facility. Of these two areas, the one upwind at any given time is the safe briefing area.

(f) Evacuation plan.

(g) Agencies to be notified in case of an emergency.

(h) A list of medical personnel and facilities, including addresses and telephone numbers.

(4) H_2S Detection and Monitoring Equipment. Each drilling facility shall have an H_2S detection and monitoring system which activates audible and visible alarms before the concentration of H_2S exceeds its threshold limit value of 10 parts per million in air. This equipment

shall be capable of sensing a minimum of five parts per million H_2S in air, with sensing points located at the bell nipple, shale shaker, mud pits, driller's stand, living quarters, and other areas where H_2S might accumulate in hazardous quantities.

H_2S detector ampules shall be available for use by all working personnel. After H_2S has been initially detected by any device, frequent inspections of all areas of poor ventilation shall be made with a portable H_2S-detector instrument.

(5) Personnel Protective Equipment.

(a) All personnel on a drilling facility or aboard marine vessels serving the facility shall be equipped with proper personnel protective-breathing apparatus. The protective breathing apparatus used in an H_2S environment shall conform to all applicable Occupational Safety and Health Administration regulations and American National Standards Institute standards. Optional equipment, such as nose cups and spectacle kits, shall be available for use as needed.

(b) The storage location of protective breathing apparatus shall be such that they are quickly and easily available to all personnel. Storage locations shall include the following:

(i) Rig floor.

(ii) Any working area above the rig floor.

(iii) Mud-logging facility.

(iv) Shale-shaker area.

(v) Mud pit area.

(vi) Mud storage area.

(vii) Pump rooms (mud and cement).

(viii) Crew quarters.

(ix) Each briefing area.

(x) Heliport.

(c) A system of breathing-air manifolds, hoses, and masks shall be provided on the rig floor and in the

briefing areas. A cascade air-bottle system shall be provided to refill individual protective-breathing-apparatus bottles. The cascade air-bottle system may be recharged by a high-pressure compressor suitable for providing breathing-quality air, provided the compressor suction is located in an uncontaminated atmosphere. All breathing-air bottles shall be labeled as containing breathing-quality air fit for human usage.

(d) Workboats attendant to rig operations shall be equipped with protective breathing apparatus for all workboat crew members. Pressure-demand or demand-type masks, connected to a breathing-air manifold, and additional protective breathing apparatus shall be available for evacuees. Whenever possible, boats shall be stationed upwind.

(e) Helicopters attendant to rig operations shall be equipped with a protective breathing apparatus for the pilot.

(f) The following additional personnel safety equipment shall be available for use as needed:

(i) Portable H_2S detectors.

(ii) Retrieval ropes with safety harnesses to retrieve incapacitated personnel from contaminated areas.

(iii) Chalk boards and note pads located on the rig floor, in the shale-shaker area, and in the cement pump rooms for communication purposes.

(iv) Bull horns and flashing lights.

(v) Resuscitators.

(6) <u>Ventilation Equipment</u>. All ventilation devices shall be explosion-proof and situated in areas where H_2S or SO_2 may accumulate. Movable ventilation devices shall be provided in work areas and be multidirectional and capable of dispersing H_2S or SO_2 vapors away from working personnel.

(7) <u>Notification of Regulatory Agencies</u>. The following agencies shall be immediately notified under the alert conditions indicated:

(a) *Moderate Danger.*

(i) *U. S. Geological Survey.*

(ii) *U. S. Coast Guard.*

(b) *Extreme Danger.*

(i) *U. S. Geological Survey.*

(ii) *U. S. Coast Guard.*

(iii) *Department of Defense (when operating in Department of Defense warning areas in the northeast Gulf of Mexico).*

(iv) *Appropriate State agencies.*

B. *Metallurgical Equipment Considerations. Equipment used when drilling zones bearing H_2S shall be constructed of materials which, according to design principles, will be able to resist damage from the phenomena known variously as sulfide stress cracking, hydrogen embrittlement, or stress corrosion cracking. Such equipment includes drill pipe, casing, casing heads, blowout-preventer stack assemblies, kill lines, choke manifolds, and other related equipment. A knowledge of the various interactions between stress, envir-oment, and the metallurgy employed is required for success-ful operation in H_2S environments. The following general practices are required for acceptable performance:*

(1) *Drill String. Drill strings shall be designed consis-tent with the anticipated depth, conditions of the hole, and reservoir environment to be encountered. Care shall be taken to minimize exposure of the drill string to high stresses as much as is practical and consistent with the anticipated hole conditions to be encountered.*

(2) *Casing. Casing, couplings, flanges, and related equip-ment shall be designed for H_2S service. Field welding on casing (except conductor and surface strings) is pro-hibited unless approved by the District Supervisor.*

(3) *Wellhead, Blowout Preventers, and Pressure Control Equipment. The blowout-preventer stack assembly shall be designed in accordance with criteria evolved through technology of the latest state-of-the-art for H_2S ser-vice. Surface equipment such as choke lines, choke manifold, kill lines, bolting, weldments, and other related well-killing equipment shall be designed and fabricated utilizing the most advanced technology con-cerning sulfide stress cracking. Elastomers, packing,*

and similar inner parts exposed to H_2S shall be resistant at the maximum anticipated temperature of exposure.

C. *Mud Program.*

(1) *Either water- or oil-base muds are suitable for use in drilling formations containing H_2S. If oil-base muds are used, cuttings shall be cleaned of oil prior to disposal into Gulf waters.*

(2) *A pH of 10.0 or above shall be maintained in a water-base mud system to control corrosion and prevent sulfide stress cracking.*

(3) *Consideration shall also be given to the use of H_2S scavengers in both water- and oil-base mud systems.*

(4) *Sufficient quantities of additives shall be maintained on location for addition to the mud system as needed to neutralize H_2S picked up by the system when drilling in formations containing H_2S.*

(5) *The application of corrosion inhibitors to the drill pipe to afford a protective coating or their addition to the mud system may be used as an additional safeguard to the normal protection of the metal by pH control and the scavengers mentioned above.*

(6) *Drilling mud containing H_2S gas shall be degassed at the optimum location for the particular rig configuration employed. The gases so removed shall be piped into a closed flare system and burned at a suitable remote stack.*

D. *General Operations. All personnel in the working area shall utilize H_2S protective-breathing apparatus when required, as specified in paragraph 5A(2). The normal fixed-point monitor system outlined in paragraph 5A(4) may be supplemented with portable H_2S detectors as conditions warrant.*

(1) *Drill String Trips or Fishing Operations. Every effort shall be made to pull a dry drill string while maintaining well control. If it is necessary to pull the drill string wet after penetration of H_2S-bearing zones, increased monitoring of the working area shall be provided and protective breathing apparatus shall be worn under conditions as outlined in paragraph 5A(2).*

(2) *Circulating Bottoms-up from a Drilling Break, Cementing Operations, Logging Operations, or Well Circulation While Not Drilling. After penetration of an H_2S-bearing zone, protective breathing apparatus shall be worn by those*

personnel in the working area in advance of circulating bottoms-up or when H_2S is indicated by the monitoring system in quantities sufficient to require protective breathing apparatus under paragraph 5A(2), should this condition occur earlier.

(3) *Coring Operations in H_2S-bearing Zones. Personnel protective-breathing apparatus shall be worn 10-20 stands in advance of retrieving the core barrel. Cores to be transported shall be sealed and marked for the presence of H_2S.*

(4) *Abandonment or Temporary Abandonment Operations. Internal well-abandonment equipment shall be designed for H_2S service.*

(5) *Logging Operations after Penetration of Known or Suspected H_2S-bearing Zones. Mud in use for logging operations shall be conditioned and treated to minimize the effects of H_2S on the logging equipment.*

(6) *Stripping Operations. Displaced mud returns shall be monitored and protective breathing apparatus worn if H_2S is detected at levels outlined for protective breathing apparatus under paragraph 5A(2).*

(7) *Gas-cut Mud or Well Kick from H_2S-bearing Zones. Protective breathing apparatus shall be worn when an H_2S concentration of 20 parts per million is detected. Should a decision be made to circulate out a kick, protective breathing apparatus shall be worn prior to and subsequent to bottoms-up, and at any time during an extended kill operation that the concentration of H_2S becomes hazardous to personnel as defined in paragraph 5A(2)(a).*

(8) *Drill String Precautions. Precautions shall be taken to minimize drill string stresses caused by conditions such as excessive dogleg severity, improper stiffness ratios, improper torque, whip, abrasive wear on tool joints, and joint imbalance. American Petroleum Institute Bulletin RP 7G shall be used as a guideline for drill string precautions. Tool-joint compounds containing free sulphur shall not be used. Proper handling techniques shall be employed to minimize notching, stress concentrations, and possible drill pipe failures.*

(9) *Flare System. The flare system shall be designed to safely gather and burn H_2S gas. Flare lines shall be located as far from the drilling facility as feasible in a manner to compensate for wind changes. The flare*

system shall be equipped with a pilot and an automatic igniter. Backup ignition for each flare shall be provided.

E. *Kick Detection and Well Control. In addition to the requirements of paragraph 3B of this Order, all efforts shall be made to prevent a well kick as a result of gas-cut mud, drilling breaks, lost circulation, or trips for bit change. Drilling rate changes shall be evaluated for the possibility of encountering abnormal pressures, and mud weights adjusted in an effort to compensate for any hydrostatic imbalance that might result in a well kick.*

In the event of a kick, the disposal of the well influx fluids shall be accomplished by one of the following alternatives, giving consideration to personnel safety, possible environmental damage, and possible facility well equipment damage:

Alternative A. To contain the well fluid influx by shutting in the well and pumping the fluids back into the formation.

Alternative B. To control the kick by using appropriate well-control techniques to prevent formation fracturing in open hole within the pressure limits of well equipment (drill pipe, casing, wellhead, blowout preventers, and related equipment). The disposal of H_2S and other gases shall be through pressured or atmospheric mud-gas separator equipment, depending on volume and pressure of H_2S gas. The equipment shall be designed to recover drilling mud and to vent to the atmosphere and burn the gases separated. The mud system shall be treated to neutralize H_2S and restore and maintain the proper mud quality.

F. *Well Testing in an H_2S Environment.*

(1) *Procedures.*

(a) *Well testing shall be performed with a minimum number of personnel in the immediate vicinity of the rig floor and test equipment to safely and adequately perform the test and maintain related equipment and services.*

(b) *Prior to initiation of the test, special safety meetings shall be conducted for all personnel who will be on the drill facility during the test, with particular emphasis on the use of personnel protective-breathing apparatus, first aid procedures, and the H_2S Contingency Plan.*

(c) *During the test, the use of H_2S detection equipment shall be intensified. All produced gases shall be vented and burned through a flare system which meets the requirements of paragraph 5D(9). Gases from stored test fluids shall be vented into the flare system.*

(d) *"No Smoking" rules in the approved Contingency Plan of paragraph 5A(3) of this Order shall be rigorously enforced.*

(2) *Equipment.*

(a) *Drill-stem test tools and wellhead equipment shall be suitable for H_2S service.*

(b) *Tubing which meets the requirements for H_2S service shall be used for drill stem testing. Drill pipe shall not be used for drill stem tests without the prior approval of the District Supervisor. The water cushion shall be thoroughly inhibited in order to prevent H_2S corrosion. The test string shall be flushed with treated fluid for the same purpose after completion of the test.*

(c) *All surface test units and related equipment shall be designed for H_2S service. Only competent personnel who are trained in and knowledgeable of the hazardous effects of H_2S shall be utilized in these tests.*

D.W. Solanas

D. W. Solanas
Oil and Gas Supervisor
Field Operations
Gulf of Mexico Area

Approved: November 25, 1974

Russell G. Wayland

Russell G. Wayland
Chief, Conservation Division

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION
GULF OF MEXICO AREA

OCS ORDER NO. 3
Effective August 28, 1969

PLUGGING AND ABANDONMENT OF WELLS

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.15. The operator shall comply with the following minimum plugging and abandonment procedures which have general application to all wells drilled for oil and gas. Plugging and abandonment operations must not be commenced prior to obtaining approval from an authorized representative of the Geological Survey. Oral approvals shall be in accordance with 30 CFR 250.13. Any departures from the requirements specified in this Order must be approved pursuant to 30 CFR 250.12(b).

1. Permanent Abandonment.

A. Isolation in Uncased Hole. In uncased portions of wells, cement plugs shall be spaced to extend 100 feet below the bottom to 100 feet above the top of any oil, gas, and fresh water zones so as to isolate them in the strata in which they are found and to prevent them from escaping into other strata.

B. Isolation of Open Hole. Where there is open hole (uncased and open into the casing string above) below the casing, a cement plug shall be placed in the deepest casing string by (1) or (2) below, or in the event lost circulation conditions exist or are anticipated, the plug may be placed in accordance with (3) below:

(1) A cement plug placed by displacement method so as to extend a minimum of 100 feet above and 100 feet below the casing shoe.

(2) A cement retainer with effective back pressure control set not less than 50 feet, nor more than 100 feet, above the casing shoe with a cement plug calculated to extend at least 100 feet below the casing shoe and 50 feet above the retainer.

(3) A permanent type bridge plug set within 150 feet above the casing shoe with 50 feet of cement on top of the bridge plug. This plug shall be tested prior to placing subsequent plugs.

C. Plugging or Isolating Perforated Intervals. A cement plug shall be placed opposite all open perforations (perforations not squeezed with cement) extending a minimum of 100 feet above and 100 feet below the perforated interval or down to a casing plug whichever is less. In lieu of the cement plug, a bridge plug set at a maximum of 150 feet above the open perforations with 50 feet of cement on top may be used provided the perforations are isolated from the hole below.

D. Plugging of Casing Stubs. If casing is cut and recovered, a cement plug 200 feet in length shall be placed to extend 100 feet above and 100 feet below the stub. A retainer may be used in setting the required plug.

E. Plugging of Annular Space. No annular space that extends to the Gulf floor shall be left open to drilled hole below. If this condition exists, the annulus shall be plugged with cement.

F. Surface Plug Requirement. A cement plug of at least 150 feet, with the top of the plug 150 feet or less below the Gulf floor, shall be placed in the smallest string of casing which extends to the surface.

G. Testing of Plugs. The setting and location of the first plug below the top 150-foot plug, will be verified by either (1) placing a minimum pipe weight of 15,000 pounds on the plug, or (2) testing with a minimum pump pressure of 1,000 psig with no more than a 10 percent pressure drop during a 15-minute period.

H. Mud. Each of the respective intervals of the hole between the various plugs shall be filled with mud fluid of sufficient density to exert hydrostatic pressure exceeding the greatest formation pressure encountered while drilling such interval.

I. Clearance of Location. All casing and piling shall be severed and removed to at least 15 feet below the Gulf floor and the location shall be dragged to clear the well site of any obstructions.

2. Temporary Abandonment. Any drilling well which is to be temporarily abandoned shall be mudded and cemented as required for permanent abandonment except for requirements F and I of paragraph 1 above.

When casing extends above the Gulf floor, a mechanical bridge plug (retrievable or permanent) shall be set in the casing between 15 and 200 feet below the Gulf floor.

Robert F. Evans

Robert F. Evans
Supervisor

Approved: August 28, 1969

Russell G. Wayland

Russell G. Wayland
Chief, Conservation Division

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION
GULF OF MEXICO AREA

OCS ORDER NO. 4
Effective August 28, 1969

SUSPENSIONS AND DETERMINATION OF WELL PRODUCIBILITY

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.12(d)(1). An OCS lease provides for extension beyond its primary term for as long as oil or gas may be produced from the lease in paying quantities. An OCS lease may be maintained beyond the primary term, in the absence of actual production, when a suspension of operations or production, or both, has been approved. An application for suspension of production for an initial period should be submitted prior to the expiration of the term of a lease. The supervisor may approve a suspension of production provided at least one well has been drilled on the lease and determined to be capable of being produced in paying quantities. The temporary or permanent abandonment of a well will not preclude approval of a suspension of production as provided in 30 CFR 250.12(d)(1). Any departures from the requirements specified in this Order must be approved pursuant to 30 CFR 250.12(b).

A well may be determined to be capable of producing in paying quantities when the requirements of either 1 or 2 below have been met.

1. Production Tests.

   A. Oil Wells. A production test of at least two hours duration, following stabilization, is required.

   B. Gas Wells. A deliverability test of at least two hours duration, following stabilization, or a four-point back-pressure test, is required.

   C. Witnessing and Results. All tests must be witnessed by an authorized representative of the Geological Survey. Test data accompanied by operator's affidavit, or third-party test data, may be accepted in lieu of a witnessed test provided prior approval is obtained from the appropriate district office. The results of the witnessed or accepted test must justify a determination that the well is capable of producing in paying quantities.

2. *Production Capability.* Information for determining producibility should be submitted in time to permit one week for evaluation and determination. In cases of urgency, determinations may be conveyed orally. The following may be considered as acceptable evidence that a well is capable of producing in paying quantities:

   A. An induction-electric log of the well, clearly showing a minimum of 15 feet of producible sand in one section which does not include any interval which appears to be water saturated. All of the section counted as producible must exhibit the following properties:

      (1) Electrical spontaneous potential exceeding 20 negative millivolts beyond the shale base line. If mud conditions prevent a 20 negative millivolt reading beyond the shale base line, a gamma ray log deflection of at least 70 percent of the maximum gamma ray deflection in the nearest clean water bearing sand may be substituted.

      (2) A minimum true resistivity ratio of the producible section to the nearest clean water sand of at least 5:1, provided the producible section exhibits a minimum resistivity of 2.0 ohm-meters.

      (3) A porosity log indicating porosity in the producible section.

   B. Sidewall cores and core analysis which indicates that the section is producible.

   C. A wire line formation test or evidence that an attempt was made to obtain such test. The test results must indicate that the section is producible.

   D. All logs run must support other evidence that the section is producible.

Robert F. Evans

Robert F. Evans
Supervisor

Approved: August 28, 1969

Russell G. Wayland

Russell G. Wayland
Chief, Conservation Division

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION
GULF OF MEXICO AREA

OCS ORDER NO. 5
Effective June 5, 1972

SUBSURFACE SAFETY DEVICES

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.41(b). Section 250.41(b) provides as follows:

> (b) Completed Wells. In the conduct of all its operations, the lessee shall take all steps necessary to prevent blowouts, and the lessee shall immediately take whatever action is required to bring under control any well over which control has been lost. The lessee shall: (1) in wells capable of flowing oil or gas, when required by the supervisor, install and maintain in operating condition storm chokes or similar subsurface safety devices; (2) for producing wells not capable of flowing oil or gas, install and maintain surface safety valves with automatic shutdown controls; and (3) periodically test or inspect such devices or equipment as prescribed by the supervisor.

The operator shall comply with the following requirements. All departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b). All applications for approval under the provisions of this Order shall be submitted to the appropriate District office. References in this Order to approvals, determinations, or requirements are to those given or made by the Supervisor or his delegated representative.

1. Installation. All new and existing tubing installations open to hydrocarbon-bearing zones shall be equipped with a subsurface-controlled or a surface- or other remotely controlled subsurface safety device, to be installed at a depth of 100 feet or more below the sea floor unless, after application and justification, the well is determined to be incapable of flowing oil or gas. These installations shall be made as required in subparagraphs A and B below within two (2) days after stabilized production is established, and during this period of time the well shall not be left unattended while open to production.

A. *New Wells.* *All tubing installations in wells completed after December 1, 1972, shall be equipped with a surface- or other remotely controlled subsurface safety device; provided, that wells with a shut-in tubing pressure of 4,000 psig or greater shall be equipped with a subsurface-controlled subsurface safety device in lieu of a surface- or other remotely controlled subsurface safety device unless a surface- or other remotely controlled subsurface safety device is approved or required. When the shut-in tubing pressure declines below 4,000 psig, a surface- or other remotely controlled subsurface safety device shall be installed when the tubing is first removed and reinstalled.*

B. *Existing Wells.* *All tubing installations in wells existing on the date of this Order shall be equipped with a surface- or other remotely controlled subsurface safety device when the tubing is first removed and reinstalled after December 1, 1972; provided, that wells with a shut-in tubing pressure of 4,000 psig or greater shall be equipped with a subsurface-controlled subsurface safety device in lieu of a surface- or other remotely controlled subsurface safety device unless a surface- or other remotely controlled subsurface safety device is approved or required. When the shut-in tubing pressure declines below 4,000 psig, a surface- or other remotely controlled subsurface safety device shall be installed when the tubing is first removed and reinstalled.*

Tubing installations in existing wells completed from single-well and multi-well satellite caissons or jackets and sea-floor completions may be equipped with a subsurface-controlled subsurface safety device, in lieu of a surface- or other remotely controlled subsurface safety device, upon application, justification, and approval.

C. *Shut-in Wells.* *A tubing plug shall be installed in lieu of, or in addition to, other subsurface safety devices if a well has been shut in for a period of six (6) months. Such plugs shall be set at a depth of 100 feet or more below the sea floor. All retrievable plugs installed after the date of this Order shall be of the pump-through type. All wells perforated and completed, but not placed on production, shall be equipped with a subsurface safety device or tubing plug within two (2) days after completion.*

D. *Injection Wells.* *Subsurface safety devices as required in subparagraphs A and B above shall be installed in all injection wells unless, after application and justification, it is determined that the well is incapable of flowing oil or gas, which condition shall be verified annually.*

2. *Technological Advancement*. As technological research, progress, and product improvement result in increased effectiveness of existing safety devices or the development of new devices or systems, such devices or systems may be required or used upon application, justification, and approval. Applications for routine use shall include evidence that the device or system has been field-tested at least once each month for a minimum of six (6) consecutive months, and that each test indicated proper operation.

3. *Testing and Inspection*. Subsurface safety devices shall be designed, adjusted, installed, and maintained to insure reliable operation. During testing and inspection procedures, the well shall not be left unattended while open to production unless a properly operating subsurface safety device has been installed in the well.

   A. *Surface-Controlled Subsurface Safety Devices*. Each surface- or other remotely controlled subsurface safety device installed in a well shall be tested in place for proper operation when installed and thereafter at intervals not exceeding six (6) months. If the device does not operate properly, it shall be removed, repaired, and reinstalled or replaced and tested to insure proper operation.

   B. *Subsurface-Controlled Subsurface Safety Devices*. Each subsurface-controlled subsurface safety device installed in a well shall be removed, inspected, and repaired or adjusted as necessary and reinstalled at intervals not exceeding six (6) months; provided, that such removable devices set in a landing nipple shall be removed, inspected, and repaired or adjusted as necessary and reinstalled at intervals not exceeding twelve (12) months. Each velocity-type device shall be designed to close at a flow rate not to exceed the larger of either 150 percent of, or 200 BFPD above, the most recent well-test rate which equals or exceeds the approved production rate. The above closing flow rate shall not exceed the calculated capacity of the well to produce against a flowing wellhead pressure of 50 psig. Each preset tubing-pressure-actuated device shall be designed to close prior to reduction of the flowing wellhead pressure to 50 psig.

   C. *Tubing Plugs*. A shut-in well equipped with a tubing plug shall be inspected for leakage by opening the well to possible flow at intervals not exceeding six (6) months. If sustained liquid flow exceeds 400 cc/min., or gas flow exceeds 15 cu. ft./min., the plug shall be removed, repaired, and reinstalled or an additional tubing plug installed to prevent leakage.

4. *Temporary Removal*. Each wireline- or pumpdown-retrievable subsurface safety device may be removed, without further authority or

notice, for a routine operation which does not require approval of a Sundry Notice and Report on Wells (Form 9-331) for a period not to exceed fifteen (15) days. The well shall be clearly identified as being without a subsurface safety device and shall not be left unattended while open to production. The provisions of this paragraph are not applicable to the testing and inspection procedures in paragraph 3 above.

5. *Additional Protective Equipment. All tubing installations made after the date of this Order in which a wireline- or pumpdown-retrievable subsurface safety device is to be installed shall be equipped with a landing nipple, with flow couplings or other protective equipment above and below, to provide for setting of the subsurface safety device. All wells in which a subsurface safety device or tubing plug is installed shall have the tubing-casing annulus packed off above the uppermost open casing perforations. The control system for all surface-controlled subsurface safety devices shall be an integral part of the platform shut-in system, or of an independent remote shut-in system.*

6. *Departures. All departures (or waivers) approved prior to the date of this Order are hereby terminated as of December 1, 1972, unless new applications are submitted prior to that date. All such new applications will be considered for approval pursuant to 30 CFR 250.12(b) and the requirements of this Order. All applications for departures shall include a detailed statement of the well conditions, efforts made to overcome any difficulties, and proposed alternate safety measures.*

7. *Emergency Action. All tubing installations open to hydrocarbon-bearing zones and not equipped with a subsurface safety device as permitted by this Order shall be clearly identified as not being so equipped, and a subsurface safety device or tubing plug shall be available at the field location. In the event of an emergency, such as an impending hurricane, such device or plug shall be promptly installed within the limits of practicability, due consideration being given to personnel safety.*

8. *Records. The operator shall maintain the following records for a minimum period of one year for each subsurface safety device and tubing plug installed, which records shall be available to any authorized representative of the Geological Survey.*

   A. *Field Records. Individual well records shall be maintained at or near the field and shall include, as a minimum, the following information:*

      (1) *A record which will give design and other information; i.e., make, model, type, spacers, bean and spring size, pressure, etc.*

(2) *Verification of assembly by a qualified person in charge of installing the device and installation date.*

(3) *Verification of setting depth and all operational tests as required in this Order.*

(4) *Removal date, reason for removal, and reinstallation date.*

(5) *A record of all modifications of design in the field.*

(6) *All mechanical failures or malfunctions, including sand-cutting, of such devices, with notation as to cause or probable cause.*

(7) *Verification that a failure report was submitted.*

B. *Other Records. The following records, as a minimum, shall be maintained at the operator's office:*

(1) *Verified design information of subsurface-controlled subsurface safety devices for the individual well.*

(2) *Verification of assembly and installation according to design information.*

(3) *All failure reports.*

(4) *All laboratory analysis reports of failed or damaged parts.*

(5) *Quarterly failure-analysis report.*

9. *Reports. Well completion reports (Form 9-330) and any subsequent reports of workover (Form 9-331) shall include the type and the depth of the subsurface safety devices and tubing plugs installed in the well or indicate that a departure has been granted.*

To establish a failure-reporting and corrective-action program as a basis for reliability and quality control, each operator shall submit a quarterly failure-analysis report to the office of the Supervisor, identifying mechanical failures by lease and well, make and model, cause or probable cause of failure, and action taken to correct the failure. The reporting period shall begin the first day of the month following the date of this Order. The reports *shall be submitted by February 28, May 31, August 31, and November 30 for the periods ending January 31, April 30, July 31, and October 31 of each year.*

Robert F. Evans

Robert F. Evans
Supervisor

Approved: June 5, 1972

Russell G. Wayland

Russell G. Wayland
Chief, Conservation Division

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION
GULF OF MEXICO AREA

OCS ORDER NO. 6
Effective August 28, 1969

COMPLETION OF OIL AND GAS WELLS

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.92. Any departures from the requirements specified in this Order must be approved pursuant to 30 CFR 250.12(b).

1. Wellhead Equipment and Testing Procedures.

   A. Wellhead Equipment. All completed wells shall be equipped with casingheads, wellhead fittings, valves and connections with a rated working pressure equal to or greater than the surface shut-in pressure of the well. Connections and valves shall be designed and installed to permit fluid to be pumped between any two strings of casing. Two master valves shall be installed on the tubing in wells with a surface pressure in excess of five thousand pounds per square inch. All wellhead connections shall be assembled and tested, prior to installation, by a fluid pressure which shall be equal to the rated test pressure of the fitting to be installed.

   B. Testing Procedure. Any wells showing sustained pressure on the casinghead, or leaking gas or oil between the production casing and the next larger casing string, shall be tested in the following manner: The well shall be killed with water or mud and pump pressure applied. Should the pressure at the casinghead reflect the applied pressure, the casing shall be condemned. After corrective measures have been taken, the casing shall be tested in the same manner. This testing procedure shall be used when the origin of the pressure cannot be determined otherwise.

2. Storm Choke. All completed wells shall meet the requirements prescribed in OCS Order No. 5.

3. *Procedures for Multiple or Tubingless Completions.*

A. *Multiple Completions.*

(1) *Information shall be submitted on, or attached to, Form 9-331 showing top and bottom of all zones proposed for completion or alternate completion, including a partial electric log and a diagrammatic sketch showing such zones and equipment to be used.*

(2) *When zones approved for multiple completion become intercommunicated the lessee shall immediately repair and separate the zones after approval is obtained.*

B. *Tubingless Completions.*

(1) *All tubing strings in a multiple completed well shall be run to the same depth below the deepest producible zone.*

(2) *The tubing string(s) shall be new pipe and cemented with a sufficient volume to extend a minimum of 500 feet above the uppermost producible zone.*

(3) *A temperature or cement bond log shall be run in all tubingless completion wells where lost circulation or other unusual circumstances occur during the cementing operations.*

(4) *Information shall be submitted on, or attached to, Form 9-331 showing the top and bottom of all zones proposed for completion or alternate completion, including a partial electric log and a diagrammatic sketch showing such zones and equipment to be used.*

Robert F. Evans

Robert F. Evans
Supervisor

Approved: August 28, 1969

Russell G. Wayland

Russell G. Wayland
Chief Conservation Division

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION
GULF OF MEXICO AREA

OCS ORDER NO. 7
Effective October 1, 1976

POLLUTION AND WASTE DISPOSAL

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.43. The operator shall comply with the following requirements. All departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b).

1. Pollution Prevention. In the conduct of all oil and gas operations, the operator shall prevent pollution of the Gulf. Furthermore, the disposal of waste materials into the Gulf shall not create conditions which will adversely affect the public health, life or property, aquatic life or wildlife, recreation, navigation, or other uses of the Gulf.

   A. Liquid Disposal.

      (1) Drilling mud containing free oil shall not be disposed of into the Gulf.

      (2) The operator shall submit with the Application for Permit to Drill (Form 9-331C) a detailed list of drilling mud components, including the common chemical or chemical trade name of each component, and a list of the drilling mud additives anticipated for use in meeting special drilling requirements. Disposal of drilling mud shall be by methods which will minimize the adverse effects to marine life. These methods shall be consistent with applicable Federal regulations. Approval of drilling mud disposal procedures will be site specific and on a case-by-case basis.

(3) *Curbs, gutters, and drains on platforms and structures shall be installed and maintained in accordance with the provisions of OCS Order No. 8.*

(4) *Discharges from fixed structures, including sanitary waste, produced water, and deck drainage, are subject to the Environmental Protection Agency's permitting procedures pursuant to the Federal Water Pollution Control Act, as amended.*

B. *Solid Waste Disposal.*

(1) *Drill cuttings, sand, and other solids containing oil shall not be disposed of into the Gulf unless all of the free oil has been removed.*

(2) *Mud containers and other similar solid waste materials shall be incinerated or transported to shore for disposal in accordance with Federal, State, or local requirements.*

2. *Personnel, Inspections, and Reports.*

A. *Personnel. The Operator's personnel shall be throughly instructed in the techniques of equipment maintenance and operation for the prevention of pollution. Nonoperator personnel shall be informed in writing, prior to executive contracts, of the operator's obligations to prevent pollution.*

B. *Pollution Inspections.*

(1) *Manned facilities shall be inspected daily.*

(2) *Unattended facilities, including those equipped with remote control and monitoring systems, shall be inspected at frequent intervals. The District Supervisor may prescribe the frequency of inspections for these facilities.*

(3) *All production facilities, such as separators, tanks, treaters, and other hydrocarbon handling equipment shall be designed and operated in a manner necessary to prevent pollution. Maintenance or repairs as are necessary to prevent pollution of the Gulf shall be undertaken immediately.*

C. *Pollution Reports.*

(1) *All spills of oil and liquid pollutants shall be recorded showing the cause, size of spill, and action taken, and the record shall be maintained and available for inspection by the District Supervisor. All spills of less than 2.4 cubic meters (15 barrels) shall be reported orally to the District Supervisor within 12 hours and shall be confirmed in writing.*

(2) *All spills of oil and liquid pollutants of 2.4 to 7.9 cubic meters (15 to 50 barrels) shall be reported orally to the District Supervisor within four (4) hours and shall be confirmed in writing.*

(3) *All spills of oil and liquid pollutants of more than 7.9 cubic meters (50 barrels) shall be reported orally without delay to the District Supervisor and the Coast Guard. All oral reports shall be confirmed in writing.*

(4) *Operators shall notify each other upon observation of equipment malfunction or pollution resulting from another's operation.*

3. *Pollution-Control Equipment and Oil Spill Contingency Plan.*

A. *Equipment. Standy pollution-control equipment and materials shall be maintained by, or shall be available to, each operator at an offshore or onshore location. This shall include containment booms, skimming apparatus, cleanup materials, and chemical agents, and shall be available prior to the commencement of operations. The use of chemicals shall be permitted only after approval by the Area Supervisor in accordance with Part 2003.2-1 Annex X, National Oil and Hazardous Substances Pollution Contingency Plan. The Equipment and materials shall be inspected monthly and maintained in good condition for use. The results of the inspections shall be recorded and maintained at the site.*

B. *Oil Spill Contingency Plan. The operator shall submit an oil spill contingency plan for approval by the*

Area Supervisor before consideration can be given to approval of an application for permit to conduct operations. This plan shall contain the following:

(1) Provisions to assure that full resource capability is known and can be committed during an oil discharge situation including the identification and inventory of applicable equipment, materials, and supplies which are available locally and regionally, both committed and uncommitted, and the time required for deployment.

(2) Provisions for varying degrees of response effort depending on the severity of the oil discharge.

(3) Establishment of notification procedures for the purpose of early detection and timely notification of an oil discharge including a current list of names, telephone numbers, and addresses of the responsible persons and alternates on call to receive notification of an oil discharge, as well as the names, telephone numbers, and addresses of regulatory organizations and agencies to be notified when an oil discharge is discovered.

(4) Provisions for well defined and specific actions to be taken after discovery and notification of an oil discharge including:

(a) Specification of an oil discharge response operating team consisting of trained, prepared, and available operating personnel.

(b) Predesignation of an oil discharge response coordinator who is charged with the responsibility and delegated commensurate authority for directing and coordinating response operations.

(c) A preplanned location for an oil discharge response operations center and a reliable communications system for directing the coordinated overall response operation.

4. *Spill Control and Removal.* Immediate corrective action shall be taken in all cases where pollution has occurred. Corrective action taken under the Oil Spill Contingency Plan shall be subject to modification when directed by the Area Supervisor. The primary jurisdiction to require corrective action to abate the source of pollution and to enforce the subsequent cleanup by the lessee or operator shall remain with the Area Supervisor pursuant to the provisions of this Order and the memorandum of understanding between the Department of Transportation (U.S. Coast Guard) and the Department of the Interior (U.S. Geological Survey) dated August 16, 1971.

5. *Annual Contingency Plan Assessment.* Annual contingency plan assessments will be conducted in conjunction with the Plan of Development review. Upon request of the Area Supervisor, revised contingency plans reflecting changes in personnel, equipment, and methods shall be submitted.

D.W. Solanas

D. W. Solanas
Oil and Gas Supervisor
Field Operations
Gulf of Mexico Area

APPROVED:

Russell G. Wayland

Russell G. Wayland
Acting Chief, Conservation Division

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION
GULF OF MEXICO AREA

OCS ORDER NO. 8

Effective October 1, 1976

PLATFORMS, STRUCTURES, AND ASSOCIATED EQUIPMENT

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.19(a). Section 250.19(a) provides as follows:

> "(a) The supervisor is authorized to approve the design, other features, and plan of installation of all platforms, fixed structures, and artificial islands as a condition of the granting of a right of use or easement under Paragraphs (a) and (b) of Section 250.18 or authorized under any lease issued or maintained under the act. ... ."

The operator shall be responsible for compliance with the requirements of this Order in the installation and operation of all platforms and structures, including all facilities installed on a platform or structure, whether or not operated or owned by the operator. All departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b). All applications for approval under the provisions of this Order shall be submitted to the appropriate District Supervisor. References in this Order to approvals, determinations, or requirements are to those given or made by the Area Oil and Gas Supervisor or his delegated representative.

Following approval of applications, installations and operations shall be performed as approved. If deemed advisable, significant changes to approved applications may be proposed; however, approval of such proposals shall be required prior to implementation. For the purposes of compliance with this paragraph, a significant change is any structural change which materially alters the original plan or any major deviation from operations as originally approved. Any question as to whether a change is significant enough to require approval shall be referred to the USGS. An operator assumes the risk for making changes without approval if he fails to contact the USGS to determine whether a permit is necessary.

The following requirements are applicable to all platforms and structures approved and installed subsequent to the effective date of the Order. When structural or equipment modifications to existing platforms and structures are proposed, only requirements relevant to the modifications shall be applicable.

1. Platform Design.

A. General Design. A platform or structure shall be designed for safe installation and operation for its intended use and service life at a specific site. Steel structures shall be designed in accordance with those provisions of API RP 2A, "Planning, Designing and Constructing Fixed Offshore Platforms," Seventh Edition, January 1976, or subsequent revisions as approved by the Area Supervisor. The design of structures other than steel shall be evaluated on an individual basis. Consideration shall be given to conditions which may contribute to structural damage such as:

(1) Wind, wave, and current forces and other environmental loading forces.

(2) Functional loading conditions including the weight of the structure and all permanently fixed equipment, and the effects of static and dynamic functional load conditions during installation and the design operational service period.

(3) Water depth, bottom topography, surface and subsurface soil conditions, slope stability, scour conditions, and other pertinent geologic conditions based on information from on-site investigations.

2. Application. Prior to installation of a fixed platform or structure, the operator shall submit for approval, in duplicate, an application showing essential features of the platform or structure and supporting design information as follows:

A. General Information.

(1) Identification data, which shall include the platform or structure designation, lease number, area name, block number, and operator.

(2) Location data, including plat showing the distance from the nearest two block lines.

(3) *Primary use and other intended functions, including planned drilling, production, and storage operations.*

(4) *Personnel facilities, personnel access to living quarters, boat landings, and heliports.*

(5) *Drawings and plats to clearly illustrate essential parts, including number and location of well slots, water depth, nominal size and thickness of jacket and deck column legs, nominal size, thickness, and design penetration of piling.*

(6) *A description of the method of corrosion protection.*

B. *Environmental Information.*

(1) *List of pertinent environmental data which have a bearing on the installation, operation, or design of the platform or structure, including wave height, current, wind velocity, water depth, storm and astronomical tide data, and factors considered in subparagraph 1.A.(3).*

(2) *Listing of total design functional loads and wind, wave, and current forces for the following approaches: longitudinal, transverse, and diagonal.*

C. *Foundation.*

(1) *A listing of on-site investigations and tests, and a basic summary of resultant determinations.*

(2) *A description of foundation loads for environmental and functional forces listed in subparagraphs 2.B(1) and (2).*

(3) *In areas susceptible to soil movement, an analysis of slope and soil stability in relation to the foundation design loads.*

D. *Installation. A statement shall be submitted to the effect that the installation recommendations contained in API RP 2A, January 1976, or approved revisions, were adopted; or that significant deviations from the recommendations of API RP 2A were adopted and are herewith submitted for approval.*

E. Exception to Supporting Design Information Submittal.

The following information shall be developed and utilized in platform design; however, submittal with the installation application is not required. This information shall be made available to the appropriate District Supervisor upon his request.

(1) A description of the critical design loading and design criteria, taking into consideration maximum environmental and operational loading conditions expected over the service life of the platform or structure. This shall include those conditions considered under subparagraphs 1.A(1), (2), and (3) above.

(2) For steel structures, a description of the materials, specifications, strength analyses, and allowable stresses over the service life.

The recommendations of API publications API RP 2A, "Planning, Designing, and Constructing Fixed Offshore Platforms," January 1976, are acceptable practice concerning subparagraphs (1) and (2) above.

(3) For concrete structures, a description of the materials, specification, and strength and serviceability requirements and analyses of the reinforcing systems.

3. Certification.

A. Detailed structural plans certified by a registered professional structural engineer shall be on file and maintained by the operator or his designee.

B. The following certifications, signed and dated by a company representative, shall accompany the application:

(1) "_____(Operator)_____ certifies that this platform has been certified by a registered professional structural engineer and the structure will be constructed, operated, and maintained as described in the application and any approved modification thereto. Certified Plans are on file at ______________________."

(2) *Certification that the mechanical and electrical systems of the facility will be designed and installed under the supervision of appropriate registered professional engineers. Maintenance of these systems shall be by qualified personnel.*

4. *Design, Installation, and Operational Features of Production Facilities.*

A. *All production facilities, including separators, treaters, compressors, headers, and flowlines, shall be designed, installed, and maintained in a manner which will facilitate efficient, safe, and pollution-free operation.*

B. *As soon as practicable, but not later than six months after the effective date of this Order, new platform production facilities shall be protected with a basic and ancillary surface safety system designed, analyzed, installed, tested, and maintained in operating condition in accordance with the provisions of API RP 14C "Analysis, Design, Installation, and Testing of Basic Surface Safety Systems on Offshore Production Platforms," June 1974, as amended November 1975, except Section A9, Pipelines, or subsequent revisions as approved by the Area Supervisor, and the additional requirements of this Order. For this application, the word "should" contained in API RP 14C shall be read "shall" except for those contained in explanatory statements, paragraphs 3.4(c), page 11 and 4.3(4)(a)-(f). In the event that processing components are to be utilized other than those for which Safety Analysis Tables (SAT's) and Safety Analysis Checklists (SAC's) are included in API RP 14C, the analysis technique and documentation specified therein shall be utilized to determine the effects and requirements of such components upon the safety system.*

Operators may utilize the alternate methods contained in API RP 14C during Safety Systems Design; however, the method selected and depicted on the schematic flow diagram and Safety Analysis Function Evaluation (SAFE) Chart are subject to approval by the appropriate District Supervisor.

C. *Prior to installation, the operator shall submit for approval, to the appropriate District Supervisor, in duplicate, information relative to design and installation features, as* *indicated in subparagraphs (1) through (6) below. This information shall also be maintained at the operator's onshore field engineering office.*

(1) *A flow schematic showing size, capacity, and design working pressure of separators, treaters, storage tanks, compressors, pipeline pumps, and metering devices.*

(2) *A schematic flow diagram (Reference API RP 14C, Example Figure E1, page 79) and the related Safety Analysis Function Evaluation (SAFE) Chart (Reference API RP 14C, paragraph 4.3(C). These shall be developed with consideration of the provisions of API RP 14C and the additional requirements of this Order.*

(3) *A schematic piping diagram showing the size and design working pressure with reference to welding specification(s) or code(s) used. The recommendations contained in API RP 14E, "Design and Installation of Offshore Production Platform Piping Systems" are acceptable for platform piping systems.*

(4) *A diagram of the fire-fighting system.*

(5) *Electrical system information including the following:*

(a) *Plan view of each platform deck outlining any nonrestricted area; i.e., areas which are unclassified with respect to electrical equipment installations, and areas in which potential ignition sources, other than electrical, are to be installed. The area outline should include the following information:*

(i) *Any surrounding production or other hydrocarbon source and a description of deck, overhead, and firewall.*

(ii) *Location of generators, control rooms, panel boards, major cabling - conduit routes and identification of wiring method.*

(b) *Elementary electrical schematic of any platform safety-shutdown system with functional legend.*

(6) *An application for the installation and maintenance of all gas detection systems. The application shall include the following:*

(a) *Type, location, and number of detection heads.*

(b) *Type and kind of alarm, including emergency equipment to be activated.*

(c) *Method used for detection of combustible gases.*

(d) *Method and frequency of calibration.*

(e) *Name of organization to perform system inspection and calibration.*

(f) *A functional block diagram of the gas detection system, including the electric power supply.*

(g) *Other pertinent information.*

D. *Additional Safety and Pollution Control Requirements. The following requirements modify, or are in addition to, those contained in API RP 14C. For platforms installed after the effective date of this Order, compliance is required as soon as practicable, but not later than six months after the effective date. Operators of facilities installed prior to the effective date of this Order shall comply with these requirements at the earliest practicable date, but not later than one year from the effective date, unless otherwise specified herein.*

(1) *Design and Installation.*

(a) *Pressure Vessels*

(i) *Pressure relief valves shall be designed, installed, and maintained in accordance with applicable provisions of Sections I, IV, and VIII of the ASME Boiler and Pressure Vessel Code, July 1, 1974. All relief valves and vents shall be piped in such a way as to minimize the possibility of fluid striking personnel or ignition sources.*

(ii) *Steam generators shall be equipped with low-water-level controls in accordance with applicable provisions of Sections I and IV of the ASME Boiler and Pressure Vessel Code, July 1, 1974.*

(iii) *All relief valves shall conform to the appropriate sizing and relieving requirements of ASME Boiler and Pressure Vessel Codes, July 1, 1974, Sections I, IV, and VIII. The high-pressure shut-in sensor shall activate sufficiently below the design working pressure to positively insure operation before the relief valve starts relieving. The low-pressure shut-in sensor shall activate no lower than 15 percent or 35 kilopascals (k Pa) (5 psi), whichever is greater below the lowest pressure in the operating range.*

(iv) *Pressure sensors may be of the automatic or nonautomatic reset type, but where the automatic reset types are used, a nonautomatic reset relay shall be installed. All pressure sensors shall be equipped to permit testing with an external pressure source.*

(v) *All pressure or fired vessels used in the production of oil or gas, installed after the effective date of this Order, shall conform to the requirements stipulated in the edition of the ASME Boiler and Pressure Vessel Code, Sections I, IV, and VIII, as appropriate, in effect at the time the vessel is installed. Uncoded vessels now in use shall have been hydrostatically tested to a pressure 1.5 times their working pressure. The test date, test pressure, and working pressure shall, within six months after the effective date of this Order, be marked on the vessel in a prominent place. A record of the test shall be maintained by the operator.*

(b) *Flowlines*

(i) *All flowlines from wells shall be equipped with high- and low-pressure shut-in sensors located downstream of the well choke. If there are more than 3 meters (10 feet) of line between the wellhead wing valve and the primary choke, an additional low-pressure shut-in sensor shall be installed in this section. The high-pressure shut-in sensor shall be set no higher than 10 percent above the highest operating pressure of the line, but in all cases, it shall be set sufficiently below the maximum shut-in pressure of the well or the gas-lift supply pressure to assure actuation of the surface safety valve. The low-pressure shut-in sensor shall be set no lower than 10 percent or 35 K Pa (5 psi), whichever is greater, below the lowest operating pressure of the line in which it is installed.*

(ii) *In the event a well flows directly to the pipeline before separation, the flowline and valves from the well located upstream of, and including, the header inlet valve(s), shall be able to withstand the maximum shut-in pressure of the well, unless 1: protected by a relief valve connected to either the platform flare scrubber or some other approved location other than into the departing pipeline, or 2: the flowline is equipped with an additional automatic shut-down valve controlled by an independent high-pressure sensor. The platform flare scrubber shall be designed to handle, without liquid hydrocarbon carryover to flare, the maximum anticipated flow of liquid hydrocarbons which may be relieved to the vessel.*

(c) *Remote Shut-in Systems*

(i) *Remote shut-in controls shall be quick-opening valves, except those on the boat landing(s), which may be a plastic loop of the control pressure line.*

(d) *Engine Exhausts*

(i) *Engine exhausts shall be equipped to comply with the insulation and personnel protection requirements of API RP 14C, Section 4.2.c.(4). Exhaust piping from diesel engines shall be equipped with spark arrestors.*

(e) *Glycol Dehydration Units*

(i) *A pressure relief valve shall be installed on the glycol reboiler, or at a location approved by the District Supervisor, which will prevent overpressurization of all glycol dehydration units. The set pressure of this valve shall be determined by the operator and approved by the District Supervisor. The discharge of the relief valve must be vented in a nonhazardous manner.*

(f) *Compressors*

(i) *Each compressor installation, existing as of the effective date of this Order shall be protected by high-liquid-level shut-in controls and a pressure relief valve on each interstage scrubber. High-temperature shutdown controls shall be installed on the compressor cylinders unless interstage scrubbers are protected by high- and low-pressure shut-in controls. Compliance is required as soon as practical, but no later than six months after the effective date of this Order.*

All compressor installations installed after the effective date of this Order shall be protected by high- and low-pressure and high-liquid-level shut-in controls and a pressure relief valve on each interstage scrubber.

All compressor interstage scrubbers shall be protected by low-liquid-level shut-in controls unless dump is through a choke restriction to another pressure vessel.

(ii) *In addition to the provisions of API RP 14C, paragraphs A8.3a and A8.3d, high- and low-pressure shut-in sensors and low-liquid-level shut-in controls protecting compressor suction and discharge piping and associated suction and interstage scrubbers shall be designed to actuate automatic isolation valves located in each compressor suction and fuel gas line so that the compressor unit and associated vessels can be isolated from all input sources.*

As an alternative, low-liquid-level shut-in control(s) installed in suction and interstage scrubber(s) may be designed to actuate automatic shutoff valve(s) installed in the scrubber dump line(s).

For compressors installed after the effective date of this Order, those compressor units installed in a building shall have the isolation valves located outside the building. Each suction and interstage high-liquid-level shut-in control shall, as a minimum, be designed to shut down the compressor prime mover.

(iii) *Compressor installations of 745 kilowatts (1,000 horsepower) or less are excluded from those requirements of API RP 14C, A8.3d which provide for installation of a blow-down valve on the discharge line.*

(iv) *Compressor installations existing prior to the effective date of this Order, and which are installed in a building, are excluded from the requirement of API RP 14C, A8.3b, Flow Safety Devices (FSV), and Section A8.3d, Shutdown Devices (SDV), which prescribes that these devices be located outside of the building.*

(v) *The automatic isolation valves installed in compressor suction and fuel gas piping shall also be actuated by shutdown of the prime mover.*

(g) Curbs, Gutters, and Drains.

(i) Curbs, gutters, and drains shall be installed in all deck areas in a manner necessary to collect all contaminants, unless drip pans or equivalent are placed under equipment and piped to a sump which will automatically maintain the oil at a level sufficient to prevent discharge of oil into Gulf waters. Sump piles shall not be used as a processing device to treat or skim liquids but shall be used to collect treated produced water, treated sand, liquids from drip pans and deck drains, and as a final trap for hydrocarbon liquids in event of equipment upsets.

(h) Fire-fighting Systems

(i) A fire-fighting water system of rigid pipe with fire hose stations shall be installed and may include a fixed water-spray system. Such a system shall be installed in a manner necessary to provide needed protection in areas where production-handling equipment is located. A fire-fighting system using chemicals may be used in lieu of a water system if determined to provide equivalent fire protection control.

An alternate fuel or power source shall be installed to provide continued pump operation for the system during platform shutdown, unless an alternate fire-fighting system is provided.

Portable fire extinguishers shall be located in the living quarters and other strategic areas.

A diagram of the fire-fighting system showing the location of all equipment shall be posted in a prominent place on the platform or structure.

(i) Gas Detection System

(i) A diagram of the gas detection system showing the location of all gas detection points shall be posted in a prominent place on the platform or structure.

(ii) All gas detection systems shall be capable of continuously monitoring for the presence of combustible gas in the areas in which the detection devices are located. The gas detector power supply shall be from a continually energized power source.

(iii) The use of fuel gas odorant is an acceptable alternate to an automatic gas detection and alarm system in enclosed, continuously manned areas of the facility.

(j) Electrical Equipment. The following requirements shall be applicable to all electrical equipment and systems installed:

(i) All engines with ignition systems shall be equipped with a low-tension ignition system of a low-fire-hazard type and shall be designed and maintained to minimize release of sufficient electrical energy to cause ignition of an external, combustible mixture.

(ii) All electrical generators, motors, and lighting systems shall be installed, protected, and maintained in accordance with the edition of the National Electrical Code and API RP 500 B in effect at the time of installation.

(iii) Wiring methods which conform to the National Electrical Code or to IEEE 45, "Recommended Practice for Electric Installations on Shipboard," in effect at the time of installation, are acceptable.

(iv) An auxiliary power supply shall be installed to provide emergency power capable of operating all electrical equipment required to maintain

safety of operations in the event
of a failure in the primary
electrical power supply.

(k) Erosion. A program of erosion control shall be in effect for wells having a history of sand production. The erosion control program may include sand probes, X-ray, ultrasonic, or other satisfactory monitoring methods. An annual report, by lease, on the results of the program shall be submitted by the first of September to the appropriate District Supervisor.

(2) Operations.

(a) Any device on wells, vessels, or flowlines temporarily out of service shall be flagged. Safety devices and systems on wells which are capable of producing shall not be bypassed or blocked out of service unless necessary during startup or maintenance operations and then only with personnel on duty aboard the platform.

(b) When wells are disconnected from producing facilities and blind flanged or equipped with a tubing plug, compliance is not required with provisions of API RP 14C and of this Order concerning (a) installation of automatic fail-close surface safety valves on wellhead assemblies, (b) installation of high- and low-pressure shut-in sensors downstream of the well choke in flowlines from wells, and (c) installation of check valves in header individual flowlines.

All open-ended lines connected to producing facilities shall be plugged or blind-flanged, except those lines designed to be open-ended, such as flare or vent lines.

(c) Simultaneous Operations. Prior to conducting activities, simultaneously with production operations, which could increase the possibility of occurrence of undesirable events such as harm to personnel or to the environment, or damage to equipment, an operator's Contingency Plan shall be filed for approval with the *appropriate District Supervisor. The plan shall be filed within 90 days after the effective date of this Order. A plan shall be submitted by each lessee/operator for each platform existing as of the effective date of this Order. The plan shall be modified and updated as appropriate. Activities requiring the plan are drilling, workover, wireline, and major construction operations. The plan shall include:*

(i) A narrative description of operations.

(ii) A plan view of each platform deck indicating critical areas of simultaneous activities.

(iii) Procedures for mitigation of potential undesirable events including:

(a) The guidelines the operator will follow to assure coordination and control of simultaneous activities.

(b) Indication as to the person having overall responsibility, as person in charge at the site, for safety of platform operations.

(c) An outline of any additional safety measures that are required for simultaneous operations.

(d) Specification of any added or special equipment or procedural conditions imposed when simultaneous activities are in progress.

(d) <u>Welding Practices and Procedures</u>. The following requirements shall apply to all platforms and structures, including mobile drilling and workover structures. These requirements shall apply to fixed structures after the drilling out of the drive or structural casing for the first well drilled on the structure, entry into a well to be tied back to the structure, or first flow of combustible fluids to the structure. The period of time during which these requirements are considered applicable to mobile drilling structures

is the interval from the drilling out of the drive or structural casing until the blowout-preventer stack and riser are pulled in the final abandonment, suspension, or completion. These requirements shall apply to workover rigs when such rigs are performing remedial work on any wells open to hydrocarbon-bearing zones.

For the purpose of this Order, the term "welding and burning" is defined to include arc or acetylene cutting and arc or acetylene welding.

Each operator shall file for approval by the appropriate District Supervisor a Welding and Burning Safe Practices and Procedures Plan. The plan shall be filed within 90 days after the effective date of this Order and shall include company qualification standards or requirements for personnel and the methods by which the operator will assure that only personnel meeting such standards or requirements are utilized. A copy of this plan shall be available in the field. Any person designated as a welding supervisor shall be thoroughly familiar with this plan.

Prior to welding or burning operations, the operator shall establish approved safe welding areas. Such areas shall be constructed of noncombustible or fire-resistant materials free of combustible or flammable contents and be suitably segregated from adjacent areas. National Fire Protection Association Bulletin No. 51B, "Cutting and Welding Processes," 1971, shall be used as a guide to designate these areas. All welding which cannot be done in the approved safe welding area shall be performed in compliance with the procedures outlined below:

(i) Such welding and burning as are necessary on a structure shall adhere to the following practices:

(a) Prior to the commencement of any welding or burning operations on a structure, the operator's designated person-in-charge at the installation

shall personally inspect the qualifications of the welder or welders to assure that they are properly qualified in accordance with the approved company qualification standards or requirements for welders. The designated person-in-charge and welders shall personally inspect the area in which the work is to be performed for potential fire and explosion hazards. After it has been determined that it is safe to proceed with the welding or burning operation, the designated person-in-charge shall issue a written authorization for the work.

(b) *All welding equipment shall be inspected prior to beginning any welding or burning. Welding machines located on production or process platforms shall be equipped with spark arrestors and drip pans. Welding leads shall be completely isulated and in good condition; oxygen and acetylene bottles secured in a safe place; and hoses leak-free and equipped with proper fittings, gauges, and regulators.*

(c) *During all welding and burning operations, one or more persons as necessary shall be designated as a Fire Watch. Persons assigned as a Fire Watch shall have no other duties while actual welding or burning operations are in progress.*

(d) *Prior to any welding or burning, the Fire Watch shall have in his possession fire-fighting equipment in a condition ready to use.*

(e) *No welding shall be done on containers, tanks, or other vessels which have contained a flammable substance unless the contents of the vessels have been* rendered inert and determined to be safe for welding or burning by the designated person-in-charge.

(f) In the event drilling, workover, or wireline operations are in progress on the platform, welding operations in other than approved safe welding areas may be conducted only if the well(s) on which work is being done contain noncombustible fluids, and entry of formation hydrocarbons into the wellbore is precluded by a positive overbalance toward the formation. Also, all other provisions of this section shall be applicable.

(g) All other producible wells shall be shut-in at the surface safety valves while welding or burning in the wellhead or production area.

(3) Safety Device Testing. The safety system devices required by this Order shall be tested by the operator at the interval specified below or more frequently if operating conditions warrant. Records shall be maintained at the field office for a period of one year, showing the present status and history of each device, including dates and details of inspection, testing, repairing, adjustment, and reinstallation. Such records shall be available to any authorized representative of the Geological Survey. Records shall be analyzed, equipment or system problem areas identified, and action taken to preclude recurrence of these problems.

Testing and reporting shall be accomplished in accordance with API RP 14C, Appendix D, and the following:

(a) All pressure relief valves shall be tested for operation annually. Pressure relief valves shall *be either bench-tested or equipped to permit testing with an external pressure source.*

(b) *All pressure sensors shall be tested at least once each calendar month, but at no time shall more than six weeks elapse between tests.*

(c) *All automatic wellhead safety devices and check valves on all flowlines shall be checked for operation and holding pressure once each calencar month, but at no time shall more than six weeks elapse between tests. If any wellhead safety valve indicates leakage, it shall be repaired or replaced.*

(d) *All liquid-level shut-in controls shall be tested at least once within each calendar month, but at no time shall more than six weeks elapse between tests. These tests shall be conducted by raising or lowering the liquid level across the level-control detector.*

(e) *All automatic inlet shutoff valves actuated by a sensor on a vessel or a compressor shall be tested for operation at least once within each calendar month, but at no time shall more than six weeks elapse between tests.*

(f) *All automatic shutoff valves located in liquid discharge lines and actuated by vessel low-level sensors shall be tested for operation once within each calendar month, but at no time shall more than six weeks elapse between tests.*

(g) *The high-temperature shutdown controls installed in all compressors which are protected against abnormal pressures solely by such temperature safety devices shall be tested annually and repaired or replaced as necessary.*

(h) *All pumps for fire-fighting water systems shall be inspected and test-operated weekly. A record of the tests shall be maintained at the field office for a period of one year.*

(i) *The Automatic Gas Detection System shall be tested for operation and recalibrated every six months.*

(4) *Training. Not later than two years after the effective date of this Order, the operator shall ensure that all personnel engaged in installing, inspecting, testing, and routinely maintaining these safety devices will have been qualified under a program as recommended by API RP T-2, September 1974, amended October 1975, or subsequent revisions approved by the Area Supervisor, or an equivalent program, approved by the Area Supervisor. Documented evidence of qualification of individuals performing these functions shall be maintained at the field headquarters and shall be available to any authorized representative of the Geological Survey.*

Manufacturers' representatives may work on component equipment supplied by their company, provided they are directly supervised by a qualified person, capable of evaluating the impact of the work on the total system. On-the-job trainees working with safety devices shall be directly supervised by a qualified person.

Not later than one year after the effective date of this Order, the operator shall submit, for approval, of the appropriate District Supervisor, a description of the training to be conducted and the methods the operator will utilize to ensure that only persons qualified as above perform these functions. The description shall include:

(a) *The operator's organizational element responsible for training and to coordinate with the Geological Survey in training program matters.*

(b) *Categories of personnel to be qualified.*

(c) *Training organizations and courses to be utilized.*

(d) *Method for ensuring qualification of third-party personnel, if utilized.*

(e) *Method for determining when additional training or requalification is required and for obtaining same.*

(f) *Method of monitoring operations to ensure that only qualified personnel perform functions.*

(g) *Method of maintaining documented evidence of qualification at work site.*

5. *Crane Operations.*

Cranes shall be operated and maintained in a manner necessary to ensure the safety of facility operations in accordance with the provisions of API RP 2D, "Operation and Maintenance of Offshore Cranes," October 1972, or other revisions approved by the Area Supervisor.

Records of inspection, testing, and maintenance shall be kept in the field office for a period of one year.
API Specification 2C, "Specification for Offshore Cranes," February 1972, or other revisions approved by the Area Supervisor, shall be used as a guideline for the selection of cranes to be used offshore.

6. *Employee Orientation and Motivation Programs for Personnel Working Offshore.*

The operator shall make a planned, continuing effort to eliminate accidents due to human error. This effort shall include the training of personnel in operational aspects of their functions and a program to instill in each individual working offshore a conscious desire to achieve safe and pollution-free operations. Minimum training of personnel going offshore for the first time shall include an orientation in accordance with API RP T-1, "Orientation Program for Personnel Going Offshore the First Time," January 1974, or equivalent. API Bulletin T-5, "Employee Motivation Programs for Safety and Prevention of Pollution in Offshore Operations," September 1974, shall be used as a guide in developing employee safety and pollution-prevention motivation programs. The applicability of any future revisions of the above API documents shall require approval by the Area Supervisor.

7. *Requirements for Drilling Rigs*.

The requirements of subparagraphs 4.D.(1)(g), 4.D(1)(j), 4.D.(2)(d), and paragraphs 5 and 6 above shall apply to all drilling rigs and mobile drilling units used to conduct drilling or workover operations on the Federal OCS in the Gulf of Mexico.

D.W Solanas

D. W. Solanas
Oil and Gas Supervisor
Field Operations
Gulf of Mexico Area

APPROVED:

Russell G. Wayland

Russell G. Wayland
Acting Chief, Conservation Division

UNITED STATES DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION
GULF OF MEXICO OCS OPERATIONS

76-6 October 21, 1976

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, GULF OF MEXICO AREA

Revision of Section 4.D(4), Training, page 8-20, OCS Order No. 8, Gulf of Mexico Area, effective October 1, 1976.

The third paragraph of this section is hereby revised as follows:

> "Not later than one year after the effective date of this Order, the operator shall submit, for approval, of the Area Supervisor, a description of the training to be conducted and the methods the operator will utilize to ensure that only persons qualified as above perform these functions. The description shall include:"

D. W. Solanas

D. W. Solanas
Oil and Gas Supervisor
Field Operations
Gulf of Mexico Area

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION
GULF OF MEXICO AREA

OCS ORDER NO. 9
Effective October 30, 1970

OIL AND GAS PIPELINES

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.19(b). Section 250.19(b) provides as follows:

> (b) The Supervisor is authorized to approve the design, other features, and plan of installation of all pipelines for which a right of use or easement has been granted under Paragraph (c) of Section 250.18 or authorized under any lease issued or maintained under the Act, including those portions of such lines which extend onto or traverse areas other than the Outer Continental Shelf.

The operator shall comply with the following requirements. Any departures from the requirements specified in this Order must be approved pursuant to 30 CFR 250.12(b).

1. General Design. All pipelines shall be designed and maintained in accordance with the following:

   A. The operator shall be responsible for the installation of the following control devices on all oil and gas pipelines connected to a platform including pipelines which are not operated or owned by the operator. Operators of platforms installed prior to the effective date of this Order shall comply with the requirements of subparagraphs (1) and (2) within six months of the effective date of this Order. The operator shall submit records semi-annually showing the present status and past history of each device, including dates and details of inspection, testing, repairing, adjustment, and reinstallation.

      (1) All oil and gas pipelines leaving a platform receiving production from the platform shall be equipped with a high-low pressure sensor to directly or indirectly shut-in the wells on the platform.

(2) (a) All oil and gas pipelines delivering production to production facilities on a platform shall be equipped with an automatic shut-in valve connected to the platform's automatic and remote shut-in system.

(b) All oil and gas pipelines coming onto a platform shall be equipped with a check valve to avoid backflow.

(c) Any oil or gas pipelines crossing a platform which do not deliver production to the platform, but which may or may not receive production from the platform, shall be equippped with high-low pressure sensors to activate an automatic shut-in valve to be located in the upstream portion of the pipeline at the platform. This automatic shut-in valve shall be connected to either the platform automatic and remote shut-in system or to an independent remote shut-in system.

(d) All pipeline pumps shall be equippped with high-low pressure shut-in devices.

B. All pipelines shall be protected from loss of metal by corrosion that would endanger the strength and safety of the lines either by providing extra metal for corrosion allowance, or by some means of preventing loss of metal such as protective coatings or cathodic protection.

C. All pipelines shall be installed and maintained to be compatible with trawling operations and other uses.

D. All pipelines shall be hydrostatically tested to 1.25 times the designed working pressure for a minimum of 2 hours prior to placing the line in service.

E. All pipelines shall be maintained in good operating condition at all times and inspected monthly for indication of leakage using aircraft, floating equipment, or other methods. Records of these inspections including the date, methods, and results of each inspection shall be maintained by the pipeline operator and submitted annually by April 1. The pipeline operator shall submit records indicating the cause, effect, and remedial action taken regarding all pipeline leaks within one week following each such occurrence.

F. All pipelines shall be designed to be protected against water currents, storm scouring, soft bottoms, and other environmental factors.

2. *Application*. *The operator shall submit in duplicate the following to the Supervisor for approval:*

A. Drawing on 8" x 10½" plat or plats showing the major features and other pertinent data including: (1) water depth, (2) route, (3) location, (4) length, (5) connecting facilities, (6) size, and (7), burial depth, if buried.

B. A schematic drawing showing the following pipeline safety equipment and the manner in which the equipment functions: (1) high-low pressure sensors, (2) automatic shut-in valves, and (3) check valves.

C. General information concerning the pipeline including the following:

(1) Product or products to be transported by the pipeline.

(2) Size, weight, and grade of the pipe.

(3) Length of line.

(4) Maximum water depth.

(5) Type or types of corrosion protection.

(6) Description of protective coating.

(7) Bulk specific gravity of line (with the line empty).

(8) Anticipated gravity or density of the product or products.

(9) Design working pressure and capacity.

(10) Maximum working pressure and capacity.

(11) Hydrostatic pressure and hold time to which the line will be tested after installation.

(12) Size and location of pumps and prime movers.

(13) Any other pertinent information as the Supervisor may prescribe.

3. *Completion Report.* *The operator shall notify the Supervisor when installation of the pipeline is completed and submit a drawing on 8" x 10½" plats showing the location of the line as installed, accompanied by all hydrostatic test data including procedure, test pressure, hold time, and results.*

Robert F. Evans
Robert F. Evans
Supervisor

Approved: October 30, 1970

Russell G. Wayland
Russell G. Wayland
Chief, Conservation Division

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION
GULF OF MEXICO AREA

OCS ORDER NO. 10
Effective August 28, 1969

SULPHUR DRILLING PROCEDURES

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.34, 250.41, and 250.91. All exploratory core holes for sulphur and all sulphur development wells shall be drilled in accordance with the provisions of this Order, except that development wells shall be drilled in accordance with field rules when established by the supervisor. Each Application to Drill (Form 9-331C) shall include all information required under 30 CFR 250.91 and the integrated casing, cementing, mud, and blowout prevention program for the well. The operator shall comply with the following requirements. Any departures from the requirements specified in this Order must be approved pursuant to 30 CFR 250.12(b).

1. Well Casing and Cementing. All wells shall be cased and cemented in accordance with the requirements of 30 CFR 250.41(a)(1). Special consideration to casing design shall be given to compensate for effects caused by subsidence, corrosion, and temperature variation. All depths refer to true vertical depth (TVD).

   A. Drive or Structural Casing. This casing shall be set by drilling, driving, or jetting to a minimum depth of 100 feet below the Gulf floor, or to such greater depth required to support unconsolidated deposits and to provide hole stability for initial drilling operations. If drilled in, the drilling fluid shall be a type that will not pollute the Gulf, and a quantity of cement sufficient to fill the annular space back to the Gulf floor must be used.

   B. Conductor Casing. This casing shall be set and cemented before drilling into shallow formations known to contain hydrocarbons or, if unknown, upon encountering such formations. Conductor casing shall extend to a depth of not less than 350 feet nor more than 750 feet below the Gulf floor. A quantity of cement sufficient to fill the annular space back to the Gulf floor must be used. The cement may be washed out or displaced to a depth of 40 feet below the Gulf floor to facilitate casing removal upon well abandonment.

C. *Caprock Casing*. This casing shall be set at the top of the caprock and be cemented with a quantity of cement sufficient to fill the annular space back to the Gulf floor. Stage cementing or other cementing method shall be used to insure cement returns to the Gulf floor.

2. *Blowout Prevention Equipment*. Blowout preventers and related well control equipment shall be installed, used, and tested in a manner necessary to prevent blowouts. Prior to drilling below the conductor casing, blowout prevention equipment shall be installed and maintained ready for use until drilling operations are completed, as follows:

   A. *Conductor Casing*. Before drilling below this string, at least one remotely controlled bag-type blowout preventer and equipment for circulating the drilling fluid to the drilling structure or vessel shall be installed. To avoid formation fracturing from complete shut-in of the well, a large diameter pipe with control valves shall be installed on the conductor casing below the blowout preventer so as to permit the diversion of hydrocarbons and other fluids; except that when the blowout preventer assembly is on the Gulf floor, the choke and kill lines shall be equipped to permit the diversion of hydrocarbons and other fluids.

   B. *Caprock Casing*. Before drilling below this string, the blowout prevention equipment shall include a minimum of: (1) three remotely controlled, hydraulically operated, blowout preventers with a working pressure which exceeds the maximum anticipated surface pressure, including one equipped with pipe rams, one with blind rams, and one bag-type; (2) a drilling spool with side outlets, if side outlets are not provided in the blowout preventer body; (3) a choke manifold; (4) a kill line; and (5) a fill-up line.

   C. *Testing*. Ram-type blowout preventers and related control equipment shall be tested with water to the rated working pressure of the stack assembly, or to the working pressure of the casing, whichever is the lesser, (1) when installed; (2) before drilling out after each string of casing is set; (3) not less than once each week while drilling; and (4) following repairs that require disconnecting a pressure seal in the assembly. The bag-type blowout preventer shall be tested to 70 percent of the above pressure requirements.

   While drill pipe is in use ram-type blowout preventers shall be actuated to test proper functioning once each day. The bag-type blowout preventer shall be actuated on the drill pipe once each week. Accumulators or accumulators and pumps shall maintain a pressure capacity reserve at all times to provide for repeated operation of hydraulic preventers. A blowout prevention drill shall be conducted weekly for each drilling crew to insure that all equipment is operational and that crews are properly trained to carry out emergency duties. All blowout preventer tests and crew drills shall be recorded on the driller's log.

D. Other Equipment. A drill string safety valve in the open position shall be maintained on the rig floor at all times while drilling operations are being conducted. Separate valves shall be maintained on the rig floor to fit all pipe in the drill string. A Kelly cock shall be installed below the swivel.

3. Mud Program - General. The characteristics, use, and testing of drilling mud and the conduct of related drilling procedures shall be such as are necessary to prevent the blowout of any well. Quantities of mud materials sufficient to insure well control shall be maintained readily accessible for use at all times. The following mud control and testing equipment requirements are applicable to operations conducted prior to drilling below the caprock casing.

A. Mud Control. Before starting out of the hole with drill pipe, the mud shall be circulated with the drill pipe just off bottom until the mud is properly conditioned. When coming out of the hole with drill pipe, the annulus shall be filled with mud before the mud level drops below 100 feet, and a mechanical device for measuring the amount of mud required to fill the hole shall be utilized. The volume of mud required to fill the hole shall be watched, and any time there is an indication of swabbing, or influx of formation fluids, the drill pipe shall be run to bottom, and the mud properly conditioned. The mud shall not be circulated and conditioned except on or near bottom, unless well conditions prevent running the pipe to bottom.

B. Mud Testing and Equipment. Mud testing equipment shall be maintained on the drilling platform at all times, and mud tests shall be performed daily, or more frequently as conditions warrant.

The following mud system monitoring equipment must be installed (with derrick floor indicators) and used throughout the period of drilling after setting and cementing the cònductor casing:

(1) Recording mud pit level indicator to determine mud pit volume gains and losses. This indicator shall include a visual or audio warning device.

(2) Mud volume measuring device for accurately determining mud volumes required to fill the hole on trips.

(3) Mud return indicator to determine that returns essentially equal the pump discharge rate.

Robert F. Evans

Robert F. Evans
Supervisor

Approved: August 28, 1969

Russell G. Wayland

Russell G. Wayland
Chief, Conservation Division

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION
GULF OF MEXICO AREA

OCS ORDER NO. 11
Effective May 1, 1974

OIL AND GAS PRODUCTION RATES, PREVENTION OF WASTE, AND PROTECTION OF CORRELATIVE RIGHTS

This Order is established pursuant to the authority prescribed in 30 CFR 250.1, 30 CFR 250.11, and in accordance with all other applicable provisions of 30 CFR Part 250, and the notice appearing in the Federal Register, dated December 5, 1970 (35 F.R. 18559), to provide for the prevention of waste and conservation of the natural resources of the Outer Continental Shelf, and the protection of correlative rights therein. This Order shall be applicable to all oil and gas wells on Federal leases in the Outer Continental Shelf of the Gulf of Mexico; provided, however, that it shall not apply to oil and gas wells on a lease of which any part lies within the disputed area referred to in paragraph 4 of the Supplemental Decree of December 20, 1971, in United States vs. Louisiana, et al., 404 U.S. 388 (1971). All departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b). References in this Order to approvals, determinations, and requirements for submittal of information or applications for approval are to those granted, made, or required by the Oil and Gas Supervisor or his delegated representative.

1. Definition of Terms. As used in this Order, the following terms shall have the meanings indicated:

   A. Waste of Oil and Gas. The definition of waste appearing in 30 CFR 250.2(h) shall apply, and includes the failure to timely initiate enhanced recovery operations where such methods would result in an increased ultimate recovery of oil or gas under sound engineering and economic principles. Enhanced recovery operations refers to pressure maintenance operations, secondary and tertiary recovery, cycling, and similar recovery operations which alter the natural forces in a reservoir to increase the ultimate recovery of oil or gas.

   B. Correlative Rights. The opportunity afforded each lessee or operator to produce without waste his just and equitable share of oil and gas from a common source of supply.

C. *Maximum Efficient Rate (MER). The maximum sustainable daily oil or gas withdrawal rate from a reservoir which will permit economic development and depletion of that reservoir without detriment to ultimate recovery.*

D. *Maximum Production Rate (MPR). The approved maximum daily rate at which oil may be produced from a specified oil well completion or the maximum approved daily rate at which gas may be produced from a specified gas well completion.*

E. *Interested Party. The operators and lessees, as defined in 30 CFR 250.2(f) and (g), of the lease or leases involved in any proceeding initiated under this Order.*

F. *Reservoir. An oil or gas accumulation which is separated from and not in oil or gas communication with any other such accumulation.*

G. *Competitive Reservoir. A reservoir as defined herein containing one or more producible or producing well completions on each of two or more leases, or portions thereof, in which the lease or operating interests are not the same.*

H. *Property Line. A boundary dividing leases, or portions thereof, in which the lease or operating interest is not the same. The boundaries of Federally approved unit areas shall be considered property lines. The boundaries dividing leased and unleased acreage shall be considered property lines for the purpose of this Order.*

I. *Oil Reservoir. A reservoir that contains hydrocarbons predominantly in a liquid (single-phase) state.*

J. *Oil Well Completion. A well completed in an oil reservoir or in the oil accumulation of an oil reservoir with an associated gas cap.*

K. *Gas Reservoir. A reservoir that contains hydrocarbons predominantly in a gaseous (single-phase) state.*

L. *Gas Well Completion. A well completed in a gas reservoir or in the gas cap of an oil reservoir with an associated gas cap.*

M. *Oil Reservoir with an Associated Gas Cap. A reservoir that contains hydrocarbons in both a liquid and a gaseous state (two-phase).*

N. *Producible Well Completion. A well which is physically capable of production and which is shut in at the wellhead or at the* *surface, but not necessarily connected to production facilities, and from which the operator plans future production.*

2. *Classification of Reservoirs.*

   A. *Initial Classification. Each producing reservoir shall be classified by the operator, subject to approval by the Supervisor, as an oil reservoir, an oil reservoir with an associated gas cap, or a gas reservoir.*

      (1) The initial classification of each reservoir from which production is commenced subsequent to the date of this Order shall be submitted for approval with the initial submittal of MER data for the reservoir.

      (2) Each reservoir from which production commenced on or prior to the date of this Order shall be classified by the operator, based on existing reservoir conditions. Such classification shall be determined and submitted to the Supervisor within six (6) months of the date of this Order.

   B. *Reclassification. A reservoir may be reclassified by the Supervisor, on his own initiative or upon application of an operator, during its productive life when information becomes available showing that such reclassification is warranted.*

3. *Oil and Gas Production Rates.*

   A. *Maximum Efficient Rate (MER). The operator shall propose a maximum efficient rate (MER) for each producing reservoir based on sound engineering and economic principles. When approved at the proposed or other rate, such rate shall not be exceeded, except as provided in paragraph 4 of this Order.*

      (1) Submittal of Initial MER. Within 45 days after the date of first production or such longer period as may be approved, the operator shall submit a Request for Reservoir MER (Form 9-1866) with appropriate supporting information.

      (2) Revision of MER. The operator may request a revision of an MER by submitting the proposed revision to the Supervisor on a Request for Reservoir MER (Form 9-1866) with appropriate supporting information. The Operator shall obtain approval to produce at test rates which exceed an approved MER when such testing is necessary to substantiate an increase in the MER.

      (3) Review of MER. The MER for each reservoir will be reviewed by the operator annually, or at such other required or ap-

proved interval of time. The results of the review, with all current supporting information, shall be submitted on a Request for Reservoir MER (Form 9-1866).

(4) <u>Effective Date of MER</u>. The effective date of an MER, or revision thereof, will be determined by the Supervisor and shown on a Request for Reservoir MER (Form 9-1866) when the MER is approved. The effective date for an initial MER shall be the first day following the completion of an approved testing period. The effective date for a revised MER shall be the first day following the completion of an approved testing period, or if testing is not conducted, the date the revision is approved.

B. <u>Maximum Production Rate (MPR)</u>. The operator shall propose a maximum production rate (MPR) for each producing well completion in a reservoir together with full information on the method used in its determination. When an MPR has been approved for a well completion, that rate shall not be exceeded, except as provided in paragraph 4 of this Order. The MPR shall be based on well tests and any limitations imposed by (1) well tubing, safety equipment, artificial lift equipment, surface back pressure, and equipment capacity; (2) sand producing problems; (3) producing gas-oil and water-oil ratios; (4) relative structural position of the well with respect to gas-oil or water-oil contacts; (5) position of perforated interval within total production zone; and (6) prudent operating practices. The MPR established for each well completion shall not exceed 110 percent of the rate demonstrated by a well test unless justified by supporting information.

(1) <u>Submittal of Initial MPR</u>. The operator shall have 30 days from the date of first continuous production within which to conduct a potential test, as specified under subparagraphs 5.B and 6.B of this Order, on all new and reworked well completions. Within 15 days after the date of the potential test, the operator shall submit a proposed MPR for the individual well completion on a Request for Well Maximum Production Rate (MPR) (Form 9-1867), with the results of the potential test on a Well Potential Test Report (Form 9-1868). Extension of the 30-day test period may be granted. The effective date for any approved initial MPR shall be the first day following the test period. During the 30-day period allowed for testing, or any approved extensions thereof, the operator may produce a new or reworked well completion at rates necessary to establish the MPR. The operator shall report the total production obtained during the test period, and approved extensions thereof, on the Well Potential Test Report (Form 9-1868).

(2) Revision of MPR Increase. *If necessary to test a well completion at rates above the approved MPR to determine whether the MPR should be increased, notification of intent to test the well at such higher rates, not to exceed a stated maximum rate during a specified test period, shall be filed with the Supervisor. Such tests may commence on the day following the date of filing notification, unless otherwise ordered by the Supervisor. If an operator determines that the MPR should be increased, he shall submit, within 15 days after the specified test period, a proposed increased MPR on a Request for Well Maximum Production Rate (MPR) (Form 9-1867), and any other available data to support the requested revision, including the results of the potential test and the total production obtained during the test period on a Well Potential Test Report (Form 9-1868). Prior to approval of the proposed increased MPR, the operator may produce the well completion at a rate not to exceed the proposed increased MPR of the well. The effective date for any approved increased MPR shall be the first day following the test period. If testing rates or increased MPR rates result in production from the reservoir in excess of the approved MER, this excess production shall be balanced by underproduction from the reservoir under the provisions of subparagraph 4.B of this Order.*

(3) Revision of MPR Decrease. *When the quarterly test rate for an oil well completion or the semiannual test rate for a gas well completion required under subparagraphs 5.C and 6.C of this Order is less than 90 percent of the existing approved MPR for the well, a new reduced MPR will be established automatically for that well completion equal to 110 percent of the test rate submitted. The effective date for the new MPR for such well completion shall be the first day of the quarter following the required date of submittal of periodic well-test results under subparagraphs 5.C and 6.C of this Order. Also, the operator may notify the Supervisor on a Request for Well Maximum Production Rate (MPR) (Form 9-1867) of, or the Supervisor may require, a downward revision of a well MPR at any time when the well is no longer capable of producing its approved MPR on a sustained basis. The effective date for such reduced MPR for a well completion shall be the first day of the month following the date of notification.*

(4) Continuation of MPR. *If submittal of the results of a quarterly well test for an oil completion or a semiannual well test for a gas well completion, as provided for in subparagraphs 5.C and 6.C of this Order, cannot be timely, continuation of production under the last approved MPR for*

the well may be authorized, provided an extension of time in which to submit the test results is requested and approved in advance.

(5) *Cancellation of MPR. When a well completion ceases to produce, is shut in pending workover, or any other condition exists which causes the assigned MPR to be no longer appropriate, the operator shall notify the Supervisor accordingly on a Request for Well Maximum Production Rate (MPR) (Form 9-1867), indicating the date of last production from the well, and the MPR will be canceled. Reporting of temporary shut-ins by the operator for well maintenance, safety conditions, or other normal operating conditions is not required, except as is necessary for completion of the Monthly Report of Operations (Form 9-152).*

C. *MER and MPR Relationship. The withdrawal rate from a reservoir shall not exceed the approved MER and may be produced from any combination of well completions subject to any limitations imposed by the MPR established for each well completion. The rate of production from the reservoir shall not exceed the MER although the summation of individual well MPR's may be greater than the MER.*

4. *Balancing of Production.*

A. *Production Variances. Temporary well production rates resulting from normal variations and fluctuations exceeding a well MPR or reservoir MER shall not be considered a violation of this Order, and such production may be sold or transferred pursuant to paragraph 8 of this Order. However, when normal variations and fluctuations result in production in excess of a reservoir MER, any operator who is overproduced shall balance such production in accordance with subparagraph 4.B below. Such operator shall advise the Supervisor of the amount of such excess production from the reservoir for the month at the same time as Form 9-152 is filed for that month.*

B. *Balancing Periods. As of the first day of the month following the month in which this Order becomes effective, all reservoirs shall be considered in balance. Balancing periods for overproduction of a reservoir MER shall end on January 1, April 1, July 1, and October 1 of each year. If a reservoir is produced at a rate in excess of the MER for any month, the operator who is overproduced shall take steps to balance production during the next succeeding month. In any event, all overproduction shall be balanced by the end of the next succeeding quarter following the quarter in which the overproduction occurred. The operator shall notify the Supervisor at the end of the month in which he has balanced the production from an overproduced reservoir.*

C. Shut-in for Overproduction. Any operator in an overproduction status in any reservoir for two successive quarters which has not been brought into balance within the balancing period shall be shut in from that reservoir until the actual production equals that which would have occurred under the approved MER.

D. Temporary Shut-in. If, as the result of storm, hurricanes, emergencies, or other conditions peculiar to offshore operations, an operator is forced to curtail or shut in production from a reservoir, the Supervisor may, on request, approve makeup of all or part of this production loss.

5. Oil Well Testing Procedures.

A. General. Tests shall be conducted for not less than four consecutive hours. Immediately prior to the 4-hour test period, the well completion shall have produced under stabilized conditions for a period of not less than six consecutive hours. The 6-hour pretest period shall not begin until after recovery of a volume of fluid equivalent to the amount of fluids introduced into the formation for any purpose. Measured gas volumes shall be adjusted to the standard conditions of 15.015 psia and 60° F. for all tests. When orifice meters are used, a specific gravity shall be obtained or estimated for the gas and a specific gravity correction factor applied to the orifice coefficient. The Supervisor may require a prolonged test or retest of a well completion if such test is determined to be necessary for the establishment of a well MPR or a reservoir MER. The Supervisor may approve test periods of less than four hours and pretest stabilization periods of less than six hours for well completions, provided that test reliability can be demonstrated under such procedures.

B. Potential Test. Test data to establish or to increase an oil well MPR shall be submitted on a Well Potential Test Report (Form 9-1868). The total production obtained from all tests during the test period shall be reported on such form.

C. Quarterly Test. Tests shall be conducted on each producing oil well completion quarterly, and test results shall be submitted on a Quarterly Oil Well Test Report (Form 9-1869). Testing periods and submittal dates shall be as follows:

Testing Period	Latest Date for Submittal of Test Results	For Quarter Beginning
September 11 - December 10	December 10	January 1
December 11 - March lo	March 10	April 1
March 11 - June 10	June 10	July 1
June 11 - September 10	September 10	October 1

There shall be a minimum of 45 days between quarterly tests for an oil well completion.

6. *Gas Well Testing Procedures.*

A. *General.* Testing procedures for gas well completions shall be the same as those specified for oil well completions in subparagraph 5.A except for the initial test which shall be a multi-point back-pressure test as described in paragraph 6.D.

B. *Potential Test.* Test data to establish or to increase a gas well MPR shall be submitted on a Well Potential Test Report (Form 9-1868).

C. *Semiannual Test.* Tests shall be conducted on each producing gas well completion semiannually, and test results shall be submitted on a Semiannual Gas Well Test Report (Form 9-1870). Testing periods and submittal dates shall be as follows:

Testing Period	For Submittal of Test Results	For Semi-Annual Period Beginning
June 11 - December 10	December 10	January 1
December 11 - June 10	June 10	July 1

There shall be a minimum of 90 days between semiannual tests for a gas well completion.

D. *Back-Pressure Tests.* A multi-point back-pressure test to determine the theoretical open-flow potential of gas wells shall be conducted within thirty days after connection to a pipeline. If bottom-hole pressures are not measured, such pressures shall be calculated from surface pressures using the method, or other similar method, found in the Interstate Oil Compact Commission (IOCC) Manual of Back-Pressure Testing of gas wells. The results of all back-pressure tests conducted by the operator shall be filed with the Supervisor, including all basic data used in determining the test results. The Supervisor may waive this requirement if multi-point back-pressure test information has previously been obtained on a representative number of wells in a reservoir.

7. *Witnessing Well Tests.* The Supervisor may have a representative witness any potential or periodic well tests on oil and gas well completions. Upon request, an operator shall notify the appropriate District office of the time and date of well tests.

8. *Sale or Transfer of Production.* Oil and gas produced pursuant to the provisions of this Order, including test production, may be sold to purchasers or transferred as production authorized for disposal hereunder.

9. *Bottom-Hole Pressure Tests*. *Static bottom-hole pressure tests shall be conducted annually on sufficient key wells to establish an average reservoir pressure in each producing reservoir unless a different frequency is approved. The Operator may be required to test specific wells. Results of bottom-hole pressure tests shall be submitted within 60 days after the date of the test.*

10. *Flaring and Venting of Gas*. *Oil- and gas-well gas shall not be flared or vented, except as provided herein.*

    A. *Small-Volume or Short-Term Flaring or Venting*. *Oil- and gas-well gas may be flared or vented in small volumes or temporarily without the approval of the Supervisor in the following situations:*

        (1) *Gas Vapors*. *When gas vapors are released from storage and other low-pressure production vessels if such gas vapors cannot be economically recovered or retained.*

        (2) *Emergencies*. *During temporary emergency situations, such as compressor or other equipment failure, or the relief of abnormal system pressures.*

        (3) *Well Purging and Evaluation Tests*. *During the unloading or cleaning up of a well and during drillstem, producing, or other well evaluation tests not exceeding a period of 24 hours.*

    B. *Approval for Routine or Special Well Tests*. *Oil- and gas-well gas may be flared or vented during routine and special well tests, other than those described in paragraph A above, only after approval of the Supervisor.*

    C. *Gas-Well Gas*. *Except as provided in A and B above, gas-well gas shall not be flared or vented.*

    D. *Oil-Well Gas*. *Except as provided in A and B above, oil-well gas shall not be flared or vented unless approved by the Supervisor. The Supervisor may approve an application for flaring or venting of oil-well gas for periods not exceeding one year if (1) the operator has initiated positive action which will eliminate flaring or venting, or (2) the operator has submitted an evaluation supported by engineering, geologic, and economic data indicating that rejection of an application to flare or vent the gas will result in an ultimate greater loss or equivalent total energy than could be recovered for beneficial use from the lease if flaring or venting were allowed.*

    E. *Content of Application*. *Applications under paragraph D above for existing operations, as of the date of this Notice, shall* *be filed within three months from the effective date of this Order. Applications under paragraph D(2) above shall include all appropriate engineering, geologic, and economic data in an evaluation showing that absence of approval to flare or vent the gas will result in premature abandonment of oil and gas production or curtailment of lease development. Applications shall include an estimate of the amount and value of the oil and gas reserves that would not be recovered if the application to flare or vent were rejected and an estimate of the total amount of oil to be recovered and associated gas that would be flared or vented if the application were approved.*

11. *Disposition of Gas. The disposition of all gas produced from each lease shall be reported monthly on, or attached to, Form 9-152. The report shall be submitted in the following manner:*

	Oil-Well Gas (MCF)	Gas-Well Gas (MCF)
Sales		
Fuel		
*Injected		
Flared		
Vented		
Other (Specify)		
Total		

*Gas produced from the lease and injected on or off the lease.

12. *Multiple and Selective Completions.*

A. *Number of Completions. A well bore may contain any number of producible completions when justified and approved.*

B. *Numbering Well Completions. Well completions made after the date of this Order shall be designated using numerical and alphabetical nomenclature. Once designated as a reservoir completion, the well completion number shall not change. Appendix A contains a detailed explanation of procedures for naming well completions.*

C. *Packer Tests. Multiple and selective completions shall be equipped to isolate the respective producing reservoirs. A packer test or other appropriate reservoir isolation test shall be conducted prior to or immediately after initiating production and annually thereafter on all multiply completed wells. Should the reservoirs in any multiply completed well become intercommunicative the operator shall make repairs and again conduct reservoir isolation tests unless some other operational procedure is approved. The results of all tests shall be submitted* on a Packer Test (Form 9-1871) within 30 days after the date of the test.

D. Selective Completions. Completion equipment may be installed to permit selective reservoir isolation or exposure in a well bore through wireline or other operations. All selective completions shall be designated in accordance with subparagraph 12.B when the application for approval of such completions is filed.

E. Commingling. Commingling of production from two or more separate reservoirs within a common well bore may be permitted if it is determined that, collectively, the ultimate recovery will not be decreased. An application to commingle hydrocarbons from multiple reservoirs within a common well bore shall be submitted for approval and shall include all pertinent well information, geologic and reservoir engineering data, and a schematic diagram of well equipment. For all competitive reservoirs, notice of the application shall be sent by the applicant to all other operators of interest in the reservoirs prior to submitting the application to the Supervisor. The application shall specify the well completion number to be used for subsequent reporting purposes.

13. Gas-Cap Well Completions. All existing and future wells completed in the gas cap of a reservoir which has been classified and approved as an associated oil reservoir shall be shut in until such time as the oil is depleted or the reservoir is reclassified as a gas reservoir; provided, however, that production from such wells may be approved when (1) it can be shown that such gas-cap production would not lead to waste of oil and gas, or (2) when necessary to protect correlative rights unless it can be shown that this production will lead to waste of oil and gas.

14. Location of Wells.

A. General. The location and spacing of all exploratory and development wells shall be in accordance with approved programs and plans required in 30 CFR 250.17 and 250.34. Such location and spacing shall be determined independently for each lease or reservoir in a manner which will locate wells in the optimum structural position for the most effective production of reservoir fluids and to avoid the drilling of unnecessary wells.

B. Distance from Property Line. An operator may drill exploratory or development wells at any location on a lease in accordance with approved plans; provided that no well directionally or vertically drilled and completed after the date of this Order in which the completed interval is less than 500 feet from a property line shall be produced unless approved by the Supervisor.

For wells drilled as vertical holes, the surface location of the well shall be considered as the location of the completed interval but shall be subject to the provisions of 30 CFR 250.40(b). An operator requesting approval to produce a directionally drilled well in which the completed interval is located closer than 500 feet from a property line, or approval to produce a vertically drilled well with a surface location closer than 500 feet from a property line, shall furnish the Supervisor with letters expressing acceptance or objection from operators of offset properties.

15. *Enhanced Oil and Gas Recovery Operations. Operators shall timely initiate enhanced oil and gas recovery operations for all competitive and noncompetitive reservoirs where such operations would result in an increased ultimate recovery of oil or gas under sound engineering and economic principles. A plan for such operations shall be submitted with the results of the annual MER review as required in paragraph 3A(3) of this Order.*

16. *Competitive Reservoir Operations. Development and production operations in a competitive reservoir may be required to be conducted under either pooling and drilling agreements or unitization agreements when the Conservation Manager determines, pursuant to 30 CFR 250.50 and delegated authority, that such agreements are practicable and necessary or advisable and in the interest of conservation.*

    A. *Competitive Reservoir Determination. The Supervisor shall notify the operators when he has made a preliminary determination that a reservoir is competitive as defined in this Order. An operator may request at any time that the Supervisor make a preliminary determination as to whether a reservoir is competitive. The operators, within thirty (30) days of such preliminary notification or such extension of time as approved by the Supervisor, shall advise of their concurrence with such determination, or submit objections with supporting evidence. The Supervisor will make a final determination and notify the operators.*

    B. *Development and Production Plans. When drilling and/or producing operations are conducted in a competitive reservoir, the operators shall submit for approval a plan governing the applicable operations. The plan shall be submitted within ninety (90) days after a determination by the Supervisor that a reservoir is competitive or within such extended period of time as approved by the Supervisor. The plan shall provide for the development and/or production of the reservoir, and may provide for the submittal of supplemental plans for approval by the Supervisor.*

(1) *Development Plan.* When a competitive reservoir is still being developed or future development is contemplated, a development plan may be required in addition to a production plan. This plan shall include the information required in 30 CFR 250.34. If agreement to a joint development plan cannot be reached by the operators, each shall submit a separate plan and any differences may be resolved in accordance with paragraph 17 of this Order.

(2) *Production Plan.* A joint production plan is required for each competitive reservoir. This plan shall include (a) the proposed MER for the reservoir, (b) the proposed MPR for each completion in the reservoir, (c) the percentage allocation of reservoir MER for each lease involved, and (d) plans for secondary recovery or pressure maintenance operations. If agreement to a joint production plan cannot be reached by the operators, each shall submit a separate plan, and any differences may be resolved in accordance with paragraph 17 of this Order.

C. *Utilization.* The Conservation Manager shall determine when conservation will be best served by unitization of a competitive reservoir, or any reservoir reasonably delineated and determined to be productive, in lieu of a development and/or production plan or when the operators and lessees involved have been unable to voluntarily effect unitization. In such cases, the Conservation Manager may require that development and/or production operations be conducted under an approved unitization plan. Within six (6) months after notification by the Conservation Manager that such a unit plan is required, or within such extended period of time as approved by the Conservation Manager, the lessees and operators shall submit a proposed unit plan for designation of the unit area and approval of the form of agreement pursuant to 30 CFR 250.51.

17. *Conferences, Decisions and Appeals.* Conferences with interested parties may be held to discuss matters relating to applications and statements of position filed by the parties relating to operations conducted pursuant to this Order. The Supervisor or Conservation Manager may call a conference with one or more, or all, interested parties on his own initiative or at the request of any interested party. All interested parties shall be served with copies of the Supervisor's or Conservation Manager's decisions. Any interested party may appeal decisions of the Supervisor or Conservation Manager pursuant to 30 CFR 250.81. Decisions of the

Supervisor or Conservation Manager shall remain in effect and shall not be suspended by reason of any appeal, except as provided in that regulation.

J. B. Lowenhaupt

J. B. Lowenhaupt
Oil and Gas Supervisor
Production Control
Gulf of Mexico Area

Approved: May 1, 1974

Russell G. Wayland

Russell G. Wayland
Chief, Conservation Division

APPENDIX A

Subparagraph 12.B.: "Numbering Well Completions. Well completions made after the date of this Order shall be designated using numerical and alphabetical nomenclature. Once designated as a reservoir completion, the well completion number shall not change..."

The intent of this subparagraph is not necessarily to change the existing well completion names but to change the method of naming well completions after the effective date of this Order in order to insure that a completion in a given reservoir and a specific well bore will be assigned a unique name and will retain that name permanently. For further clarification, the following guidelines and examples are offered:

1. *Each well bore will have a distinct, permanent number.*
2. *Each reservoir completion in a well bore will have a unique permanent designation which includes the well bore number in its nomenclature.*
3. *For the purpose of this subparagraph, a "completion" is defined as all perforations in a given reservoir in a specific well bore and is not necessarily associated with a tubing string or strings.*
4. *If more than one completion is made in a well bore, an alphabetical suffix must be used in the nomenclature to differentiate between completions.*
5. *An alphabetical prefix may be utilized to designate the platform from which the well will be produced.*

Example No. 1: *The first well drilled from the A platform is a single completion.*

Well No. A-1

(Should an operator wish to use an alphabetical suffix with a single completion, he may do so.)

Example No. 2: *A well drilled by a mobile rig need not carry an alphabetical prefix.*

Well No. 1

(If the well is later connected to and produced from a production platform, the well shall be redesignated to reflect an alphabetical prefix.)

Example No. 3: *The second well drilled from the A Platform is a triple completion.*

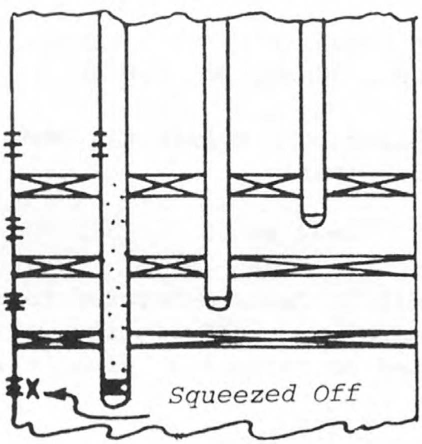
First Completion	*Second Completion*	*Third Completion*
A-2	*A-2-D*	*A-2-T*

(In the above example, the letters "D" and "T" were used in naming the second and third completions utilizing current industry practice, although the intent is not to restrict operators to the use of these particular alphabetical suffixes. Any alphabetical suffix may be used as long as it is unique to the completion in that reservoir.)

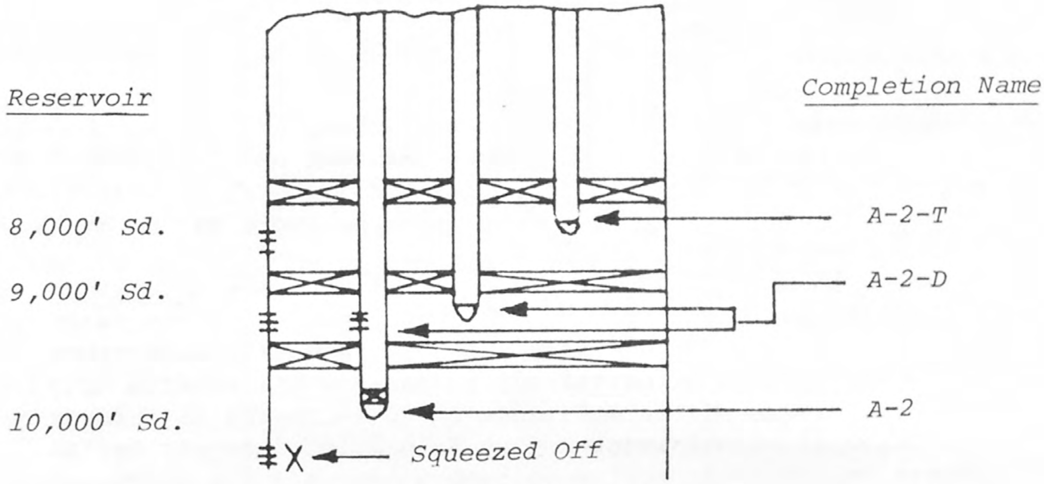
Example No. 4: *The drawing is shown to illustrate the fact that once a completion in a specific well bore is designated in a given reservoir, it will retain that name permanently. Let us consider the A-2 completion shown in Example No. 3. Should a recompletion be made in a different reservoir at a later date, it shall be renamed; however, the production from the reservoir associated with the original A-2 completion will always be identified with the A-2 completion. Once the A-2 completion in the 10,000' sand is squeezed and plugged off and the recompletion made to the 7,000' sand, the completion in the 7,000' sand would be designated A-2-A (or some other alphabetical suffix other than the "D" or "T" presently associated with other completions in the 9,000' and 8,000' sands).*

The Sundry Notices and Reports on Wells (Form 9-331) submitted to obtain approval for the workover shall be the vehicle for naming the new completion.

Reservoir	*Completion Name*
7,000' Sd.	*A-2-A*
8,000' Sd.	*A-2-T*
9,000' Sd.	*A-2-D*
10,000' Sd.	*A-2*



Example No. 5: *If the A-2 completion in Example No. 4 had been recompleted from the 10,000' sand to the 9,000' sand (where the A-2-D is currently completed), the completion would still be named A-2-D as both tubing strings would be considered one completion for purposes of this Order.*



UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION
GULF OF MEXICO AREA

OCS ORDER NO. 12
Effective February 1, 1975

PUBLIC INSPECTION OF RECORDS

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.97 and 43 CFR 2.2, and supersedes OCS Order No. 12, dated August 13, 1971. Section 250.97 of 30 CFR provides as follows:

> Public Inspection of Records. Geological and geophysical interpretations, maps, and data required to be submitted under this part shall not be available for public inspection without the consent of the lessee so long as the lease remains in effect or until such time as the supervisor determines that release of such information is required and necessary for the proper development of the field or area.

Section 2.2 of 43 CFR provides in part as follows:

> Determinations as to Availability of Records. (a) Section 552 of Title 5, U.S. Code, as amended by Public Law 90-23 (the act codifying the "Public Information Act") requires that identifiable agency records be made available for inspection. Subsection (b)[1] of section 552 exempts several categories of records from the general requirement but does not require the withholding from inspection of all records which may fall

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[1] Subsection (b) of section 552 provides that:

(b) This section does not apply to matters that are --

* * *

(4) Trade secrets and commercial or financial information obtained from a person and privileged or confidential;

* * *

(9) Geological and geophysical information and data, including maps, concerning wells.

within the categories exempted. Accordingly, no request made of a field office to inspect a record shall be denied unless the head of the office or such higher field authority as the head of the bureau may designate shall determine (1) that the record falls within one or more of the categories exempted and (2) either that disclosure is prohibited by statute or Executive Order or that sound grounds exist which require the invocation of the exemption. A request to inspect a record located in the headquarters office or a bureau shall not be denied except on the basis of a similar determination made by the head of the bureau or his designee, and a request made to inspect a record located in a major organizational unit of the Office of the Secretary shall not be denied except on the basis of a similar determination by the head of that unit. Officers and employees of the Department shall be guided by the "Attorney General's Memorandum on the Public Information Section of the Administrative Procedure Act" of June 1967.

(b) An applicant may appeal from a determination that a record is not available for inspection to the Solicitor of the Department of the Interior, who may exercise all of the authority of the Secretary of the Interior in this regard. The Deputy Solicitor may decide such appeals and may exercise all of the authority of the Secretary in this regard.

The operator shall comply with the requirements of this Order. Any departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b).

1. Availability of Records Filed on or after December 1, 1970. It has been determined that certain records pertaining to leases and wells in the Outer Continental Shelf and submitted under 30 CFR 250 shall be made available for public inspection, as specified below, in the Area Office, Metairie, Louisiana.

   A. Form 9-152 - Monthly Report of Operations. All information contained on this form shall be available, except the information required in the Remarks column.

   B. Form 9-330 - Well Completion or Recompletion Report and Log.

      (1) Prior to commencement of production, all information contained on this form shall be available, except Item 1a, Type of Well; Item 4, Location of Well,

At top prod. interval reported below; Item 22, if Multiple Compl., How many; Item 24, Producing Interval; Item 26, Type Electric and Other Logs Run; Item 28, Casing Record; Item 29, Liner Record; Item 30, Tubing Record; Item 31, Perforation Record; Item 32, Acid, Shot, Fracture, Cement Squeeze, etc.; Item 33, Production; Item 37, Summary of Porous Zones; and Item 38, Geologic Markers.

(2) *After commencement of production, all information shall be available, except Item 37, Summary of Porous Zones; and Item 38, Geologic Markers.*

(3) *If production has not commenced after an elapsed time of five years from the date of filing Form 9-330 as required in 30 CFR 250.38(b), all information contained on this form shall be available, except Item 37, Summary of Porous Zones; and Item 38, Geologic Markers. Within 90 days prior to the end of the 5-year period, the lessee or operator shall file a Form 9-330 containing all information requested on the form, except Item 37, Summary of Porous Zones; and Item 38, Geologic Markers, to be made available for public inspection. Objections to the release of such information may be submitted with the completed Form 9-330.*

C. Form 9-331 - Sundry Notices and Report on Wells

(1) *When used as a "Notice of Intention to" conduct operations, all information contained on this form shall be available, except Item 4, Location of Well, At top prod. interval; and Item 17, Describe Proposed or Completed Operations.*

(2) *When used as a "Subsequent Report of" operations, and after commencement of production, all information contained on this form shall be available, except information under Item 17 as to subsurface locations and measured and true vertical depths for all markers and zones not placed on production.*

D. Form 9-331C - Application for Permit to Drill, Deepen or Plug Back. *All information contained on this form, and location plat attached thereto, shall be available, except Item 4, Location of Well, At proposed prod. zone; and Item 23, Proposed Casing and Cementing Program.*

E. *Form 9-1869 - Quarterly Oil Well Test Report.* All information contained on this form shall be available.

F. *Form 9-1870 - Semi-Annual Gas Well Test Report.* All information contained on this form shall be available.

G. *Multi-point Back Pressure Test Report.* All information contained on this form used to report the results of required multi-point back pressure test of gas wells shall be available.

H. *Sales of Lease Production.* Information contained on monthly Geological Survey computer printout showing sales volumes, value, and royalty of production of oil, condensate, gas and liquid products, by lease, shall be made available.

2. *Filing of Reports.* All reports on Forms 9-152, 9-330, 9-331, 9-331C, 9-1869, 9-1870, and the forms used to report the results of multi-point back pressure tests, shall be filed in accordance with the following: All reports submitted on these forms after the effective date of this Order shall include a copy with the words "Public Information" shown on the lower right-hand corner. All items on the form not marked "Public Information" shall be completed in full; and such forms, and all attachments thereto, shall not be available for public inspection. The copy marked "Public Information" shall be completed in full, except that the items described in 1(A), (B), (C), and (D) above, and the attachments relating to such items, may be excluded. The words "Public Information" shall be shown on the lower right-hand corner of this set. This copy of the form shall be made available for public inspection.

3. *Availability of Records Filed Prior to December 1, 1970.* Information filed prior to December 1, 1970, on Forms 9-152, 9-330, 9-331, and 9-331C is not in a form which can readily made available for publc inspection. Requests for information on these forms shall be submitted to the Supervisor in writing and shall be made available in accordance with 43 CFR Part 2.

4. *<u>Availability of Inspection Records</u>. All accident investigation reports, pollution incident reports, facilities inspection data, and records of enforcement actions are also available for public inspection.*

D.W. Solanas

D. W. Solanas
Oil and Gas Supervisor
Field Operations

Approved: January 27, 1975

Russell G. Wayland

Russell G. Wayland
Chief, Consevation Division

UNITED STATES DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION
GULF OF MEXICO AREA

OCS ORDER NO. 13
EFFECTIVE OCTOBER 1, 1975

PRODUCTION MEASUREMENT AND COMMINGLING

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.45, 250.60, and 250.61, and 250.68.

Section 250.60 provides as follows:

> *Measurement of oil. The lessee shall gauge and measure all production in accordance with methods approved by the Supervisor. The lessee shall provide tanks suitable for measuring accurately the crude oil produced from the lease (exact copies of 100 percent capacity tank tables to be furnished to the Supervisor) or may arrange with the Supervisor for other acceptable methods of measuring, storing, and recording production. The quantity and quality of all production shall be determined in accordance with the standard practices, procedures, and specifications generally used by the industry.*

Section 250.61 provides as follows:

> *Measurement of gas. The lessee shall measure all gas production in accordance with methods approved by the Supervisor, and the measured volumes shall be adjusted to the standard pressure base of 10 ounces above the atmospheric pressure of 14.4 pounds per square inch, a standard temperature of 60° Fahrenheit, and for deviation from Boyle's law. If gas is being disposed of at a different pressure base, the Supervisor may require that gas volumes be adjusted to conform to such base.*

Section 250.68 provides as follows:

> *Commingling production. Subject to such conditions as he may prescribe for measurement and allocation of production, the Supervisor may authorize the lessee to move production from the lease to a central point for purposes of treating, measuring, and storing, and in moving such production, the lessee may commingle the production from different wells,*

leases, pools, and fields, and with production of other operators. The central point may be on shore or at any other convenient place selected by lessee.

The operator shall be responsible for compliance with the requirements of this Order in the installation and operation of all terminals or offshore sales points, including all facilities installed at measurement terminals or offshore sales points, whether or not operated or owned by the operator. Any departures from the requirements specified in this Order must be approved pursuant to 30 CFR 250.12(b).

1. *Definition of Terms. As used in this Order, the following terms shall have the meanings indicated:*

    A. *Terminal. Any onshore facility used in measuring the quantity and quality of produced liquids from Gulf of Mexico OCS leases for the purpose of computing royalties due the United States.*

    B. *Offshore Sales Point. Any facility located on an offshore structure, at which point the produced fluids are measured by automatic custody transfer equipment, tank gauges, or meters for the purpose of computing royalties due the United States.*

2. *Liquid Sales Meters. The following requirements shall apply to all sales meters located at terminals and offshore sales points. Operators of sales meters at terminals and offshore sales points shall comply with the requirements of subparagraphs A through C by the first day of the month following six months after the date of this Order.*

    A. *Equipment Requirements. Metering facilities at terminals or offshore sales points shall include the following components, which shall be compatible with the systems to which they are connected:*

        (1) *Meter. Positive-displacement meter or other liquid meter approved by the Supervisor, equipped with a nonreset totalizer to remain sealed while the meter is in service. A temperature or other compensator, or a recorder, may be a component of the meter, but all such devices shall be sealed or shall be tamper proof while in service. The piping*

system shall be arranged to prevent reversal of flow of liquid through the meter. Meters subjected to pressure pulsation or surges shall be adequately protected by surge tanks, expansion chambers, or similar devices. No meter shall be subjected to shock pressures which are greater than its maximum-rated working pressure. All meter installations shall be designed to operate within the gravity range specified by the meter manufacturer. The pressure and flow rate through each meter shall be maintained within manufacturer's maximum and minimum specifications for rated capacity. There shall be no bypasses around the meter.

(2) Meter Prover. Calibrated prover tank, master meter, or mechanical displacement proved.

(3) Sampler. Proportional-to-flow sampling device, with sampling point immediately upstream of the meters and downstream of any diverter valve installed upstream of the meters. The sample container shall be vaportight, with a mixing device to permit complete mixing of the sample prior to removal from the container. The sampler probe shall extend into the center of the flow piping in a vertical run. The probe shall always be in a horizontal position. The composite sample accumulated in a run period, which is the basis of the gravity and BS&W measurements, shall be representative of all crude oil delivered.

(4) Deaerator. When a deaerator is utilized, it shall be located upstream of the meters and shall in no case be of a smaller rated maximum capacity then that of the pump or feed lines and shall provide complete air elimination.

(5) BS&W Monitor. When a BS&W monitor is used it shall be installed upstream of the meters and sampling device, and designed to sound an alarm, shut down the pumps, or to divert the liquid stream back to the treater vessels, water separation tanks, or bad-oil tank in the event excessive BS&W content is detected in the oil.

B. *<u>Gravity, BS&W, and Temperature Determinations</u>. The volume of metered oil shall be corrected, using factors determined as follows:*

(1) *<u>API Gravity</u>. The hydrometer method is the most suitable for determining the API gravity of crude petroleum. The testing procedure shall be in accordance with API Standard 2544 and ASTM Designation D287-67, Standard Method of Test for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method), 1967.*

(2) *<u>BS&W</u>. Determination of water and sediment in crude oils shall be in accordance with API Standard 2542 and ASTM Designation D96-68, Standard Methods of Test for Water and Sediment in Crude Oils (1968).*

(3) *<u>Temperature</u>. Determination of the average temperature necessary to calculate volumes at a standard temperature of 60° Fahrenheit shall be in accordance with API Standard 2543 and ASTM Designation D1086-64, American Standard Method of Measuring the Temperature of Petroleum and Petroleum Products (1964), except when the volume is determined from a temperature-compensated or temperature-recording meter.*

C. *<u>Sales Meter Proving Requirement</u>. The following meter proving procedures shall be followed by all operators of liquid sales meters. Calibration of the sales meters shall be witnessed by purchaser (if different from the seller), USGS, or other party acceptable to the Supervisor.*

(1) *<u>Certification</u>. The integrity of the calibration of each mechanical displacement prover or prover tank or master meter must be traceable to test measures which have been certified by the National Bureau of Standards.*

(2) *<u>Frequency</u>. Each operating meter or master meter shall be proved every month within a tolerance of fifteen (15) days, or at any other time upon request of the Supervisor.*

(3) *Establishing Meter Factors.*

(a) *Prover Tank. In establishing the meter factor with a prover tank, proof runs shall be made and recorded until two (2) consecutive runs have results within a tolerance of 0.0005 (.05 percent) prover tank volume. An average of the results of these two (2) runs will be used for the meter factor.*

(b) *Master Meter. In establishing the operating meter factor with a master meter, the master meter shall first be operating within manufacturer's specifications, calibrated with similar gravity crude and flow rate. Proof runs shall be made until three (3) consecutive runs have results within a tolerance of 0.0002. The volume of each run shall be at least ten (10) percent of the hourly rated capacity of the operating meter but must be of sufficient amount for determination of an accurate operating meter factor. The master metering installation shall include:*

(i) *A back-pressure valve downstream of the operating and master meter.*

(ii) *A check valve to prohibit back flow.*

(c) *Mechanical-Displacement Prover. In establishing the operating meter factor with a mechanical-displacement prover, a minimum of five (5) out of six (6) consecutive runs for an unidirectional prover or round trips for a bidirectional prover shall be within a tolerance of 0.0005. An average of these five runs will be used to compute the meter factor.*

(d) *Preliminary Run. For any of the three methods of proving the operating meter (prover tank, master meter, or mechanical-displacement prover), a preliminary unrecorded run should be made to equalize temperatures, displace vapors or gases, and wet the interior of* *the prover, where necessary. More than one run may be made. If four consecutive prover runs are made without any two consecutive runs checking within the 0.0005 tolerance, the installation shall be inspected; and if inspection discloses mechanical defects, necessary repairs shall be made.*

(e) *Fluid Compressibility. In calibrating meters with a mechanical-displacement prover, or master meter, or pressurized prover tank (volumetric provers), fluid compressibility shall be taken into account (API Standard 1101, Table II). This factor is referred to as Cpl.*

(f) *Other Required Considerations. In calibrating meters with a mechanical-displacement prover or pressurized prover tank, the following correction factors shall be taken into account:*

(i) *The change in prover volume due to pressure in the steel pipe (API Standard 2531, USA Standard for Mechanical-Displacement Meter Provers, Table II, Steel Correction Factor for Pressure, Cps (1963)). This correction factor is referred to as Cps and will always be unity or greater.*

(ii) *The change in volume of the test liquid with change in temperature as determined from API Standard 2540 and ASTM-D1250, Table 6, "Reduction of Volume to 60° F against API gravity at 60° F," (1952) or expanded tables based on the same. This correction factor is referred to as Ctl.*

(iii) *The change in tank shell dimensions with change in temperature (API Standard 2531, "USA Standard for Mechanical Displacement Meter*

Prover," Table I, "Steel Correction Factor for Temperature, Cts.," App. B (1963)). This correction factor is referred to as Cts.

(iv) API Standard 2541 and ASTM Designation D1750-62, "Standard Tables for Positive Displacement Meter Prover Tank" (1966), Table A, or expanded tables based on same, may be used where applicable. This table is a combined factor for temperature correction of liquid and steel (API Standard 2540 and ASTM Designation D1250-56, "Standard Petroleum Measurement Tables" (1966), Table 6, "Reduction of Volume to 60° F against API Gravity at 60° F," combined with a temperature factor for the cubical expansion of mild steel).

(g) Deviation and Meter Factor. A maximum deviation of ± 0.0025 in any factor obtained since a meter was last proved or repaired, or from the original factor with a new meter, will be allowed without declaration of a malfunction. Any factor which exceeds this limit will be declared a malfunction factor. It shall be clearly indicated on the proving report when a malfunction factor has been obtained. If a malfunction factor occurs, the operator shall submit a Meter Adjustment Ticket (Form 9-1910) to adjust the volume of oil run during the period ending with the malfunction factor. The factor obtained at the beginning of the run will be used on the current ticket in the meter printer. Adjustments to the calculated run volume will be indicated on the Meter Adjustment Ticket and will eliminate the necessity of changing or adjusting the total production figure shown on the meter totalizer.

(4) Meter Malfunction. After a malfunction, an operating meter shall be repaired or adjusted, and recalibrated as required. The

proving report must indicate the repairs or maintenance which were performed. The operator shall have a run ticket made within 24 hours after proving any sales meter and shall submit copies of all such run tickets to the Area office within 7 days after completion.

(5) <u>Proving Report Forms</u>. Meter Proving Report A (Form 9-1912) shall be used when proving meters using mechanical-displacement prover. Meter Proving Report B (9-1913) shall be used when performing meter provings using prover tanks or master meter. The operator shall submit a copy of the official proving record to the Area office within seven days after proving a meter.

3. <u>Sale Tanks</u>. Operators of liquid sales tanks and facilities shall comply with the following:

A. <u>Equipment Requirements</u>. To reduce evaporation losses, sales tank facilities shall be equipped with a pressure-vacuum thief hatch and vent-line valve, and a fill line designed to minimize free fall and splashing.

B. <u>Calibration Chart</u>. A complete set of calibration charts (tank tables) for each tank shall be submitted to the Area office. Tank calibrations shall be according to API Standard 2550 and ASTM Designation D1220-65, "Measurement and Calibration of Upright Cylindrical Tanks" (1966) and shall be performed by qualified personnel, subject to witnessing by representatives of the purchaser, seller, and USGS.

C. <u>Gauging and Sampling</u>. Gauging of storage tanks shall be performed according to API Standard 2545, and ASTM Designation D1085-65, "USA Standard Method of Gauging Petroleum and Petroleum Products" (1965), and sampling of petroleum and petroleum products in accordance with API Standard 2546 and ASTM Designation D270-65, "Standard Method of Sampling Petroleum and Petroleum Products" (1965).

D. <u>Temperature Correction</u>. The change in volume of the liquid with the change in temperature shall be determined from API Standard 2540 and ASTM

Designation D1250, Table 6, "Reduction of Volume to 60° F against API Gravity at 60° F" (1952), or expanded tables based on the same. Reduction for BS&W shall be made after making the correction for temperature.

4. *Allocation Meter Facilities. Allocation meter facilities shall include the following components:*

   A. *Meter. Positive-displacement meter, positive volume meter, turbine meter, or other acceptable measurement equipment.*

   B. *Meter Prover. Calibrated mechanical-displacement prover, master meter, or prover tank.*

   C. *Sampler. Equipment for continuous or periodic liquid sampling.*

5. *Gas Measurement. The operator shall be responsible for compliance with the requirements of this Order pertaining to all sales meters at their delivery points and all meters used for allocation purposes.*

   A. *Standards for Measurement. The following requirements shall apply to all meters:*

      (1) *Equipment. The measuring equipment so installed shall conform to and shall be operated in accordance with the specifications and the recommendations contained in the American Gas Association publication Orifice Metering of Natural Gas, Gas Measurement Committee Report No. 3, including the appendix as published September 1969.*

      (2) *Deliveries. The volume of gas delivered shall be in accordance with the specifications and the recommendations contained in said Gas Measurement Committee Report No. 3.*

   B. *Specifications for Measurement. The following requirements shall apply to all gas meters:*

      (1) *Sales Unit. For purposes of reporting sales, the measurement unit shall be one MCF of gas (1,000 cubic feet).*

(2) *Unit of Volume.* For purposes of calculation, the unit of volume shall be one cubic foot at a base temperature of 60^{o} Fahrenheit and at a base pressure of 15.025 pounds per square inch absolute.

(3) *Pressure Base.* For purposes of measurement and meter calibration, the atmospheric or barometric pressure shall be assumed to be constant at 14.7 pounds per square inch absolute.

(4) *Test Frequency.* The accuracy of the measuring equipment at the point of delivery or allocation shall be tested at reasonable intervals, not to exceed forty-five (45) days.

(5) *Malfunction.* If at any time the measuring equipment is found to be out of service or not registering within the limits prescribed by the manufacturer, it shall be repaired or adjusted to read accurately. If the error in the measuring equipment is found to be within two percent, previous readings of such equipment shall be considered correct in computing the deliveries of gas thereunder. If the error in the measuring of equipment is found to be more than two percent, the volume measured since the last calibration shall be corrected. The volume adjustment should be calculated from the time the error occurred, if such time is ascertainable, and if not ascertainable, then back one-half of the time elapsed since the last date of calibration or as much as 23 days. If for any reason the measuring equipment is out of service or malfunctioning with the result that the quantity of gas delivered is not known, the volume of gas delivered through the period during which such equipment is out of service or malfunctioning shall be estimated on the basis of the best data available, using one of the following methods in order of priority:

(a) By using the registration of any check-measuring equipment, if installed and accurately registering; or

(b) By correcting the error if the percentage of error is ascertainable by calibration, test, or mathematical calculations: or

(c) By estimating the quantity of delivery by reference to actual deliveries during preceding periods under similar conditions when the unserviceable equipment was registering accurately.

C. Witnessing. The tests and calibrations made under Paragraph B above shall be run by qualified personnel. Representatives of the seller, buyer, and USGS shall have the right to witness such tests and calibrations.

D. Record Retention. The operator shall preserve or cause to be preserved all test data, meter reports, charts, or other similar records for a period of not less than one year. At any time within such period, the Supervisor may request such records and charts, subject to return within 20 days from receipt thereof.

E. Record Submittal. Upon request, one copy of the meter reports specified in D above shall be forwarded to the Supervisor. No special form is required, but all meter report forms shall include the following information where applicable:

(1) Producer or Seller.

(2) Purchaser.

(3) OCS lease number or other identifying designation.

(4) Station or meter number.

(5) Time and date of test.

(6) Location.

(7) Meter data (make, serial number, differential range, static range).

(8) Type connections (flange or pipe).

(9) Orifice data ("found" and "left" for line size and orifice size).

(10) Zero data for differential and for static spring.

(11) Calibration data ("found" and "left" for differential and for static).

(12) Remarks.

(13) Signature and affiliation of tester.

(14) Signature and affiliation of witness.

6. <u>Commingling of Production</u>. Commingling production of different ownership and/or from different leases prior to sales shall be subject to the approval of the Supervisor prior to the actual commingling. Unless otherwise established, the sales delivery shall be considered on the lease and appropriate measurement shall be provided. Well production test may be approved for allocation purposes.

A. <u>Applications</u>. Applications for approval of a commingling procedure shall contain the following information:

(1) An accurate description of any measuring devices and samplers, including schematics of the total system, and detailed sections.

(2) A list of the leases and fields involved.

(3) The estimated amounts and types of production involved.

(4) Details of the allocation procedure.

(5) Description of calibration equipment and intervals.

(6) Sales contract, agreement for disposal, or posted price.

B. *Allocation Schedule*. If production from more than one lease or owner is measured by the same sales meter, an allocation schedule of the monthly sales volume of commingled production shall be furnished to the Supervisor. The allocation schedule shall contain:

(1) Total sales volume.

(2) All storage volumes located upstream of the sales meter on the first and last day of the month.

(3) Total lease production from actual allocation meter readings with appropriate corrections (if allocated by meter measurements).

(4) Total lease production calculated from required well tests (if allocated by well test).

(5) Final allocation of actual sales to contributing leases.

7. *Automatic Custody Transfer*. Automatic custody transfer shall be subject to approval of the Supervisor.

A. *Application*. An application to the Supervisor for approval of the meter measurement and facilities shall include:

(1) Flow schematic of the ACT Unit showing and labeling all components.

(2) Leases and fields involved.

(3) Estimated amounts and types of production involved.

(4) Calibration documents for the prover.

B. *ACT Failure*. Any ACT failure, such as electrical, meter, prover loop, or other failure (this does not include malfunction as defined in subparagraph 2.C.(4) of the Order), which may require other methods of measurement shall be reported to the Supervisor within 24 hours. The Supervisor shall approve other methods of measurement *during the ACT failure period. A complete, detailed report shall be submitted to the Supervisor within 10 days.*

8. *Accidents. Any accident causing fire, damage to equipment, serious injuries, or pollution shall be reported to the Supervisor within 24 hours. A complete, detailed report shall be submitted to the Supervisor within 10 days.*

J. B. Lowenhaupt

J. B. Lowenhaupt
Oil and Gas Supervisor
Production Control
Gulf of Mexico Area

Approved:

Russell G. Wayland

Russell G. Wayland
Chief, Conservation Division

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
CONSERVATION DIVISION

GULF OF MEXICO AREA

OCS ORDER NO. 14

Effective January 1, 1977

APPROVAL OF SUSPENSIONS OF PRODUCTION

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.12(d).

If the Supervisor in his discretion approves a request for suspension of production pursuant to 30 CFR 250.12(d)(1), the terms of the lease will not be deemed to expire as long as the suspension remains in effect.

The Supervisor may not approve a request for a suspension of production to facilitate proper development of a lease because of a lack of transportation facilities unless he is satisfied that the lessee: (1) has made the request in good faith; and (2) is taking and will continue to take all reasonable actions to place the leasehold on production in accordance with applicable laws and regulations.

1. Suspension of Production to Facilitate Proper Development. A lease on which a well has been drilled and determined by the Supervisor to be capable of being produced in paying quantities according to the provisions of OCS Order No. 4 and thereafter temporarily abandoned or permanently plugged and abandoned is being properly developed if the lessee:

   A. is waiting for completion of drilling platform construction and installation or delivery of equipment or facilities which are necessary for production and for which the lessee has signed a contract that specifies a delivery date; or

   B. has pending before any Federal, State, or local government authority an application for a permit *which is necessary before the lessee can produce oil or gas from the lease; or*

C. *has submitted to the Department of the Interior a development plan or unitization agreement for the lease and is waiting for the Department to complete action on the plan or agreement; or*

D. *has submitted to the Department of the Interior and is actually conducting a geological and geophysical exploration or development program that includes drilling to develop sufficient reserves to produce either from the lease alone or in connection with other leases. For purposes of receiving a suspension under this provision, drilling activity on one lease may be determined by the Supervisor to be activity on all leases which are to be considered as a unit for purposes of providing sufficient reserves to establish economic justification for development wells, structures, facilities, and/or pipelines to recover, process, and transport such reserves as necessary; or*

E. *because of water depth or bottom conditions, is developing new and special production equipment, apparatus devices, or techniques in order to obtain, bring about, or create actual production capability .*

2. *Suspension of Production Because of Lack of Transportation Facilities. A lease on which a well has been drilled and determined by the Supervisor to be capable of being produced in paying quantities, according to the provisions of OCS Order No. 4, and thereafter temporarily abandoned or permanently plugged and abandoned and cannot be produced because of lack of transportation facilities, is being properly developed if the lessee:*

A. *is waiting for the completion of pipeline construction or delivery of pipeline equipment or facilities which are necessary for the transportation of oil and gas and for which the lessee has signed a contract that specifies the completion or delivery date; or*

B. *has pending before any Federal, State, or local government authority an application or a permit which* *is necessary before the lessee can transport oil and gas from the lease; or*

C. *has a contract to use an existing pipeline, but is unable to use the pipeline for reasons beyond the lessee's control.*

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