MINUTE ITEM

31

03/23/89
W 22649.2
Pelkofer

REPEAL COMMISSION REGULATIONS IN TITLE 2, DIVISION 1, ARTICLES 3.2, 3.3, AND 3.4; AND ADOPT JOINT OFFSHORE OIL AND GAS REGULATIONS IN TITLE 14, DIVISION 2, CHAPTER 4, SUBCHAPTER 6, COMMENCING WITH SECTION 2000.0

Calendar Item 31, attached, was pulled from the agenda prior to the meeting.

Attachment: Calendar Item 31.

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CALENDAR ITEM

A)
) Statewide
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31

03/23/89
W 22649.2
W 9668.8
W 24255
Pelkofer

REPEAL COMMISSION REGULATIONS IN TITLE 2, DIVISION 1, ARTICLES 3.2, 3.3, AND 3.4; AND ADOPT JOINT OFFSHORE OIL AND GAS REGULATIONS IN TITLE 14, DIVISION 2, CHAPTER 4, SUBCHAPTER 6, COMMENCING WITH SECTION 2000.0.

SUMMARY

Both the State Lands Commission (SLC) and the Division of Oil and Gas (Division) of the Department of Conservation currently have separate regulations and administrative procedures for the exploration, development, and production of oil and gas in State waters. The two agencies have decided to jointly adopt regulations to: (1) reduce the number of regulations, (2) increase safety to humans and the environment, (3) improve administrative efficiency, (4) eliminate potential conflicts between regulations, and (5) provide comprehensive integrated regulations.

STATEMENT OF REASONS

The State Lands Commission has exclusive authority and responsibility for the management of State-owned tide and submerged lands. Part of this responsibility includes the leasing of such lands for oil and gas exploration, development, and production, and the regulation of such activities necessary.

The Division of Oil and Gas also has the authority and responsibility for regulating the conduct of well-drilling and production operations in State waters.

Both agencies currently have separate regulations and administrative procedures governing exploration, development, and production operations in State waters. SLC and the

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Division of Oil and Gas have determined that the best alternative is to repeal their separate regulations and adopt the joint regulations.

The joint regulations address: (1) general administrative provisions; (2) well-design requirements and drilling safety; (3) plugging and abandonment of wells; (4) well-completion and well-work requirements and safety; (5) requirements for underground injection; (6) production facility safety equipment and procedures; (7) platform design and safety; (8) pipeline design and safety; (9) and operating plans for the prevention and control of pollution.

The current regulations of the agencies, formulated after the 1969 blowout in federal waters, have standardized operations and have been instrumental in protecting the health and safety of offshore workers, as well as the environment.

The proposed joint regulations, update, expand, and refine the regulations and reduce government duplication. State Land's responsibilities, as land managers and the Division of Oil and Gas's regulatory authority over California oilfields, are combined into one comprehensive code to regulate oil and gas operators working on State lands.

PURPOSE OF THE REGULATIONS

The purpose of the existing and the proposed Joint Offshore Oil and Gas Regulations is to ensure safe exploration and production operations in State waters. Safe operation includes protection of the persons employed in the industry, protection of the marine environment, and protection of the public's health and safety.

The regulations detail how operations are to be conducted but allow for individual modifications, when necessary, with specified approval. The joint regulations address the following:

Drilling Program; The regulations specify the actual design (location, drilling procedures, casing and cementing programs, blowout prevention, mud program, directional program, logging and testing program, etc.) of a well with such specificity that a repeat of a blowout such as occurred in 1969, in federal is waters, is a virtual impossibility.

Oil Spill Contingency Plan; Operators are required to have adequate spill containment and recovery equipment to combat oil spills up to 15 bbls on site, as well as plans for follow-up assistance. They are to train their persommel and maintain rediness and upgrade equipment so as to have state of the art capability. The SLC and the Division will continue to periodically test the various facilities for readiness with impromtu drills.

Critical Operations and Curtailment Plan; This spells out certain critical operations (well testing, running casing, etc.) that are not to be attempted or continued if weather conditions are severe, or, if oil spill or backup equipment is not available or out of service, or if drilling mud materials are insufficient for emergency control purposes.

H2S Contingency Plan; The proposed regulations provide for safer operation in area where hydrogen sulfide gas may be encountered. Lower threshold levels for sensors and personel exposure enhance safety. Operators are required to have current H2S and contingency plans that include information on the effects of H2S, safety procedures, training, evacuation plans and a list of agencies to notify in the event of an emergency.

Facility Emergency Evacuation Plans; Emergency evacuation plans are specifically required and such plans must consider alternative evacuation situations such as fire, explosion, H2S leak, blowout, or earthquake.

Systems Safety; Operators are required to have facilities which have approved structuaral design, safety equipment and survival gear, detailed drawings and descriptions of production, processing eguipment, integrated safety systems, hydrocarbon and H2S detection systems, and firefighting and fire detection systems.

Pipeline Inspections; In addition to requiring approval of all pipeline installations, annual inspection of existing lines is reguired to detect any deterioration that may cause a leak, spill, or explosion. New installations are designed to have leak detection and shut-in mechanisms to minimize spillage in the event of a leak.

With the adoption of Title 14, Division 2, Chapter 4, Subchapter 6, California will have the strongest and most comprehensive set of offshcre oil and gas regulations. The adoption of the proposed joint regulations will continue our State's exemplary record in offshore oil and gas safety.

Staff is recommending that the existing regulations governing these activities be repealed and that the proposed joint regulations be adopted by the Commission.

The Office of Administrative Law procedures have been followed, including the giving of appropriate notice, review and comment by the public, and response and explanation by the staff.

AB 884 N/A

EXHIBIT: A. Proposed Joint Regulations.

IT IS RECOMMENDED THAT THE COMMISSION:

1. FIND THAT THIS ACTIVITY IS EXEMPT FROM THE REQUIREMENTS OF CEQA, PURSUANT TO 14 CAL. CODE REGS. SEC. 15061 BECAUSE IT IS CATEGORICALLY EXEMPT AS DEFINED IN P.R.C. 21084 AND 14 CAL. CODE REGS. SEC. 15307 and 15308.

2. REPEAL ARTICLES 3.2, 3.3, and 3.4 of CHAPTER 1, DIVISION 3, TITLE 2 OF ITS REGULATIONS, AND ADOPT AND APPROVE FOR FILING WITH THE OFFICE OF ADMINISTRATIVE LAW THOSE CHANGES IN ITS REGULATIONS AS ARE SET FORTH IN EXHIBIT "A" ATTACHED.
3. DELEGATE AUTHORITY TO THE EXECUTIVE OFFICER TO MAKE MINOR NON-SUBSTANTIVE CHANGES TO THE PROPOSED REGULATIONS, AS MAY BE REQUIRED BY THE OFFICE OF ADMINISTRATIVE LAW.

4. AUTHORIZE THE EXECUTIVE OFFICER TO DEVELOP AND EXECUTE A MEMORANDUM OF UNDERSTANDING WITH THE DIVISION OF OIL AND GAS WHICH WILL DEFINE THE ADMINISTRATIVE PROCEDURES TO IMPLEMENT THE JOINT REGULATIONS.

5. AUTHORIZE STAFF TO TAKE ALL OTHER ACTIONS NECESSARY AND APPROPRIATE TO GIVE EFFECT TO THE ABOVE DECISIONS, ADOPTIONS, AND DELEGATIONS.

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OFFSHORE OIL AND GAS REGULATIONS

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Enact Title 14, Division 2, Chapter 4, Subchapter 6

SUBCHAPTER 6

JOINT OFFSHORE OIL AND GAS REGULATIONS

ARTICLE 1. GENERAL PROVISIONS

2000.0 Scope and Purpose

(a) These regulations have been adopted by the Division of Oil and Gas and the State Lands Commission to govern the safe conduct of oil and gas drilling and production operations on lands within the offshore territorial boundaries, inland bays and waterways of the State of California.

(b) The State Lands Commission limits its regulatory authority under these regulations to operations conducted on lands under State oil and gas leases or permits.

(c) To provide continuity and convenience, certain regulatory requirements mandated by only one of the agencies are included in these regulations. Accordingly, the sections containing these requirements will note the statutory authority and reference of the Agency adopting the specific rule.

Authority: Sections 3013, 3106, and 6108, PRC

Reference: Sections 3203-3220, 3227-3237, 6216, and 6873(d), PRC

2001.0 Definitions

Unless the context otherwise requires, the following definitions shall apply to these regulations:

(a) "Division", in reference to the government of this state, means the Division of Oil and Gas in the Department of Conservation.

(b) "Commission" means the State Lands Commission.

(c) "Staff" shall mean the Executive Officer or other authorized member of the Staff of the State Lands Commission.

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(d) "Rework" shall mean any well work other than the initial drilling or final abandonment that permanently alters in any manner the well casing or well function.

(e) "Well maintenance work" means any well work performed to restore or improve production without altering the well casing or the producing intervals.

Authority: Sections 3013, 3106, and 6108, PRC.
Reference: Sections 3106, 6216, and 6873(d), PRC

2002.0 Administration

2002.1 General

(a) These regulations shall be administered jointly by the Division and Staff. These regulations have been designed in great detail; however, the Division and Staff recognize that situations may arise which are not specifically covered herein and that emergency situations may arise which will require immediate decisions. In such situations, the Division and Staff shall authorize appropriate procedures to be followed.

Authority: Sections 3013, 3106, and 6108, PRC
Reference: Sections 3106, 6216, and 6873(d), PRC

2002.2 Notices of Intent to Perform Work and Other Applications.

(a) Application. Notices of intent for well drilling, completion, reworking, abandonment and supplementary work filed under Sections 3203 and 3229 of the Public Resources Code and proposed applications for fluid injection projects shall be submitted by the operator in quadruplicate to the Staff for its review and approval. Upon issuance of its written approval, the Staff shall then transmit duplicate copies of each approved notice and application to the Division for its review, modification if warranted, and approval and

issuance of a Division permit. Any modification by the Division shall require concurrence by the Staff. The date on which the Division receives the notice from the Staff shall be the date of filing the notice with the supervisor or district deputy under Sections 3203 and 3229 of the Public Resources Code. Applications concerning offshore structures, production facilities and pipelines shall be submitted in duplicate to the Staff.

(b) Notification of Well Maintenance Work. With the exception of routine well maintenance work such as pump changes and wire line work not effecting a change in production interval, the operator shall provide prior written notification to the appropriate Division district office and to the Staff of its intention to perform well maintenance work on any well. (Refer to Subsections 2011.2 and 2011.3).

Authority: Sections 3013, 3106, and 6108, PRC
Reference: Sections 3106, 3203, 3229, and 6216, PRC

2002.3 Approvals.

(a) Written Approvals. Staff approvals of notices of intent for well drilling, completion, reworking, abandonment, and supplementary work, and for applications for fluid injection projects shall be issued in writing to the operator upon transmittal of the notice or application by the Staff to the Division. Division approvals of the aforementioned notices and applications shall then be issued prior to commencing the proposed work or project. Approval of applications concerning offshore structures, production facilities and pipelines shall be issued only from the Staff.

(b) Emergency Approvals. Emergency verbal approval to commence well-work operations delineated in Subsection 2002.3(a) above, may be granted by the appropriate

~~Division district office and the~~ Staff when operations are necessary to avert a threat to life, health, property, or natural resources, or when approved operations are in progress and newly discovered well ~~conditions are such that~~ immediate corrective or abandonment operations are required. Such approval shall be granted only after the operator has provided all information pertaining to the condition of the well; including but not limited to, geological, mechanical ~~information,~~ and the results of tests and surveys. Notwithstanding any such emergency approval, the operator shall immediately file a confirming written application as required in Subsection 2002.2(a).

(c) Extension of Approvals. If operations have not commenced within one year of receipt of the notice, the notice ~~will be~~ considered cancelled. However, an approval ~~for~~ proposed operations may be extended for one year if the operator submits a supplementary notice pursuant to Subsection 2002.2 of these regulations prior to expiration of the one-year period and can show good cause for such extension, and if this supplementary notice is approved by both the Staff and the Division, pursuant to Subsection 2002.3 of these regulations.

(d) Other Approvals. Other approvals shall be obtained from the Division and/or Staff as hereinafter specified.

Authority: Sections 3013, 3106, and 6108, PRC
Reference: Sections 3106, 6216, and 6873(d), PRC

2002.4 Reports

(a) Final Reports of Well Work. Final written reports of well drilling, completion, reworking and abandonment work, and copies of electric logs and other well information shall be submitted in duplicate to the

Division and Staff within 60 days after completion of the work.

(b) Other Well Reports. Other reports and well information shall be submitted to the Division and/or Staff as hereinafter specified.

(c) Accidents/Incidents Relating to Facilities. Well blowouts, fires, hazardous oil or gas leaks, disasters, major accidents, or similar incidents on or emanating from an oil or gas drilling, producing, or treating facility shall be reported to the Division and Staff immediately.

(d) Oil Spills. Oil spills or slicks shall be reported immediately to the Division and Staff in accordance with the applicable Oil Spill Contingency Plan.

Authority: Sections 3013, 3106, and 6108, PRC

Reference: Sections 3106, 3203, 3229, 6216, and 6873(b),(d), PRC

2003.0 General Requirements

(a) Conduct of Operations. All operations shall be conducted in a proper and workmanlike manner and in accordance with good oil field practice.

(b) Approval of Emergency Plans. When filing a notice of intent to drill a well or perform remedial and/or well maintenance work, the operator shall submit or shall have previously submitted to the Staff the appropriate plans (in quadruplicate) that are required in Subsection 2005.4(e) and further plans described in Subsections 2005.12(c), 2005.13(b), 2011.5(d), 2014.6(b), 2017.3 and 2017.5. Upon its review and approval, the Staff will transmit the plans to the Division for its review and approval in accordance with Subsection 2002.2. These plans include a Well Control Drill Plan, Hydrogen Sulfide Contingency Plans, Oil Spill Contingency Plan, and a Critical Operations and Curtailment Plan.

(c) Approved Well Program at Well Site. A copy of the approved well-work program and subsequent approval forms issued by the Division and the Staff shall be available at the well site while conducting the work.

(d) Deviation from Approved Well Program. Operators shall not deviate from the approved basic well-work program without prior approval of the Division and Staff in accordance with Subsection 2002.3(b); additional requirements may be made at that time.

(e) Notification for Inspection. Operators shall give adequate prior notice to the appropriate Division or Staff office of the time for inspection or witnessing of tests as hereinafter required.

Authority: Sections 3013, 3106, and 6108, PRC

Reference: Sections 3106, 3213, 6216, and 6873(d), PRC

2004.0 Well and Facility Identification

(a) Well Designation. The well designation shall be affixed to the wellhead or guard rail of each completed well. Wells completed from two or more zones shall have the zones individually identified at the wellhead. The Division may approve other well identification methods if they substantially comply with the intent of this section. Identifying signs shall be maintained in a legible condition.

(b) Structure Designation. Platforms, islands, or other fixed structures shall be identified by at least two signs. The signs shall be located at diagonal corners of the platform or structure using letters and figures that are not less than 12 inches in height. The following information shall be indicated on these signs:

the platform or structure designation, the name of the lease operator, and the lease designation. The Division may approve abbreviations.

(c) Mobile Vessel Identification. Mobile offshore drilling vessels shall be identified by one (1) sign affixed to the derrick or to the heliport so as to be visible to approaching traffic. The signs shall indicate the name of the operator and the lease designation in letters and figures not less than 12 inches in height.

Authority: Sections 3013, 3106, and 6108, PRC

Reference: Sections 3106, 6216, and 6873(d), PRC

ARTICLE 2. DRILLING OPERATIONS

2005.0 General Provisions.

All exploratory wells and initial development wells shall be drilled in accordance with the provisions of these regulations until field rules are established. After field rules are established, development wells shall be drilled according to such rules.

Authority: Sections 3013, 3106, and 6108, PRC

Reference: Sections 3106, 6216, and 6873(d), PRC

2005.1 Field Rules.

When sufficient geological and engineering information has been compiled on a field from exploratory and initial development well drilling, the Division and Staff may establish field rules. The operator may also make application to the Division and Staff for the establishment or change of field rules. The Division and Staff shall jointly review and approve the field rules. Field rules generally include casing setting depths, casing cementing requirements, and wellhead and blowout prevention equipment. Before adopting a field rule or change, the Division and Staff shall distribute the proposal to affected operators and provide at least 15 days for comments. The Division and Staff shall jointly notify operators in writing of the establishment or change of any field rule.

Authority: Sections 3013, 3106, and 6108, PRC

Reference: Sections 3106, 6216, and 6873(d), PRC

2005.2 Daily Drilling Reports.

The operator shall provide daily reports of drilling and rework activities as required by the Division and Staff.

Authority: Sections 3013, 3106, and 6108, PRC

Reference: Sections 3106, 6216, and 6873(d), PRC

2005.3 Well Site Investigation.

Prior to commencing drilling operations on any well from a mobile drilling rig, the operator shall investigate the conditions of the ocean floor and near sub-bottom including sediment characteristics in the area of the proposed well site. The investigation shall be adequate to (1) ascertain the presence of shallow geological anomalies and gather other information to be used as an aid in the design of a safe well drilling and casing program, and (2) determine the presence and location of significant cultural resources. A report of the findings and provisions for mitigating any problems disclosed by the investigation shall be provided to and must be approved jointly by the Division and Staff. Where a number of wells are proposed to be drilled, the area of study may be expanded to cover all the well sites. The plan(s) of investigation shall be in accordance with guidelines provided by the Staff. This investigation may be conducted concurrently as part of any required environmental review.

Authority: Sections 3013, 3106, and 6108, PRC

Reference: Sections 3106, 6216, and 6873(d), PRC

2005.4 Drilling Program.

The operator shall submit as part of its notice of intention to drill, a detailed drilling program which shall contain the following information:

(a) Detailed Programs. Well location map; proposed well course; detailed drilling procedures; casing and cementing program; blowout prevention program; drilling mud program; directional survey program; electrical

logging; mud logging and sampling programs; and well testing procedures.

(b) Drilling Hazards. In all exploratory well drilling proposals, the operator shall provide in the detailed procedures, a description and depth of the possible drilling hazards that might be encountered in drilling the well. The drilling hazards shall include, but not be limited to, possible unstable bottom sediments, shallow gas-charged sediments, zones of lost circulation, oil and gas bearing zones and abnormally pressured zones.

(c) Safety Program for Running Surface Casings on Mobile Vessel. In drilling operations using a mobile drilling rig, the operator shall provide in the detailed drilling procedures, an operational program which describes procedures and personnel assignments to be employed for rig and personnel safety while drilling the hole and for running the surface casing(s). The program shall cover, but not be limited to, requirements and procedures for testing and use of the diverter system; establishment of safe penetration rates; monitoring of mud returns for indication of gas and loss of circulation; evaluation of drilling breaks; evaluation of severity of gas shows or kicks; stand-by liquid mud and its use in well control; emergency plugging of the well; safeguards while removing the drilling riser for running and cementing the surface casing(s); precautionary measures for fire prevention; and emergency movement of drilling rig off location.

(d) Rig Specifications. The specifications and performance data of the drilling rig to be used.

(e) Emergency Plans. Well Control Drill Plan; Critical Operations and Curtailment Plan; Oil Spill Contingency

Plan, ~~and~~ Hydrogen Sulfide Contingency Plan and a Facility Emergency Evacuation Plan.

Authority: Sections 3013, 3106, and 6108, PRC

Reference: Sections 3106, 6216, and 6873(d), PRC

2005.5 Well Casing Requirements.

All wells shall be cased and cemented in such a manner as to protect all zones that contain oil, gas or fresh water and to provide well control during drilling operations.

(a) ing Setting Depth Criteria. The casing setting pths shall be based upon all relevant geological and engineering factors, including the presence of shallow geological anomalies, the presence or absence of hydrocarbons, formation fracture gradients, formation pore pressures, water depth, and zones of lost circulation or other unusual characteristics.

Casing setting depths of the intermediate casing(s) shall be justified by calculations of the competency of the preceding casing seat to withstand anticipated mud weights, as well as the pressure generated by simulated well kicks from known or potential gas bearing zones, taking into consideration actual or estimated reservoir pressures, formation fracture gradients, minimum programmed mud weights and anticipated kick volumes.

The known and estimated factors and calculations used to determine the casing setting depths, as well as the casing design safety factors and specifications shall be shown in the casing and cementing program required in Subsection 2005.4(a).

(b) Formation Fracture Gradients. In situations where formation fracture gradients are not known, a formation leak-off or predetermined equivalent mud weight test shall be conducted to obtain estimated formation fracture gradients for use in the calculations. These tests shall be conducted after drilling a maximum of 50

feet of new hole below the shoe of the second surface and intermediate casings. The results of all the tests shall be recorded on the driller's log and reported to the Division and Staff.

(c) Abnormally Pressured Zones. The operator shall utilize current technological methods during drilling operations to aid in the prediction of possible abnormally pressured zones in order to minimize the potential for the development of a formation flow or kick.

(d) Casing Inspection. All casing shall be new pipe or the equivalent and shall be inspected by the operator prior to running it into a well. The inspection shall be sufficient to detect transverse and longitudinal defects, to determine wall thickness, pipe eccentricity and grade uniformity, and shall include a 100 percent thread check of the exposed threads. Casing inspection reports shall be maintained by the operator in its district office for a period of five years, and shall be available to the Division and Staff.

(e) Casing Program - General. Except in cases where casing requirements have been established by field drilling rules or where the Division and Staff determine that geological and engineering factors, including those provided by the operator, indicate that a different program should be used, the following casing and setting-depth requirements shall be included in all well casing programs. All depths refer to true vertical depth (TVD) below the ocean floor or ground level unless otherwise specified. In order of normal installation, the casings are identified as conductor, first and second surface, intermediate, and production casing.

(1) Conductor Casing (Referred to as drive or structural casing in 30 CFR 250.54(b).
This casing shall be set by drilling, driving, or jetting to a depth of approximately 100 feet below the ocean floor or ground level in order to support unconsolidated sediments and thereby provide hole stability for initial drilling operations. If drilled or jetted in, the fluid circulated to the ocean floor shall be a type that will not pollute the ocean environment.

(2) First Surface Casing (Referred to as conductor casing in 30 CFR 250.54(b).
This casing shall be set at a depth between 300 feet and 500 feet below the ocean floor; provided, however, that this casing shall be set before drilling into shallow formations known to contain oil and gas or, if unknown, upon encountering such formations.

(3) Second Surface Casing (Referred to as surface casing in 30 CFR 250.54(b).
This casing shall be set at a depth between 1,000 feet and 1,200 feet below the ocean floor, but may be set as deep as 1,500 feet in the event the first surface casing is set at least 450 feet below the ocean floor.

(4) Intermediate Casing.
Intermediate casing shall be set in accordance with the requirements of Subsection 2005.5(a). Notwithstanding these requirements, the Division and Staff may specify the use and setting depth of the intermediate casing. Also, intermediate casing shall be set at any depth below the second surface casing when required by well conditions such as abnormal pressure, loss of circulation, hole problems, and for the protection of

productive zones while performing deeper drilling. A blank liner may be used as intermediate casing provided the existing casing string is of adequate strength for conducting deeper drilling. The top of the liner shall overlap a minimum of 100 feet into the next larger casing string. The lap shall be tested for fluid entry to determine whether a seal between the liner top and next larger string has been achieved. The test may be witnessed and approved by a Division or Staff inspector. The test shall be recorded in the driller's log. If the test indicates an improper seal, the top of the liner shall be squeezed with cement and retested.

(5) Production Casing.

Production casing shall be set before completing the well for production. A blank or combination liner may be run and cemented as production casing providing the existing intermediate casing string is of adequate strength for the safe conduct of production operations. The overlap requirement and the testing of the seal between the liner top and next larger casing shall be conducted as specified in Subsection 2005.5(e)(4) for intermediate liners. The surface casing shall not be used as production casing.

a. Test of Water Shut-Off. When required by the Division, a test of water shut-off shall be made above the zones to be produced or injected into. The test may be witnessed and approved by a Division inspector before completing the well for production or injection. If the water shut-off test fails, the casing shall be squeezed with cement and retested. In injection wells, the Division

may approve the demonstration of the shut-off by running of a survey within 30 days after injection commences. The survey must show that injection fluid is confined to the approved injection interval. Duplicate copies of the survey shall be filed with the Division and Staff within 60 days.

Authority: Sections 3013, 3106, and 6108 PRC

Reference: Sections 3106, 3220, 3222, 6216, and 6873(d), PRC

2005.6 Casing Cementing Requirements.

The operator shall utilize appropriate cementing technology and casing equipment in order to achieve adequate cement fill- up and bonding on all casing cementing operations.

(a) Conductor and Surface Casings. The conductor (if drilled or jetted) and surface casings shall be cemented with sufficient cement to fill the annular space back to the surface or ocean floor. Cement fill shall be verified by the observation of cement returns. The cementing operation may be considered adequate if cement is circulated to the surface or ocean floor within the range of the calculated hole volume. In the event that cement returns are not obtained or cement channeling occurs during cementing of the surface casings, the operator shall run a temperature and/or cement bond survey and/or pressure test the casing shoe to evaluate the adequacy of the cement job. If the casing is determined to be inadequately cemented, the operator shall re-cement the casing string or perform other operations as jointly approved by the Division and Staff to ensure the competency of the cement job. In cases where cement has filled annular space back to the ocean floor, while conducting cementing operations from a mobile rig, the cement may be washed out to a

depth of 40 feet below the ocean floor or the depth of the conductor, whichever is less.

(b) Intermediate, Protective and Production Casings. The intermediate casings shall be cemented with sufficient cement to fill the annular space a minimum of 200 feet into the preceding larger casing string. The protective and production casings shall be cemented in a manner such that cement will cover or isolate zones of unusually high or low pressure and zones containing hydrocarbons. Sufficient cement shall be used to provide annular fill-up at least 500 feet above the zones to be covered or isolated or above the casing shoe in cases where zonal coverage is not required.

(c) Cement Bond Surveys. A cement bond survey shall be run following primary cementing of the intermediate and production casings to aid in determining whether the casings are adequately cemented. If a casing is thereby determined not to be adequately cemented, the operator shall re-cement the casing as necessary to achieve annular fill-up and isolation of zones. If, following a primary cementing operation, it has been determined without the aid of a cement bond survey that remedial cementing is necessary, the running of such survey may be deferred until after re-cementing. The operator shall verify the adequacy of the remedial cementing operations by running a cement bond survey or by other methods jointly approved by the Division and Staff.

(d) Surveys Filed with Division and Staff. A copy of each temperature and cement bond survey shall be filed immediately with the Division and Staff.

(e) Minimum Compressive Strength. After cementing any of the above casings, drilling shall not be commenced until sufficient time has elapsed for the cement to reach a compressive strength of at least 500 pounds per

square inch for the bottom 500 feet of the casing string. To determine the time at which a minimum compressive strength of 500 pounds per square inch has been attained, the operator shall pretest the cement slurry at the projected hole temperature and pressure at the cementing depth in accordance with "API Specification for Materials and Testing for Well Cements", API Spec. 10. Records of cement pretests shall be available for review by the Division and Staff.

Authority: Sections 3013, 3106, and 6108, PRC
Reference: Sections 3106, 3220, 6216, and 6873(d), PRC

2005.7 Pressure Testing of Casing.

(a) Prior to drilling out the plug after cementing, all casings except the conductor casing shall be pressure tested to at least the minimum pressure shown in the table below. In the event that the cement is under-displaced, the pressure test shall be conducted just before drilling out the casing shoe. This test shall not exceed 70 percent of the minimum internal yield pressure for the casing. If during the test, the pressure declines more than 10 percent in 30 minutes, or if there is another indication of a leak, corrective measures shall be taken so that a satisfactory test is obtained.

Casing String	Minimum Surface Test Pressure
First Surface	200 psi
Second Surface	1,000 psi
Intermediate, Production, Liner and Liner Lap	1,500 psi or 0.2 psi.ft. whichever is greater.

(b) All casing pressure tests shall be witnessed and approved by a Division inspector prior to drilling out of the casing or perforating opposite possible oil and gas zones. Inspection of data recorded by a device

approved by the Division may be substituted for witnessing.

(c) In the event of prolonged drill pipe operations which could cause damage to the casing, the casing shall be pressure-tested, calipered or otherwise evaluated to determine its adequacy for continued drilling operations.

Authority: Sections 3013, 3106, and 6108, PRC
Reference: Sections 3106, 3220, 6216, and 6873(d), PRC

2005.8 Directional Surveys.

Each well shall be drilled in accordance with the approved well course.

(a) Frequency. All wells drilled shall be directionally surveyed as drilling progresses giving both inclination and azimuth measurements. Directional survey shots shall be taken below the setting depth of the conductor casing string at intervals not exceeding 250 feet during the normal course of drilling and at intervals not exceeding 60 feet in angle changing portions of the hole. A multi-shot directional survey shall be run at casing setting depths and/or total depth. For wells whose average hole deviation does not exceed three degrees, a composite directional survey or a directional survey extracted from a continuous dipmeter log may be substituted for the multi-shot directional survey requirement.

(b) Survey Results. Results of directional and inclination survey shots shall be reported promptly to the Division and Staff. Copies of all composite and multi-shot directional surveys shall be filed with the Division and Staff.

Authority: Sections 3013, 3106, and 6108, PRC
Reference: Sections 3106, 6216, and 6873(d), PRC

2005.9 Blowout Prevention and Related Well-Control Equipment Requirements.

Blowout prevention equipment shall be installed, tested, used, and maintained in a manner necessary to prevent an uncontrolled flow of fluid from a well. Specific blowout prevention equipment requirements, mud monitoring systems, and relevant elements and procedures are set forth in the Division of Oil and Gas Manual No. M07 entitled "Blowout Prevention In California". Division and Staff personnel shall use Manual No. M07 as a guide for the determination of blowout prevention equipment requirements for individual wells and field rules for development drilling and well work.

Authority: Sections 3013, 3106, and 6108, PRC

Reference: Sections 3219, 6219, and 6873(d), PRC.

2005.10 Mud Program.

The characteristics, use, and testing of drilling mud properties, and the related procedures to be followed during drilling operations, shall be designed so as to prevent loss of well control. Adequate quantities of mud materials shall be maintained at the drill-site and shall be readily accessible for use in well control.

(a) Mud Quantities.

(1) The lessee shall include in the drilling mud program a tabulation by well depths of the minimum quantities of mud material to be maintained at the drill site. The minimum quantities of mud materials required shall be at least equal to the capacity of the downhole and active surface mud system. Sufficient weight material shall be maintained in order to condition the reserve mud to the maximum density programmed.

(2) A daily inventory of the mud materials shall be recorded and maintained at the drill site. Drilling operations shall be suspended whenever the required

minimum quantities of mud materials are not maintained at the drill site.

(b) Mud Control.

(1) Before starting out of the hole with the drill pipe, the mud shall be circulated with the drill pipe just off bottom, until the mud is properly conditioned. Proper conditioning requires, at a minimum, circulation to the extent that the annulus volume is displaced to ensure that the hole is clean and zonal pressures are being controlled by the mud column. When pulling the drill pipe, the annulus shall be filled with mud so that the mud level does not drop below a calculated depth of 100 feet below the derrick floor. The number of stands of drill pipe and drill collars that may be pulled before stopping to fill the hole and their equivalent mud displacement volumes shall be calculated and posted at the driller's station. A mechanical, volumetric, or electronic device shall be utilized for accurate measurement of the amount of mud used to fill the hole.

(2) A degasser and mud/gas separator shall be employed on all wells unless not required by field rules. This equipment shall be installed on the mud system prior to commencement of drilling operations, and shall be maintained for use throughout the drilling and completion of the well.

(c) Mud Testing Equipment. Mud testing equipment shall be maintained on the drilling rig at all times, and mud tests that are consistent with good operating practice shall be performed at least once each 8-hour period while drilling, or more frequently if conditions warrant.

(d) Mud Logging Equipment. Continuous mud logging equipment shall be employed on all exploratory drilling.

(e) Mud Monitoring Equipment. Mud-system monitoring equipment, as specified in the Division of Oil and Gas Manual No. M07, shall be installed with indicators located at the driller's station and used throughout the period of drilling after setting and cementing the conductor casing.

Authority: Sections 3013, 3106, and 6108, PRC

Reference: Sections 3106, 6216, and 6873(d), PRC

2005.11 Drilling Practices.

(a) Observing for Changes in Mud Volume. The volume of mud required to fill the hole shall be carefully observed, and if at any time there is an indication of swabbing or influx of formation fluids, the necessary safety device(s) shall be installed on the drill pipe. The drill pipe shall be run to bottom and the mud properly conditioned to stabilize the well. The mud shall not be circulated and conditioned except on or near the bottom, unless well conditions prevent the running of pipe to bottom.

(b) Posting Maximum Permissible Casing Head Pressure. The operator shall post at the driller's station, for each casing, the maximum permissible pressure that is allowed to build up against the blowout preventers before controlling the pressure by bleeding through the choke. This limiting pressure shall be based upon the formation fracture gradient at the depth of the casing shoe.

(c) Rate of Pulling Drill Pipe. The rate of pulling or running drill pipe shall be controlled to ensure that the hole is not being swabbed, or that formations exposed to the well bore will not be broken down. Special precautions shall be observed to prevent swabbing when full-hole tools are employed.

(d) Handling Drill-Stem Test Formation Fluid. All formation fluid produced during drill-stem testing shall be directed to the producing or test facilities, and fluid remaining in the drill string after drill-stem testing shall be reverse-circulated from the drill pipe. The mud shall be adequately conditioned prior to pulling the drill-stem test tools.

Authority: Sections 3013, 3106, and 6108, PRC
Reference: Sections 3106, 6216, and 6873(d), PRC

2005.12 Supervision and Training.

(a) Operator's Drilling Supervisor On-Site 24 Hours. The operator shall provide on-site company supervision (company toolpusher) of drilling operations on a 24-hour basis, unless it is determined upon the request of the operator and confirmed in writing by the Staff and Division that some lesser amount of supervision is appropriate. At least one member of the drilling crew or the toolpusher shall maintain rig-floor surveillance at all times, unless the well is secured with blowout preventers, bridge plugs, or cement plugs.

(b) Well Control Training-Certification Requirement. Except as provided below in Subsection 2005.12(c), the operator and drilling contractor personnel engaged in drilling operations shall be trained and qualified in well-control equipment, operations and techniques in accordance with the provisions of the Minerals Management Service Outer Continental Shelf Standard No. T-1, "Training and Qualifications of Personnel in Well-Control Equipment and Techniques for Drilling on Offshore Location," (MMSS-OCS-T1). Written certification shall be filed with the Division and Staff to confirm compliance with this provision before commencing drilling operations.

(c) Well Control Drill Plan and Frequency. In addition to the Well Control Drill Plan required in Section 4 of document MMSS-OCS-T1 referred to above, well control drills shall be held for each crew on a daily basis until each crew demonstrates its ability to effect proper closure of the well within the time established by the Well Control Drill Plan. Thereafter, the drills may be held on a weekly basis for each crew as set forth in Section 4. The performance of well control drills shall be recorded in the driller's log.

Authority: Sections 3013, 3106, and 6108, PRC
Reference: Sections 3106, 6216, and 6873(d), PRC

2005.13 Hydrogen Sulfide Gas Detection and Precaution During Drilling, Reworking and Maintenance of Wells.

(NOTE: For applicable regulations concerning PRODUCTION FACILITIES in an H2S environment, please see section 2014.6.)
When drilling operations are planned which will penetrate reservoirs known or expected to contain hydrogen sulfide (H2S), or in those areas where the presence or absence of H2S is unknown, or when reworking or maintaining wells completed in reservoirs known to contain H2S that could potentially result in an atmospheric concentration of 10 ppm or greater, the operator shall abide by the preventive measures and the operating practices set forth in this section. The requirements of this section are not applicable to operations in zones where the absence of H2S has been confirmed.

(a) Definitions. As used in this section, the terms shall have the following meanings:
"Facility" means a vessel, a structure or platform or an artificial island used for drilling, well completion, well workover and/or any other well work.
"Well-control fluid" means drilling mud, completion fluid, or workover fluid as appropriate to the particular operation being conducted.

(b) Hydrogen Sulfide Gas Detection and Alarm System.

(1) A separate automatic hydrogen sulfide (H2S) gas detector and alarm system shall be provided. This equipment shall be capable of sensing a minimum of five parts per million (ppm) H2S in air, with sensing points located in all enclosed and hazardous areas where gas handling facilities are located, as well as any living quarters and other areas where H2S might accumulate in hazardous quantities. The H2S detection devices shall activate audible and visible alarms when the concentration of H2S reaches 20 ppm in air.

(c) Hydrogen Sulfide Contingency Plan. A contingency plan shall be developed prior to the commencement of operations and, as applicable, encompass all phases of the work to be done. The plan and any subsequent revisions thereto shall be submitted for joint approval by the Division and Staff. A copy of the approved plan shall be located at the facility. The plan shall include the following:

(1) General information and physiological responses to H2S and SO2 exposure.

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

(3) Procedures for normal operating conditions and for H2S emergency conditions.

(4) Responsibilities, duties and procedures when the concentration of H2S in the atmosphere reaches the following:

a. 10 ppm level,

b. 20 ppm level,

c. 50 ppm level.

(5) Designation of briefing areas as location for assembly of personnel during an emergency condition. At least two briefing areas shall be established on each facility. Of these two areas,

the one up wind at any given time is the safe briefing area.

(6) Evacuation plan.

(7) Agencies to be notified in case of an emergency (must include the State Lands Commission and the California Division of Oil and Gas).

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

(d) Personnel Training Program.

(1) To promote efficient safety procedures, an on-site H2S safety program, which includes training sessions and drills, shall be established. Records of attendance shall be maintained on the production facility.

(2) A training session and drill shall be conducted for each person within 24 hours after arrival on the facility and biweekly thereafter.

(3) All regularly assigned working personnel shall have completed a basic first-aid course applicable to victims of H2S exposure. During on-site training sessions and drills, emphasis shall be placed upon rescue and first aid for H2S victims.

(4) Each facility shall have the following equipment, and the facility operator and each crew member shall be thoroughly familiar with the location and use of these items:

a. A first-aid kit appropriately sized for the normal number of working personnel.

b. Resuscitators, complete with face masks, oxygen bottles and spare oxygen bottles.

c. At least one litter or equivalent device.

(5) All personnel, whether regularly assigned, contracted or employed on an unscheduled basis, shall be informed as to the hazards of H2S and SO2. They shall also be instructed in the proper

use of personnel safety equipment which they may be required to use and be informed of H2S detectors and alarms, ventilation equipment, prevailing winds, briefing areas, warning systems and evacuation procedures.

(e) Personnel Protective Equipment.

(1) All facilities, and all marine vessels serving the facilities, shall have proper personal breathing apparatus immediately available for all personnel serving on board and additional equipment for possible use in evacuations. The protective breathing apparatus used in an H2S environment shall conform to all applicable Occupational Safety and Health Administration regulations as set forth in the Code of Federal Regulations 29 CFR 1910.134 and American National Standards Institute standards. Additional equipment, such a nose cups and spectacle kits, shall be available for use as needed.

(2) A system of breathing-air manifolds, hoses and masks shall be provided on the facility 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. The compressor and compressed air system shall comply with 29 CFR 1910.134 (OSHA).

(3) The storage locations of protective breathing apparatus shall be such that they are quickly and

easily available to all personnel. Storage locations shall include the following:

a. Facility operator's office

b. Each working deck

c. Crew quarters

d. Equipment storage room

e. Designated briefing areas

f. Heliport access.

(4) Workboats attendant to facility operations shall be equipped with a protective breathing apparatus for all workboat crew members. Additional protective breathing apparatus shall be available for evacuees. When possible, boats shall be stationed up wind from the facility.

(5) Helicopters attendant to facility operations shall be equipped with protective breathing apparatus for the flight crew.

(6) The following additional personnel safety equipment shall be available for use as needed.

a. Portable H2S detectors.

b. Retrieval ropes with safety harnesses to retrieve incapacitated personnel from contaminated areas.

c. chalkboards and note pads at convenient locations for communication purposes.

d. Bull horns and flashing lights.

e. Resuscitators.

(f) Visual Warning System.

(1) Wind direction equipment shall be installed at prominent locations to indicate to all personnel, on or in the immediate vicinity of the production facility, the wind direction at all times for determining safe up wind areas in the event that H2S or SO2 is present in the atmosphere.

(2) Operational danger signs shall be displayed from each side of the facility, and a number of rectangular red flags shall be hoisted, and other visual alarms shall be activated in a manner visible to watercraft and aircraft.

The signs shall have a minimum width of 8 feet and a minimum height of 4 feet and shall be painted a high-visibility yellow color with black lettering of a minimum of 12 inches in height, reading as follows:

DANGER -- HYDROGEN SULFIDE -- H2S

Each flag shall be a minimum width of 3 feet and a minimum height of 2 feet. When in use, all signs and flags shall be illuminated under conditions of poor visibility and at night. These signs and flags shall indicate the following conditions and operations requirements.

a. When H2S is present, signs shall be displayed.

b. When H2S is determined to have reached or exceeded a level of 20 ppm in environmental areas, red flags shall be hoisted, other visual alarms shall be activated, and protective equipment shall be worn by all personnel in those areas. Nonessential personnel shall be removed to a safe location or evacuated as appropriate. Radio communications shall be used to alert all known aircraft and watercraft in the immediate vicinity of this condition.

(g) Audible Warning System. A public address system and a siren, horn or other audible warning device with a unique sound used only for H2S warnings shall be installed at appropriate locations on the facility. When the warning devices are activated, (at the 20 ppm

threshold level) the designated responsible persons shall inform personnel of the level of danger and issue instructions on the initiation of appropriate protective measures.

(h) Ventilation Equipment. All ventilation devices shall be explosive proof when used in areas where H2S may accumulate. Moveable ventilation devices shall be provided in work areas and be multidirectional and capable of dispersing H2S or SO2 vapors away from working personnel.

(i) Flare Systems. The flare system shall be designed to safely gather and burn H2S gas. Flare lines shall be located as far from the other facilities 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.

(j) Notification of Regulatory Agencies. The following agencies shall be notified immediately if H2S has been determined to have reached or exceeded a level of 20 ppm or greater at the facility or in the environmental areas.

(1) State Lands Commission.

(2) Division of Oil and Gas.

(3) United States Coast Guard.

(k) Drilling, Completion and Workover Fluids Program When Operating in Zones Known to Contain H2S.

(1) Either oil or water base fluids may be used in drilling or working in formations containing H2S.

(2) If H2S is detected by air sensors, the mud or other hold fluids shall be checked for soluble sulfides by any appropriate test available (such as the Garrett Gas Train). Personnel conducting such tests shall don breathing equipment when air concentrations exceed 20 ppm.

(3) Additives for the control of H2S, (such as zinc and iron compounds) fluid pH, (caustic materials) and corrosion of equipment (such as oxygen scavengers and amines) shall be maintained on the facility.

a. When H2S is detected in the drilling fluid, appropriate scavengers shall be added as needed. If needed, drilling should be suspended until the entire system can be treated with such materials.

b. Additives for the control of pH (and fluid rheology) shall be added to water based drilling fluids in sufficient quantities to maintain the pH of the fluid above 10.0, if H2S is encountered in significant quantities.

c. Additional corrosion inhibitors may be added if the pH is not over 10 or it is deemed desirable.

(4) Well fluids containing H2S shall be degassed and the gases shall be collected and burned in a closed flare system.

(l) Kick Detection and Well Control. 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 and possible environmental damage.

(1) Contain the well fluid influx by shutting in the well and pumping the fluids back into the formation.

(2) Control the kick by using appropriate well control techniques to prevent formation fracturing in an open hole within the pressure limits of the well equipment (drill pipe, work string, casing, wellhead, BOP system and related equipment). The disposal of H2S and other gases shall be through

pressurized or atmospheric mud-gas separator equipment depending on volume, pressure and concentration of H2S. The separated gas shall be collected and burned in a closed flare system. The recovered well control fluid shall be treated to neutralize the H2S in solution and restore and maintain the proper qualities.

(m) Well Testing in a Zone Known to Contain H2S.

(1) Prior to initiation of a well test, safety meetings shall be conducted for all personnel who will be on the facility during the test. The meetings shall emphasize the use of protective breathing equipment, first aid procedures and the Contingency Plan.

(2) Well testing shall be performed with the minimum number of personnel in the immediate vicinity of the rig floor and with the appropriate test equipment to safely and adequately perform the test. During the test, H2S levels shall be continuously monitored.

(3) All produced gases shall be vented and burned through a flare which meets the requirements of paragraph (o)(6) of this section. Gases from stored test fluids shall be vented into the flare outlet.

(4) Downhole test tools and wellhead equipment shall be suitable for H2S service.

(5) Tubulars suitable for H2S service shall be used for well testing. Water cushions shall be thoroughly treated in order to prevent hydrogen embrittlement and corrosion. The test string shall be flushed with fluid treated for this purpose after completion of the test.

(6) All surface test units and related equipment shall be designed for H2S service.

(n) Metallurgical Properties of Equipment for Use in a Zone Known to Contain H2S.

(1) Equipment used in H2S environments shall be constructed of materials whose metallurgical properties resist or prevent stress cracking or hydrogen embrittlement.

(2) Tubulars shall also be designed for H2S service.

(3) Wellhead and BOPE components exposed to H2S bearing fluids shall conform to NACE standard MR-01-75 or a design shown to be a suitable equivalent.

(4) Temporary or permanent downhole devices, such as packers and bridge plugs, shall be designed for H2S service.

(o) General Requirements When Operating in H2S Zone.

(1) After penetration of an H2S zone, H2S levels shall be continuously monitored in the work areas, in addition to monitoring requirements stated above, during the following operations.

a. When it is necessary to pull a wet string of drill pipe or workover string;

b. While circulating bottoms up after a drilling break or trip;

c. During cementing and logging operations; and

d. While circulating to condition mud or other well control fluids.

(2) Coring. Protective breathing equipment shall be worn by those personnel in the working area at least ten stands in advance of retrieving a core barrel. Cores to be transported shall be sealed and marked for the presence of H2S.

(3) Logging. Well control fluid in use for logging operations shall be conditioned and treated to minimize the effects of H2S on the logging equipment.

(4) **Stripping operations.** Displaced well control fluid returns shall be monitored, and protective breathing equipment shall be worn by those personnel in the working area when the atmospheric concentration of H2S reaches or exceeds 20 ppm.

(5) **Gas cut fluid or well kick.** Should a decision be made to circulate out a kick, protective breathing equipment shall be worn by those personnel in the working area prior to and subsequent to bottoms up and throughout the kill operation.

(6) **Flare system.** The flare outlet shall be of such diameter to allow easy nonrestricted flow of gas. Flare line outlets shall be located on the downwind side and as far from the facility as is feasible, taking into account the prevailing wind directions, the wake effects caused by the facility and adjacent structure(s), and the height of all such facilities and structures. The flare outlet shall be equipped with an automatic pilot gas source or an equivalent system. Alternate methods shall be available for igniting the flare. All vents from production process equipment, tanks, relief valves, burst plates and similar devices shall be piped to the flare system used for H2S.

(7) **Corrosion monitoring.** Specific corrosion monitoring and mitigating measures shall be taken in areas of unusually severe corrosion or where high solution concentrations of H2S exist.

(8) BOPE and lubricator seals and sealing elements. All blowout prevention equipment and lubricator seals and sealing elements which may be exposed to the well fluids shall be of H2S resistant materials.

(9) Fuel and/or instrument gas. No gas containing H2S shall be used for fuel or instrument gas.

(10) Water disposal. Formation water from tests shall be treated for removal of H2S.

Authority: Sections 3013, 3106 and 6108, PRC

Reference: Sections 3105, 6216, 6108 and 6973(d), PRC

2006.0 Redrilling and Deepening.

Pursuant to Subsection 2002.2(a), the operator shall submit a detailed rework program for approval prior to commencement of redrilling or deepening operations. Drilling operations to redrill or deepen a well shall be conducted in accordance with the foregoing drilling regulations and the additional regulations listed below.

(a) Determination of Existing Casing Adequacy by Survey. A well shall not be redrilled or deepened unless it is determined that the casing exposed in the well will provide adequate strength for the proposed drilling and for subsequent production operations. Where well conditions permit, a casing inspection survey, indicating actual remaining wall thickness and internal diameter, shall be run to determine the condition of the casing and whether or not it is of adequate strength.

(b) Pressure Test of Existing Casing in Lieu of Survey. If it is not possible to run a casing inspection survey, the casing shall be pressure tested to 70 percent of minimum internal yield pressure or 1.25 times the anticipated surface pressure that it might be subjected to either during the drilling operations or subsequent production operations (including injection), or to the amount stipulated in Subsection 2005.7, whichever is greater.

(c) Pressure Test of Existing Casing if Surveyed. If the casing inspection survey indicates that the casing

strength is adequate, then the casing also shall be pressure tested as provided in Subsection 2006(b).

(d) Corrective Measures if Existing Casing Inadequate. In the event it is determined that the condition of the casing is inadequate, drilling shall not be initiated until corrective measures jointly approved by the Division and Staff are taken by the operator. The casing shall then be tested to the minimum pressure stipulated above in Subsection 2006(b).

(e) Survey Filing with Staff. A copy of the casing inspection survey shall be filed immediately with the Division and Staff.

(f) Determination of Adequacy of Existing Casing Cement. Prior to redrilling or deepening a well the operator shall demonstrate that the casing is adequately cemented above the point of new drilling. In the event it is thereby determined that the casing is not adequately cemented the operator shall properly recement the casing. The operator shall verify the adequacy of the remedial cementing operations by running a cement bond survey or other methods jointly approved by the Division and Staff.

(g) Abandonment Prior to Redrilling. Prior to redrilling a well, all oil, gas and water zones exposed in the well below the kickoff depth shall be properly abandoned in accordance with the plugging and abandonment requirements in Section 2007.0.

(h) Cementing Off Shallow Low-Pressure Zones. If a well is to be redrilled or deepened to a zone(s) having a pressure significantly higher or lower than that of the shallower producing zone(s), which drilling might cause lost circulation and thereby endanger the well, the shallower producing zones shall be squeeze cemented or

cased and cemented, prior to penetrating the lower zone(s).

Authority: Sections 3013, 3106, and 6108, PRC.
Reference: Sections 3013, 3106, 6216, and 6873(d), PRC

2007.0 Plugging and Abandonment of Wells.

2007.1 General.

(a) Detailed Program to be Approved Prior to Work. The operator shall submit a detailed well abandonment program together with the notice of intent to abandon pursuant to Subsection 2002.2(a). The program shall show the present condition of the well, freshwater-saltwater interface, all oil and gas bearing zones and the proposed method of abandonment.

(b) Verbal Approval to Plug During Ongoing Approved Operations. In the case of a newly drilled dry hole or where approved operations on a well are in progress, the operator may commence plugging operations by securing verbal approval from the Division and Staff as to the abandonment procedure and the time that plugging operations are to begin. The operator shall furnish the Division and Staff a description of the mechanical condition of the well, depth and description of all oil and gas shows and tests, and any other well data necessary for review of the abandonment procedure. The operator shall immediately submit an abandonment program in accordance with Subsection 2002.2(a) for confirmation of the approved abandonment procedure.

Authority: Sections 3013, 3106, and 6108, PRC
Reference: Sections 3210-3214, 6108, 6216, and 6873(d), PRC

2007.2 Permanent Abandonment.

The operator shall plug and abandon all wells in accordance with the following minimum requirements.

(a) Isolation of Zones in Open Hole. In the open hole portion of the well, cement plugs shall be placed to extend from 100 feet below to 100 feet above each oil or gas bearing zone or zone that is productive of hydrocarbons elsewhere in the field, and a cement plug at least 200 feet long shall be placed across the intrazone freshwater-saltwater interface, so as to isolate fluids in the strata in which they are found and to prevent them from migrating into other strata.

(b) Isolation of Open Hole from Casing. Where there is open hole below the casing, a cement plug shall be placed in the deepest casing 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 from 100 feet below to 100 feet above 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 from 100 feet below the casing shoe to 50 feet above the retainer.

(3) A permanent type bridge plug set within 150 feet above the casing shoe with 50 feet of cement placed 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 extending from 100 feet below to 100 feet above the perforations shall be placed opposite all open perforations. Other procedures such as cement squeezing through a retainer or bridge plug may be specified or authorized by the Division and Staff as circumstances justify.

(d) Miscellaneous Cementing Points. A cement plug shall be placed across all liner tops, stage cementing collars, cemented perforations, and known bad spots in the casing. Each plug shall extend at least 100 feet below to a minimum of 100 feet above the referenced cementing points.

(e) Isolation of Zones Behind Uncemented Casing. All oil, gas or freshwater bearing zones located behind casing in the uncemented portion of the hole shall be squeeze cemented to isolate fluids in the strata in which they occur.

(f) Isolating Zones Behind Cemented Casing. Inside cemented casing, a 100 foot cement plug shall be placed above each oil or gas zone and above the shoe of the intermediate or second surface casing. A cement plug at least 200 feet long also shall be placed across the intrazone freshwater-saltwater interface.

(g) Junk in Hole or Collapsed Casing. A diligent effort shall be made to recover junk when such junk may prevent proper abandonment of the hole. In the event that junk cannot be removed from the hole, cement plugs shall be placed as follows:

(1) Sufficient cement shall be squeezed through the junk to isolate the lower oil, gas, or freshwater zones and 100 feet of cement placed on top of the junk.

(2) If the top of the junk is opposite uncemented casing, the casing annulus immediately above the junk shall be squeeze-cemented with sufficient cement to insure isolation of the lower zones.

(h) Plugging of Casing Stubs. If casing is cut and recovered, a cement plug shall be placed so as to extend from 100 feet below the casing stub to 100 feet above the top of the casing stub.

(1) If the stub extends up into the next larger casing, then a retainer may be set 50 feet above the top of the stub and cement placed 150 feet below and 50 feet above the retainer. If the foregoing methods cannot be used, a bridge plug shall be set 50 feet above the top of the stub and capped with 50 feet of cement.

(2) If the stub is below the next larger casing, plugging of the open hole interval above the stub shall be accomplished in accordance with Subsection 2007.2(a) and, then in addition, a cement plug shall be placed so as to extend from 100 feet below to 100 feet above the casing shoe that is exposed above the stub in accordance with Subsection 2007.2(b).

(i) Plugging of Annular Space. No casing annular space that extends to the ocean floor shall be left open to the drilled hole below. If this condition exists, 200 feet of the annulus immediately above the shoe of the preceding casing shall be plugged with cement. If an uncemented inner casing is cut and recovered to accomplish this requirement, this casing stub shall be plugged in accordance with Subsection 2007.2(h).

(j) Surface Plug Requirement. A cement plug of at least 100 feet, with the top of the plug not more than 150 feet or less than 50 feet below the ocean floor, shall be placed in the well. Prior to the placement of the surface plug all inside casings which are uncemented at the surface plugging depth shall be cut and recovered. Casing cutting methods shall be employed that will not damage the well casing so as to prevent re-entry of the well.

(k) Testing of Plugs. The location and hardness of all cement plugs shall be tested by placement of drill

string weight (10,000 pounds minimum) on the plug, and by application of pump circulation.

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

(m) Clearance of Location. All casing and anchor piling shall be severed and removed from below the ocean floor at a depth approved by the Staff. The area in the vicinity of the well shall be inspected and the ocean floor shall be cleared of any other obstructions. A method shall be employed to sever or cut the casing that will not damage the well casing so as to prevent re-entry of the well.

(n) Alternate Procedures. Other procedures may be specified or authorized by the Division and Staff as circumstances justify.

(o) Record of Abandonment. All plugging and abandonment operations shall be recorded on the driller's log.

Authority: Sections 3013, 3106, and 6108, PRC

Reference: Sections 3210-3214, 6108, 6216, and 6873(d), PRC

2007.3 Temporary Abandonment.

(a) Any well that is to be temporarily abandoned shall be mudded and cemented as required for permanent abandonment, but the requirements of Subsection 2007.2 (d), (f), (i), (j) and (m) may be deferred. In lieu of a surface cement plug, for ocean floor and platform sites, a bridge plug (retrievable or drillable) may be set in the well between 15 and 200 feet below the ocean floor.

For land fill, pier, and island sites, the well shall be securely capped or closed at the surface until operations are resumed.

(b) The use of a bridge plug is not permitted to exclude a producing interval when recompleting a well, unless adequate plans for its future removal and proper abandonment of the zone are approved in advance of the work.

Authority: Sections 3013, 3106, and 6108, PRC
Reference: Sections 3210-3214, 6108, 6216 and 6873(d), PRC

2007.4 Witnessing of Abandonment Operations.

Operations to be witnessed by a Division inspector include tests for location and hardness of plugs placed across oil and gas zones open to the well, across freshwater zones, across casing shoes, cementing through junk, and placing of the surface plug. Geologic or mechanical conditions may require changes or additions to the schedule of inspections.

Authority: Sections 3013, 3106, and 6108, PRC
Reference: Sections 3228-3230, 3232, 6108, 6216, and 6873(d), PRC

2008.0 Records at Well Site.

During the performance of proposed operations, a copy of a well's tour reports shall be maintained at the well site. All pertinent well records shall be made available to the Division and Staff.

Authority: Sections 3013, 3106, and 6108, PRC
Reference: Sections 3106, 6216, and 6873(d), PRC

2009.0 Maintenance of Records.

(a) The operator shall keep a careful and accurate log, core record, and history of the drilling of each well.

(b) The operator shall provide field copies of electric logs and other surveys as necessary for the Division and Staff to approve expeditiously subsequent well operations.

(c) Within 60 days following the completion, abandonment, or the suspension of operations of any well, the

operator shall file in accordance with Subsection 2002.4, final copies of all logs, including electric logs, surveys, drilling records, well histories, core records and related information as measured and recorded for the well.

Authority: Sections 3013, 3106, and 6108, PRC
Reference: Sections 3210-3214, 6108, 6216, and 6873(d), PRC

ARTICLE 3. PRODUCTION OPERATIONS

2010.0 Well Completion.

2010.1 Well Completion Program.

(a) Pursuant to Subsection 2002.2(a), the operator shall submit to the Division and Staff a detailed completion program for approval prior to commencement of operations on each well.

(b) The program shall include detailed information of the proposed completion interval, wellhead assembly, surface and downhole production equipment and controls, and safety system. Working drawings as appropriate shall be provided.

Authority: Sections 3013, 3106, and 6108, PRC
Reference: Sections 3210-3214, 6108, 6216, and 6873(d), PRC

2010.2 Wellhead Equipment.

(a) The wellhead equipment associated with casing(s) and tubing(s) and all valves and fittings which may be subjected to wellbore pressure under any condition, shall have a rated working pressure exceeding the maximum anticipated surface pressure to which they may be subjected.

(b) All wellhead equipment, valves and flow lines installed on offshore wells shall be flange or other non- thread connected. All wellhead equipment, valves and flow lines on upland wells that are designed for a working

pressure of 2,000 psi or greater shall be flange or other nonthread connected.

(c) Valves shall be installed to permit fluids to be pumped into each casing. Two master valves shall be installed on any well capable of flowing.

(d) All wellhead equipment shall be tested by a fluid pressure equal to its rated working pressure after installation on a well.

(e) All wellhead components, valves and flow lines in service upon adoption of these regulations are exempted from the requirements in Subsection 2010.2(b); except that any modifications to existing equipment or piping, unless otherwise approved jointly in writing by the Division and Staff, shall be flange or other nonthread connected.

(f) All wellhead equipment, valves and flow lines on any well to be redrilled, recompleted or converted to fluid injection shall comply with the provisions of Subsections 2010.2(a)-(e) above.

(g) All pressure test results shall be recorded on the daily well work report.

(h) Subsea Wellhead Equipment. Wellhead equipment for subsea completed wells shall be jointly approved by the Division and Staff on an individual well basis.

Authority: Sections 3013, 3106, and 6108, PRC
Reference: Sections 3106, 6216, and 6873(d), PRC

2010.3 Blowout Preventer Removal.

If a well is capable of flowing oil or gas, a back-pressure valve or suitable tubing plug shall be installed in the tubing(s) to seal the bore of the tubing while removing or installing the blowout preventer or Christmas tree.

Authority: Sections 3013, 3106, and 6108, PRC
Reference: Sections 3106, 6216, and 6873(d), PRC

2010.4 Sealing of Casing - Tubing Annulus.

All wells capable of flowing oil or gas shall be equipped with production packer(s) to seal the casing-tubing annulus. All production packers shall be properly tested upon installation.

Authority: Sections 3013, 3106, and 6108, PRC

Reference: Sections 3106, 6216, and 6873(d), PRC

2010.5 Perforation and Wireline Operations Under Pressure.

(a) All perforation and wireline operations conducted under pressure shall be performed through a lubricator installed on appropriate wireline blowout-prevention equipment. The pressure rating of the lubricator shall be equal to or greater than the maximum possible surface shut-in pressure of the well.

(b) The well shall not be left unattended unless all wellhead flow valves and the wireline blowout preventer are closed in or unless the tools are pulled up into the lubricator and the master valve closed.

Authority: Sections 3013, 3106, and 6108(d), PRC

Reference: Sections 3106, 6216, and 6873(d), PRC

2010.6 Subsurface Safety Valves.

(a) All wells capable of flowing oil or gas shall be equipped with a surface-controlled subsurface safety valve installed in the tubing(s) at a depth of 100 feet or more below the ocean floor, or ground level for upland wells. Such valve shall be installed in artificial lift wells, unless proof is provided to the Division and Staff that such wells are incapable of flowing. Wells which are presently equipped with direct-controlled subsurface safety valves shall have surface-controlled subsurface safety valves installed the first time the tubing is pulled. The control system for the surface-controlled subsurface safety valves

shall be connected to the facility integrated safety-control system, where applicable.

(b) Subsurface safety valves at the time of installation shall conform to the "API Specifications for Subsurface Safety Valve Equipment", API Specification 14A.

(c) Subsurface safety valves shall be installed, adjusted and maintained in accordance with the "API Recommended Practice for Design, Installation and Operation of Subsurface Safety Valve Systems", API RP 14B.

(d) Each subsurface safety valve installed in a well shall be tested by the operator for proper operation each month. The Division or Staff may adjust the testing frequency based upon the performance record of the valve. The tests may be witnessed and approved by the Division or Staff. If the valve does not operate properly, it shall be repaired or replaced and retested.

(e) When a subsurface safety valve is removed from a well for repair or replacement it shall be replaced immediately or a tubing plug shall be installed before the well is left unattended.

(f) The well history and any subsequent report of workover shall state the type and depth of the subsurface safety valve or tubing plug installed in the well.

(g) Records shall be maintained at the facility or at the nearest onshore office of the operator. The records shall contain a description and show the present status and past history of each subsurface safety valve or tubing plug, including dates and details of any inspection, testing, repairing, and reinstallation or replacement. The operator shall submit a copy of such records semiannually to the Division and Staff.

Authority: Sections 3013, 3106, and 6108, PRC.

Reference: Sections 3106, 6216, and 6873(c), PRC.

2010.7 Wellhead Surface Safety Valves.

(a) All wells capable of flowing oil or gas and all artificial lift wells capable of afterflow when the source of power is shut off shall be equipped with an automatic, fail-close, wellhead surface safety valve. High-low pressure sensors shall be located in the flowline near the wellhead and shall be set to cause shut-in of the valve in the event of abnormally high or low flowline pressures. In addition, each valve shall be connected to the integrated safety control system on the facility.

(b) Wellhead surface safety valves shall be employed in the safety control system on the facility and shall be tested in accordance with the provisions of the "API Recommended Practice for Analysis, Design, Installation, and Testing of Basic Surface Safety Systems on Offshore Production Platforms", API RP 14C.

(c) Wellhead surface safety valves at the time of installation shall conform to the "API Specifications for Wellhead Surface Safety Valves and Underwater Safety Valves for Offshore Service" API Specification 14D and shall be operated and maintained in accordance with "API Recommended Practice for Use of Surface Valves and Underwater Safety Valves Offshore," API RP 14H.

(d) All wellhead surface safety valves shall be tested monthly by the operator for operation and holding pressure. If the valve fails to test properly, it shall be repaired or replaced and retested. Pressure sensors shall be operated and tested monthly by the operator for proper pressure settings. The monthly tests may be witnessed and approved by the Division or Staff. Results of all tests shall be recorded and maintained

at the facility or at the nearest onshore office of the operator.

Authority: Sections 3013, 3106, and 6108, PRC
Reference: Sections 3106, 6216, and 6873(d), PRC

2010.8 Wells on Artificial Lift.

(a) Artificial lift wells not equipped with a wellhead surface safety valve shall have safety devices installed to shut off the source of power in the event of abnormally high or low flowline pressures. The source of power shall be controllable by the integrated safety system.

(b) The safety devices shall be actuated and tested monthly by the operator. If the device fails to test properly, it shall be repaired or replaced and retested. The monthly tests may be witnessed and approved by the Division or Staff. The results of all tests shall be recorded and maintained at the facility or at the nearest onshore office of the operator.

Authority: Sections 3013, 3106, and 6108, PRC
Reference: Sections 3106, 6216, and 6873(d), PRC

2010.9 Production Headers.

(a) All well flowlines shall be equipped with a check valve located downstream at the production header. All check and header valves, as well as any piping that might be subjected to wellhead pressure, shall be of sufficient strength to withstand any possible shut-in wellhead pressure.

(b) The flowline check valve shall be tested monthly by the operator for holding pressure. If the valve fails to test properly, it shall be repaired or replaced and retested. The monthly tests may be witnessed and approved by the Division or Staff. The results of all tests shall be recorded and maintained at the

facility or at the nearest onshore office of the operator.

Authority: Sections 3013, 3106, and 6108, PRC
Reference: Sections 3106, 3219, 6108, and 6873(d), PRC

2011.0 Remedial and Well-Maintenance Work.

2011.1 Remedial Work.

(a) The operator shall obtain written approval from the Division and Staff in accordance with Subsections 2002.2(a) and 2002.3(a) prior to performing remedial work on any well that involves the alteration of its casing or that will result in changing its producing interval. Such work includes, but is not necessarily limited to, casing and liner repair or replacement, squeeze cementing, plugging, perforating, and the installation or removal of bridge plugs and packers.

(b) Each notice of intent for remedial work shall be accompanied by a statement reflecting the reason for the work and a detailed work and blowout prevention equipment program. The work program also shall include the static formation pore pressure of all oil and gas zones exposed or to be exposed in the well, the type and densities of circulating fluids to be used, and any other data that are pertinent to well control.

Authority: Sections 3013, 3106, and 6108, PRC
Reference: Sections 3106, 3203, 6216, and 6873(d), PRC

2011.2 Nonroutine Well-Maintenance Work.

(a) The operator shall provide written notification to the Division and Staff of its intention to perform nonroutine well-maintenance work on any well. Such work includes, but is not limited to, formation fracturing, acidization or solvent stimulation, snubbing operations, wireline work resulting in a change of

producing interval, such as shifting of a tubing sleeve, any work on a subsea completed well that involves entry of the well, and any other well work that involves a higher than normal degree of risk.

(b) The written notification shall include a description of the work to be performed, the type of blowout prevention equipment and safety equipment to be used, and the anticipated date that the work will commence.

Authority: Sections 3013, 3106, and 6108, PRC
Reference: Sections 3106, 6212, and 6873(d), PRC

2011.3 Routine Well-Maintenance Work.

Routine well-maintenance work such as pump changes and wireline work not resulting in a change in the producing interval shall not require advance notification or approval. However, routine well-maintenance work shall be recorded on the operator's daily operations report and copies of the report shall be provided to the Division and Staff upon request.

Authority: Sections 3013, 3106, and 6108, PRC
Reference: Sections 3106, 6212, and 6873(d), PRC

2011.4 Blowout Prevention Equipment Requirements.

(a) Blowout prevention equipment requirements for remedial and well-maintenance work shall be in accordance with established field rules, or if not established, in accordance with the provisions of Subsection 2005.9.

(b) On wells capable of flowing oil or gas, the bore of the tubing(s) shall be sealed with a back-pressure valve, safety valve or suitable tubing plug during the removal or installation of the Christmas tree or blowout preventer.

(c) All perforating and wireline operations conducted under pressure shall be performed through a lubricator installed on appropriate wireline blowout prevention equipment. The pressure rating of the lubricator shall

be equal to or greater than the maximum possible surface shut-in pressure of the well. The well shall not be left unattended unless all wellhead flow valves and the wireline blowout preventer are closed in, or tools are pulled up into the lubricator and the master valve closed.

(d) Within 60 days after the completion of remedial and nonroutine well-maintenance work, the operator shall file a history with the Division and Staff that describes the work performed and final condition of the well.

Authority: Sections 3013, 3106, and 6108, PRC

Reference: Sections 3106, 3219, 6212, and 6873(d), PRC

2011.5 Supervision and Training.

(a) The operator shall provide full-time onsite company supervision of well completion and other production well work which is performed on any well that may be capable of flowing oil, gas or water. This also includes wireline perforating and any well work performed under pressure.

(b) At least one member of the production well work crew or the production supervisor shall maintain surveillance of the well at all times, unless the well is secured with blowout preventers, bridge plugs, tubing plugs or appropriate valving.

(c) Operator and contractor supervisory personnel and crew chiefs who are engaged in offshore production well work operations shall be trained and qualified in well-control equipment, operations and techniques. These persons shall successfully complete a basic well-control course every four years and take a refresher course in well-control each year. The basic and refresher course curriculums shall be submitted to and approved by the Division and Staff. Written

certification shall be filed with the Division and Staff upon compliance with these training requirements.

(d) A well control drill plan shall be prepared by the operator for each production facility for the training of crews engaged in production well work. The plan shall be submitted to and jointly approved by the Division and Staff.

(e) Well control drills shall be held for each crew on a daily basis until each crew member demonstrates the ability to perform satisfactorily his well control assignment. Thereafter, drills shall be held at least once a week for each crew. All drills shall be recorded on the daily well work report.

(f) The operator shall be responsible for ensuring that all personnel who are engaged in the installation, inspection, testing and maintenance of surface and subsurface devices, that are used to ensure safety and to prevent pollution on offshore platforms, are trained and qualified in accordance with "API Recommended Practice For Qualification Programs For Offshore Production Personnel Who Work With Anti-Pollution Safety Devices," API RP T-2. Training programs shall be submitted to and jointly approved by the Division and Staff. Written certification shall be filed with the Division and Staff upon compliance with these training requirements.

Authority: Sections 3013, 3106, and 6108, PRC

Reference: Sections 3106, 3219, 6108, and 6873(d), PRC

2012.0 <u>Anomalous Casing Annulus Pressure.</u>

(a) The casing annulus pressure(s) on each well shall be checked monthly and a record of the pressure readings shall be maintained at the facility or at the nearest onshore office of the operator if the facility is not manned. The operator shall give immediate written

notification to the Division and Staff of the occurrence of any anomalous pressure between casings in any well.

(b) The operator shall investigate to determine the source of any anomalous pressure and, if required, shall seal off the source in a manner approved jointly by the Division and Staff.

(c) Any attempt by the operator to reduce the surface pressure by producing the fluid from the casing annulus, must include a monthly production test of each annulus.

Authority: Sections 3013, 3106, and 6108, PRC
Reference: Sections 3106, 3219, 6108, and 6873(d), PRC

2013.0 Approval of Underground Injection or Disposal Projects.
The approval of any subsurface injection or disposal project shall be obtained from the Division and Staff, in accordance with Subsections 2002.2(a) and 2002.3(a), before underground injection or disposal can begin. The operator requesting approval for such a project must provide any data that, in the judgment of the Division and Staff, are pertinent and necessary for the proper evaluation of the proposed project.
Authority: Sections 3013, 3106 and 6108 PRC
Reference: Section 3106, 6108 and 6873(d) PRC

2013.1 Project Data Requirements.
(NOTE: See Subsection 2013.2 for special requirements for cyclic steam projects, and Subsection 2013.3 for supplementary requirements for gas storage projects.) The data required to be filed include the following, where applicable:

(a) An engineering study, including but not limited to:
(1) Statement of primary purpose of the project.
(2) Reservoir characteristics of each injection zone, such as porosity, permeability, average thickness, areal extent, fracture gradient, original and

present temperature and pressure, and original and residual oil, gas and water saturations.

(3) Reservoir fluid data for each injection zone, such as oil gravity and viscosity, water quality, and specific gravity of gas.

(4) Casing diagrams, including cement plugs and actual or calculated cement fill behind casing, of all idle, abandoned, or deeper-zone producing wells within the area affected by the project, and evidence that abandoned wells in the area will not have an adverse effect on the project or cause damage to life, health, property, or natural resources.

(5) The planned well-drilling and abandonment program to complete the project, including a flood-pattern map showing all injection, production, and abandoned wells, and unit boundaries.

(b) A geologic study, including but not limited to:

(1) Structural contour map drawn on a geologic marker at or near the top of each injection zone in the project area.

(2) Isopachous map of each injection zone or subzone in the project area.

(3) At least one geologic cross section through at least one injection well in the project area.

(4) Representative electric log to a depth below the deepest producing zone (if not already shown on the cross section), identifying all geologic units, formations, freshwater aquifers, and oil or gas zones.

(c) An injection plan, including but not limited to:

(1) A map showing injection facilities.

(2) Maximum anticipated surface injection pressure (pump pressure) and daily rate of injection, by well.

(3) Monitoring system or method to be utilized to ensure that no formation or mechanical damage is occurring and that the injection fluid is confined to the intended zone or zones of injection.

(4) Method of injection.

(5) List of proposed cathodic protection measures for plant, lines, and wells, if such measures are warranted.

(6) Treatment of water to be injected.

(7) Source and analysis of the injection liquid.

(8) Location and depth of each water-source well that will be used in conjunction with the project.

(d) Copies of letters sent to offset operators notifying them of the proposed injection project, with return receipt evidencing proof of delivery.

(e) Other data as required for large, unusual, or hazardous projects, for unusual or complex structures, isogor maps, water-oil ratio maps, isobar maps, equipment diagrams, and safety programs.

(f) All maps, diagrams and exhibits required in Subsections 2013.1 (a) through (e) shall be clearly labeled as to scale and purpose and shall clearly identify wells, boundaries, zones, contacts, and other relevant data.

Authority: Sections 3013, 3106 and 6108 PRC
Reference: Sections 3106, 6108 and 6873(d) PRC

2013.2 Data Required for Cyclic Steam Injection Project Approval.

The data required prior to approval of a cyclic steam (steam soak) project include, but are not limited to, the following:

(a) A letter from the operator notifying the Division and Staff of the intention to conduct cyclic steam injection operations on a specific lease, in a specific reservoir, or in a particular well.

(b) All applicable items listed in Subsections 2013.1(a) through (f).

Authority: Sections 3013, 3106, and 6108 PRC

Reference: Sections 3106, 6108, and 6873(d) PRC

2013.3 Data Required for Gas Storage Project Approval.

The data required prior to approval of a gas storage project include all applicable items listed in Subsection 2013.1 (a) through (f), and the following, where applicable:

(a) Characteristics of the cap rock, such as areal extent, average thickness, and threshold pressure.

(b) Oil and gas reserves of storage zones prior to start of injection, including calculations.

(c) A list of proposed surface and subsurface safety devices, tests, and precautions to be taken to ensure safety of the project. Refer to Subsections 2010.6 and 2010.7.

(d) Proposed waste water disposal method.

Authority: Sections 3013, 3106, and 6108 PRC

Reference: Section 3106, 6108 and 6873(d) PRC

2013.4 Filing, Notification, Operating, and Testing Requirements for Underground Injection Projects.

(a) The Staff and appropriate Division district deputy shall be notified of any anticipated changes in a project resulting in alteration of conditions originally approved, such as: increase in size, change of injection interval, or increase in injection pressure. Such changes shall not be carried out without Division and Staff approval.

(b) Notices of intention to drill, redrill, deepen, or rework shall be submitted for approval in accordance with Subsection 2002.2(a) whenever a new well is to be drilled for use as an injection well and whenever an

existing well is converted to an injection well, even if no-work is required on the well.

(c) An injection report on a current Division form or in a computerized format acceptable to the Division shall be filed with the Division and Staff on or before the last day of each month, for the last preceding calendar month.

(d) A chemical analysis of the liquid being injected shall be made and filed with the Division and Staff whenever the source of injection liquid is changed, or as requested by the Division and Staff.

(e) An accurate, operating pressure gauge or pressure recording device shall be available at all times, and all injection wells shall be equipped for installation and operations of such gauge or device. A gauge or device used for injection-pressure testing, which is permanently affixed to the well or any part of the injection system, shall be calibrated at least every six months. Portable gauges shall be calibrated at least every two months. Evidence of such calibration shall be available to the Division or Staff upon request.

(f) All injection piping, valves, and facilities shall meet or exceed design standards for the maximum anticipated injection pressure, and shall be maintained in a safe and leak-free condition.

(g) All injection wells, except steam, air, and pipeline-quality gas injection wells, shall be equipped with tubing and packer set immediately above the approved zone of injection. New or recompleted injection wells shall be equipped with tubing and packer upon completion or recompletion. Exceptions may be made when there is:

(1) No evidence of freshwater-bearing strata.

(2) More than one string of casing cemented below the base of fresh water.

(3) Other justification, as determined by the Division and Staff based on documented evidence that freshwater and oil zones can be protected without the use of tubing and packer.

(h) Data shall be maintained to show performance of the project and to establish that no damage to life, health, property, or natural resources is occurring by reason of the project. Injection shall be stopped if there is evidence of such damage, or loss of hydrocarbons, or upon jointly written notice from the Division and Staff. Project data shall be available for periodic inspection by the Division or Staff.

(i) To determine the maximum allowable surface injection pressure, a step-rate test shall be conducted prior to sustained liquid injection. Test pressure shall be from hydrostatic to the pressure required to fracture the injection zone or the proposed injection pressure, whichever occurs first. Maximum allowable surface injection pressure shall be less than the fracture pressure. The appropriate Division office shall be notified prior to conducting the test so that it may be witnessed by a Division inspector. The Division may waive or modify the requirement for a step-rate test if it is determined that surface injection pressure for a particular well will be maintained considerably below the estimated pressure required to fracture the zone of injection.

(j) All injection wells will be monitored to ensure that the injected fluid is confined to the intended zone or zones. Except for steam and air injection wells, sufficient surveys shall be filed with the Division and Staff within three (3) months after injection has commenced, once every year thereafter, after any

significant anomalous rate or pressure change, or as requested by the Division or Staff, to confirm that the injection fluid is confined to the proper zone or zones. Typical surveys used to monitor injection wells are the radioactive tracer, spinner, and static temperature. The monitoring schedule may be modified by the Division and Staff if supported by documented evidence showing good cause. The appropriate Division office shall be notified before such surveys are made, as they may be witnessed by a Division inspector.

(k) Additional requirements or modifications of the above requirements may be necessary to fit specific circumstances and types of projects. Examples of such additional requirements or modifications are:

(1) Injectivity tests.

(2) Graphs of time vs. oil, water, and gas production rates, maintained for each pool in the project and available for periodic inspection by the Division or Staff.

(3) Graphs of time vs. tubing pressure, casing pressure, and injection rate maintained for each injection well and available for periodic inspection by division personnel.

(4) List of all observation wells used to monitor the project, indicating what parameter each well is monitoring (i.e., pressure, temperature, etc.), submitted to the division annually.

(5) List of all injection-withdrawal wells in a gas storage project, showing casing-integrity test methods and dates, the type of safety valves used, submitted to the division annually.

(6) Isobaric maps of the injection zone, submitted to the division annually.

(7) Notification of any change in waste disposal methods.

Authority: Sections 3013, 3106, and 6108 PRC
Reference: Sections 3106, 6108 and 6873(d) PRC

2014.0 Production Facility Safety Equipment and Procedures.
Unless otherwise provided for in this Section, safety equipment, systems and procedures on offshore production facilities shall be based upon the "API Recommended Practice for Analysis, Design, Installation and Testing of Basic Surface Safety Systems on Offshore Production Platforms," API RP 14C.
Authority: Sections 3013, 3106, and 6108, PRC
Reference: Sections 3106, 6216, 6108, and 6873(d), PRC

2014.1 Integrated Safety-Control System.
Each offshore production facility shall be equipped with an approved integrated safety-control system that will cause shut-in of all wells and shut-down of the complete production facility in the event of fire, pipeline failure or other accident. Proposed modifications to the system shall also be approved by the Division and the Staff. A complete testing of the safety-control system shall be conducted by the operator every six months and may be witnessed and approved by the Division or Staff.
The integrated safety-control system shall be actuated by the following devices which shall be installed and maintained in operating condition at all times. The devices shall be tested monthly by the operator, which tests may be witnessed and approved by the Division or Staff. The operator shall maintain records at the production facility or at its nearest onshore office showing the present status and past history of each device, including dates and details of inspection, testing, repairing, adjustment, and reinstallation or replacement.

(a) Emergency manually operated controls to actuate the integrated safety system shall be located on all exit

stairway landings leading to the helicopter deck and to all boat landings.

(b) All oil and gas pipelines receiving production from offshore production facilities shall be equipped with high-low-pressure shut-in sensors. The low-pressure sensor shall be set so as to actuate the integrated safety-control system in the event of pipeline failure. The high and low pressure settings shall be determined by pipeline operating characteristics, and shall be set as close as practicable to the normal operating pressure of the pipeline.

(c) All pneumatic, hydraulic, and other shut-in control lines shall be equipped with fusible material at strategic points. Fire-detector systems shall be equipped with devices to actuate the integrated safety-control system.

(d) The automatic gas-detector system shall be so equipped as to actuate the integrated safety-control system at a point not higher than 60 percent of the lower explosive limit.

Authority: Sections 3013, 3106, and 6108, PRC
Reference: Sections 3106, 6216, 6108, and 6873(d), PRC

2014.2 Safety Devices on Vessels and Tanks.

All production vessels and tanks shall be equipped with safety devices as listed below that will cause shut-in of the wells connected to the vessel or tank. The devices shall be tested monthly by the operator, which tests may be witnessed and approved by the Division or Staff. The operator shall maintain records on the production facility showing the present status and past history of each such device, including dates and details of inspection, testing, repairing, adjustment, and reinstallation or replacement.

(a) All separators shall be equipped with high-low pressure shut-in sensors and high-low liquid level shut-in controls.

(b) All pressure surge tanks shall be equipped with high-low pressure shut-in sensors and high-low liquid level shut-in controls.

(c) Atmospheric surge tanks shall be equipped with high liquid level shut-in sensors.

(d) All other hydrocarbon handling pressure vessels shall be equipped with high-low pressure shut-in sensors and high liquid level shut-in controls unless they are determined jointly by the Division and Staff to be otherwise protected.

(1) High pressure shut-in sensors shall be set no higher than five percent below the rated or designed working pressure, and low pressure shut-in sensors shall be set no lower than ten percent below the lowest pressure in the operating pressure range on all vessels with a rated or designed working pressure of more than 400 psi. On lower pressure vessels, the above percentages shall be used as guidelines for sensor settings considering pressure and operating conditions involved, except that sensor settings shall not be within five psi of the rated or designed working pressure or the lowest pressure in the operating pressure range.

(2) All pressure operated sensors shall be equipped to permit testing with an external pressure source.

Authority: Sections 3013, 3106, and 6108, PRC

Reference: Sections 3106, 6216, 6108, and 6873(d), PRC

2014.3 Pressure Relief Valves.

(a) All pressure vessels shall be equipped with relief valves connected into a gas vent line. All gas vent

line systems shall be equipped with a scrubber or similar separation equipment.

(b) A relief valve shall be set no higher than the safe working pressure of the vessel to which it is attached.

(c) Pilot operated pressure-relief valves shall be equipped to permit testing with an external pressure source. Spring loaded pressure relief valves shall either be bench-tested or equipped to permit testing with an external pressure source.

(d) Relief valves shall be tested by the operator every six months. The tests may be witnessed and approved by the Division or Staff. The operator shall maintain records on the production facility showing the present status and past history of each relief valve, including dates and details of inspection, testing, repairing, adjustment and installation or replacement.

Authority: Sections 3013, 3106, and 6108, PRC

Reference: Sections 3106, 6216, 6108, and 6873(d), PRC

2014.4 Firefighting System.

Unless otherwise provided in this Subsection, a firefighting system shall be installed and maintained in operating condition on each offshore production facility in accordance with the "API Recommended Practice for Fire Prevention and Control on Open Type Offshore Production Platforms", API RP 14G.

(a) A fixed automatic water spray system or other system jointly approved by the Division and Staff shall be installed in all wellhead areas and in areas where production handling equipment is located.

(b) A firewater system of rigid pipe with fire-hose stations shall be installed on all levels of the facility.

(c) A system employing chemicals or chemical additives may be used in appropriate areas in lieu of or in addition

to a firewater system to provide more effective fire protection and control.

(d) An auxiliary connection to the firewater piping shall be installed at a remote location to supply the firefighting system in case of need.

(e) The firefighting system shall be equipped with reserve firewater pumps to provide for the operating of the system during routine pump maintenance work and in the event of pump failure. The firewater pumps shall be test-operated weekly, and the automatic water spray systems shall be test-operated monthly by the operator. Testing methods other than the use of water shall be approved by the Division or Staff. Monthly tests of the firewater pumps and the automatic water spray systems may be witnessed and approved by the Division or Staff. The operator shall maintain a good record of the tests at the production facility or at its nearest onshore office.

(f) Portable fire extinguishers shall be located in the living quarters and in other strategic areas. A record showing the date when fire extinguishers were last inspected, tested, or recharged shall be maintained on the production facility.

(g) A diagram of the firefighting system showing the location of all equipment shall be posted in a prominent place on the production facility.

(h) Fire drills shall be conducted weekly by the supervisor in charge of the production facility. Drills shall be scheduled so that production personnel may participate in at least one drill per month. A record showing the date that fire drills were conducted shall be maintained on the production facility for at least one year.

Authority: Sections 3013, 3106, and 6108, PRC

Reference: Sections 3106, 6216, 6108, and 6873(d), PRC

2014.5 Combustible Gas Detector and Alarm System.

An automatic hydrocarbon/combustible gas detector and alarm system shall be installed and maintained on each offshore production facility in accordance with the following:

(a) Gas-detection systems shall be installed in all areas containing gas-handling facilities or equipment and in enclosed areas which are classified as hazardous areas as defined in the California Administrative Code, Title 24, Part 3.

(b) 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.

(c) The central control shall be capable of giving an audible alarm at a point not higher than 25 percent of the lower explosive limit.

(d) The central control shall automatically activate the shut-in sequences of the integrated safety control system and emergency equipment at a point not higher than 60 percent of the lower explosive limit.

(e) A diagram of the gas-detection systems showing the location of all gas-detection points shall be posted in a prominent place on the production facility.

(f) The gas detection systems shall be tested monthly by the operator, which tests may be witnessed and approved by the Division or Staff. The operator shall maintain a record of the tests at the production facility or at its nearest onshore office.

Authority: Sections 3013, 3106, and 6108, PRC

Reference: Sections 3106, 6216, 6108, and 6873(d), PRC

2014.6 Hydrogen Sulfide Gas Detection and Precaution on Oil and Gas Production Facilities.

(NOTE. For applicable regulations concerning DRILLING,

REWORKING, and MAINTENANCE OF WELLS in an H2S environment, please see Section 2005.13.)

Any offshore production facility that handles production known to contain hydrogen sulfide (H2S) gas, which could potentially result in an atmospheric concentration of 10 ppm or greater, shall be equipped and maintained in accordance with the following requirements to provide for the safety of personnel:

(a) Hydrogen Sulfide Gas Detection and Alarm System.

(1) A separate automatic hydrogen sulfide (H2S) gas detector and alarm system shall be provided. This equipment shall be capable of sensing a minimum of five parts per million (ppm) H2S in air, with sensing points located in all enclosed and hazardous areas where gas handling facilities are located, as well as any living quarters and other areas where H2S might accumulate in hazardous quantities. The H2S detection devices shall activate audible and visible alarms when the concentration of H2S reaches 20 ppm in air.

(2) H2S detector ampules or other approved devices shall be available for use by all working personnel. After H2S has been initially detected by any device, frequent inspections of all areas of poor ventilation shall be made with a portable H2S detector instrument.

(b) Hydrogen Sulfide Contingency Plan. A contingency plan shall be developed for each production facility that handles production known to contain H2S. The plan and any subsequent revisions thereto shall be submitted for joint approval by the Division and Staff. A copy of the approved plan shall be located at the facility. The plan shall include the following:

(1) General information and physiological responses to H2S and SO2 exposure.

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

(3) Procedures for normal operating conditions and for H2S emergency conditions.

(4) Responsibilities, duties and procedures when the concentration of H2S in the atmosphere reaches the following:

a. 10 ppm level.

b. 20 ppm level.

c. 50 ppm level.

(5) Designation of briefing areas as locations for assembly of personnel during emergency conditions. At least two briefing areas shall be established on each facility. Of these two areas, the one up wind at any given time is the safe briefing area.

(6) Evacuation plan.

(7) Agencies to be notified in case of an emergency (must include the State Lands Commission and the California Division of Oil and Gas).

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

(c) Personnel Training Program.

(1) To promote efficient safety procedures, an on-site H2S safety program, which includes training sessions and drills, shall be established. Records of attendance shall be maintained on the production facility.

(2) A training session and drill shall be conducted for each person within 24 hours after arrival on the facility and biweekly thereafter.

(3) All regularly assigned working personnel shall have completed a basic first-aid course applicable to victims of H2S exposure. During on-site training sessions and drills, emphasis shall be placed upon rescue and first aid for H2S victims.

(4) Each production facility shall have the following equipment, and the facility operator and each crew member shall be thoroughly familiar with the location and use of these items:

a. A first-aid kit appropriately ~~approximately~~ sized for the normal number of working personnel. . . .

b. Resuscitators, complete with face masks, oxygen bottles, and spare oxygen bottles.

c. At least one litter or an equivalent device.

(5) All personnel, whether regularly assigned, contracted, or employed on an unscheduled basis, shall be informed as to the hazards of H2S and SO2. They shall also be instructed in the proper use of personnel safety equipment which they may be required to use, and informed of H2S detectors and alarms, ventilation equipment, prevailing winds, briefing areas, warning systems and evacuation procedures.

(d) Personnel Protective Equipment.

(1) Production facilities, and all marine vessels serving the production facilities, shall have proper personnel breathing apparatus immediately available for all personnel serving on board and additional equipment for possible use in evacuations. The protective breathing apparatus used in an H2S environment shall conform to all applicable Occupational Safety and Health Administration regulations as set forth in the Code of Federal Regulations 29 CFR 1910.134 and American National Standards Institute standards. Additional equipment, such as nose cups and spectacle kits, shall be available for use as needed.

(2) A system of breathing air manifolds, hoses and masks shall be provided on the facility 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. The compressor and compressed air system shall comply with 29 CFR 1910.134 (OSHA).

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

a. Facility operator's office.
b. Each working deck.
c. Crew quarters.
d. Equipment storage room.
e. Designated briefing areas.
f. Heliport access.

(4) Workboats attendant to facility operations shall be equipped with a protective breathing apparatus for all workboat crew members. Additional protective breathing apparatus shall be available for evacuees. When possible, boats shall be stationed up wind from the facility.

(5) Helicopters attendant to facility operations shall be equipped with protective breathing apparatus for the flight crew.

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

a. Portable H2S detectors.

b. Retrieval ropes with safety harnesses to retrieve incapacitated personnel from contaminated areas.

c. Chalkboards and note pads at convenient locations for communication purposes.

d. Bull horns and flashing lights.

e. Resuscitators.

(e) Visible Warning System.

(1) Wind-direction equipment shall be installed at prominent locations to indicate to all personnel, on or in the immediate vicinity of the production facility, the wind direction at all times for determining safe up wind areas in the event that H2S or SO2 is present in the atmosphere.

(2) Operational danger signs shall be displayed from each side of the facility, and a number of rectangular red flags shall be hoisted, and other visual alarms shall be activated in a manner visible to watercraft and aircraft.

The signs shall have a minimum width of 8 feet and a minimum height of 4 feet and shall be painted a high-visibility yellow color with black lettering of a minimum of 12 inches in height reading as follows:

DANGER -- HYDROGEN SULFIDE -- H2S

Each flag shall be a minimum width of 3 three feet and a minimum height of 2 feet. When in use, all signs and flags shall be illuminated under conditions of poor visibility and at night. These signs and flags shall indicate the following conditions and operational requirements.

a. When H2S is present, signs shall be displayed.

b. When H2S is determined to have reached or exceeded a level of 20 ppm in environmental

areas, red flags shall be hoisted, other visual alarms shall be activated, and protective equipment shall be worn by all personnel in those areas. Nonessential personnel shall be removed to a safe location or evacuated as appropriate. Radio communications shall be used to alert all known aircraft and watercraft in the immediate vicinity of this condition.

(f) Audible Warning Systems. A public address system and a siren, horn or other audible warning device with a unique sound used only for H2S warnings shall be installed at appropriate locations on the facility. When the warning devices are activated, (at the 20 ppm threshold level) the designated responsible persons shall inform personnel of the level of danger and issue instructions on the initiation of appropriate protective measures.

(g) Ventilation Equipment. All ventilation devices shall be explosive proof when used in areas where H2S may accumulate. Moveable ventilation devices shall be provided in work areas and be multidirectional and capable of dispersing H2S or SO2 vapors away from working personnel.

(h) Flare System. The flare system shall be designed to safely gather and burn H2S gas. Flare lines shall be located as far from the other facilities 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.

(i) Drilling Operations. See section 2005.13.

(j) Remedial and Well-Maintenance Operations. See section 2005.13.

(k) Notification of Regulatory Agencies. The following agencies shall be notified immediately if H2S has been determined to have reached or exceeded a level of 20 ppm in the environmental area:

(1) State Lands Commission.

(2) Division of Oil and Gas.

(3) United States Coast Guard.

Authority: Sections 3013, 3106, and 6108, PRC

Reference: Sections 3106, 6216, 6108, and 6873(d), PRC

2014.7 Electrical Equipment and Systems.

(a) An auxiliary electrical power supply shall be installed to provide sufficient emergency power for all electrical equipment required to maintain safety of operation in the event the primary electrical power supply fails. The auxiliary electrical power-supply system shall be tested monthly by the operator and may be witnessed and approved by the Division or Staff. The operator shall maintain a record of the tests at the production facility or at its nearest onshore office.

(b) All electrical generators, motors, electrical power control, and lighting systems shall be designed, installed, protected, and maintained in accordance with "API Recommended Practice for Design and Installation of Electrical Systems for Offshore Production Platforms," API RP 14F.

Authority: Sections 3013, 3106, and 6108, PRC

Reference: Sections 3106, 6216, 6108, and 6873(d), PRC

2014.8 Welding Practices and Procedures.

The following requirements shall apply to all production facilities during any time in which drilling or producing operations are taking place. The term "welding and burning" is defined to include arc or acetylene welding and arc or acetylene cutting.

(a) All welding and burning shall be minimized by utilizing fabrication ashore.

(b) If possible, all welding and burning shall be done in an approved, properly functioning welding room.

(c) If welding or burning is necessary outside the welding room, it shall be conducted in accordance with a facility welding plan that is jointly approved by the Division and Staff. The plan shall include the following minimum requirements:

(1) The operator's supervisor in charge at the installation shall issue written authorization for the work after he has inspected the area in which the work is to be done. If both drilling and producing operations are taking place, the drilling supervisor and the production supervisor shall both sign this authorization.

(2) During all welding and burning operations, a person designated as a "fire watch" shall operate a portable gas detector and shall have in possession a portable fire extinguisher. In addition a fire hose shall be laid out to the welding area and it shall remain pressurized to the nozzle during the entire period of welding and burning. The "fire watch" shall inspect the area with the gas detector prior to commencement of the welding or burning, shall continuously monitor the area, and shall cause the welding or burning to cease at any time that conditions become unsafe.

(3) If welding or burning must be done on a vessel which has contained a flammable substance, all connections to the vessel shall be broken and displaced or slip blanked, and the vessel shall be thoroughly cleaned and rendered free of such flammable substance and tested for gas before the work begins. Prior to performing hot work on the

outside of a vessel, the vessel shall be completely flooded with water.

(4) If welding or burning must be done on in-service or connected-up piping, that section of pipe shall be isolated by the installation of slip blanks or blind flanges, thoroughly purged and cleaned to render it free of any flammable substance, and tested for gas before the work begins. When welding or burning on an isolated, clean and gas-free piping section, one end must remain open.

(5) If welding or burning must be done in a confined space, the space shall be adequately vented and a continuous source of fresh air shall be supplied by blowers, so positioned that the intakes will not pick up exhausted gases, fumes, or vapors.

(6) If any welding or burning is done on bulkheads, decks, or overheads, the adjacent overlying or underlying spaces shall be examined to determine that it is safe for the work to proceed. If deemed advisable, a second "fire watch" shall be employed in the contiguous area.

(7) If any welding or burning must be done on structural members, it shall be determined by a State of California registered professional structural or civil engineer specializing in structural design that such welding or burning will not endanger the integrity of the structure.

Authority: Sections 3013, 3106, and 6108, PRC

Reference: Sections 3106, 6108, 6216, and 6873(d), PRC

ARTICLE 4. FIXED OFFSHORE PLATFORMS

2615.0 General Requirements.

(a) All fixed offshore platforms shall be designed, fabricated, installed, inspected and surveyed in accordance with the following API publications: "API

Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms", API RP 2A; "API Recommended Practice for Production Facilities on Offshore Structures," API RP 2G; "API Recommended Practice for Analysis, Design, Installation and Testing of Basic Surface Safety Systems for Offshore Production Platforms," API RP 14C; "API Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems," API RP 14E; "API Recommended Practice for Design and Installation of Electrical Systems for Offshore Production Platforms," API RP 14F; and "API Recommended Practice for Fire Prevention and Control on Open Type Offshore Production Platforms," API RP 14G.

(b) It should be noted that specific requirements for platform and well production safety equipment and procedures are contained in Subsections 2010.6 through 2010.9 and 2014.1 through 2014.8 and for pipeline safety equipment located on a platform are contained in subsection 2016.4.

(c) The operator shall provide a written report to the Staff by a structural engineer registered in the State of California and specializing in platform structural design, attesting to his/her review and approval of the proposed platform design, fabrication and installation. The operator shall file written certification with the Staff, that the platform will be fabricated and installed in accordance with the approved design.

(d) All proposals for the installation of platforms or other structures on state offshore lands shall be reviewed and approved by the Staff.

Authority: Section 6108, PRC

Reference: Sections 6216, 6108, and 6873(d), PRC

2015.1 Platform Safety, Survival Equipment and Emergency Evacuation Plan.

All offshore fixed platforms (and artificial islands) shall be equipped with safety and survival equipment and have on board an emergency evacuation plan in accordance with the requirements set forth in Title 33 CFR 140, 142 through 146. The Staff may inspect these facilities to ensure compliance with these requirements and approve the emergency evacuation plan.

Authority: Section 6108, PRC

Reference: Sections 6216, 6108, and 6873(d), PRC

2015.2 Platform Site Investigation.

In addition to the ocean floor investigations required in API RP 2A for platform foundation design, the operator shall investigate the conditions of the ocean floor and near sub- bottom in the area of the platform site to determine the presence and location of significant cultural and biological resources. A report of the findings and provisions for mitigating any problems disclosed by the investigation shall be provided to the Staff and must be approved by the Staff. The plan(s) of investigation shall be in accordance with guidelines provided by the Staff.

Authority: Section 6108, PRC

Reference: Sections 6216, 6108, and 6873(d), PRC.

2015.3 Platform Application.

(a) The operator shall submit to the Staff in accordance with Subsection 2002.2(a) the following general information.

(1) Identification of platform.

(2) Location plat showing longitude and latitude coordinates, as well as Lambert grid coordinates.

(3) Primary use of platform.

(4) Drawings showing general layout of facilities on each deck.

processing, measuring and shipping facilities.

(6) Diagrams and description of the platform integrated safety system, hydrocarbon and H2S gas detection system, firefighting and fire detection systems.

(7) Location and description of oil spill containment and recovery equipment.

(8) Other information as may be required.

Authority: Section 6108, PRC

Reference: Sections 6216, 6108, and 6873(d), PRC

2015.4 Reports.

Reports of platform structural integrity surveys that are required in Section 7 of API RP 2A shall be filed with the Staff within 60 days following completion of the work.

Authority: Section 6108, PRC

Reference: Sections 6108, 6216, and 6873(d), PRC

ARTICLE 5. OFFSHORE PIPELINES

2016.0 General Requirements.

(a) Except as otherwise provided for in Subsections 2016.4 and 2016.5, the design, construction, operation and maintenance of oil and gas pipelines on State offshore lands shall be in accordance with the applicable minimum safety standards for the transportation of petroleum gas and liquid as set forth in Title 49, of the Code of Federal Regulations Parts 192, Transportation of Natural and other Gas by Pipeline and 195, Transportation of Hazardous Liquids by Pipeline.

(b) Offshore oil and gas pipelines that operate by gravity or at a stress level of 20% or less of their specified minimum yield strength are not exempted from these regulations and the requirement to meet the above referenced federal standards.

(c) All new or replacement oil and gas pipelines shall be designed and constructed to enable the running of conventional internal inspection tools.

(d) All proposals for the installation of oil and gas pipelines on state offshore lands shall be reviewed and approved by the Staff.

Authority: Section 6108, PRC

Reference: Sections 6216, 6108, and 6873(d), PRC

2016.1 Pipeline Route Survey.

Prior to the approval of the pipeline proposal, the operator shall investigate the conditions of the ocean floor and near sub-bottom including sediment characteristics along its projected route. The investigation shall be adequate to: (1) ascertain the presence of shallow geological anomalies and gather other information to be used as an aid in designing a safe pipeline, and (2) determine the presence and location of significant cultural and biological resources. A report of the findings and provisions for mitigating any problems disclosed by the investigation shall be provided to and must be approved by the Staff. The plan(s) of investigation shall be in accordance with guidelines provided by the Staff.

Authority: Section 6108, PRC

Reference: Sections 6216, 6108, and 6873(d), PRC

2016.2 "As Built" Survey.

After installation the pipeline shall be surveyed to determine its actual route. If the pipeline is found to be located outside the area of investigation, additional investigative surveys as described in Subsection 2016.1 may be required. Duplicate copies of the "as built" survey shall be filed with the Staff.

Authority: Section 6108, PRC

Reference: Sections 6216, 6108, and 6873(d), PRC

2016.3 Pipeline Application.

The application for the installation of an oil or gas pipeline shall include the following data:

(a) Product to be transported by the pipeline.

(b) Engineering drawings, showing:

(1) Location plan and profile of the pipeline and underwater bed.

(2) Valve locations and piping details.

(3) Safety controls and devices to be installed.

(4) Special construction features such as pipe risers, pipe support and anchors.

(c) Design: Undersea pipelines shall be designed to the extent it is practical, with smooth surfaces and shrouded valves and other protrusions so as to prevent loss or damage to fishing gear from pipeline snags.

(d) Engineering specifications, stating:

(1) Pipe size, wall thickness, weight, applicable standard specification number and grade, and details of the pipe joints.

(2) Protective coating.

(3) Corrosion protection (cathodic and other).

(4) Internal design pressure and capacity.

(5) Expected maximum operating pressure and capacity.

(6) Hydrostatic test pressure and test procedures during construction.

(7) Method of installation.

(e) Contractor's construction specifications when completed.

(f) Pipeline stability data:

(1) Burial depth of pipeline and description of burying method through and beyond the surf zone.

(2) Means of anchoring and protecting the pipeline through the surf zone.

(3) Means used to maintain the position of the pipe under anticipated conditions of buoyancy and water motion.

(4) An analysis of the forces acting on the unburied pipeline caused by wave action, on-bottom currents or tidal flows. Such forces shall be based on the occurrence of a 100 year storm.

Authority: Sections 6108, PRC

Reference: Sections 6216, 6108, and 6873(d), PRC.

2016.4 Safety Equipment Requirement

(a) All oil and gas pipelines receiving production from offshore production facilities shall be equipped with high-low-pressure shut-in sensors and with an automatic shut-in valve located at the offshore facility. The pressure sensors shall be connected so as to actuate the automatic shut-in valves on the pipelines, as well as all shut-in devices on input sources to the pipelines. The pressure settings shall be determined by pipeline operating characteristics, and shall be set as close as practicable to the normal operating pressure of the pipeline. The automatic shut-in valves also shall be actuated by the integrated safety-control system of the production facility.

(b) All oil and gas pipelines that deliver production to an onshore production facility shall be equipped with a remote-controlled shut-in valve or check valve at or near the receiving facility.

(c) All oil and gas pipelines that cross an offshore facility which do not deliver production to the facility, and may or may not receive production from the facility, shall be equipped with an automatic shut-in valve to be located in the upstream portion of the pipeline at the facility, so as to prevent uncontrolled flow at the facility. This automatic shut-in valve

shall be controllable by the integrated safety-control system of the facility.

(d) Any pipeline that delivers gas to an offshore facility for the purpose of gas lift or other operations shall be equipped with an automatic shut-in valve to be located in the upstream portion of the pipeline at the facility, so as to prevent uncontrolled flow at the facility. This automatic shut-in valve shall be controllable by the integrated safety-control system of the facility.

(e) All oil pumps and gas compressors shall be equipped with high-low-pressure shut-in devices.

(f) All pressure sensors, pressure shut-in devices, and automatic shut-in valves shall be tested monthly by the operator, and may be witnessed and approved by the Division or Staff. The operator shall maintain records on the production facility showing the present status and past history of each device, including dates and details of inspection, testing and repairing, adjustment, and reinstallation or replacement.

Authority: Sections 3013, 3106 and 6108, PRC

Reference: Sections 3106, 6108, 6216, and 6873(d), PRC

2016.5 Pipeline Operations and Maintenance.

All oil and gas pipelines on state offshore lands shall be operated and maintained in accordance with the following minimum requirements:

(a) General Requirements.

(1) Each operator shall establish and maintain current written procedures:

a. To insure the safe operation and maintenance of its pipeline system during normal operations.

b. To be followed during abnormal operations and emergencies.

(2) An operator shall not operate or maintain its pipeline system at a level of safety lower than that required by Subsection 2016.5 and the procedures that the operator is directed to establish in (1) above.

(3) Whenever an operator discovers any conditions that presents an immediate hazard to persons, property, or the environment, the operator shall not operate the affected part of the system until the unsafe condition has been corrected.

(b) Maximum Operating Pressures.

(1) Except for surge pressures and other variations from normal operations, an operator shall not operate a pipeline at a pressure which exceeds any of the following:

a. The internal design pressure of the pipe as determined in accordance with ANSI Code B31.4 for Liquid Petroleum Transportation Piping Systems and ANSI Code B31.8 for Gas Transmission and Distribution Piping Systems.

b. The design pressure of any other component of the pipeline.

c. 80 percent of hydrostatic test pressure to which the pipeline or any component of the pipeline has been hydrostatically tested.

(2) An operator shall not permit the pressure in a pipeline during surges or other variation from normal operations to exceed 110 percent of the maximum allowable operating pressure limit established in (1) above. The operator shall provide adequate controls and protective equipment to control the pressure within this limit.

(c) Communications. Each operator shall have a communications system for the transmission of the

information required for the safe operation of its pipeline system.

(d) External Corrosion Control. All pipelines shall be cathodically protected to prevent external corrosion. The operator shall conduct tests annually on all cathodically protected pipelines to assure an adequate level of protection. Cathodic protection rectifiers shall be inspected by a qualified electrical inspector every three months. The output of the rectifiers shall be checked daily. The operator shall maintain records on the production facility showing the daily output readings and the dates, details of inspection, and repairs to each rectifier.

(e) Internal Corrosion Control. Where corrosion inhibitors are necessary to mitigate internal corrosion, they shall be used in sufficient quantities to protect the entire pipeline. The operator shall use coupons or other monitoring equipment to determine the effectiveness of the inhibitors. The operator shall, at intervals not exceeding six months, examine coupons or other corrosion- monitoring equipment to assure effectiveness of any inhibitors used.

(f) Pipeline Inspections.

(1) All pipeline risers on platforms shall be visually inspected annually by the operator for damage, evidence of corrosion and other hazardous conditions. If necessary, the corroded or damaged portion shall be repaired or replaced.

All oil and gas pipelines shall be inspected externally at least once a year by side-scan sonar or other methods acceptable to the staff to identify all exposed portions of the pipelines. Should the inspection show any signs of bridging or other hazard to the pipeline, then further detailed inspection shall be made and appropriate

action shall be taken to repair or maintain the pipeline.

(2) Where mechanically possible, all oil and gas pipelines shall be internally inspected annually by the operator using an electronic survey tool. Upon request of the operator the frequency of inspections may be reduced depending upon the degree of corrosion observed. A corrosion prevention and monitoring program shall be provided for pipelines that exhibit internal corrosion. Minimum requirements shall include routine inhibitor treatment and pigging, use of coupons and internal inspection tools. Pipelines found to have severe corrosion shall be further examined and are to be repaired or replaced as necessary to provide for safe operation. The proposed remedial work shall require the approval of the staff.

(3) If it is not mechanically possible to run an electronic survey tool, the operator shall hydrostatically pressure test each oil and gas pipeline to at least 1.25 times its maximum operating pressure. The test procedure shall be approved by the Staff.

(4) If a leak occurs, in addition to repairing the leak, the operator shall further examine the pipeline to determine its condition for continued safe usage. The method utilized to repair the leak and further examine the pipeline shall require the approval of the Staff.

(5) The ocean surface above all pipelines that service offshore facilities shall be inspected a minimum of once each week for indication of leakage, using aircraft or boats. Records of these inspections, including the date, methods, and results of each

inspection, shall be maintained by the operator at its nearest onshore office.

(g) Reports of Inspection. The operator shall file a report with the Staff describing the testing procedure and results of (1) the annual test of the cathodic protection system on each pipeline and (2) the annual external and internal electronic inspection or hydrostatic test of each oil and gas pipeline. The reports shall be filed within 60 days following completion of the work.

Authority: Section 6108, PRC

Reference: Sections 6108, 6216, and 6873(d), PRC

ARTICLE 6. POLLUTION CONTROL

2017.0 General.

(a) Pollution and contamination of the ocean and tidelands and any impairment of or interference with recreation, fishing, or navigation in the waters of the ocean or any bay or any inlet thereof is prohibited; and no oil, tar, residuary product of oil or any refuse of any kind from any well or facility that is deleterious to marine life shall be permitted to be deposited on or pass into the waters of the ocean or any bay or any inlet thereof.

(b) All drilling and production operations shall be conducted in manner that will eliminate, insofar as is practical, any dust, noise, vibration, or noxious odors.

(c) An operator shall suspend immediately any drilling and production operations, except those which are corrective, protective, or mitigative, in the event of any disaster or contamination or pollution caused in any manner or resulting from drilling and/or production operations under its lease. Such drilling and/or production operations shall not be resumed until

adequate corrective measures have been taken and authorization for resumption of such operations has been made by the Division and Staff. Corrective measures shall be taken immediately whenever pollution has occurred.

Authority: Sections 3013, 3106, and 6108, PRC
Reference: Sections 3106, 6108, 6216, and 6873(b), PRC

2017.1 Waste Disposal.

All waste discharged into the ocean from drilling and production operations shall be treated and monitored in accordance with the discharge requirements of the appropriate Regional Water Quality Control Board.

Authority: Sections 3013, 3106, and 6108, PRC
Reference: Sections 3106, 6108, 6216, and 6873(b), PRC

2017.2 Containment of Pollutants.

All mobile drilling rigs and offshore drilling or production facilities shall be equipped in a manner that will prevent spilling of contaminants into the ocean. Curbs, gutters, and drains shall be constructed and maintained in good condition in all deck areas in a manner necessary to collect all contaminants. Drip pans or the equivalent shall be placed under equipment. The contaminants shall be collected in a sump(s) that is/are provided with appropriate pumping equipment, liquid level controls, and alarms to prevent accidental discharge of oil into the ocean waters. Alternate methods to obtain the same results may be jointly approved by the Division and Staff. These systems shall not permit spilled oil to flow into the well-head area of a platform or pier.

Authority: Sections 3013, 3106, and 6108, PRC
Reference: Sections 3106, 6216, and 6873(b), PRC

2017.3 Oil Spill Contingency Plan.

Each operator shall prepare and maintain a current oil spill contingency plan for initiating corrective action to control and recover oil spilled in or on the ocean. The plan shall cover both minor and major oil spills associated with lease drilling and production operations. The plan and any subsequent revisions thereto shall be submitted for joint approval by the Division and Staff.

Authority: Sections 3013, 3106, and 6108, PRC

Reference: Sections 3106, 6108, 6216, and 6873(b), PRC

2017.4 Pollution Control and Removal Equipment.

(a) Pollution control equipment and material shall be available immediately to each operator for use in oil pollution control and removal operations on its lease. The equipment and material shall include, but need not be limited to, containment booms, skimming apparatus, licensed chemicals, and absorbents and shall be the most effective equipment and material available, given the current state of pollution control and removal research and development at the time of acquisition. The operator shall, however, update such equipment whenever any significant technological improvements are developed.

(b) Emergency equipment shall be maintained on each mobile drilling rig and fixed offshore drilling or production facility for immediate cleanup of small oil spills. Each mobile drilling rig shall be equipped with a minimum of 1,500 feet of oil containment boom, an oil skimming or recovery device that is capable of open ocean use, an amount of absorbent material sufficient to remove 15 barrels of spilled oil, and a floating oil storage container having a capacity of at least 29 barrels. In addition, a boat that is capable of deploying this equipment shall be maintained onsite or

available to the rig within 15 minutes. This equipment and material required on each fixed offshore drilling or production facility shall be determined and approved jointly by the Division and Staff on an individual basis considering the type of structure, location, current activity, oil production capability, method of well production and other factors peculiar to the facility.

Equipment for the control and removal of larger oil spills shall be maintained at an offshore or onshore location near the area of drilling operations where deployment and response to the spill would provide the most feasible protection of coastal resources. All equipment shall be inspected regularly and shall be maintained in good condition for immediate use.

(c) The operator shall conduct training classes and periodic drills in the deployment and use of pollution control and removal equipment to ensure that designated personnel can carry out the assignments which are necessary for effective control and removal of oil spilled in the ocean. Impromptu drills shall be required by the Division or Staff.

(d) The operator shall maintain an inventory of the emergency equipment that is stored on each mobile drilling rig and offshore drilling or production facility, as well as an inventory showing the description, application, and location of all pollution control and removal equipment that is immediately available for a major oil spill. In addition, the operator shall maintain a listing of equipment, material, services, and labor forces that are immediately available for beach cleanup and restoration operations. The inventories shall be updated as changes

occur and current copies shall be filed with the Division and Staff annually.

Authority: Sections 3013, 3106, and 6108, PRC

Reference: Sections 3106, 6108, 6216, and 6873(b), PRC

2017.5 Critical Operation and Curtailment Plan.

The primary purpose of a Critical Operation and Curtailment Plan is to provide additional precautionary measures to minimize the likelihood of an oil spill incident occurring from offshore drilling and production well work during (1) adverse weather and sea conditions when oil spill containment and recovery equipment, material and techniques are not effective and marine transportation is severely hampered; and (2) the time that oil spill containment and recovery equipment, material, manpower, and transportation thereof are not readily available to the site of operation.

Certain operations performed in drilling and production well work are more critical than others with respect to well control and accidental discharge of oil and gas. This is particularly so when subsurface formations are exposed in the well that are capable of flowing oil and gas to the surface or when the well has been pressured by outside means. It is these critical operations that should cease, be limited or not commenced in order to minimize the likelihood of oil spills occurring during adverse weather and sea conditions which could seriously impede both well control and oil cleanup efforts.

The operator shall file with the Division and Staff, for joint approval, a Critical Operation and Curtailment Plan to be followed while conducting drilling and/or production well work on the lease. A plan shall be filed for each exploratory well in order to accommodate different drilling rigs, circumstances and conditions. A separate plan shall be filed for development drilling and production well work on the lease. These plans shall contain the following:

(a) A descriptive list of the critical drilling and production well work that is likely to be conducted on the lease, such as:

(1) Drilling in proximity to another well.

(2) Drilling into a known lost circulation zone or into a zone capable of flowing oil and/or gas.

(3) Continuation of drilling into zones that are suspected to be capable of flowing oil and/or gas or into zones suspected to be abnormally pressured.

(4) If zones capable of flowing oil and/or gas are exposed or suspected to be exposed in the well then the following are considered to be critical operations:

a. Pulling out of the hole.
b. Fishing operations.
c. Drill-stem testing.
d. Wireline logging in open hole.
e. Running casing.
f. Cutting and recovering casing.
g. Perforating casing.
h. Well completion work.
i. Remedial well work.
j. Well stimulation.

(b) A descriptive list of circumstances or conditions under which the critical drilling and production well work shall cease, be limited, or not be commenced. This list shall be developed from all the factors and conditions relating to the lease and shall take into account but may not to be limited to the following:

(1) Whether or not well operations are being conducted from a mobile rig or a fixed structure.

(2) Presence or anticipation of adverse meterological or oceanographical conditions.

(3) Limited availability and capability of oil containment and cleanup equipment.

(4) Significant increase in oil spill control system response time for any reason.

(5) Unavailability of personnel or equipment for conducting particular critical operations.

(6) Insufficient supply of drilling mud materials on the drill site for emergency well control purposes.

(7) Unavailability of transportation equipment for personnel, supplies and oil spill containment and cleanup equipment.

(8) Performance of construction and maintenance work involving welding and moving of heavy equipment.

(9) Other factors peculiar to the particular lease under consideration.

(c) When any circumstances or condition listed or described in the plan occurs or other operational limits are encountered, the operator shall cease, limit, or not commence the affected critical operation(s) as set forth in Subsection 2017.5(a).

(d) Any deviation from the approved plan shall require prior written joint approval by the Division and Staff. If emergency action requires deviation from the plan, and there is inadequate time to seek approval, the Division and Staff shall be notified immediately after said deviation occurs.

(e) The plan shall be reviewed at least annually, and any changes thereto shall be submitted to the Division and Staff for joint approval.

Authority: Sections 3013, 3106, and 6108, PRC

Reference: Sections 3106, 6216, and 6873 (b),(d), PRC

2017.6 Pollution Reports.

(a) All spills or leakage of oil or other pollutants originating from operations on State oil and gas leases shall be reported verbally without delay to the Division and Staff in accordance with the applicable Oil Spill Contingency Plan. Thereafter, a written report shall be filed with the Division and Staff stating the source, cause, size of spill and the action taken.

(b) Operators shall report to the Division and Staff any pollution of unknown source or pollution not associated with lease operations that is observed on or in State waters.

(c) Operators shall notify one another of pollution resulting from another's operation.

Authority: Sections 3013, 3106, and 6108, PRC

Reference: Sections 3106, 6216, and 6873(b), PRC