Chapter 25
Alaska Oil and Gas Conservation Commission

Article 1
Drilling

20 AAC 25.005. Permit to drill.

(a) Before drilling or redrilling a well or re-entering an abandoned well, a person shall submit and obtain the commission's approval of an application for a Permit to Drill (Form 10-401). If, after drilling a well, a person wishes immediately to redrill below the structural or conductor casing to a new bottom-hole location not requiring a spacing exception under 20 AAC 25.055, the person may request oral approval from the commission to avoid interruption of operations. If oral approval is obtained, the name of the representative of the commission who provided oral approval and the date of the approval must be included on the application for a Permit to Drill, which must be submitted by the commission's next working day for final approval by the commission.

(b) The commission will classify a well as

(1) exploratory;

(2) development, either oil or gas;

(3) service; or

(4) stratigraphic test.

(c) An application for a Permit to Drill must be accompanied by each of the following items, except for an item already on file with the commission and identified in the application:

(1) repealed 4/4/2013;

(2) a plat identifying the property and the property's owners and showing

(A) the coordinates of the proposed location of the well at the surface, at the top of each objective formation, and at total depth, referenced to governmental section lines;

(B) the coordinates of the proposed location of the well at the surface, referenced to the state plane coordinate system for this state as maintained by the National Geodetic Survey in the National Oceanic and Atmospheric Administration;

(C) the proposed depth of the well at the top of each objective formation and at total depth; and

(D) other information required by 20 AAC 25.050(b);

(3) a diagram and description of the blowout prevention equipment (BOPE) as required by 20 AAC 25.035 or 20 AAC 25.036, as applicable;

(4) information on drilling hazards, including

(A) the maximum downhole pressure that may be encountered, criteria used to determine it, and maximum potential surface pressure based on a pressure gradient to surface of 0.1 psi per foot of true vertical depth, unless the commission approves a different pressure gradient that provides a more accurate means of determining the maximum potential surface pressure;

(B) data on potential gas zones; and

(C) data concerning potential causes of hole problems such as abnormally geo-pressured strata, lost circulation zones, and zones that have a propensity for differential sticking;

(5) a description of the procedure for conducting formation integrity tests, as required under 20 AAC 25.030(f);

(6) a complete proposed casing and cementing program as required by 20 AAC 25.030, and a description of any slotted liner, pre-perforated liner, or screen to be installed;

(7) a diagram and description of the diverter system as required by 20 AAC 25.035, unless this requirement is waived by the commission under 20 AAC 25.035(h)(2);

(8) a drilling fluid program, including a diagram and description of the drilling fluid system, as required by 20 AAC 25.033;

(9) for an exploratory or stratigraphic test well, a tabulation setting out the depths of predicted abnormally geo-pressured strata as required by 20 AAC 25.033(f);

(10) for an exploratory or stratigraphic test well, a seismic refraction or reflection analysis as required by 20 AAC 25.061(a);

(11) for a well drilled from an offshore platform, mobile bottom-founded structure, jack-up rig, or floating drilling vessel, an analysis of seabed conditions as required by 20 AAC 25.061(b);

(12) evidence showing that the requirements of 20 AAC 25.025 have been met;

(13) a copy of the proposed drilling program; the drilling program must indicate if a well is proposed for hydraulic fracturing as defined in 20 AAC 25.283(m); to seek approval to perform hydraulic fracturing, a person must make a separate request by submitting an Application for Sundry Approvals (Form 10-403) with the information required under 20 AAC 25.280 and 20 AAC 25.283;

(14) a general description of how the operator plans to dispose of drilling mud and cuttings and a statement of whether the operator intends to request authorization under 20 AAC 25.080 for an annular disposal operation in the well.

(d) For a well that is to be intentionally deviated, the requirements of 20 AAC 25.050(b) must be met.

(e) Each well branch requires a separate Permit to Drill. If a previously drilled well is proposed to be redrilled below the structural or conductor casing to a new bottom-hole location, the application for a Permit to Drill must be accompanied by all items required under (c) of this section. If concurrent multiple well branches are proposed from a single conductor, surface, or production casing,

(1) the applicant shall designate one well branch as the primary wellbore and include all items required under (c) of this section with the application for a Permit to Drill for that well branch; and

(2) for each other well branch, the application for a Permit to Drill need only include information under (c) of this

section that is unique to that well branch.
(f) Each well must be identified by a unique name designated by the operator and a unique API number assigned by the commission under 20 AAC 25.040(b). For a well with multiple well branches, each branch must similarly be identified by a unique name and API number by adding a suffix to the name designated for the well by the operator and to the number assigned to the well by the commission.
(g) If drilling operations are not commenced with 24 months after the commission approves an application for a Permit to Drill, the Permit to Drill expires.
(h) A Permit to Drill is not valid at a location where the applicant does not have a right to drill for oil and gas.

20 AAC 25.010. Re-entry of a suspended well.
(a) Before re-entering a suspended well to conduct completion operations, the operator shall submit and obtain the commission's approval of an Application for Sundry Approvals (Form 10-403). The Application for Sundry Approvals must set out the current condition of the well and the proposed program for completion operations.
(b) Before re-entering a suspended well to conduct drilling operations, the operator shall submit and obtain the commission's approval of an application for a Permit to Drill (Form 10-401) in conformance with 20 AAC 25.005.
(c) The operator shall file with the commission within 30 days after completion, abandonment, or suspension of the well a Well Completion or Recompletion Report and Log (Form 10-407) and all information required by 20 AAC 25.070(3) and 20 AAC 25.071.

20 AAC 25.015. Changes to a program in a permit to drill.
(a) To change a program approved in a Permit to Drill (Form 10-401) before drilling operations start, the operator shall
(1) submit and obtain the commission's approval of a new application for a Permit to Drill if the proposed surface location is changed, if the proposed bottom-hole location or the proposed location of an objective formation is changed by more than 500 feet laterally or vertically, or if the change requires a spacing exception under 20 AAC 25.055; or
(2) otherwise notify the commission and obtain its approval of the change if the change is not covered by (1) of this subsection.
(b) To change a program approved in a Permit to Drill or to change information under 20 AAC 25.005(c) after drilling operations start, the operator shall
(1) submit and obtain the commission's approval of a new application for a Permit to Drill if the proposed bottom-hole location or the proposed location of an objective formation is changed by more than 500 feet laterally or vertically, or if the change requires a spacing exception under 20 AAC 25.055; or
(2) submit and obtain the commission's approval of an Application for Sundry Approvals (Form 10-403) if the change is not covered by (1) of this subsection; the Application for Sundry Approvals must set out the approved program, the current condition of the well, and the proposed changes; in cases where prompt approval is needed, oral approval may be requested from the commission; if oral approval is obtained, the name of the representative of the commission who provided oral approval and the date of the approval must be included on the Application for Sundry Approvals, which must be submitted within three days for final approval by the commission.

20 AAC 25.020. Designation of operator.
(a) If an owner of a property wishes to designate a new operator for the property, the owner shall submit to the commission for approval a Designation of Operator (Form 10-411). The commission will not approve the designation of a new operator without the signature of the newly designated operator on the same Designation of Operator form. By signing the Designation of Operator form, the newly designated operator agrees to accept the obligations of an operator. The newly designated operator shall furnish a bond and, if required, security as provided for in 20 AAC 25.025. The commission's acceptance of the designated operator's bond constitutes the release of the former operator's bonding obligation for the property indicated on the Designation of Operator form.
(b) The operator shall notify the commission in writing not later than 30 days after any change in the operator's office address, primary telephone number, electronic mail address, or principal contact.

20 AAC 25.022. Notice of ownership.
Within 15 days after a person becomes an owner of a property on which operations subject to this chapter are proposed to the commission or are being conducted, the person shall file a Notice of Ownership (Form 10-417).

20 AAC 25.025. Bonding.
(a) An operator proposing to drill a well for which a permit is required under 20 AAC 25.005 shall file a bond and, if required under (2) of this subsection, security to ensure that each well is drilled, operated, maintained, repaired, plugged and abandoned and each location is cleared in accordance with this chapter. The bond must be
(1) a surety bond issued on Form 10-402A in favor of the Alaska Oil and Gas Conservation Commission by an authorized insurer under AS 21.09 whose certificate of authority is in good standing; or
(2) a personal bond of the operator on Form 10-402B accompanied by security guaranteeing the operator's performance; security must be in the form of a certificate of deposit or irrevocable letter of credit issued in the sole favor of the Alaska Oil and Gas Conservation Commission by a bank authorized to do business in the state, or must be in another form that the commission determines to be adequate to ensure payment.
(b) A bond, and if required, security must be in compliance with the following:
(1) a bond, and if required, security must be in the amount specified in the following table:
Number of Permitted WellheadsBond Amount1 - 5 wells$400,000 per well6 - 20 wells$2,000,000
plus an additional
$250,000 per well for
each well above five
(e.g., the bond for an operator
with eight wells
would be $2,750,000 for
the first five wells plus
$250,000 per well for

wells 6 through 8)21 - 40 wells$6,000,00041 - 100 wells$10,000,000101 - 1,000 wells$20,000,000Over 1,000 wells$30,000,000

(2) for the purposes of this section, a wellhead is considered any well, excepting lateral well branches drilled from an existing well, for which the commission has issued a Permit to Drill (Form 10-401) that has not been permanently plugged and abandoned;

(3) upon request of an operator, or its own motion, the commission may increase or decrease the amounts set out in (1) of this subsection based on evidence that

(A) engineering, geotechnical, environmental, or location conditions warrant an adjustment of those amounts;

(B) a bond and, if required, security that is exclusively dedicated to the plugging and abandonment of one or more wells is in place with each landowner; or

(C) a bond and, if required, security that is in place with the United States Environmental Protection Agency is dedicated to the plugging and abandonment of underground injection control permitted Class I disposal wells.

(c) An operator with a bond and, if required, security in place on May 18, 2019 will be allowed to increase the amount of its bond and, if required, security to the amount required under (b) of this section in seven installments. The installments shall be made as follows:

(1) the first installment is due August 16, 2019 and must be a minimum of $500,000 or one-quarter of the difference between the operator's existing level of bonding and, if required, security and the level required under (b) of this section, whichever is greater;

(2) the second through sixth installments are due annually on August 16 of the five years following the first installment and must be a minimum of one-sixth of the difference between the operator's level of bonding, rounded up to the nearest thousand, and, if required, security after payment of the first installment and the level required under (b) of this section; and

(3) the final seventh installment is due on August 16 of the year following the sixth installment and must be in the amount of the difference between the operator's existing level of bonding, rounded up to the nearest thousand, and, if required, security and the level required under (b) of this section.

(d) A bond and, if required, security must remain in effect until the operator's wells have been permanently plugged and abandoned in accordance with 20 AAC 25.105 and the commission approves final clearance of the locations. The commission may then, at the operator's request and depending upon the count of active permitted wellheads for the operator, release all or a portion of the bond and security upon written request of the operator.

(e) The operator must provide written proof that the company that provides its bond or security in accordance with (a) of this section has agreed to provide the commission with written notification at least 90 days before the expiration or termination of any bond or security.

(f) Payment under a surety bond or security does not relieve an operator from any other legal requirements.

(g) The commission will not approve a permit to drill application from an operator that is out of compliance with this section.

20 AAC 25.026. Claims.

Commission approval of the abandonment of a well and the release of the bond required by 20 AAC 25.025 constitutes a presumption of proper abandonment, but does not relieve an operator of further claim by the commission after the abandonment.

20 AAC 25.030. Casing and cementing.

(a) A complete proposed well casing and cementing program must be submitted with an application for a Permit to Drill (Form 10-401). Unless modified or altered by pool rules established under 20 AAC 25.520, a well casing and cementing program must be designed to

(1) provide suitable and safe operating conditions for the total measured depth proposed;

(2) confine fluids to the wellbore;

(3) prevent migration of fluids from one stratum to another;

(4) ensure control of well pressures encountered;

(5) protect against thaw subsidence and freezeback effects within permafrost;

(6) prevent contamination of freshwater;

(7) protect significant hydrocarbon zones; and

(8) provide well control until the next casing is set, considering all factors relevant to well control including formation fracture gradients, formation pressures, casing setting depths, and proposed total depth.

(b) General well casing and cementing provisions are as follows:

(1) casing design and setting depth must be based on engineering and geologic factors relevant to the immediate vicinity, including the presence or absence of hydrocarbons, potential drilling hazards, and permafrost;

(2) for all casing strings on which blowout prevention equipment (BOPE) will be installed, cement may not be drilled out until sufficient compressive strength has been reached to obtain a valid formation integrity test;

(3) within permafrost intervals, fluids that have a freezing point above the minimum permafrost temperature may not be left in casing-by-casing annuli or inside the casing upon completion, suspension, or shutdown of well operations, without commission approval of an alternate method that the commission determines will prevent damage to the casing;

(4) if casing is subjected to prolonged drilling operations, the commission will, as necessary to verify casing integrity, require the casing to be pressure-tested, calipered, or otherwise evaluated by a method approved by the commission;

(5) if zonal coverage is required under (a) of this section, and the commission believes zonal isolation might not have been established, the commission will require a cement quality log or other method to demonstrate isolation of the zone.

(c) Specific well casing provisions are as follows:

(1) structural casing must be set by driving, jetting, or drilling to a minimum depth of 70 feet in offshore wells to support unconsolidated shallow strata, to provide hole stability for initial drilling operations, and to provide a competent anchor for a diverter system;

(2) for onshore wells, conductor casing must be set by driving, jetting, or drilling to a depth sufficient to provide anchorage for a diverter system, and for offshore wells, conductor casing must be set no less than 300 feet and no more than 1,000 feet below the mudline datum; however, the commission will

(A) approve a different casing setting depth if necessary to permit the casing shoe to be set in a competent formation or below formations that should be isolated; or

(B) authorize an operator to drill without setting conductor casing based upon information from wells drilled in the immediate vicinity and other available data, if the commission determines that the absence of conductor casing will not jeopardize well control;

(3) surface casing must be set below the base of all strata known or reasonably expected to serve as a source of drinking water for human consumption, below the base of permafrost, and at a depth sufficient to provide a competent anchor for BOPE;

(4) one or more intermediate casing strings must be set if required for protection of oil or gas or for protection against abnormally geo-pressured strata and lost circulation zones, or if otherwise required by well conditions;

(5) production casing must be set and cemented through, into, or just above the production interval;

(6) slotted liners, pre-perforated liners, and screens installed below a production packer are considered production equipment and not casing.

(d) Specific well casing cementing provisions are as follows:

(1) if structural casing is set by drilling or jetting, the structural casing must be cemented with sufficient cement to fill the annular space from the shoe to the surface;

(2) if conductor casing is set by drilling or jetting, the conductor casing must be cemented by filling the annular space with cement from the shoe to the surface; if BOPE is to be installed on the conductor casing, the adequacy of the cement to contain potential wellbore pressures and fluids must be demonstrated by a formation integrity test;

(3) conductor casing cement may be washed out to a depth not exceeding the depth of the structural casing shoe, if installed;

(4) surface casing must be cemented by filling the annular space with cement from the shoe to the surface; however, if cement does not circulate to the surface, if an excessive quantity of cement circulates to the surface, or if the formation integrity test shows an inadequate cement job,

(A) the operator shall notify the commission before drilling ahead; and

(B) the commission will require

(i) a cement quality log or other approved method to evaluate the adequacy of the cement to contain potential wellbore pressures and fluids; and

(ii) remedial action as necessary to meet the requirements of (a) of this section before drilling ahead;

(5) intermediate and production casing must be cemented with sufficient cement to fill the annular space from the casing shoe to a minimum of 500 feet measured depth or 250 feet true vertical depth, whichever is greater, above all significant hydrocarbon zones and abnormally geo-pressured strata or, if zonal coverage is not required under (a) of this section, from the casing shoe to a minimum of 500 feet measured depth or 250 feet true vertical depth, whichever is greater, above the casing shoe; if indications of improper cementing exist, such as lost returns, or if the formation integrity test shows an inadequate cement job,

(A) the operator shall notify the commission and obtain approval before drilling ahead; and

(B) the commission will require

(i) a cement quality log or other approved method to evaluate the adequacy of the cement to contain potential wellbore pressures and fluids; and

(ii) a plan of the remedial actions proposed to bring the well into compliance with (a) of this section;

(6) if the intermediate or production string is a liner, a minimum of 100 measured feet overlap between the outer and inner strings is required; the interval of overlap must be made pressure competent and must be pressure-tested in accordance with (e) of this section;

(7) for intermediate or production casing in a service well used for injection, a cement quality log or other evaluation log approved by the commission must be run to demonstrate isolation of the injected fluids to the approved interval.

(e) A casing pressure test must be performed if BOPE is to be installed on a casing. The casing must be tested to hold a minimum surface pressure equal to 50 percent of the casing internal yield pressure. The test pressure must show stabilizing pressure and may not decline more than 10 percent within 30 minutes. The results of this test and any subsequent tests of the casing must be recorded as required by 20 AAC 25.070(1).

(f) Except for through-tubing drilling, a formation integrity test must be performed if BOPE is installed on a casing. The test must be performed to a predetermined equivalent mud weight, leak-off, or fracture pressure as specified in the application for the Permit to Drill. The test must be conducted after drilling out of the casing shoe into at least 20 feet but not more than 50 feet of new formation. The test results must demonstrate that the integrity of the casing shoe is sufficient to contain anticipated wellbore pressures identified in the application for the Permit to Drill. The test procedure followed and the data from the test and any subsequent tests of the formation must be recorded as required by 20 AAC 25.070(1).

(g) Upon written request of the operator showing good cause, the commission may modify a deadline in this section, approve a variance from any requirement of this section if the variance provides at least an equally effective means of complying with the requirement, or approve a waiver of a requirement of this section if the waiver will not promote waste, is based on sound engineering and geoscience principles, will not jeopardize the ultimate recovery of hydrocarbons, will not jeopardize correlative rights, and will not result in an increased risk to health, safety, or the environment, including freshwater.

20 AAC 25.033. Primary well control for drilling: drilling fluid program and drilling fluid system.

(a) A drilling operation must be equipped with a drilling fluid system meeting the requirements of this section, unless the commission determines that a drilling fluid system is not necessary for primary well control. The operator shall submit with an application for a Permit to Drill (Form 10-401) a proposed drilling fluid program and a diagram with a list of equipment for a drilling fluid system designed to prevent the loss of primary well control. The drilling fluid system must be designed to maintain the wellbore in overbalanced condition except as otherwise provided under (i) of this section. A drilling operation is also subject to the requirements of 20 AAC 25.527.

(b) A drilling fluid program and drilling fluid system intended to maintain the wellbore in overbalanced condition must be designed to provide and maintain

(1) a drilling fluid

(A) of sufficient density to overbalance the pressure of uncased formations penetrated; and

(B) with rheological properties designed to

(i) minimize the potential of a hydrostatic pressure surge or swab when the drilling assembly is run into or pulled out of the wellbore; and

(ii) enhance the drop-out of solids and the escape of entrained gas; and

(2) a volumetric capacity for drilling fluid reserves adequate for the volume of the wellbore, based on known or anticipated drilling conditions to be encountered, rig storage capacity, weather conditions, and estimated time for delivery.

(c) A drilling fluid system intended to maintain the wellbore in overbalanced condition must include

(1) a recording drilling fluid pit level indicator with both visual and audible warning devices located in the immediate area of the driller's station;

(2) a drilling fluid measuring system or trip tank for accurately determining drilling fluid volumes required to fill the wellbore on trips;

(3) a drilling fluid flow sensor with a readout convenient to the driller's station to enable the operator to determine whether drilling fluid returns equal drilling fluid pump discharge rates;

(4) equipment to keep the drilling mud conditioned as appropriate for the drilling operation being conducted; and

(5) methane and hydrogen sulfide detection equipment as required by 20 AAC 25.066.

(d) Drilling fluid testing equipment must be on the drill site at all times. Tests to determine drilling fluid density and viscosity must be performed once each tour, or more frequently if conditions warrant.

(e) To ensure that primary well control is effectively maintained, the following practices must be employed in rotary drilling rig operations when tripping the drilling assembly out of the wellbore:

(1) the drilling fluid within the wellbore must be in balance and conditioned to maintain drilling fluid properties within close tolerance to the properties necessary for well control;

(2) the flow nipple or trip tank must be visually observed to ensure that there is no indication of formation fluid influx;

(3) the wellbore must be kept full of drilling fluid at all times;

(4) the annulus must be filled with fluid

(A) each time that five stands of drill pipe have been removed from the wellbore; and

(B) more frequently than required in (A) of this paragraph, if necessary to prevent the hydrostatic pressure from dropping by 75 psi or more;

(5) the volume of drilling fluid required to keep the wellbore full while tripping the drilling assembly out of the wellbore must be measured and recorded on the daily drilling report or trip sheet.

(f) Additional requirements that apply to exploratory and stratigraphic test wells are as follows:

(1) the operator shall include with an application for a Permit to Drill a tabulation that sets out the depths of predicted abnormally geo-pressured strata;

(2) if the operator has geophysical data from the area, the operator shall include with an application for a Permit to Drill a seismic velocity analysis constrained by germane well data to predict the potential of encountering abnormally geo-pressured strata, with the analysis displayed by plotting interval transit time versus depth; as the commission considers necessary to evaluate the potential for a well control problem, the commission will require a review from the operator of the velocity analysis and of the plot of interval transit time versus depth;

(3) if the operator does not have geophysical data from the area, the operator shall include with an application for a Permit to Drill an analysis of germane well data to predict the potential of encountering abnormally geo-pressured strata;

(4) a drilling fluid monitoring unit must be used and continuously observed during drilling rig operations, including tripping, to monitor and record

(A) gas entrained in the drilling fluid;

(B) drilling fluid density;

(C) drilling fluid salinity;

(D) the rate of penetration; and

(E) hydrogen sulfide, as required by 20 AAC 25.065;

(5) means for communication between the drilling fluid monitoring unit and the drill rig floor must be installed and maintained in working condition while open hole operations are taking place, and drill rig floor personnel must be notified immediately if excursions from normal trends occur for any of the parameters set out in (4) of this subsection.

(g) If drilling an exploratory or stratigraphic test well, or if drilling a development or service well while known hydrocarbon-bearing strata are exposed to open hole, the operator shall take a drilling fluid return sample and test the sample to determine density just before tripping the drill pipe. Density test results must be recorded as required by 20 AAC 25.070(1). If the density is less than that of the drilling fluid being pumped down the drilling assembly, the drilling fluid must be circulated and conditioned until a close tolerance of the properties of the return drilling fluid with the input drilling fluid is achieved.

(h) If formation competence at the structural casing setting depth is not adequate to permit circulation of drilling fluids while drilling the conductor hole, a program that provides for safety in that drilling operation must be described and submitted to the commission for approval. This program must be supported by pertinent information including seismic and geologic data, water depth, drilling fluid hydrostatic pressure, and a contingency plan for moving off location.

(i) The commission will approve underbalanced drilling operations and associated equipment changes if the commission determines that underbalanced drilling operations can be performed without loss of well control. A request for underbalanced drilling must include a description of all equipment and procedures to ensure proper containment of formation and return fluids.

(j) Upon request by the operator, the commission will, in its discretion, approve a waiver of the requirements of (c) - (g) of this section if the alternative drilling fluid program and drilling fluid system meet the design criteria of (b) of this section and the corresponding equipment and procedures are at least equally effective in preventing the loss of primary well control.

20 AAC 25.035. Secondary well control for primary drilling and completion: blowout prevention equipment and diverter requirements.

(a) This section applies to drilling and completion operations other than those covered by 20 AAC 25.036. These operations are also subject to the requirements of 20 AAC 25.527.

(b) The operator shall submit the following information with the application for a Permit to Drill (Form 10-401) or refer in the application to that information if that information is already on file with the commission:

(1) a diagram of the blowout preventer (BOP) stack or diverter and related equipment for each proposed casing installation;

(2) a list of the blowout prevention equipment (BOPE) and if applicable, diverter equipment with specifications.

(c) Except as provided in (d) and (h) of this section, a high capacity flow diverter system must be installed to provide safety for personnel and equipment before rotary rig drilling is performed below a well's structural or conductor casing, unless the casing is equipped with BOPE conforming with (e) of this section. The following provisions apply to a diverter system:

(1) the diverter system must consist of a remotely operated annular pack-off device, a full-opening vent line valve, and a diverter vent line with a diameter

(A) of at least 16 inches, unless a smaller diameter is approved by the commission to account for smaller hole size, geological conditions, rig layout, or surface facility constraints; and

(B) at least as large as the diameter of the hole to be drilled, unless a pilot hole with a diameter no larger than that of the vent line is drilled first; the commission will waive the requirement of this paragraph if the operator demonstrates, based on drilling experience in the near vicinity, that drilling a pilot hole would not be necessary for safety;

(2) the diverter system must be assembled as follows:

(A) the diverter vent line outlet must be located below the annular pack-off, either as an integral part of the annular pack-off device or as a vent-line outlet spool immediately below it;

(B) the actuating mechanism for the vent line valve must be integrated with the actuating mechanism for the annular pack-off device in a fail-safe manner so that the vent line valve automatically opens before full closure of the annular pack-off;

(C) the vent line must extend to a point at least 75 feet

(i) away from a potential source of ignition; and

(ii) beyond the drill rig substructure, or to a point within the reserve pit and at least 50 feet beyond the drill rig substructure;

(D) the vent line must be as straight as possible, secured to prevent movement, and designed to avoid freeze-up;

(E) the vent line may be secured to the rig and with portable cradle supports, but may not be attached to flowlines, cable trays, or other processing equipment;

(F) all turns with a bend radius less than 20 times the inside diameter of the vent line must be targeted;

(G) all valves must be full-opening;

(3) a clearly marked "warning zone" must be established on each side and ahead of the vent line tip, and the following restrictions must be in effect within the warning zone, beginning with the function test of the diverter system immediately before drilling operations begin and ending with diverter system rig-down:

(A) a prohibition on vehicle parking;

(B) a prohibition on ignition sources or running equipment;

(C) a prohibition on staged equipment or materials;

(D) the restriction of traffic to essential foot or vehicle traffic only;

(4) the commission will, in its discretion, inspect the diverter system for compliance with the requirements of this subsection and require the operator to test the system to ensure proper operation.

(d) If the formation competence at the structural casing setting depth is not adequate to permit use of a diverter system while drilling the conductor hole, a program that provides for safety in that drilling operation must be described and submitted to the commission for approval. This program must be supported by pertinent information including seismic and geologic data, water depth, drilling fluid hydrostatic pressure, and a contingency plan for moving off location.

(e) A well must be equipped with BOPE meeting the requirements of this subsection from the time that open hole drilling operations begin below the surface casing until the drilled portion has been plugged or the well is completed, except if hydraulic communication to the open hole section is isolated. The following provisions apply to BOPE and other well control equipment:

(1) in rotary drilling rig operations,

(A) for an operation with a maximum potential surface pressure of 3,000 psi or less, BOPE must have at least three preventers, including

(i) one equipped with pipe rams that fit the size of drill pipe, tubing, or casing being used, except that pipe rams need not be sized to bottom-hole assemblies (BHAs) and drill collars;

(ii) one with blind rams, except that a subsea BOPE assembly must have blind/shear rams in place of blind rams; and

(iii) one annular type; and

(B) for an operation, other than a casing or liner operation, with a maximum potential surface pressure of greater than 3,000 psi, BOPE must have at least four preventers, including

(i) two equipped with pipe rams that fit the size of the drill pipe or tubing being used, except that pipe rams need not be sized to BHAs and drill collars;

(ii) one with blind rams, except that a subsea BOPE assembly must have blind/shear rams in place of blind rams; and

(iii) one annular type;

(C) for a casing or liner operation with a maximum potential surface pressure of greater than 3,000 psi, BOPE must have at least four preventers, including

(i) one equipped with pipe rams that fit the size of the drill pipe or tubing being used, except that pipe rams need not be sized to BHAs and drill collars;

(ii) one equipped with pipe rams that fit the size of casing or liner being used;
(iii) one with blind rams, except that a subsea BOPE assembly must have blind/shear rams in place of blind rams; and
(iv) one annular type;
(2) in coiled tubing unit operations, the well control equipment must include
(A) for an operation with a maximum potential surface pressure of 5,000 psi or less,
(i) BOPE rams providing for pipe, slip, cutting, and blinding operations on the coiled tubing in service;
(ii) a high pressure pack-off, stripper, or annular type preventer;
(iii) if pressure deployment of tools, tubing, liner, or casing is planned, a riser or lubricator sized to the BHA and providing for pressure integrity from the BOPE rams to the high pressure pack-off, stripper, or annular type preventer; and
(iv) at least one preventer equipped with pipe rams that fit the size of tubing, liner, or casing being used, except that pipe rams need not be sized to BHAs and drill collars; and
(B) for an operation, other than a casing or liner operation, with a maximum potential surface pressure of greater than 5,000 psi,
(i) BOPE rams providing for pipe, slip, cutting, and blinding operations on the coiled tubing in service;
(ii) two high pressure pack-offs, strippers, or annular type preventers;
(iii) if pressure deployment of tools, tubing, liner, or casing is planned, a riser or lubricator sized to the BHA and providing for pressure integrity from the BOPE rams to the high pressure pack-off, stripper, or annular type preventer; and
(iv) at least two preventers equipped with pipe rams that fit the size of tubing being used, except that pipe rams need not be sized to BHAs and drill collars;
(C) for a casing or liner operation with a maximum potential surface pressure of greater than 5,000 psi,
(i) BOPE rams providing for pipe, slip, cutting, and blinding operations on the coiled tubing in service;
(ii) two high pressure pack-offs, strippers, or annular type preventers;
(iii) if pressure deployment of tools, tubing liner, or casing is planned, a riser or lubricator sized to the BHA and providing for pressure integrity from the BOPE rams to the high pressure pack-off, stripper, or annular type preventer;
(iv) at least one preventer equipped with pipe rams that fit the size of the tubing being used, except that pipe rams need not be sized to BHAs and drill collars; and
(v) at least one preventer equipped with pipe rams that fit the size of casing or liner being used;
(3) the rated working pressure of the BOPE and other well control equipment must exceed the maximum potential surface pressure to which it may be subjected; the commission will specify in the approved Permit to Drill the working pressure that the equipment must be rated to meet or exceed; however, the rated working pressure of the annular type preventer need not exceed 5,000 psi, unless the commission requires a higher rated working pressure as the commission considers necessary to maintain well control; if the maximum potential surface pressure exceeds the rated working pressure of the annular type preventer, the operator shall submit with the application for a Permit to Drill a well-control procedure that indicates how the annular type preventer will be used and what pressure limitations will be applied during each mode of pressure control;
(4) a BOPE assembly must include
(A) a hydraulic actuating system with
(i) sufficient accumulator capacity to supply 150 percent of the volume necessary to close all BOPs, except blind rams, and to open the remotely controlled hydraulic valve while maintaining a minimum pressure of 200 psi above the required precharge pressure when all BOPs, except blind rams, are closed and all power sources are shut off; and
(ii) an accumulator pump system consisting of two or more pumps with independent primary and secondary power sources and an accumulator backup system having sufficient capacity to close all BOPs and to hold them closed;
(B) locking devices on the ram-type preventers;
(C) a fire wall to shield accumulators and primary controls;
(D) in rotary drilling rig operations, one complete set of operable remote BOPE controls on or near the driller's station, in addition to controls on the accumulator system;
(E) in coiled tubing operations, one complete set of operable remote BOPE controls on or near the operator's station and, if these controls are not in close proximity to the drilling platform floor, a second annular type preventer closing control located on the drilling platform floor;
(F) a kill line and a choke line each connected to a flanged or hubbed outlet on a drilling spool or on the BOP body with two full-opening valves on each outlet, conforming to the following specifications:
(i) the outlets must be at least two inches in nominal diameter, except that for rotary drilling rig operations, if the operation has a maximum potential surface pressure of greater than 3,000 psi, the nominal diameter of the choke outlets must be at least three inches;
(ii) each valve must be sized at least equal to the required size of the outlet to which it is attached;
(iii) the outer valve on the choke side must be a remotely controlled hydraulic valve;
(iv) the inner valve on both the choke and kill sides may not normally be used for opening or closing on flowing fluid;
(G) in rotary drilling rig operations, a fill-up line above the uppermost BOP; and
(H) a choke manifold equipped with
(i) two or more adjustable chokes, one of which must be hydraulic and remotely controlled from near the driller's station if the operation has a maximum potential surface pressure of greater than 3,000 psi;
(ii) a line at least two inches in nominal diameter downstream of each choke;
(iii) immediately upstream of each choke, at least one full-opening valve for an operation with a maximum potential surface pressure of 3,000 psi or less, or at least two full-opening valves for an operation with a maximum potential surface pressure of greater than 3,000 psi; and
(iv) a bypass line, at least the diameter of the choke line, with at least one full-opening valve for an

operation with a maximum potential surface pressure of 3,000 psi or less, or at least two full-opening valves for an operation with a maximum potential surface pressure of greater than 3,000 psi;

(5) the rated working pressure of the wellhead assembly and of all valves, pipes, rotary hoses, and other fittings, including all sections of the choke manifold that are subject to full wellhead pressure, must equal or exceed the required working pressure specified for the BOPE in the approved Permit to Drill, except that the rated working pressure of lines downstream of the choke need not exceed 50 percent of the required working pressure of the BOPE;

(6) kill and choke lines must

(A) be constructed of rigid steel pipe, fire-resistant rotary hose, or other conduit that has been approved by the commission as capable of withstanding the temperature and pressure of an ignited uncontrolled release;

(B) be as straight as practical;

(C) if constructed of rigid steel pipe, use targeted turns where the bend radius is less than 20 times the inside diameter of the pipe;

(D) be secured to prevent excessive whip or vibration;

(E) be sized to prevent excessive erosion or fluid friction; and

(F) be assembled without hammer unions or internally clamped swivel joints, unless the commission determines that those joints do not compromise maintenance of well control;

(7) for lubricated drilling operations or operations below a normally closed annular type preventer, the choke line may be used for drilling returns;

(8) connections attached directly to the wellhead, tree, or BOPE must be flanged or hubbed;

(9) for rotary drilling rig operations, auxiliary well control equipment must include

(A) a kelly cock valve installed below the swivel and, at the bottom of the kelly, a full-opening lower kelly valve of a design that allows it to be run through the BOP stack, with a properly sized wrench for each valve stored in a conspicuous location readily accessible to the drilling crew; and

(B) an inside BOP and a full-opening drilling assembly safety valve in the open position on the drill rig floor to fit all connections that are in the drilling assembly;

(10) the BOPE must be tested as follows:

(A) when installed, repaired, or changed on a development or service well and at time intervals not to exceed each 14 days thereafter, BOPE, including kelly valves, emergency valves, and choke manifolds, must be function pressure-tested to the required working pressure specified in the approved Permit to Drill, using a non-compressible fluid, except that an annular type preventer need not be tested to more than 50 percent of its rated working pressure; however, the commission will require that the BOPE be function pressure-tested weekly, if the commission determines that a weekly BOPE pressure test interval is indicated by a particular drilling rig's BOPE performance;

(B) when installed, repaired, or changed on an exploratory or stratigraphic test well and at least once a week thereafter, BOPE, including kelly valves, emergency valves, and choke manifolds, must be function pressure-tested to the required working pressure specified in the approved Permit to Drill, using a non-compressible fluid, except that an annular type preventer need not be tested to more than 50 percent of its rated working pressure;

(C) if any BOP equipment components have been used for well control or other equivalent purpose, or when routine use of the equipment may have compromised its effectiveness, the components used must be function pressure-tested, before the next wellbore entry, to the required working pressure specified in the approved Permit to Drill, using a non-compressible fluid, except that an annular type preventer need not be tested to more than 50 percent of its rated working pressure;

(D) BOP ram and annular components except blind rams must be function-tested weekly, and all BOP ram and annular components must be function-tested after an action that disconnects the hydraulic system lines from the BOPE, except that if the workstring is continuously in the well, function-testing of blind rams must be performed as soon as possible after the workstring is pulled out of the well and the BHA clears the BOP;

(E) for each BOPE test during drilling and completion operations, variable bore rams must be function pressure-tested to the required pressure on the smallest outside diameter (OD) and largest outside diameter (OD) tubulars that may be used during that test cycle, except that variable bore rams need not be tested on BHAs and drill collars;

(F) after they are installed in the BOP stack, the rams for casing or liner must be function pressure-tested to the required pressure before running casing;

(G) BOPE test results must be recorded as part of the daily record required by 20 AAC 25.070(1), and must be provided to the commission, in a format approved by the commission, within five days after completing the test;

(H) at least 24 hours notice of each BOPE function pressure test must be provided to the commission so that a commission representative can witness the test;

(11) the operator shall report to the commission within 24 hours any instance of BOPE use to prevent the flow of fluids from a well.

(f) In consultation with the drilling rig supervisor, the commission will, in its discretion, require drills simulating well control problems. The commission will, in its discretion, include in the drills any combination of raising or lowering the pit level indicator, advancing or retarding the flow rate indicator, or actuating the gas detectors.

(g) In a rotary drilling rig operation, the operator shall have on location a copy of the approved Permit to Drill and shall post on the drilling rig floor the drilling hazard information required by 20 AAC 25.005(c)(4) and a copy of the operator's standing orders specifying well control procedures. In a coiled tubing operation, the operator shall post in the operator's cab a copy of the approved Permit to Drill, the drilling hazard information required by 20 AAC 25.005(c)(4), and a copy of the standing orders specifying well control procedures. If an additional or separate substructure is used in a coiled tubing operation, the operator shall post a second set of standing orders on the drilling platform floor.

(h) Upon request of the operator, the commission will, in its discretion, approve a variance

(1) from the BOPE requirements in (e) of this section if the variance provides at least an equally effective means of well control; and

(2) from the diverter system requirements in (c) of this section if the variance provides at least equally effective means of diverting flow away from the drill rig or if drilling experience in the near vicinity indicates that a diverter system is not necessary.

20 AAC 25.036. Secondary well control for through-tubing drilling and completion: blowout prevention equipment requirements.

(a) This section applies to drilling and completion operations performed through existing production tubing. These operations are also subject to the requirements of 20 AAC 25.527.

(b) The operator shall submit the following information with the application for a Permit to Drill (Form 10-401) or refer in the application to that information if that information is already on file with the commission:

(1) a diagram of each blowout preventer (BOP) stack and related well control equipment to be used;

(2) a list of the blowout prevention equipment (BOPE) with specifications.

(c) A well must be equipped with BOPE meeting the requirements of this subsection from the time that drilling penetrates beyond casing or liner until the drilled portion has been plugged or the well is completed, except if hydraulic communication to the open hole section has been isolated. The following provisions apply to BOPE and other well control equipment:

(1) in rotary drilling rig operations,

(A) for an operation with a maximum potential surface pressure of 5,000 psi or less, BOPE must have at least three preventers, including

(i) one equipped with pipe rams that fit the size of drill pipe, tubing, or casing being used, except that pipe rams need not be sized to bottom-hole assemblies (BHAs) and drill collars;

(ii) one with blind rams, except that a subsea BOPE assembly must have blind/shear rams in place of blind rams;

(iii) one annular type; and

(B) for an operation other than a casing or liner operation, with a maximum potential surface pressure of greater than 5,000 psi, BOPE must have at least four preventers, including

(i) two equipped with pipe rams that fit the size of the drill pipe or tubing being used, except that pipe rams need not be sized to BHAs and drill collars;

(ii) one with blind rams, except that a subsea BOPE assembly must have blind/shear rams in place of blind rams; and

(iii) one annular type; and

(C) for a casing or liner operation with a maximum potential surface pressure of greater than 5,000 psi, BOPE must have at least four preventers, including

(i) one equipped with pipe rams that fit the size of the drill pipe or tubing being used, except that pipe rams need not be sized to BHAs and drill collars;

(ii) one equipped with pipe rams that fit the size of casing or liner being used;

(iii) one with blind rams, except that a subsea BOPE assembly must have blind/shear rams in place of blind rams; and

(iv) one annular type;

(2) in coiled tubing unit operations, the well control equipment must include

(A) for an operation with a maximum potential surface pressure of 5,000 psi or less,

(i) BOPE rams providing for pipe, slip, cutting, and blinding operations on the coiled tubing in service;

(ii) a high pressure pack-off, stripper, or annular type preventer;

(iii) if pressure deployment of tools, tubing, liner, or casing is planned, a riser or lubricator sized to the BHA and providing for pressure integrity from the BOPE rams to the high pressure pack-off, stripper, or annular type preventer; and

(iv) at least one preventer equipped with pipe rams that fit the size of the tubing, liner, or casing being used, except that pipe rams need not be sized to BHAs and drill collars;

(B) for an operation, other than a casing or liner operation with a maximum potential surface pressure of greater than 5,000 psi,

(i) BOPE rams providing for pipe, slip, cutting, and blinding operations on the coiled tubing in service;

(ii) two high pressure pack-offs, strippers, or annular type preventers;

(iii) if pressure deployment of tools, tubing, liner, or casing is planned, a riser or lubricator sized to the BHA and providing for pressure integrity from the BOPE rams to the high pressure pack-off, stripper, or annular type preventer; and

(iv) at least two preventers equipped with pipe rams that fit the size of the tubing being used, except that pipe rams need not be sized to BHAs and drill collars; and

(C) for a casing or liner operation with a maximum potential surface pressure of greater than 5,000 psi,

(i) BOPE rams providing for pipe, slip cutting, and blinding operations on the coiled tubing in service;

(ii) two high pressure pack-offs, strippers, or annular type preventers;

(iii) if pressure deployment of tools, tubing, liner, or casing is planned, a riser or lubricator sized to the BHA and providing for pressure integrity from the BOPE rams to the high pressure pack-off, stripper, or annular type preventer;

(iv) at least one preventer equipped with pipe rams that fit the size of the tubing being used, except that pipe rams need not be sized to BHAs and drill collars; and

(v) at least one preventer equipped with pipe rams that fit the size of casing or liner being used;

(3) the rated working pressure of the BOPE and other well control equipment must exceed the maximum potential surface pressure to which it may be subjected; the commission will specify in the approved Permit to Drill the working pressure that the equipment must be rated to meet or exceed; however, the rated working pressure of an annular type preventer need not exceed 5,000 psi, unless the commission requires a higher rated working pressure as the commission considers necessary to maintain well control; if the maximum potential surface pressure exceeds the rated working pressure of the annular type preventer, the operator shall submit with the application for a Permit to Drill a well control procedure that indicates how the annular type preventer will be used and the pressure limitation that will be applied during each mode of pressure control;

(4) a BOPE assembly must include

(A) a hydraulic actuating system with

(i) sufficient accumulator capacity to supply 150 percent of the volume necessary to close all BOPs, except blind rams, and to open the remotely controlled hydraulic valve while maintaining a minimum pressure of 200 psi above the required precharge pressure when all BOPs, except blind rams, are closed and all power sources are shut off; and

(ii) an accumulator pump system consisting of one or more pumps with independent primary and secondary power sources, and an accumulator backup system having sufficient capacity to close all BOPs and to hold them closed;

(B) locking devices on the ram-type preventers;

(C) a fire wall to shield accumulators and primary controls;

(D) in rotary drilling rig operations, one complete set of operable remote BOPE controls on or near the driller's station, in addition to controls on the accumulator system;

(E) in coiled tubing operations, one complete set of operable remote BOPE controls on or near the operator's station and, if these controls are not in close proximity to the drilling platform floor, a second annular type preventer closing control located on the drilling platform floor;

(F) a kill line and a choke line each connected to a flanged or hubbed outlet on a drilling spool, the BOP body, or the tree, with two full-opening valves on each outlet, conforming to the following specifications:

(i) the outlets and valves must be at least two inches in nominal diameter;

(ii) the outer valve on the choke side must be a remotely controlled hydraulic valve;

(iii) the inner valve on both the choke and kill sides may not normally be used for opening or closing on flowing fluid;

(G) for open hole deployment, an annular type preventer, unless a lubricator of sufficient length to enclose the entire BHA below a high pressure sealing element is used; and

(H) for conventional open loop fluid process drilling operations, a choke manifold equipped with

(i) two or more adjustable chokes, one of which must be hydraulic and remotely controlled from near the driller's or operator's station if the operation has a maximum potential surface pressure of greater than 3,000 psi;

(ii) a line at least two inches in nominal diameter downstream of each choke;

(iii) immediately upstream of each choke, at least one full-opening valve for an operation with a maximum potential surface pressure of 5,000 psi or less, or at least two full-opening valves for an operation with a maximum potential surface pressure of greater than 5,000 psi; and

(iv) a bypass line at least two inches in nominal diameter with at least one full-opening valve immediately upstream of each choke for an operation with a maximum potential surface pressure of 5,000 psi or less, or with at least two full-opening valves immediately upstream of each choke for an operation with a maximum potential surface pressure of greater than 5,000 psi;

(5) in an underbalanced drilling operation, well control equipment must have bi-directional slip capabilities;

(6) the rated working pressure of the wellhead assembly and of all valves, pipes, rotary hoses, and other fittings, including all sections of the choke manifold that are subject to full wellhead pressure, must equal or exceed the required working pressure specified for the BOPE in the approved Permit to Drill, except that the rated working pressure of lines downstream of the choke need not exceed 50 percent of the required working pressure of the BOPE;

(7) for lubricated drilling operations or operations below a normally closed annular type preventer, the choke line may be used for drilling returns;

(8) at least one positive seal manual or hydraulic valve or BOPE blind ram, one set of BOPE pipe rams, and, if used, the drilling spool must be flanged to the wellhead or tree;

(9) connections directly to the BOPE, other than connections described in (8) of this subsection, must be flanged or hubbed, except that suitably pressure-rated quick connects may be used if a positive seal manual valve, hydraulic valve, or BOPE blind ram and an annular type preventer or sealing ram are flanged to the wellhead or tree below the quick connection;

(10) kill and choke lines must

(A) be constructed of rigid steel pipe, fire-resistant rotary hose, or other conduit that has been approved by the commission as capable of withstanding the temperature and pressure of an ignited uncontrolled release;

(B) be as straight as practical;

(C) if constructed of rigid steel pipe, use targeted turns where the bend radius is less than 20 times the inside diameter of the pipe;

(D) be secured to prevent excessive whip or vibration;

(E) be sized to prevent excessive erosion or fluid friction; and

(F) be assembled without hammer unions or internally clamped swivel joints, except that hammer unions and internally clamped swivel joints may be used on the kill line upstream of the valves that are flanged to the wellhead or tree.

(d) A BOPE assembly must be tested as follows:

(1) when installed, repaired, or changed on a development or service well and at time intervals not to exceed each 14 days thereafter, BOPE, including kelly valves, emergency valves, and choke manifolds, must be function pressure-tested to the required working pressure specified in the approved Permit to Drill, using a non-compressible fluid, except that an annular type preventer need not be tested to more than 50 percent of its rated working pressure; however, the commission will require that the BOPE be function pressure-tested weekly, if the commission determines that a weekly BOPE pressure test interval is indicated by a particular drilling rig's BOPE performance;

(2) when installed, repaired, or changed on an exploratory or stratigraphic test well and at least once a week thereafter, BOPE, including kelly valves, emergency valves, and choke manifolds, must be function pressure-tested to the required working pressure specified in the approved Permit to Drill, using a non-compressible fluid, except that an annular type preventer need not be tested to more than 50 percent of its rated working pressure;

(3) other well control equipment must be pressure-tested to the maximum potential wellhead pressure after each installation of the well control equipment and before wellbore entry, except that an annular type preventer need not be tested to more than 50 percent of its rated working pressure;

(4) if any BOP equipment components have been used for well control or other equivalent purpose, or when routine use of the equipment may have compromised its effectiveness, the components used must be function pressure-tested,

before the next wellbore entry, to the required working pressure specified in the approved Permit to Drill, using a non-compressible fluid, except that an annular type preventer need not be tested to more than 50 percent of its rated working pressure;

(5) BOP ram and annular components except blind rams must be function-tested weekly, and all BOP ram and annular components must be function-tested after an action that disconnects the hydraulic system lines from the BOPE, except that if the workstring is continuously in the well, function-testing of blind rams must be performed as soon as possible after the workstring is pulled out of the well and the BHA clears the BOP;

(6) for each BOPE test during drilling and completion operations, variable bore rams must be function pressure-tested to the required pressure on the smallest outside diameter (OD) and largest outside diameter (OD) tubulars that may be used during that test cycle, except that variable bore rams need not be tested on BHAs and drill collars;

(7) BOPE test results must be recorded as part of the daily record required by 20 AAC 25.070(1), and must be provided to the commission, in a format approved by the commission, within five days after completing the test;

(8) at least 24 hours notice of each BOPE function pressure test must be provided to the commission so that a representative of the commission can witness the test.

(e) In a rotary drilling rig operation, the operator shall have on location a copy of the approved Permit to Drill and shall post on the drilling rig floor the drilling hazard information required by 20 AAC 25.005(c)(4) and a copy of the operator's standing orders specifying well control procedures. In a coiled tubing operation, the operator shall post in the operator's cab a copy of the approved Permit to Drill, the drilling hazard information required by 20 AAC 25.005(c)(4), and a copy of the standing orders specifying well control procedures. If an additional or separate substructure is used in a coiled tubing operation, the operator shall post a second set of standing orders on the drilling platform floor.

(f) Upon request of the operator, the commission will, in its discretion, approve a variance from the requirements of this section if the variance provides at least an equally effective means of well control.

(g) The operator shall report to the commission within 24 hours any instance of BOPE use to prevent the flow of fluids from a well.

20 AAC 25.037. Well control requirements for other drilling and completion operations.

Repealed.

20 AAC 25.040. Well identification.

(a) Every well must be identified by a sign posted in a conspicuous place. During the period of time from commencement of drilling operations to well completion, suspension, or abandonment, the sign must be on or near the drill rig, but not more than 100 feet from the well. After well completion or suspension, the well sign must be at the wellhead or on the wellhead building. The sign must be of durable construction, large enough to be legible under normal conditions at a distance of 50 feet, and maintained in legible condition. Each sign must show the

(1) name of the well or primary wellbore as designated by the operator under 20 AAC 25.005(f) for the well drilled from the surface location;

(2) name of the owner;

(3) name of the operator if different from the owner;

(4) API number that the commission has, under (b) of this section, assigned to the well;

(5) well surface location by governmental quarter section, section, township, and range; and

(6) Permit to Drill number that the commission has assigned under (b) of this section.

(b) The commission will assign a Permit to Drill number and an API number when a Permit to Drill (Form 10-401) is approved.

(c) For platforms or multiple-well drill sites, the information required in (a)(2) - (a)(5) of this section may be posted on one sign on the platform or at the main entrance to the drill site.

(d) For wells with more than one permitted wellbore (i.e. multi-branch completion) the primary wellbore will require compliance with (a)(1) - (6) of this section. Individual branch details as specified by (a)(1) - (6) of this section need not be posted but must be available upon request. The wellhead sign must include the suffix "ML" in the wellname indicating multiple active wellbores are present.

20 AAC 25.045. Sealing off strata.

Repealed 4/2/86.

20 AAC 25.047. Reserve pits and tankage.

Repealed.

20 AAC 25.050. Wellbore surveys.

(a) A well that is not intentionally deviated must be

(1) drilled as close to vertical as is possible using conventional drilling techniques, except that deviation is permitted for short intervals to straighten the hole, sidetrack junk, or correct mechanical difficulties;

(2) surveyed to determine the inclination from vertical with surveys starting at 500 feet and no more than 500 feet apart to total depth; and

(3) surveyed by a complete continuous directional survey if a portion of the well path is less than 500 feet from a property line where the ownership by owner or landowner is not identical on both sides of the line, or if a portion of the well path is less than 200 feet from any other vertical or deviated well; the survey must be taken at intervals not more than 100 feet apart, beginning within 100 feet of the surface.

(b) If a well is to be intentionally deviated, the application for a Permit to Drill (Form 10-401) must

(1) include a plat, drawn to a suitable scale, showing the path of the proposed wellbore, including all adjacent wellbores within 200 feet of any portion of the proposed well; and

(2) for all wells within 200 feet of the proposed wellbore

(A) list the names of the operators of those wells, to the extent that those names are known or discoverable in public records, and show that each named operator has been furnished a copy of the application by certified mail; or

(B) state that the applicant is the only affected owner.

(c) A well that is intentionally deviated must be

(1) directionally surveyed at intervals not more than 500 feet apart on straight or tangent sections of the well during the normal course of drilling, and at intervals not exceeding 100 feet in all portions of the hole where intentional angle changes are performed;

(2) surveyed by a continuous directional survey if a portion of the well path is less than 500 feet from a property line where the ownership by owner or landowner is not identical on both sides of the line; the survey must be taken at intervals not more than 100 feet apart, beginning within 100 feet of the surface; and

(3) surveyed by a continuous directional survey if a deviated portion of the wellbore is less than 200 feet from any other vertical or deviated well; the survey must be taken at intervals not more than 100 feet apart, beginning within 100 feet of the surface.

(d) Within 30 days after the completion, abandonment, or suspension of a well, and within 30 days after completion or plugging of a well branch, a complete digital copy of each inclination and directional survey not previously filed must be filed with the commission in a format acceptable to the commission. A composite survey may additionally be filed if the operator believes this would better represent the well course. If a composite survey is filed, the operator shall specify the portion of each survey used in the composite.

(e) If the final location of the producing interval of a well is not in compliance with 20 AAC 25.055 or with pool rules established under 20 AAC 25.520, the operator shall apply for an exception. The commission will review the application in accordance with 20 AAC 25.540. The well may not be produced until the exception is granted.

(f) A wellbore survey report required by (a) or (c) of this section must contain

(1) the name of the surveying company;

(2) the name, title, and signature of the person who actually performed the survey;

(3) the date on which the survey was performed;

(4) the type of survey conducted;

(5) the method used in calculating the survey;

(6) a complete identification of the well or, in the case of a well with more than one bottom-hole location, a complete identification of the well branch; the identification must show the name of the well designated by the operator under 20 AAC 25.005(f), the name of the operator, the property name or lease number, the Permit to Drill number assigned under 20 AAC 25.040(b), the API number, and the field name;

(7) the depth interval over which the survey was conducted; and

(8) a plat showing the coordinates

(A) of the surface location, the plotted well course, and wells within 500 feet of any portion of the wellbore; these coordinates must be referenced to governmental section lines; and

(B) of the surface location, referenced to the state plane coordinate system for this state as maintained by the National Geodetic Survey in the National Oceanic and Atmospheric Administration.

(g) The commission will, in its discretion, require submittal of the original film, time sheets, charts, graphs, discs, and other data used to compile the survey required by (a) or (c) of this section.

(h) Upon application, the commission will, in its discretion, waive all or part of the directional survey requirements of this section or approve alternate means for determining the location of a wellbore if the variance at least equally ensures accurate surveying of the wellbore to prevent well intersection, to comply with spacing requirements, and to ensure protection of correlative rights.

20 AAC 25.055. Drilling units and well spacing.

(a) The commission will, in its discretion, establish drilling units to govern well spacing and prescribe a spacing pattern by pool rules adopted in accordance with 20 AAC 25.520. In the absence of an order by the commission establishing drilling units or prescribing a spacing pattern for a pool, the following statewide spacing requirements apply:

(1) for a well drilling for oil, a wellbore may be open to test or regular production within 500 feet of a property line only if the owner is the same and the landowner is the same on both sides of the line;

(2) for a well drilling for gas, a wellbore may be open to test or regular production within 1,500 feet of a property line only if the owner is the same and the landowner is the same on both sides of the line;

(3) if oil has been discovered, the drilling unit for the pool is a governmental quarter section; not more than one well may be drilled to and completed in that pool on any governmental quarter section; a well may not be drilled or completed closer than 1,000 feet to any well drilling to or capable of producing from the same pool;

(4) if gas has been discovered, the drilling unit for the pool is a governmental section; not more than one well may be drilled to and completed in that pool on any governmental section; a well may not be drilled or completed closer than 3,000 feet to any well drilling to or capable of producing from the same pool.

(b) A well may not begin regular production of oil from a property that is smaller than the governmental quarter section upon which the well is located or begin regular production of gas from a property that is smaller than the governmental section upon which the well is located, unless the interests of the persons owning the drilling rights in and the right to share in the production from the quarter section or section, respectively, have been pooled under AS 31.05.100.

(c) A pooling agreement under AS 31.05.100 must be filed with the commission before regular production from the affected property begins.

(d) The commission will review an application for an exception to the provisions of this section in accordance with 20 AAC 25.540. The applicant for an exception shall send notice of the application by certified mail to the owners, landowners, and operators described in (1) of this subsection and shall furnish the commission with a copy of the notice, the date of mailing, and the addresses to which the notice was sent. The application must include

(1) the names of all owners, landowners, and operators of all properties within 1,000 feet of a well drilling for oil or within 3,000 feet of a well drilling for gas for which an exception is sought;

(2) a plat drawn to a scale of one inch equaling 2,640 feet or larger, showing the location of the well for which the exception is sought, all other completed and drilling wells on the property, and all adjoining properties and wells; and

(3) an affidavit by a person acquainted with the facts, verifying that all facts are true and that the plat correctly portrays pertinent and required data.

(e) Upon application by the operator, the commission will establish notice requirements different from those of (d) of this section if the operator demonstrates to the commission's satisfaction that compliance with the notice requirements in (d) of this section is not feasible because of the complexity of ownership within the notice area.

20 AAC 25.061. Well site surveys.

(a) For an exploratory or stratigraphic test well, near surface strata to a depth of 2,000 feet in the vicinity of the well must be evaluated seismically by common depth point refraction or reflection profile analysis, or by another method approved by the commission, to identify anomalous velocity variations indicative of potential shallow gas sources. Analysis results must be included with the application for the Permit to Drill (Form 10-401).
(b) For a well drilled offshore from a mobile bottom-founded structure, jack-up rig, or floating drilling vessel, the vicinity of the well must be evaluated by sidescan sonar and other pertinent surveys to determine whether potential seabed hazards to drilling operations are present. Survey results must be included with the application for Permit to Drill.
(c) Upon request by the operator, the commission will, in its discretion, waive the requirements of this section if the operator can identify, by other equally effective means, the likelihood of encountering potential shallow gas or seabed hazards or if the commission already has information that substantiates the presence or absence of shallow gas or seabed hazards.

20 AAC 25.065. Hydrogen sulfide.

(a) If hydrogen sulfide gas is encountered in excess of 20 ppm, the operator shall notify the commission within 24 hours after the encounter.
(b) If a well is to be drilled in an area where a formation to be penetrated is known to contain hydrogen sulfide gas, or if hydrogen sulfide gas is encountered while drilling, the operator shall conform with API RP 49, Recommended Practices for Safe Drilling of Wells Containing Hydrogen Sulfide, 2d edition, April 15, 1987, which is adopted by reference.
(c) If the history of drilling in an area is insufficient to know whether hydrogen sulfide gas exists, the commission will specify on the Permit to Drill (Form 10-401) that the operator shall comply with the minimum requirements for detection monitoring, contingency and control, and training, as follows:

(1) in addition to the automatic hydrogen sulfide detection system required in 20 AAC 25.066, at least three manual detectors must be available on the location;

(2) hydrogen sulfide treating material for the drilling mud must be available on or near the location, in good condition and in sufficient quantity to adequately treat the mud system should hydrogen sulfide be encountered;

(3) detailed emergency operating procedures must be defined and posted to ensure the safety of all personnel should hydrogen sulfide be encountered;

(4) detailed step-by-step remedial procedures must be developed and posted to cover emergencies while drilling or tripping;

(5) personnel protective equipment must be available on the location;

(6) all persons engaged in drilling operations must be trained for emergency procedures in the presence of hydrogen sulfide gas and in the use of personal protective equipment, alarm systems, and emergency exit procedures.

(d) Repealed 11/7/99.

20 AAC 25.066. Gas detection.

(a) Drilling and workover rigs must meet the following minimum requirements for methane and hydrogen sulfide gas detection:

(1) the methane detection system must have a minimum of three sensing points; one sensing point must be under the substructure near the cellar, one must be over the shale shaker, and one must be above the drill rig floor near the driller's station or above the drilling platform; if the mud pits are remote from the shale shaker and enclosed, a fourth sensor must be located over the mud pits;

(2) methane sensors must be placed to detect a "lighter-than-air" gas;

(3) the hydrogen sulfide detection system must have a minimum of three sensing points; one sensing point must be under the substructure near the cellar, one must be near the shale shaker, and one must be above the drill rig floor near the driller's station or above the drilling platform; the commission will require additional sensors as the commission considers necessary for safety, such as at the entrance to living quarters if they are adjacent to the drill rig, or over the mud pits if they are remote from the shaker and enclosed;

(4) hydrogen sulfide sensors must be placed to detect a "heavier-than-air" gas;

(5) sensors must be automatic, acting independently and in parallel, and with one-minute minimum sampling intervals;

(6) each detection system must include separate and distinct visual and audible alarms; the visual alarm must signal the low level gas alarm and the audible alarm the high level gas alarm; an audible alarm may have an "acknowledge" button;

(7) the methane low level gas alarm must be set at not over 20 percent LEL; the high level alarm must be set at not over 40 percent LEL;

(8) the hydrogen sulfide low level gas alarm must be set at 10 ppm; the high level alarm must be set at not over 20 ppm;

(9) each alarm must be automatic and must be visible and audible from the driller's or operator's station; the hydrogen sulfide alarm must be audible throughout the drilling location, including the camp buildings.

(b) A gas detection system that continuously performs self-checking or diagnostics must be function-tested when a BOP stack is initially installed after a drill rig is set up, when a commission-witnessed BOP test occurs, and no less frequently than once every six months. If a BOP stack is not required, a gas detection system that continuously performs self-checking or diagnostics must be function-tested when drilling or workover operations begin, when a commission-witnessed BOP test occurs, and no less frequently than once every six months. Other gas detection systems must be calibrated and tested when a BOP stack is initially installed after a drill rig is set up, when a commission-witnessed BOP test occurs, and no less frequently than once every 30 days. If a BOP stack is not required, other gas detection systems must be calibrated and tested when drilling or workover operations begin, when a commission-witnessed BOP test occurs, and no less frequently than once every 30 days. The operator shall maintain at the drill rig an accessible record of gas detection system tests and calibrations.

(c) A failure in a gas detection system must be reported to the commission within 24 hours after the failure. The commission will, in its discretion, require well operations to be discontinued if a gas detection system fails.
(d) Upon request of the operator, the commission may

(1) waive the methane detection requirements of this section, if the commission determines that the configuration of the drilling or workover rig and any associated equipment and structures eliminates the potential for methane to accumulate;

(2) allow the use of a single hydrogen sulfide sensor on site in place of the three sensing points required under (a)(3) of this section, if the commission determines that the configuration of the drilling or workover rig and any associated equipment and structures eliminates the potential for hydrogen sulfide to accumulate; or

(3) approve a variance from the requirements of this section if the variance provides at least an equally effective means of gas detection.

20 AAC 25.070. Records and reports.

The operator of a well shall

(1) keep a detailed accurate daily record of the actual drilling, completion, workover, repair, and plugging operations, and of the tests required by this chapter; the daily record must be available for inspection at reasonable times by the commission

(A) at the well; and

(B) in the state for five years after the date of well abandonment;

(2) file with the commission before well completion or, if the well is not completed, before well abandonment a survey plat certified by a registered land surveyor showing the precise surface location of the well; however, only the first well drilled from a fixed platform or a multiple-well location must have a certified survey;

(3) file with the commission, within 30 days after completion, abandonment, or suspension of the well and within 30 days after completion or plugging of a well branch, if occurring at a different time, a complete well record on the Well Completion or Recompletion Report and Log (Form 10-407), including the tests required by this chapter and a summary of daily well operations reporting drilling depths, abnormally geo-pressured strata, lost circulation and other hole difficulties encountered, simulated kick drills, mud weight, and a brief description of principal items of work done, such as running and cementing casing, drill stem tests, BOP tests, coring, sidewall sampling, and logging; in the case of a well with multiple well branches, information pertaining to and filed under this paragraph with respect to a portion of a well need not be re-filed unless changed; and

(4) upon request of the commission after completion, abandonment, or suspension of the well or completion or plugging of a well branch, file with the commission a copy of the daily record required by (1) of this section.

20 AAC 25.071. Logs and geologic data.

(a) An operator shall log the well from total depth to the base of conductor pipe by either a complete electrical or gamma-ray log unless the commission specifies the type of each log to be run.
(b) Not later than 90 days after completion, suspension, or plugging of a well or well branch, or not later than 90 days after the date of acquisition of the data, whichever occurs first, the operator shall file with the commission, unless previously filed,

(1) an electronic image file in formats acceptable to the commission of a complete mud log or a lithology log consisting of a detailed record and description of the sequence of strata encountered, including the kind and character of the rock and all shows of hydrocarbons;

(2) a complete set of washed and dried, legibly identified samples of all drill cuttings, as caught by the operator in accordance with good geological practices, consisting of a minimum of one-quarter cup in volume or three ounces in weight of cuttings for each sample interval;

(3) a lithologic description and, if available, photographs of each conventional and sidewall core; conventional core descriptions must include apparent textural, fluid, and lithologic variations, including rock type, porosity, fractures, bedding plane attitudes, sedimentary structure, grain size, and presence of hydrocarbons;

(4) chips from each foot of recovered conventional core, except that chips need not be submitted until 30 days after the conventional core is analyzed; the chips must be representative of the one-foot interval, and must be approximately either one cubic inch in volume, or two ounces in weight;

(5) a list of the geologic markers and each formation top encountered and the measured and true vertical depths of each marker and formation top;

(6) an electronic image file in formats acceptable to the commission of all open-hole logs and mud logs run, including common derivative formats such as tadpole plots of dipmeter data and borehole images produced from sonic or resistivity data, and including composite log formats; however, copies of velocity surveys and experimental logs need not be included; the operator shall provide the commission the opportunity to examine open-hole logs for exploration or stratigraphic test wells not later than 72 hours after the logs are run and before abandonment;

(7) digital data and a verification listing for all open-hole logs, all mud logs, and all cased-hole formation evaluation and cement evaluation logs run, except velocity surveys and experimental logs; the logs shall be stored on electronic media and use file formats that are acceptable to the commission;

(8) the following items, or a written request proposing a date for submitting those items, subject to commission approval of that date for timeliness, if those items are unavailable within the 90-day filing period set out in this subsection:

(A) copies of all drill stem tests and production test data and charts;

(B) a brief summary of production tests, drill stem tests, wireline formation tests, and other formation tests performed, including test date, time, depth, duration, method of operation, recovered fluid types, fluid amounts, gas-oil ratio, oil gravity, pressure, and choke size;

(C) conventional and sidewall core analysis determinations, if any, of porosity, permeability, and fluid saturation;

(D) geochemical and formation fluid analyses obtained, if any; and

(9) an electronic image file in formats acceptable to the commission of all cased-hole formation evaluation logs and cement evaluation logs run, including common derivative formats.

(c) The commission may waive or modify the requirements of this section for a well if those requirements would not significantly add to the geologic or engineering knowledge of the area in light of the information that is available from the well or other wells in the area.

(d) In this section,

(1) "experimental logs" means logs that are not commercially available from a well logging contractor;

(2) "velocity survey" means a survey, a purpose of which is to determine velocity of seismic waves through formations penetrated by a well by measuring travel times of seismic pulses from or near the surface to geophones placed at various depths in the well.

20 AAC 25.072. Temporary shutdown of drilling or completion operations.

(a) If circumstances prevent the continuation of the program approved on a Permit to Drill (Form 10-401), or if an operator wishes to change drill rigs, the operator shall apply to the commission for approval to shut down drilling or completion operations temporarily. Based on the information received under this subsection, the commission will decide whether to approve the temporary shutdown of drilling or completion operations. The request for operation shutdown must be submitted on an Application for Sundry Approvals (Form 10-403), providing a full justification for the shutdown, a description of the proposed condition of the wellbore upon shutdown of drilling or completion operations, the approximate date when drilling or completion operations will resume, and a proposed program for securing the well during the period of shutdown. An Application for Sundry Approvals is not required for planned shutdowns of well operations, if those shutdowns are described in the approved Permit to Drill.

(b) The operator shall file with the commission, within 30 days after operation shutdown, a complete well record on a Report of Sundry Well Operations (Form 10-404), including a summary of daily well operations as described in 20 AAC 25.070(3) and a copy of all logs run in the well as required by 20 AAC 25.071(b)(6). The commission will, in its discretion, waive the requirements of this subsection if drilling or completion operations are to be resumed within 60 days after operation shutdown.

(c) Shutdown of well operations does not establish a completion, suspension, or abandonment date for a well.

(d) If well operations are not resumed within 12 months, the operator shall immediately proceed to abandon or suspend the well. Wells drilled from a mobile offshore drilling unit that are not located on a fixed offshore platform are not eligible for suspension. Upon application of the operator, the commission will extend the 12-month period, if the operator shows that operational circumstances beyond the operator's control prevent resumption within the 12-month period.

20 AAC 25.075. Other wells in designated areas.

There are areas in the state where drilling operations could unexpectedly encounter oil, gas, or hazardous substances at shallow depths. When the commission obtains sufficient evidence to define a specific area and the approximate depth range of the substances, it will issue an order that will present the evidence, define the area, and stipulate a drilling depth. After the issuance of such an order, any well drilled in the defined area, for any purpose, that exceeds the stipulated depth will require a drilling permit and may be subject to the other requirements of this chapter.

20 AAC 25.080. Annular disposal of drilling waste.

(a) A person may not dispose of drilling waste through the annular space of a well unless authorized by the commission under this section. The operator of a well permitted under AS 31.05.090 may request authorization for the disposal of drilling waste through the well's annular space by filing with the commission an Application for Sundry Approvals (Form 10-403) supplemented with additional information as required under this section.

(b) A request for authorization under this section must include the following information or refer to that information if that information is already on file with the commission:

(1) the annulus to be used for disposal;

(2) the depth to the base of freshwater aquifers and permafrost, if present;

(3) a stratigraphic description of the interval exposed to the open annulus and other information sufficient to support a commission finding that the waste will be confined and will not come to the surface or, except to the extent allowed under (e)(1) of this section, contaminate freshwater;

(4) a list of all publicly recorded wells within one-quarter mile, and all publicly recorded water wells within one mile, of the well that will receive drilling waste;

(5) the types and maximum volume of waste to be disposed of and the estimated density of the waste slurry;

(6) a description of any waste sought to be determined as drilling waste under (h)(3) of this section;

(7) an estimate of the maximum anticipated pressure at the outer casing shoe during disposal operations and calculations showing how this value was determined;

(8) details that show that the shoe of the outer casing is set below the base of permafrost, if present, and any freshwater aquifer, other than freshwater excepted under (e)(1) of this section, and is adequately cemented to provide zone isolation; the information relied upon and submitted must include

(A) cementing records; and

(B) a cement quality log or formation integrity test records;

(9) details that show that the inner and outer casing strings have sufficient strength in collapse and burst to withstand the anticipated pressure of disposal operations;

(10) the downhole pressure obtained during a formation integrity test conducted below the outer casing shoe;

(11) identification of the hydrocarbon zones, if any, above the depth to which the inner casing is cemented;

(12) the duration of the disposal operation, not to exceed 90 days;

(13) whether drilling waste has previously been disposed of in the annular space of the well and, if so, a summary of the dates of the disposal operations, the volumes of waste disposed of, and the wells where the drilling waste was generated;

(14) the well where the drilling waste to be disposed of was or will be generated;

(15) if the operator proposes not to comply with a limitation established in (d) of this section, an explanation of why compliance would be imprudent;

(16) any additional data required by the commission to confirm containment of drilling waste.

(c) The commission will authorize an annular disposal operation described in the Application for Sundry Approvals, as that application has been supplemented under this section, and subject to any modifications prescribed by the commission, if

the commission determines that the
(1) waste will be adequately confined;
(2) disposal will not
(A) contaminate freshwater, except to the extent allowed under (e)(91) of this section;
(B) cause drilling waste to surface;
(C) impair the mechanical integrity of any well; or
(D) damage a producing or potentially producing formation or impair the recovery of oil or gas from a pool; and
(3) disposal will not circumvent 20 AAC 25.252 or 20 AAC 25.412.

(d) Unless the operator demonstrates that compliance with a limitation established in (1) - (4) of this subsection is imprudent, the commission will not authorize disposal of drilling waste
(1) in a volume greater than 35,000 barrels through the annular space of a single well;
(2) for a period longer than one year through the annular space of a single well;
(3) into a hydrocarbon-bearing stratum; or
(4) through the annular space of a well not located on the same drill pad or platform as the drilling operation generating the drilling waste.

(e) On a case-by-case basis, and as the commission considers necessary to ensure that the standards in (c) of this section are met, the commission will impose conditions upon an authorization to dispose of drilling waste under this section. In addition, an authorization to dispose of drilling waste under this section is subject to the following conditions:
(1) drilling waste may not be disposed of into freshwater, unless the
(A) freshwater is identified in the Application for Sundry Approvals; and
(B) commission finds that the freshwater has a total dissolved solids content of more than 3,000 mg/l, and is not reasonably expected to supply a public water system; the commission will, in its discretion, provide 15 days notice and the opportunity for a public hearing in accordance with 20 AAC 25.540 before making that finding;
(2) the downhole disposal pressure may not exceed the downhole pressure obtained during the formation integrity test conducted below the outer casing shoe, or a higher pressure specified in the authorization upon the commission's finding that the higher pressure will not cause drilling waste to migrate above the confining zone;
(3) if drilling waste appears above the confining zone, the operator shall immediately cease disposal, notify the commission, and take appropriate remedial action;
(4) if the commission notifies the operator that disposal operations pose a threat to well integrity, safety, oil or gas recovery, or freshwater, except to the extent allowed under (1) of this subsection, the operator shall immediately cease disposal and take appropriate remedial action as approved or required by the commission.

(f) For each annular disposal operation authorized under this section, the operator shall report the following information to the commission on a Report of Annular Disposal (Form 10-423) not later than 30 days after the end of the period authorized for the disposal operation:
(1) the dates when disposal began and ended;
(2) the volume of drilling waste disposed of in each of the following categories:
(A) the aggregate of drilling wastes described in (h)(1) of this section;
(B) the aggregate of drilling wastes described in (h)(2) of this section; and
(C) each substance determined to be a drilling waste under (h)(3) of this section.

(g) The provisions of 20 AAC 25.252 and 20 AAC 25.402 - 20 AAC 25.460 do not apply to the disposal of drilling waste authorized under this section.

(h) In this section, "drilling waste" means the following substances, unless identified as a hazardous waste in 40 C.F.R. 261:
(1) drilling mud, drilling cuttings, reserve pit fluids, cement-contaminated drilling mud, completion fluids, formation fluids associated with the act of drilling a well permitted under 20 AAC 25.005, and any added water needed to facilitate pumping of drilling mud or drilling cuttings;
(2) drill rig wash fluids and drill rig domestic waste water; and
(3) other substances that the commission determines upon application are wastes associated with the act of drilling a well permitted under 20 AAC 25.005.

(i) For purposes of this section, in AS 31.05.030(e)(2), "oil or gas well" means a well permitted under AS 31.05.090, other than a water well associated with oil or gas exploration and production.

Article 2
Abandonment and Plugging

20 AAC 25.105. Abandonment of wells.

(a) All wells that have been permitted on a property under 20 AAC 25.005 must be abandoned before expiration of the owner's rights in that property or if, after notice and hearing, the commission orders abandonment for safety reasons or because the operator has effectively abandoned operations prior to the expiration of the lease. If the owner is the landowner, all wells that have been permitted on a property by 20 AAC 25.005 must be abandoned within one year following permanent cessation of the operator's oil and gas activity within the field where the wells are located or according to an abandonment schedule approved by the commission, unless the wells are earlier abandoned for safety reasons.

(b) A well drilled onshore or from a fixed offshore platform must be abandoned before removal of the drill rig unless the well is completed as an oil, gas, or service well or is suspended, or unless well operations are shut down in accordance with 20 AAC 25.072. Each well drilled from a fixed offshore platform must be abandoned before the platform is removed or dismantled.

(c) A well drilled offshore from a mobile bottom-founded structure, jack-up rig, or floating drilling vessel must be abandoned before removal of the drill rig unless
(1) the well is completed as an oil, gas, or service well; or
(2) subsea equipment for well re-entry is properly installed and well operations are shut down in accordance with 20 AAC 25.072.

(d) A well drilled from a beach, artificial island, or shifting natural island must be abandoned before removal of the drill rig unless the well is completed as an oil, gas, or service well or is suspended, or unless well operations are shut down in accordance with 20 AAC 25.072 and plans for maintaining the integrity of the location are approved by the commission.
(e) An Application for Sundry Approvals (Form 10-403) must be submitted to and approved by the commission before work is begun to abandon a well, except that oral approval may be obtained from the commission if it is followed within three days by the submission of an Application for Sundry Approvals for final approval by the commission. The commission will attach conditions to its approval as necessary to protect freshwater and hydrocarbon resources. The Application for Sundry Approvals must include

(1) the reason for abandoning the well; and

(2) a statement of proposed work, including

(A) information on abnormally geo-pressured strata;

(B) the manner of placement, kind, size, and location, by measured depth, of existing and proposed plugs;

(C) plans for cementing, shooting, testing, and removing casing;

(D) if the Application for Sundry Approvals is submitted after beginning work, the name of the representative of the commission who provided oral approval, and the date of the approval; and

(E) other information pertinent to abandonment of the well.

20 AAC 25.107. Plugging well branches.

(a) An operator may plug a well branch before abandoning or suspending the well. If a well branch has not been completed, the operator shall plug the well branch before removal of the drill rig, unless well operations are shut down in accordance with 20 AAC 25.072.
(b) An Application for Sundry Approvals (Form 10-403) must be submitted to and approved by the commission before work is begun to plug a well branch, except that oral approval may be obtained from the commission if it is followed within three days by the submission of an Application for Sundry Approvals for final approval by the commission. The provisions of 20 AAC 25.105(e) apply to the application, except that instead of including the reason for abandoning the well, the application must include the reason for plugging the well branch and the reason for not immediately abandoning or suspending the well.
(c) The provisions of 20 AAC 25.112(a) - (c) and (e) - (i) apply to plugging a well branch.
(d) This section does not apply to the temporary plugging of a well branch for production control purposes.

20 AAC 25.110. Suspended wells.

(a) If allowed under 20 AAC 25.105, an operator may apply to the commission under this section to approve the suspension of a well or to renew the approval of the suspension of a well. The operator must

(1) state the reasons the well should be suspended, and not completed or abandoned;

(2) demonstrate to the commission's satisfaction that

(A) the well

(i) is mechanically sound;

(ii) will not allow the migration of fluids;

(iii) will not damage freshwater or producing or potentially producing formations;

(iv) will not impair the recovery of oil or gas;

(v) is secure, safe, and not a threat to public health;

(vi) is located on a valid lease that authorizes the operator to drill for oil, gas, coal bed methane, gas hydrates, or shale gas, or to evaluate underground coal gasification or geothermal resources; and

(vii) is in compliance with all provisions of AS 31.05, this chapter, and any order, stipulation, or permit issued by the commission; and

(B) the well

(i) has future utility as an exploratory, development, or service well;

(ii) is a viable candidate for redrilling; or

(iii) in the case of initial suspensions only, is located on a pad or platform with active producing or service wells; and

(3) for a well that does not lie within a unitized area with active production,

(A) provide the commission with a list of the leases that the wellbore traverses, from surface location to bottom-hole location, and the expiration date of each lease; and

(B) notify the commission not later than 30 days after the change, if the status of any lease changes.

(b) An Application for Sundry Approvals (Form 10-403) must be approved by the commission before operations to suspend a well commence or for a well suspension renewal, except that oral approval may be requested under 20 AAC 25.507(b). In addition to meeting the requirements of (a) of this section, the application must include the following:

(1) wellbore diagrams illustrating the current and proposed mechanical configurations of the well;

(2) information on abnormally geo-pressured or depleted strata;

(3) a description of the proposed work plan, including how the integrity of existing and proposed plugs will be demonstrated;

(4) evidence or a statement that confirms that a well inspection was conducted within 12 months before the suspension renewal date, if the operator is applying for a well suspension renewal;

(5) a list of the leases that the wellbore traverses, from surface location to bottom-hole location, and the expiration date of each lease.

(c) Unless the commission otherwise requires or approves a variance under 20 AAC 25.112(i), any well suspended under this section must be plugged in accordance with 20 AAC 25.112, except that the requirements of 20 AAC 25.112(d) do not apply if

(1) a wellhead and tree are installed; or

(2) the well is capped with a mechanical device to seal the opening and a bridge plug capped with 50 feet of cement or a continuous cement plug extending 200 feet within the interior casing string is placed at or above 300 feet below the surface.

(d) The operator of a suspended well shall maintain the integrity and safety of the well and surrounding location.

(e) A well-site inspection is required within 12 months after the approval of an initial well suspension. A subsequent inspection shall be conducted within 12 months before the suspension renewal date, as approved by the commission. For all inspections under this section, the operator shall provide the commission notice at least 10 days before the inspection and the opportunity for commission inspectors to accompany the operator on the inspection tour. If convenient for the commission, shorter notice periods may be accepted.
(f) A Report of Sundry Well Operations (Form 10-404) is required not later than 30 days after any well-site inspection required under this section. The report must include

(1) a description of the condition of the wellhead and surface location, including any discoloration, fluid or sheen visible on the ground or in any nearby water;

(2) a plat showing the location of the suspended well and any wells within a one-quarter-mile radius of the wellbore;

(3) well pressure readings;

(4) photographs clearly showing the condition of the wellhead and surrounding location; and

(5) an update of all information and documentation required in (b) of this section.

(g) A suspension or renewal of a suspension approval is valid for up to five years from the date of the suspension or renewal of a suspension approval.
(h) Renewal of an existing suspension may be requested by the submission of an Application for Sundry Approvals (Form 10-403) meeting all requirements of (b) of this section. A renewal is not effective until approved by the commission. If a complete renewal application is submitted at least 60 days before the expiration of an existing suspension, the existing suspension continues until the commission acts on the application. If the well does not lie within a unitized area with active production, the application to renew an existing suspension must include a list of all leases that the wellbore traverses, from surface location to bottom-hole location, and the expiration date of each lease.
(i) The operator shall immediately notify the commission and propose appropriate action if the operator learns that there is a reasonable risk that a suspended well is

(1) mechanically unsound;

(2) allowing the migration of fluids;

(3) causing damage to freshwater or producing or potentially producing formations;

(4) impairing the recovery of oil or gas;

(5) a threat to public health or not secure or safe; or

(6) not in compliance with all provisions of AS 31.05, this chapter, and any order, stipulation, or permit issued by the commission.

(j) Not later than five working days after notifying the commission under (i) of this section, the operator shall file a report and all relevant information and documentation regarding the well, including all information and documentation that may be required by the commission.
(k) If the operator learns that any information required under this section is no longer complete or accurate, the operator shall, within 30 days, notify the commission in writing, provide updated information, and propose appropriate action.
(l) At any time, the commission may request that an operator provide, not later than 10 days after the date of request, any information concerning whether suspension remains appropriate for a well. If the operator does not comply with the information request or if the commission determines that information is insufficient to support allowing the well to remain suspended, the commission may take action under 20 AAC 25.540, including

(1) revoking the well's suspended status, effective as of the date determined by the commission;

(2) prescribing actions the operator must take, which may include plugging and abandonment of the well; if action is ordered, including plugging and abandonment under this chapter, a separate notice and hearing is not required notwithstanding any other provision of this chapter, including 20 AAC 25.105.

(m) Upon written request of the operator, the commission may modify a deadline in this section upon a showing of good cause, approve a variance from any other requirement of this section if the variance provides at least an equally effective means of complying with the requirement, or approve a waiver of a requirement of this section if the waiver will not promote waste, is based on sound engineering and geoscience principles, will not jeopardize the ultimate recovery of hydrocarbons, will not jeopardize correlative rights, and will not result in an increased risk to health, safety, or the environment, including freshwater.

20 AAC 25.112. Well plugging requirements.

(a) Plugging of the uncased portion of a wellbore must be performed in a manner that ensures that all hydrocarbons and freshwater are confined to their respective indigenous strata and are prevented from migrating into other strata or to the surface. The minimum requirements for plugging the uncased portion of a wellbore are as follows:

(1) by the displacement method, a cement plug must be placed

(A) from 100 feet below the base to 100 feet above the top of all hydrocarbon-bearing strata;

(B) from the well's total depth to 100 feet above the top of all hydrocarbon-bearing strata;

(C) from the well's plugged back total depth to 100 feet above the top of all hydrocarbon-bearing strata, if all hydrocarbon-bearing, abnormally geo-pressured, and freshwater strata below are isolated; however, the commission will approve plugging from the top of fill or the top of junk instead of from the plugged back total depth, if the commission determines that the objectives of this subsection will be met; or

(D) from 100 feet below the base to 50 feet above the base of each significant hydrocarbon-bearing stratum and from 50 feet below the top to 100 feet above the top of each significant hydrocarbon-bearing stratum;

(2) by the displacement method, a cement plug must be placed from 100 feet below the base to 50 feet above the base of each abnormally geo-pressured stratum and from 50 feet below the top to 100 feet above the top of each abnormally geo-pressured stratum;

(3) by the displacement method, a cement plug must be placed from 150 feet below the base to 50 feet above the base of the deepest freshwater stratum.

(b) Plugging of a well must include effectively segregating uncased and cased portions of the wellbore to prevent vertical movement of fluid within the wellbore. The minimum requirement for plugging to segregate uncased and cased portions of a wellbore is one of the following:

(1) by the displacement method, a continuous cement plug must be placed from 100 feet below to 100 feet above

the casing shoe;

(2) by the downsqueeze method using a retainer set no less than 50 feet but no more than 100 feet above the casing shoe, a volume of cement sufficient to fill the wellbore from the retainer to 100 feet below the casing shoe must be pumped through the retainer, and cement must be pumped above the retainer to cap it with a 50 foot cement plug;

(3) by the downsqueeze method using a production packer set no less than 50 feet but no more than 500 feet above the casing shoe, a volume of cement sufficient to fill the wellbore from 100 feet below the casing shoe to the packer must be pumped through the packer, and cement must be pumped above the packer to cap it with a 50 foot cement plug.

(c) Plugging of cased portions of a wellbore must be performed in a manner that ensures that all hydrocarbons and freshwater are confined to their respective indigenous strata and are prevented from migrating into other strata or to the surface. The minimum requirements for plugging cased portions of a wellbore are as follows:

(1) perforated intervals must be plugged by one of the following methods:

(A) by the displacement method, a cement plug placed from 100 feet below the base to 50 feet above the base of the perforated interval and from 50 feet below the top to 100 feet above the top of the perforated interval;

(B) by the displacement method, a cement plug placed from the well's total depth to 100 feet above the top of the perforated interval;

(C) by the displacement method, a cement plug placed from the well's plugged-back total depth to 100 feet above the top of the perforated interval, if all hydrocarbon-bearing, abnormally geo-pressured, and freshwater strata below are isolated; however, the commission will approve plugging from the top of fill or the top of junk instead of from the plugged-back total depth, if the commission determines that the objectives of this subsection will be met;

(D) by the downsqueeze method using a cement retainer or production packer set no less than 50 feet but no more than 500 feet above the perforated interval, a volume of cement pumped through the retainer or packer sufficient to fill the wellbore from 100 feet below the base of the perforated interval to the retainer or packer;

(E) if the perforations are isolated from open hole below, a mechanical bridge plug set no more than 50 feet above the top of the perforated interval, and either a minimum of 75 feet of cement placed on top of the plug by the displacement method or a minimum of 25 feet of cement placed on top of the plug with a dump bailer;

(2) casing stubs within outer casing must be plugged by one of the following methods:

(A) by the displacement method, a cement plug placed from 100 feet below the stub to 100 feet above the stub;

(B) by the downsqueeze method using a retainer set 50 feet above the stub, a volume of cement pumped below the retainer sufficient to fill the casing stub with 150 feet of cement, and cement pumped above the retainer to cap it with a 50 foot cement plug;

(C) if the casing stub annulus is cemented, a mechanical bridge plug set no more than 25 feet above the casing stub, and either a minimum of 75 feet of cement placed on top of the plug by the displacement method or a minimum of 25 feet of cement placed on top of the plug with a dump bailer;

(3) if freshwater is present, the smallest diameter casing string extending to the surface must be plugged by one of the following methods:

(A) by the displacement method, a cement plug placed from 100 feet below the depth of the surface casing shoe to 100 feet above the depth of the shoe;

(B) a mechanical bridge plug set 100 feet below the depth of the surface casing shoe and at least 200 feet of cement placed on top of the plug.

(d) Plugging of the surface of a well must meet the following requirements:

(1) by the displacement method, a cement plug at least 150 feet in length, with the top of the cement no more than five feet below original ground level onshore, or between 10 and 30 feet below the mudline datum offshore, must be placed within the smallest diameter casing string;

(2) either

(A) all annular space open at the surface onshore, or in communication with open hole and extending to the mudline datum offshore, must be plugged with cement to seal the annular space in a manner satisfactory to the commission; or

(B) all casing interior to the surface casing must be recovered to a depth of 100 feet or more below the original ground level onshore or the mudline datum offshore and the casing stubs plugged with cement as provided in (c)(2)(A) of this section; if the cement plug is extended to within the distance from the surface specified in (1) of this subsection, the requirement of (1) of this subsection need not be met.

(e) Cement used for plugging within zones of permafrost must be designed to set before freezing and have a low heat of hydration.

(f) Each of the respective intervals of a wellbore between the various plugs must be filled with fluid of sufficient density to exert a hydrostatic pressure exceeding the greatest formation pressure of permeable formations in the intervals between the plugs at the time of abandonment.

(g) Except for surface plugs, the operator shall record the actual location and integrity of cement plugs, cement retainers, or bridge plugs required by this section, using one of the following methods, which in the case of a cement retainer or bridge plug may be performed before cement is placed on top of the plug:

(1) placing sufficient weight on the plug to confirm its location and to confirm that the plug has set and a competent plug is in place;

(2) testing the plug to hold a surface pressure of 1,500 psig or 0.25 psi/ft multiplied by the true vertical depth of the casing shoe, whichever is greater, and tagging the plug to confirm location; however, surface pressure may not subject the casing to a hoop stress that will exceed 70 percent of the minimum yield strength of the casing.

(h) At least 24 hours notice of plugging operations must be given to the commission so that a representative of the commission can witness the operations.

(i) The commission will, in its discretion, approve a variance from the requirements of this section if the variance provides for at least equally effective plugging of the well and prevention of fluid movement into sources of hydrocarbons or freshwater.

20 AAC 25.115. Shut-in wells.

(a) No later than March 31 of each year, an operator shall file with the commission a report on completed development or service wells that have been shut in for 365 days or longer as of January 1 of that year. The report must provide

(1) the current known mechanical condition of the well, including the condition of installed tubing and casing strings;

(2) the date the well was shut in and the circumstances surrounding the decision to shut in the well; and

(3) an analysis of the future utility of the well.

(b) The commission will require an operator of a shut-in well to file additional information as the commission considers necessary to ensure that freshwater and hydrocarbon sources are protected.

20 AAC 25.120. Well abandonment marker.

The exact surface location of an abandoned onshore well must be shown by a well abandonment marker plate that

(1) is constructed of steel that is at least 1/4 inch thick;

(2) is welded to, and covers, the outermost casing string, including the conductor casing;

(3) does not extend beyond the outermost casing string; and

(4) contains the following information bead-welded directly to the marker plate:

(A) The name of the operator that plugged and abandoned the well;

(B) the number assigned by the commission to the Permit to Drill (Form 10-401) for the well under 20 AAC 25.040(b);

(C) the name designated for the well by the operator under 20 AAC 25.005(f);

(D) the API number for the well, with any suffix appended to the number under 20 AAC 25.005(f).

20 AAC 25.140. Water wells.

If a well drilled onshore for oil or gas is to be abandoned, but is safe for use as a freshwater well, a person who wishes to use the well as a freshwater well must obtain written authorization to do so from the landowner and the owner of the surface rights. The authorization must provide for the authorized person's assumption of full responsibility for the final plugging of the water well. This authorization must be filed with the commission and is subject to commission approval, based upon the commission's determination that the proposed use as a freshwater well is bona fide. After the commission's approval of the plugging of the well to protect the freshwater bearing strata to a depth approved by the commission for conversion to a water well, and after the commission's approval of the location clearance for compliance with 20 AAC 25.170(a)(2) or (b) or 20 AAC 25.172(c)(2) or (d), the operator is relieved of further obligation under the operator's bond.

20 AAC 25.170. Onshore location clearance.

(a) At or after the time that a well drilled onshore is abandoned and before the earlier of one year after well abandonment or the expiration of the owner's rights in the property,

(1) the operator shall remove the wellhead equipment and casing to a depth at least three feet below original ground level and install a well abandonment marker in accordance with 20 AAC 25.120; and

(2) unless the operator demonstrates to the commission that the surface owner has authorized a different disposition to facilitate a genuine beneficial use, the operator shall

(A) remove all materials, supplies, structures, and installations from the location;

(B) remove all loose debris from the location;

(C) fill and grade all pits or close them in another manner approved by the commission as adequate to protect public health and safety; and

(D) leave the location in a clean and graded condition.

(b) If a well described in (a) of this section is located on state or federal land, and if the agency acting on behalf of the state or federal government as lessor approves a disposition different from that required under (a)(2) of this section, the commission will accept that disposition instead of requiring the operator to comply with (a)(2) of this section.

(c) The commission will modify the time period set out in (a) of this section as follows:

(1) if the Department of Natural Resources, as to a state lease, or the United States Department of the Interior, as to a federal lease approves a time period beyond one year after well abandonment for location clearance, the commission will set an identical time period for compliance with (a) of this section;

(2) the commission will grant an extension of time beyond one year after well abandonment, if the commission determines that the extension does not threaten public health or safety or the surface owner's interests, and that the operator does not seek an extension for purposes of delay; to seek an extension under this paragraph, the operator must submit an Application for Sundry Approvals (Form 10-403) stating

(A) a request for a specific extension not to exceed one year;

(B) the reason an extension is necessary;

(C) a description of location clearance progress; and

(D) the expiration date of the owner's rights to enter the location.

(d) After the work required under (a) of this section has been completed at a location, the commission will, in its discretion, conduct an on-site inspection to verify the location condition at the time of inspection, including the presence of a proper well marker if above ground, as required under 20 AAC 25.120, and will provide the operator a report of the inspection.

20 AAC 25.172. Offshore location clearance.

(a) No later than the time that all wells drilled from a fixed offshore platform are abandoned and the platform is removed or dismantled, the operator shall remove all well casing to a depth at least one foot below the mudline. The operator shall provide the commission with verification, using appropriate means approved by the commission, that the casing has been removed as required. If an agency acting on behalf of the state or federal government as lessor approves leaving the platform in place after well abandonment, the commission will accept that approval and waive requirements of this subsection.

(b) When a well is abandoned from a mobile bottom-founded structure, jack-up rig, or floating drilling vessel, the operator shall remove the wellhead equipment, casing, piling, and other obstructions to a depth at least five feet below the mudline

before removing the drill rig, unless otherwise approved by the commission as adequate to protect public health and safety. The operator shall provide the commission with verification, using appropriate means approved by the commission, that the requirements of this subsection have been met.
(c) At or after the time that a well drilled from a location on a beach, artificial island, or shifting natural island is abandoned, and before the earliest of one year after well abandonment, the time that the operator stops activities necessary to ensure the integrity of the location, or the expiration of the owner's rights in the property,

(1) the operator shall remove the wellhead equipment and casing to a depth at least five feet below the mudline datum; and

(2) unless the operator demonstrates to the commission that the surface owner has authorized a different disposition to facilitate a genuine beneficial use, the operator shall

(A) remove all materials, supplies, structures, and installations from the location;

(B) remove all loose debris from the location;

(C) fill and grade all pits or close them in another manner approved by the commission as adequate to protect public health and safety; and

(D) leave the location in a clean and graded condition.

(d) If a well described in (c) of this section is located on state or federal land, and if the agency acting on behalf of the state or federal government as lessor approves a disposition different from that required under (c)(2) of this section, the commission will accept that disposition instead of requiring the operator to comply with (c)(2) of this section.
(e) If the Department of Natural Resources, as to a state lease, or by the United States Department of the Interior, as to a federal lease approves a time period beyond one year after well abandonment for location clearance, the commission will set an identical time period for compliance with (c) of this section.
(f) After the work required under (c) of this section has been completed at a location, the commission will, in its discretion, conduct an on-site inspection to verify the location condition at the time of inspection. If the commission conducts an inspection, the commission will provide the operator a report of the inspection.

Article 3
Production Practices

20 AAC 25.200. Production equipment.

(a) Surface production equipment must be installed to control, separate, clean, gather, and carry to the point of custody transfer or other disposition in a safe manner all produced oil, gas, and water. All equipment must be installed, operated, and maintained in accordance with good oil field engineering practices.
(b) All equipment must be designed and protected to ensure reliable operation under the range of weather conditions expected for the specific location.
(c) Wellhead equipment must include appropriate gauges and valves installed on the tubing, casing-tubing annulus and casing-casing annuli to show surface pressures and to control the well flow for the range of conditions expected. Other alternatives will, in the commission's discretion, be approved for subsea completions.
(d) All producing wells capable of unassisted flow must be completed with downhole production equipment consisting of suitable tubing and a packer that effectively isolate the tubing-casing annulus from fluids being produced, unless the commission specifically approves production through the annulus to increase flow rate without jeopardizing ultimate recovery from the well.

20 AAC 25.205. Notification of uncontrolled release of oil or gas.

(a) The operator shall immediately notify the commission of any uncontrolled release exceeding 10 barrels of oil or 1,000 mscf of gas from a well or production handling operation or any uncontrolled release that results in a shutdown of operations at a production facility.
(b) Within five days after the release, the operator shall submit a preliminary written report to the commission, followed by a final written report within 30 days, detailing the following facts:

(1) the time of the incident;
(2) the location where the incident took place;
(3) the volumes of oil and gas released and recovered;
(4) the cause of the release;
(5) responsive actions taken to prevent additional releases;
(6) plans, actions, equipment, or procedural changes to prevent or minimize the risk of future releases.

20 AAC 25.210. Multiple completions of wells.

A well may not be completed in more than one pool without approval of the commission. The commission will require evidence of complete separation of flowstreams from separate pools, as ascertained by a pressure test or other acceptable test conducted at the time the packers are set. Subsequently, if packer leakage is suspected, the commission will require the operator to provide proof of complete separation of the pools involved in the completions or make a packer leakage test. At least 24 hours notice must be given so that the packer leakage test may be witnessed by a representative of the commission.

20 AAC 25.215. Commingling of production and injection into two or more pools.

(a) On the surface, the production from one pool may not be commingled with that from another pool except if the quantities from each pool are determined by monthly well tests or by another method of determining pool production approved by the commission.
(b) Commingling of production within the same wellbore from two or more pools is not permitted unless, after request, notice, and opportunity for public hearing in conformance with 20 AAC 25.540, the commission

(1) finds that waste will not occur, and that production from separate pools can be properly allocated; and
(2) issues an order providing for commingling for wells completed from these pools within the field.

(c) Injection into two or more pools within the same wellbore is not permitted unless, after request, notice, and opportunity for public hearing in conformance with 20 AAC 25.540, the commission

(1) finds that the proposed injection activity will not result in waste or damage to a pool, and that injection volumes can be properly allocated; and

(2) issues an order providing for injection into wellbores completed to allow for simultaneous injection into two or more pools.

20 AAC 25.225. Potential of gas wells.

Repealed.

20 AAC 25.228. Production measurement equipment for custody transfer.

(a) Hydrocarbon production must be measured in accordance with this section before severance from the property or unit where produced. Crude oil sample collection, handling, and analysis in connection with production measurement must be performed in conformance with relevant parts of the API Manual of Petroleum Measurement Standards, as revised as of November 30, 1998.

(b) Hydrocarbon measurement equipment must be fabricated, installed, and maintained in conformance with relevant parts of the API Manual of Petroleum Measurement Standards, as revised as of November 30, 1998. Before installing or altering hydrocarbon measurement equipment used for custody transfer purposes, the operator shall submit to the commission information demonstrating conformance and obtain commission approval of the proposed installation or alteration and the methodology proposed for determining hydrocarbon volumes. The submitted information must include sample calculations, with the underlying measured data, generated using the proposed methodology. The operator may not change an approved methodology without commission approval.

(c) If a totalizer system is microprocessor-based, it must be equipped with

(1) a backup battery or uninterruptible power supply that provides for operation during times of system power failures; or

(2) a backup pulse accumulator or other approved equivalent that counts and preserves meter pulses in the event of a power or computer failure.

(d) If a microprocessor totalizing system is used, the reports of net measured volumes for the custody transfer intervals must, at a minimum, show the raw or factored pulses, average temperature, pressure, relative density or gravity, meter factors, correction factors, and gross standard volumes.

(e) Fluid samplers must be a probe or a slipstream type. The sampler location must be located in conformance with Chapter 8 of the API Manual of Petroleum Measurement Standards, as revised as of November 30, 1998.

(f) Functional bypasses may not be connected around custody transfer or sales measurement equipment such as tanks, meters, gauges, sample containers, or gas meter runs.

(g) Oil meters must be periodically proved and gas meters must be periodically calibrated in conformance with relevant parts of the API Manual of Petroleum Measurement Standards, as revised as of November 30, 1998, and on a schedule approved by the commission according to the volumes being metered and the need to quickly detect inaccuracies. In metering operations, the actual throughput or gross standard volume must be determined by multiplying the indicated volume, corrected for temperature and pressure, by the meter factor obtained during proving. If a meter factor differs by more than 0.0025 from the previously obtained meter factor, from the applicable value on the meter curve, or from a baseline factor in the absence of a meter curve, the meter must be taken out of service or corrective action performed to bring the meter factor within the required tolerance.

(h) Provers used for certification of custody transfer meters must be calibrated by the waterdraw method, master meter method, or other commission-approved equivalent, in conformance with relevant parts of the API Manual of Petroleum Measurement Standards, as revised as of November 30, 1998.

(i) The commission will, in its discretion, require at least 24 hours notice before the following operations so that a representative of the commission can witness the operation:

(1) calibration of provers used for certification of custody transfer meters;

(2) crude oil sample collection, handling, and analysis in connection with production measurement;

(3) oil meter proving and volume calculations;

(4) gas meter calibration and volume calculations.

(j) Upon request, the commission will, in its discretion, approve a variance from the requirements of this section if the variance will result in equal or improved accuracy in measuring hydrocarbons severed from the property or unit.

(k) In this section, "relevant parts of the API Manual of Petroleum Measurement Standards" means the API Manual of Petroleum Measurement Standards excluding Chapter 19 in its entirety and excluding those portions of Chapter 11 other than Chapter 11.1, Volume 1; Chapter 11.1, Volume X; Chapter 11.2.1; Chapter 11.2.2; Addendum to Section 2.2; and Chapter 11.2.3. The relevant parts of the API Manual of Petroleum Measurement Standards, as revised as of November 30, 1998, are adopted by reference.

20 AAC 25.230. Measurement, allocation, and reporting of well production.

(a) Production from each well must be measured to determine the quantities of oil, gas, and water, using equipment and techniques acceptable to the commission as accurate and reliable. Production from a group of wells, property, or unit may be measured as a whole, if individual well test facilities and allocation methods acceptable to the commission are employed to test and allocate production to each well at least monthly.

(b) The volumes of produced gas, oil, and water must be reported monthly for each well on the Monthly Production Report (Form 10-405) or by an alternate format, including electronic means, acceptable to the commission. A well must be identified by its API number and the name designated by the operator under 20 AAC 25.005(f). Production from a well with multiple well branches must be aggregated and reported under the API number and well name of the primary wellbore.

20 AAC 25.235. Gas disposition.

(a) For each production facility the operator shall compile and report monthly gas disposition and acquisition on the Facility Report of Produced Gas Disposition (Form 10-422). If a facility's production comes from multiple pools, the operator shall allocate production between each producing pool as a percentage of the total volume of gas that the facility handled for the month. The operator shall report gas acquisition or disposition by category, as follows:

(1) gas sold;
(2) gas reinjected;
(3) gas flared or vented;
(4) gas used for lease operations other than flaring or venting;
(5) natural gas liquids (NGLs) produced;
(6) gas purchased;
(7) gas transferred;
(8) other.

(b) Any release, burning, or escape into the air of gas other than incidental de minimis venting as authorized under (d)(4) of this section must be reported as flared or vented on the Facility Report of Produced Gas Disposition (Form 10-422). The operator shall submit a written supplement for any flaring or venting incident exceeding one hour. The supplement must describe why the gas was flared or vented, list the beginning and ending time of the flaring or venting, report the volume of gas flared or vented, and describe actions taken to comply with (c) of this section.

(c) The operator shall take action in accordance with good oil field engineering practices and conservation purposes to minimize the volume of gas released, burned, or permitted to escape into the air.

(d) Gas released, burned, or permitted to escape into the air constitutes waste, except that

(1) flaring or venting gas for a period not exceeding one hour as the result of an emergency or operational upset is authorized for safety;

(2) flaring or venting gas for a period not exceeding one hour as the result of a planned lease operation is authorized for safety;

(3) flaring pilot or purge gas to test or fuel the safety flare system is authorized for safety;

(4) de minimis venting of gas incidental to normal oil field operations is authorized;

(5) within 90 days after receipt of the report required under (b) of this section, the commission will, in its discretion, authorize the flaring or venting of gas for a period exceeding one hour

(A) if the flaring or venting is necessary for facility operations, repairs, upgrades, or testing procedures;

(B) if an emergency that threatens life or property requires the flaring or venting, unless failure to operate in a safe and skillful manner causes the emergency; or

(C) if the flaring or venting is necessary to prevent loss of ultimate recovery;

(6) upon application, the commission will, in its discretion, authorize the flaring or venting of gas for purposes of testing a well before regular production.

(e) Notwithstanding an authorization under (d) of this section, the commission will, in its discretion, review flaring or venting of gas and classify as waste any volume of gas flared or vented in violation of (c) of this section.

(f) Notwithstanding conservation orders that the commission issued before 1/1/95, this section applies to flaring or venting of gas that occurs on or after 1/1/95.

20 AAC 25.240. Gas-oil ratio limitations.

(a) An oil well may not be produced if the gas-oil ratio of the well exceeds the original solution gas-oil ratio of the crude within the producing pool by more than 100 percent.

(b) Upon written application by an operator, the commission will, in its discretion, waive the limitation in (a) of this section if

(1) an enhanced recovery project operates in the pool from which the well is producing;

(2) produced gas is being returned to the same pool; or

(3) acquisition of pool performance data is necessary to determine an optimum reservoir management program.

(c) The commission will, in its discretion, grant exceptions to the limitation in (a) of this section for conditions other than those specified in (b) of this section only after application, notice, and an opportunity for public hearing in accordance with 20 AAC 25.540.

20 AAC 25.245. Common production facilities.

Repealed.

20 AAC 25.250. Disposal of salt water and other wastes.

Repealed 4/2/86.

20 AAC 25.252. Underground disposal of oil field wastes and underground storage of hydrocarbons.

(a) The underground disposal of oil field wastes and the underground storage of hydrocarbons are prohibited except as ordered by the commission under this section. In response to a letter of application for injection filed by an operator, the commission will issue an order authorizing the underground disposal of oil field wastes that the commission determines are suitable for disposal in a Class II well, as defined in 40 C.F.R. 144.6(b) as revised as of July 1, 1998, which is adopted by reference, or the underground storage of hydrocarbons. An order authorizing disposal or storage wells remains valid unless revoked by the commission.

(b) The operator has the burden of demonstrating that the proposed disposal or storage operation will not allow the movement of oil field wastes or hydrocarbons into sources of freshwater. Disposal or storage wells must be cased and the casing cemented in a manner that will isolate the disposal or storage zone and protect oil, gas, and freshwater sources.

(c) An application for underground disposal or storage must include

(1) a plat showing the location of all proposed disposal and storage wells, abandoned or other unused wells, production wells, dry holes, and any other wells within one-quarter mile of each proposed disposal or storage well;

(2) a list of all operators and surface owners within a one-quarter mile radius of each proposed disposal or storage well;

(3) an affidavit showing that the operators and surface owners within a one-quarter mile radius have been provided a copy of the application for disposal or storage;

(4) the name, description, depth, and thickness of the formation into which fluids are to be disposed or stored and appropriate geological data on the disposal or storage zone and confining zones, including lithologic descriptions and geologic names;

(5) logs of the disposal or storage wells, if not already on file, or other similar information;

(6) a description of the proposed method for demonstrating the mechanical integrity of the casing and tubing under 20 AAC 25.412 and for demonstrating that fluids will not move behind casing beyond the approved disposal or storage zone, and a description of

(A) the casing of the disposal or storage wells, if the wells are existing; or

(B) the proposed casing program, if the disposal or storage wells are new;

(7) a statement as to the type of oil field wastes to be disposed or hydrocarbons stored, their composition, their source, the estimated maximum amounts to be disposed or stored daily, and the compatibility of fluids to be disposed or stored with the disposal or storage zone;

(8) the estimated average and maximum injection pressure;

(9) evidence to support a commission finding that the proposed disposal or storage operation will not initiate or propagate fractures through the confining zones that might enable the oil field wastes or stored hydrocarbons to enter freshwater strata;

(10) a standard laboratory water analysis, or the results of another method acceptable to the commission, to determine the quality of the water within the formation into which disposal or storage is proposed;

(11) a reference to any applicable freshwater exemption issued in accordance with 20 AAC 25.440; and

(12) a report on the mechanical condition of each well that has penetrated the disposal or storage zone within a one-quarter mile radius of a disposal or storage well.

(d) The mechanical integrity of a disposal or storage well must be demonstrated under 20 AAC 25.412 before disposal or storage operations are begun, after a well workover affecting mechanical integrity is conducted, and at least once every four years. To confirm continued mechanical integrity, the operator shall monitor the injection pressure and rate and the pressure in the casing-tubing annulus during actual disposal or storage operations. The monitored data must be reported monthly on the Monthly Injection Report (Form 10-406).

(e) If an injection rate, operating pressure observation, or pressure test indicates pressure communication or leakage in any casing, tubing, or packer, the operator shall notify the commission by the next working day and shall implement corrective action or increased surveillance as the commission requires to ensure protection of freshwater.

(f) The commission will require additional mechanical integrity tests if the commission considers them prudent for conservation purposes or protection of freshwater.

(g) Modifications of existing or pending disposal or storage operations will be approved by the commission, in its discretion, under 20 AAC 25.507, upon application containing sufficient detail to evaluate the proposed modification. No modification will be approved unless the applicant proves to the commission that the modification will not allow the movement of fluids into sources of freshwater.

(h) If wells, including freshwater wells or other borings, are located within a one-quarter mile radius of the disposal or storage well, are a possible means for oil field wastes or hydrocarbons to move into sources of freshwater, and are under the control of

(1) the operator, the operator shall ensure that the wells are properly repaired, plugged, or otherwise modified to prevent the movement of oil field wastes or hydrocarbons into sources of freshwater; or

(2) a person other than the operator, the commission will not issue an order under (a) of this section to the operator until the operator presents evidence to the commission's satisfaction that the person who controls the wells has properly repaired, plugged, or otherwise modified the wells to prevent the movement of oil field wastes or hydrocarbons into sources of freshwater.

(i) The commission will publish notice of the disposal or storage application and will provide opportunity for a hearing in accordance with 20 AAC 25.540.

(j) If disposal or storage operations are not begun within 24 months after the approval date, the injection approval will expire unless an application for extension is approved by the commission.

(k) The annular disposal of drilling wastes approved under 20 AAC 25.080 is an operation incidental to drilling a well and is not a disposal operation subject to this section.

(l) This section does not apply to underground disposal that is regulated under 40 C.F.R. 147.101 by the United States Environmental Protection Agency.

20 AAC 25.255. Equitable distribution of production.

Repealed 4/2/86.

20 AAC 25.260. Illegal production.

Repealed.

20 AAC 25.265. Well safety valve systems.

(a) A completed well must be equipped with a functional safety valve system unless the well is

(1) a water source well;

(2) a disposal injection well;

(3) an observation well;

(4) shut-in; or

(5) suspended.

(b) A safety valve system must have a surface safety valve with an actuator and a low-pressure mechanical or electrical detection device with the capability to shut-in a well when the well's flow line pressure drops below the required system actuation pressure.

(c) A safety valve system must meet the following requirements:

(1) the surface safety valve must be located within the vertical run of a well's tree;

(2) the low-pressure mechanical or electrical detection device must be installed on the well's flow line;

(3) the safety valve system control unit must be placed in a location that allows unobstructed control unit access for operation, maintenance, repair, and inspection;

(4) for a producing well, a check valve must be installed in the well's flow line upstream of the production manifold, except for a well that cycles between gas storage injection and production;

(5) in a well's safety valve system a fusible plug or a functionally equivalent device must be installed near enough to the wellhead so that the well will be immediately shut-in if there is a fire;

(6) a structure containing multiple wells in a common area must have a gas detection system and a fire detection system that will immediately shut-in the wells located within the structure;

(7) safety valve system equipment must be maintained in good operating condition at all times and must be protected to ensure reliable operation under the range of weather conditions expected at the well site; and

(8) components of a safety valve system installed before December 3, 2010 which do not meet the requirements of (1) - (7) of this subsection, require commission approval no later than one year after December 3, 2010 to remain in operation.

(d) In addition to meeting the other requirements of this section, the following wells must be equipped with a fail-safe automatic surface controlled subsurface safety valve capable of preventing an uncontrolled flow of fluid from the well's tubing:

(1) a well that is capable of unassisted flow of hydrocarbons to surface and that has an offshore surface location;

(2) a well that is capable of unassisted flow of hydrocarbons to surface and that has an onshore surface location that is 660 feet or less of

(A) a permanent dwelling intended for human occupancy, including a billeting camp or private residence;

(B) an occupied commercial building, excluding a structure located within an existing oil or gas field;

(C) a road accessible to the public;

(D) an operating railway;

(E) a government maintained airport runway;

(F) a coast line measured at mean high water;

(G) a public recreational facility; or

(H) navigable waters as defined by the United States Army Corps of Engineers in 33 C.F.R. Part 329.4 with boundaries defined in 33 C.F.R. 329.11;

(3) a well that the commission determines, after notice and an opportunity for hearing in accordance with 20 AAC 25.540, must be equipped with a subsurface safety valve;

(4) an onshore well in a location described under (2) of this subsection and equipped with an electric submersible pump, velocity string, or capillary string run within the tubing is not required to be equipped with a subsurface safety valve; or

(5) gas-only injection wells must be equipped with either a subsurface safety valve as stated in this subsection, or an injection valve capable of preventing back flow; the commission will address wells cycling between gas storage injection and production on a case-by-case basis.

(e) If a well is being produced by artificial lift, the capability must exist to shut down artificial lift to the well.

(f) A well that was completed before December 3, 2010 that is subject to the requirements of (d) of this section and that is not equipped with the functional hardware that would make a subsurface safety valve installation possible sooner, must comply with the provisions of (d) of this section no later than the date that the well undergoes a tubing workover.

(g) A subsurface safety valve required under this section must be installed in the tubing string and

(1) located a minimum of 100 feet below the following:

(A) original ground level for onshore wells;

(B) mudline datum for offshore wells;

(2) notwithstanding the provisions of (1) of this subsection, if permafrost is present, the subsurface safety valve must be located below the permafrost.

(h) Except for a well injecting water, safety valve system testing is required. Safety valve system testing may consist of a function-test, a performance-test, or both. A performance-test includes a function pressure-test of the system's valves and a function-test of the mechanical or electrical actuating device. A safety valve system component fails a performance-test when a test criterion in (9) - (12) of this subsection is not met on the first attempt. The safety valve system must be tested as follows:

(1) performance-testing of the safety valve system must be accomplished using a calibrated pressure gauge of suitable range and accuracy;

(2) a performance-test is required following installation, repair, or replacement of a low-pressure mechanical or electrical detection device, surface safety valve, or subsurface safety valve;

(3) a function-test only is required following the installation, repair, or replacement of safety valve system components other than those listed in (2) of this subsection, before or at the time of placing a well in service;

(4) a new well requiring a safety valve system may not be operated unless it passes a performance-test not later than five days after placing the well in service; the timing of all other safety valve system performance-testing must be consistent with the requirements of (i) of this section;

(5) a performance-test must be conducted semi-annually, not to exceed 210 days between tests, unless the commission prescribes a different testing interval based on test performance results;

(6) a well isolated from its flow line or other production offtake mechanism need not be tested at the time of the required performance-test stated in this subsection, but the safety valve system must be performance-tested not later than five days after the well's return to stabilized production or injection;

(7) performance-test results must be verified by an operator's designated representative and submitted electronically to the commission not later than the 15th calendar day of the month following the testing;

(8) at least 24 hours notice of safety valve system performance-testing must be provided to the commission so that a commission representative can witness the test; however, at least 48 hours notice must be provided if the test location is remote from the nearest commission office;

(9) the system actuation pressure of the low-pressure mechanical or electrical detection device installed on a production well must be at least 50 percent of the separator inlet pressure or at least 25 percent of the flowing tubing pressure, whichever is greater;

(10) when a safety valve system is required, the system actuation pressure of the low-pressure mechanical or electrical detection device installed on injection wells must be greater than 50 percent of the injection tubing pressure;

(11) not later than two minutes after the actuation of a mechanical or electrical detection device, a required surface

safety valve must close; after valve closure with a measurable pressure differential across the valve, there must be no detectable leakage as evidenced by a stabilized, flat-line pressure response;

(12) not later than four minutes after the actuation of a mechanical or electrical detection device, a required subsurface safety valve must close; after valve closure with a measurable pressure differential across the valve, there must be no detectable leakage as evidenced by a stabilized, flat-line pressure response;

(13) preventive maintenance records for the consecutive six months immediately before the testing must be made available at the request of a commission representative; the records must indicate the date and type of safety valve system maintenance completed.

(i) If a component of a safety valve system fails a performance-test, the component must be repaired or replaced, or the well shut-in as follows:

(1) if the mechanical or electrical actuating device fails to actuate or actuates below the required trip pressure, the actuating device must immediately be repaired or replaced and performance-tested, or the well must immediately be shut-in;

(2) for a well equipped with only a surface safety valve,

(A) if the surface safety valve fails to close, it must immediately be repaired or replaced and performance-tested, or the well must immediately be shut-in; or

(B) if the surface safety valve leaks, the valve must, not later than 24 hours after the leak is found, be both repaired or replaced and performance tested, or the well must be shut-in;

(3) for a well equipped with both a surface safety valve and a commission-required subsurface safety valve,

(A) if either the surface safety valve or subsurface safety valve fails to close, the failing valve must, not later than 48 hours after the failure is found be both repaired or replaced and performance-tested, or the well must be shut-in;

(B) if either the surface safety valve or commission-required subsurface safety valve leaks, the leaking valve must, not later than 14 days after the leak is found, be both repaired or replaced and performance-tested, or the well must be shut-in; and

(C) if both the surface safety valve and subsurface safety valve fail a performance-test, at least one valve must immediately be both repaired or replaced and performance-tested in place, or the well must immediately be shut-in; the remaining valve must, not later than 14 days after the failure is found, be repaired or replaced and performance-tested, or the well must be shut-in;

(4) if the positive sealing device used to test a safety valve system leaks or otherwise precludes a successful safety valve system test, testing may continue with a substitute valve upon commission approval; the positive sealing device must be repaired or replaced before the next required safety valve system test.

(j) When required by a tubing workover, well intervention, or by routine well pad or platform operations,

(1) the subsurface safety valve may be temporarily blocked or removed; however, the subsurface safety valve must be made operable not later than 14 days after the date that the well is returned to service, and be tested not later than five days after installation in accordance with (h) of this section; and

(2) the surface safety valve and the mechanical or electrical detection device may be temporarily removed or defeated; however, unless otherwise authorized by the commission, the well pad or platform must be continuously manned, or the well must be shut-in, until the surface safety valve and mechanical or electrical detection device are made operable; well pads, platforms, islands, or similar groups of wells are continuously manned if sufficient responsible personnel are physically on-site and manually able to provide a level of protection equivalent to the removed or defeated safety valve system equipment.

(k) An operator may demonstrate by a no-flow test that a well is incapable of the unassisted flow of hydrocarbons to the surface subject to the following:

(1) a no-flow test must be performed according to commission-approved procedures, and to demonstrate no-flow, there must be a commission-witnessed three-hour period of no-flow;

(2) at least 24 hours notice must be provided to the commission so that a commission representative can witness the test; however, at least 48 hours notice must be provided if the test location is remote from the nearest commission office;

(3) upon notice to the commission of an upcoming no-flow test, a well may be produced without a subsurface safety valve for not more than five days in order to reach a stabilized condition before the test;

(4) well work activities that have the potential to impact a well's flow capability invalidate the well's no-flow status.

(l) For purposes of (d) of this section, a well is incapable of the unassisted flow of hydrocarbons to the surface when

(1) a witnessed no-flow test demonstrates that either

(A) the measured liquid production is not greater than 6.3 gallons per hour, and the measured gas production is not greater than 900 standard cubic feet per hour; or

(B) well pressure is discharged not later than five minutes after a three-hour charted pressure build-up period; and

(2) the operator receives written confirmation, including confirmation by electronic mail that is retained as a record by the operator, from the commission that the results of the witnessed no-flow test were accepted.

(m) If a required component of a well's safety valve system is inoperable, removed, or blocked, the well must be tagged. Tagging is not required during well work activities and continuously manned operational activities that affect a safety valve system. The tag must identify the following:

(1) the inoperable, removed, or blocked component;

(2) the date and reason, if known, that the component was inoperable, removed, or blocked;

(3) the name of the individual completing the tag.

(n) The operator of each field shall designate and report to the commission a position as the single-point-of-contact. The single-point-of-contact is responsible for the following:

(1) ensuring that a safety valve system test schedule is coordinated with the commission;

(2) ensuring that actions consistent with these regulations are taken in the event of a safety valve system failure and reported to the commission;

(3) ensuring that the commission is notified when a safety valve system has been repaired and is ready for testing;

(4) maintaining records of safety valve system performance tests, failures, repairs, and retests for a period of at least five years;

(5) ensuring that the commission is notified if well conditions cause a change in safety valve system requirements, such as when a no-flow well is returned to flowing status.

(o) Unless notice and a hearing are required under (d)(3) of this section, upon written request from the operator, the commission may approve

(1) a variance from a requirement of this section if the variance provides at least an equally effective means of complying with the requirement; or

(2) a waiver of a requirement of this section if the waiver does not promote waste, is based on sound engineering and geoscience principles, will not jeopardize the ultimate recovery of hydrocarbons, does not jeopardize correlative rights, and does not result in an increased risk to health, safety, or the environment, including freshwater.

(p) In this section, unless the context otherwise requires, "well's flowline" means the section of line between a well tree and the first piping manifold.

20 AAC 25.270. Reservoir properties.

(a) The operator shall determine the initial reservoir pressure in each new pool before regular production. The results must be reported to the commission on a Reservoir Pressure Report (Form 10-412).

(b) The operator shall obtain fluid samples from each new pool at the time of discovery or before regular production and determine

(1) crude oil composition;

(2) pressure, volume, and temperature properties of the crude oil; and

(3) solution or non-associated gas composition.

(c) Sampling and analysis must be conducted and reported in accordance with good oil field engineering practices. Reports must be submitted to the commission within 45 days following the completion of the determinations required in (b) of this section.

(d) The operator shall determine within three months after discovery of each new oil pool the original solution gas-oil ratio by a well test conducted in a manner approved by the commission. The operator shall report the results on the Well Status Report and Gas-Oil Ratio Tests (Form 10-409) within 45 days after the test.

(e) Annually and not later than April 1 or the date that the operator must submit a pool-specific annual surveillance report for the reservoir under 20 AAC 25.520, whichever date is later, the operator shall submit to the commission an Annual Reservoir Properties Report (Form 10-428).

20 AAC 25.275. Reservoir fluid properties.

Repealed.

20 AAC 25.280. Workover operations.

(a) An Application for Sundry Approvals (Form 10-403) must be submitted to and approved by the commission in order to enter a well and conduct one or more of the following types of well workover operations:

(1) the perforation or reperforation of casing;

(2) stimulation;

(3) the pulling of tubing;

(4) alteration of the casing;

(5) repairs to the well.

(b) The Application for Sundry Approvals must set out

(1) the current condition of the well;

(2) a copy of the proposed program for well work;

(3) unless already on file with the commission, a diagram and description of the well control equipment to be used, including if applicable a list of the blowout prevention equipment (BOPE) with specifications;

(4) the maximum downhole pressure that may be encountered, criteria used to determine it, and the maximum potential surface pressure based on a pressure gradient to surface of 0.1 psi per foot of true vertical depth, unless the commission approves a different pressure gradient that provides a more accurate means of determining the maximum potential surface pressure, such as using a stabilized shut-in tubing pressure;

(5) a description of any wellbore fluid to be used for primary well control; and

(6) the current bottom-hole pressure, or, if data setting out the actual pressure are not available, an estimate of the current bottom-hole pressure.

(c) The operator shall keep records and reports of well workover operations, including BOPE test results, in conformance with the requirements of 20 AAC 25.070(1).

(d) The operator shall file with the commission, within 30 days after completion of workover operations, on a Report of Sundry Well Operations (Form 10-404), a complete record of the work performed and the tests conducted, and a summary of daily well operations as described in 20 AAC 25.070(3). Upon request, the operator shall file with the commission a copy of the daily record required by 20 AAC 25.070(1).

(e) Upon application, the commission will, in its discretion, waive the requirements of this section for wells in a pool for which pool rules have been prescribed under 20 AAC 25.520.

(f) An Application for Sundry Approvals for a well proposed for stimulation by hydraulic fracturing as defined in 20 AAC 25.283(m) must also comply with 20 AAC 25.283. The commission will post the application on its public Internet website. If the application contains confidential information the operator shall submit, for posting on the commission's public Internet website, an additional copy of the application with all confidential information redacted.

(g) If workover operations are not commenced within 12 months after the commission approves an Application for Sundry Approvals, the Application for Sundry Approvals expires.

20 AAC 25.283. Hydraulic fracturing.

(a) Before hydraulic fracturing, the operator must submit an Application for Sundry Approvals (Form 10-403) under 20 AAC 25.280. Unless modified or altered by pool rules established under 20 AAC 25.520, the application must include

(1) an affidavit stating that all owners, landowners, surface owners, and operators within a one-half mile radius of the current or proposed wellbore trajectory have been provided a notice of operations that is in compliance with the

requirements of this paragraph; in the notice of operations, the operator must

(A) state that upon request a complete copy of the application is available from the operator; and

(B) include the operator contact information;

(2) a plat

(A) showing the well location;

(B) identifying each water well, if any, located within a one-half mile radius of the well's surface location; and

(C) identifying for all well types

(i) each well penetration, if any, within one-half mile of the current or proposed wellbore trajectory and fracturing interval; and

(ii) the source of information used in identifying each well penetration;

(3) identification of each freshwater aquifer, if any, within a one-half mile radius of the current or proposed wellbore trajectory, the geological name of the freshwater aquifer, the measured depth of the freshwater aquifer, and the true vertical depth of the freshwater aquifer;

(4) a plan for baseline water sampling of water wells before hydraulic fracturing, as follows:

(A) water sampling consists of collection of baseline water data before hydraulic fracturing, within a one-half mile radius of the current or proposed wellbore trajectory;

(B) the operator must detail the well selection process for identifying wells to sample;

(C) if a surface owner denies permission for baseline water sampling or for disclosure of the results, the operator

(i) must document the reasonable and good-faith efforts taken to secure that permission; and

(ii) is not required to include the surface owner in any sampling required under (j) of this section of water wells after hydraulic fracturing;

(D) sample parameters must include

(i) pH;

(ii) alkalinity, measured as the presence of total bicarbonate and carbonate, and expressed as parts per million of calcium carbonate;

(iii) specific conductance;

(iv) the presence of bacteria that is iron-related, sulfate-reducing, or slime-forming;

(v) arsenic;

(vi) barium;

(vii) bicarbonate;

(viii) boron;

(ix) bromide;

(x) cadmium;

(xi) calcium;

(xii) chloride;

(xiii) chromium;

(xiv) flouride;

(xv) hydroxide;

(xvi) iodide;

(xvii) iron;

(xviii) lithium;

(xix) magnesium;

(xx) manganese;

(xxi) total nitrate and nitrate, measured as the presence of nitrogen;

(xxii) phosphorus;

(xxiii) potassium;

(xxiv) radium, measured as the presence of combined radium-226 and radiurn-228;

(xxv) selenium;

(xxvi) silicon;

(xxvii) sodium;

(xxviii) strontium;

(xxix) sulfate;

(xxx) total dissolved solids;

(xxxi) total petroleum hydrocarbons, expressed as the results of the analyses made under (xxxii) - (xxxvi) of this subparagraph;

(xxxii) benzene, toluene, ethylbenzene, and total xylene isomers (BTEX); the Application for Sundry Approvals (Form 10-403) must state whether the operator proposes to measure those substances using the United States Environmental Protection Agency's methods 5035, 8260B, or 8260C in Test Methods for Evaluating Solid Waste, Physical/Chemical Methods (EPA publication SW-846), or an alternate method proposed for commission approval as effective for measuring those substances;

(xxxiii) gasoline range organics (GRO); the Application for Sundry Approvals (Form 10-403) must state whether the operator proposes to measure those substances using the United States Environmental Protection Agency's methods 5035, 8015C, or 8015D in Test Methods for Evaluating Solid Waste, Physical/Chemical Methods (EPA publication SW-846), method AK 101 in the Department of Environmental Conservation's Underground Storage Tanks Procedures Manual, or an alternate method proposed for commission approval as effective for measuring those substances;

(xxxiv) diesel range organics (DRO); the Application for Sundry Approvals (Form 10-403) must state whether the operator proposes to measure those substances using the United States Environmental Protection Agency's methods 8015C or 8015D in Test Methods for Evaluating Solid Waste, Physical/Chemical Methods (EPA publication SW-846) with silica gel cleanup, method AK 102 in the Department of Environmental Conservation's Underground Storage Tanks Procedures Manual, or an alternate method proposed for commission approval as effective for measuring those substances;

(xxxv) polynuclear aromatic hydrocarbons, including benzo(a)pyrene; and

(xxxvi) dissolved methane, dissolved ethane, and dissolved propane; the Application for Sundry Approvals (Form 10-403) must state whether the operator proposes to measure those substances using the United States Environmental Protection Agency's Standard Operating Procedure: Sample Preparation and Calculations for Dissolved Gas Analysis in Water Samples Using a GC Headspace Equilibration Technique (EPA publication RSK SOP 175, Revision No. 2) or an alternate method proposed for commission approval as effective for measuring those substances;

(E) the plan must require documentation of odor, water color, sediment, bubbles, effervescence, and other field observations;

(F) the plan must require that if free gas or a dissolved methane concentration greater than 1.0 mg/l is detected in a water sample, the gas type shall be determined by means of a gas compositional analysis and stable isotope analysis of the methane; a stable isotope analysis must include an analysis of carbon-12, carbon-13, hydrogen-1, and hydrogen-2 isotopes;

(G) the plan must require that the operator notify the commission, the Department of Environmental Conservation, and the surface owner within 24 hours if

(i) the test results indicate thermogenic or a mixture of thermogenic and biogenic gas;

(ii) the plan requires multiple samples within a stated timeframe, and the methane concentration increases by more than 5.0 mg/l between sampling periods;

(iii) the methane concentration is detected at or above 10 mg/l; or

(iv) total petroleum hydrocarbons as described in (D)(xxxi) of this paragraph, benzene, toluene, ethylbenzene, xylene isomers, gasoline range organics, or diesel range organics are detected;

(H) except as otherwise provided under this paragraph, the plan must provide for the use of current applicable sample custody and collection protocols and analytical methods that the Department of Environmental Conservation or the United States Environmental Protection Agency (EPA) has approved, or an alternate protocol or method proposed for commission approval as effective for custody, collection, or analysis of a sample; the plan must provide that analyses be performed by laboratories that maintain nationally accredited programs;

(I) not later than 90 days after a sample is collected, a copy of each test result, analytical result, and sample location must be provided to the commission and to the Department of Environmental Conservation in printed form and in an electronic data deliverable format that is acceptable to the commission;

(5) detailed casing and cementing information;

(6) an assessment of each casing and cementing operation performed to construct or repair the well; the assessment must include sufficient supporting information, including cement evaluation logs and other evaluation logs approved by the commission, to demonstrate that

(A) casing is cemented

(i) below the base of the lowermost freshwater aquifer; and

(ii) in accordance with 20 AAC 25.030; and

(B) each hydrocarbon zone penetrated by the well is isolated;

(7) pressure test information if available and plans to pressure-test the casings and tubing installed in the well;

(8) accurate pressure ratings and schematics for the wellbore, wellhead, BOPE, and treating head;

(9) data for the fracturing zone and confining zones, including

(A) a lithologic description of each zone;

(B) the geological name of each zone;

(C) the measured depth and true vertical depth of each zone;

(D) the measured thickness and true vertical thickness of each zone; and

(E) the estimated fracture pressure for each zone;

(10) the location, the orientation, and a report on the mechanical condition of each well that may transect the confining zones, and information sufficient to support a determination that the well will not interfere with containment of the hydraulic fracturing fluid within the one-half mile radius of the proposed wellbore trajectory;

(11) the location of, orientation of, and geological data for each known or suspected fault or fracture that may transect the confining zones, and information sufficient to support a determination that the known or suspected fault or fracture will not interfere with containment of the hydraulic fracturing fluid within the one-half mile radius of the proposed wellbore trajectory;

(12) a detailed copy of the proposed hydraulic fracturing program; the proposed program must include the pumping procedure by stage if applicable, with a chemical disclosure based on the total amounts and volumes per well, including the

(A) estimated total volumes planned;

(B) trade name, generic name, and purpose of each base fluid and additive to be used; the estimated or maximum rate or concentration of each additive must be provided in appropriate measurement units;

(C) chemical ingredient name of, and the Chemical Abstracts Service (CAS) registry number assigned to, each base fluid and additive to be used; the actual or maximum concentration of each chemical ingredient in each base fluid and additive used must be provided in percent by mass; the actual or maximum concentration of each chemical ingredient in the hydraulic fracturing fluid must be provided in percent by mass; freeze-protect fluids pumped before or after hydraulic fracturing may not be included;

(D) estimated weight or volume of each inert substance, including a proppant or other substance injected;

(E) maximum anticipated treating pressure and information sufficient to support a determination that the well is appropriately constructed for the proposed hydraulic fracturing program; and

(F) designed height and length of each proposed fracture, including

(i) the calculated measured depth and true vertical depth of the top of the fracture; and

(ii) a description of each method and assumption used to determine designed fracture height and length; and

(13) a detailed description of the plan for post-fracture wellbore cleanup and fluid recovery through to production operations.

(b) When hydraulic fracturing is done through production casing or through intermediate casing, the casing must be tested

to 110 percent of the maximum anticipated pressure differential to which the casing may be subjected. If the casing fails the pressure test, the casing must be repaired or the operator must use a fracturing string.
(c) When hydraulic fracturing is done through a fracturing string, the fracturing string must be
(1) stung into a liner or run on a packer set at a measured depth of not less than 100 feet below the cement top of the production casing or intermediate casing; and
(2) tested to not less than 110 percent of the maximum anticipated pressure differential to which the fracturing string may be subjected.
(d) A pressure relief valve must be installed on the treating line between a pump and the wellhead to limit the line pressure to the test pressure determined under (a)(12)(E) of this section. The well must be equipped with a remotely controlled shut-in device unless the operator requests and obtains a waiver from the commission under (l) of this section.
(e) The placement of all hydraulic fracturing fluids shall be confined to the approved formations during hydraulic fracturing.
(f) If the surface casing annulus is not open to atmospheric pressure, the surface casing pressures shall be monitored with a gauge and pressure relief device while hydraulic fracturing operations are in progress. The annular space between the fracturing string and the intermediate or production casing must be continuously monitored. The pressure in that annular space may not exceed the pressure rating of the lowest rated component that would be exposed to pressure if the fracturing string failed.
(g) During hydraulic fracturing operations, all annulus pressures must be continuously monitored and recorded. If at any time during hydraulic fracturing operations the annulus pressure increases more than 500 psig above those anticipated increases caused by pressure or thermal transfer, the operator shall
(1) notify the commission as soon as practicable, but not later than 24 hours following the incident;
(2) implement corrective action or increased surveillance as the commission requires; and
(3) submit a Report of Sundry Well Operations (Form 10-404) not later than 15 days after the incident; in the report the operator shall give all details of the incident, including corrective actions taken.
(h) Not later than 30 days after completion of hydraulic fracturing, operations, the operator shall file with the commission, on a Report of Sundry Well Operations (Form 10-404), a complete record of the work performed and the tests conducted, a summary of daily well operations as described in 20 AAC 25.070(3), and a copy of the daily record required under 20 AAC 25.070(1). As part or the filing the operator shall include,
(1) for each hydraulic fracturing interval,
(A) the measured depth and true vertical depth of each perforation or sleeve for the actual treated interval; and
(B) the amount and type of each base fluid and each additive pumped during each stage; and
(2) for each hydraulic fracturing treatment addressed in the Report of Sundry Well Operations, the total amount and type of each base fluid and each additive pumped, including
(A) a description of each hydraulic fracturing fluid pumped, identified by individual base fluid or additive; the description must include
(i) the trade name for the base fluid or additive;
(ii) the supplier of the base fluid or additive; and
(iii) a brief description of the purpose of the base fluid or additive; that purpose may be expressed as acid, biocide, breaker, brine, corrosion inhibitor, crosslinker, de-emulsifier, friction reducer, gel, iron control, oxygen scavenger, pH adjusting agent, proppant, scale inhibitor, surfactant, or another similar brief description; and
(B) the chemical ingredient name of, and the Chemical Abstracts Service (CAS) registry number assigned to, each base fluid and additive used; the actual or maximum concentration of each chemical ingredient in each base fluid and additive used must be provided in percent by mass: the actual or maximum concentration of each chemical ingredient in the hydraulic fracturing fluid must be provided in percent by mass; freeze-protect fluids pumped before or after hydraulic fracturing may not be included.
(i) Before submitting a Report of Sundry Well Operations under (h) of this section, the operator shall
(1) post information required by the Interstate Oil and Gas Compact Commission and the Ground Water Protection Council on the FracFocus Chemical Disclosure Registry, or its successor database, maintained on the Internet by those organizations; and
(2) file a printed copy and electronic copy of that information, in a format acceptable to the commission and as an attachment with the Report of Sundry Well Operations.
(j) The commission may require water sampling of water wells after hydraulic fracturing. If required, and in accordance with a sampling and monitoring plan approved by the commission, water sampling may consist of collection of water data within a one-half mile radius of the wellbore trajectory after hydraulic fracturing. The operator shall detail the well selection process for identifying wells to sample. Methods, parameters, and analysis must be similar to those under (a)(4) of this section as required by the commission.
(k) Any information required to be filed under this section that the filing party believes to be a confidential trade secret shall be separately filed in an envelope clearly marked "confidential" along with a list of the documents that the party believes to be wholly or partially nondisclosable as trade secrets, and the specific legal authority and specific facts supporting nondisclosure. The commission will review the information, and will maintain it as confidential. If the commission receives a request under AS 40.25.100 - 40.25.295 (Alaska Public Records Act) for disclosure of the information, the commission will promptly forward the request to the party claiming confidentiality. Not later than five business days after receiving the request, the party claiming confidentiality shall file with the commission an affidavit verifying that the documents remain wholly or partially confidential, identifying any portions of the document that are not confidential, and setting out the specific facts and legal authority supporting nondisclosure. After reviewing the affidavit, in accordance with and within the time allowed to respond under 2 AAC 96.325, the commission will determine whether to provide the party making the public records request the requested documents or the list of nondisclosable documents, the specific legal authority and facts supporting nondisclosure, and the affidavit provided by the party claiming confidentiality. The commission will notify the party claiming confidentiality if an appeal is requested under AS 40.25.123(e) and 2 AAC 96.340, or if judicial relief is sought under AS 40.25.124 or 40.25.125.
(l) Upon written request of the operator, the commission may modify a deadline in this section upon a showing of good cause, approve a variance from any other requirement of this section if the variance provides at least an equally effective means of complying with the requirement, or approve a waiver of a requirement of this section if the waiver will not

promote waste, is based on sound engineering and geoscience principles, will not jeopardize the ultimate recovery of hydrocarbons, will not jeopardize correlative rights, and will not result in an increased risk to health, safety, or the environment, including freshwater.
(m) In this section,
(1) "additive" means a chemical substance or combination of substances, including a proppant, that is contained in a hydraulic fracturing fluid and that is intentionally added to a base fluid for a specific purpose, whether or not that purpose is to create fractures in a formation;
(2) "chemical ingredient" means a discrete chemical constituent that is contained in an additive and that has its own Chemical Abstracts Service (CAS) registry number or other specific name or identity;
(3) "diesel range organics" means mid-range petroleum products, including diesel fuel, with petroleum hydrocarbon compounds corresponding to an alkane range from the beginning of n-decane (C10) to the beginning of n-pentacosane (C25) and with a boiling point range between approximately 170 - 400° Centigrade;
(4) "fracturing string" means any pipe or casing string used for the transport of hydraulic fracturing fluids during hydraulic fracturing operations;
(5) "gasoline range organics" means light range petroleum products, including gasoline, with petroleum hydrocarbon compounds corresponding to an alkane range from the beginning of n-hexane (C6) to the beginning of n-decane (C10) and with a boiling point range between approximately 60 - 170° Centigrade;
(6) "hydraulic fracturing" means the treatment of a well by the application of hydraulic fracturing fluid under pressure for the express purpose of initiating or propagating fractures in a target geologic formation to enhance production of oil or natural gas;
(7) "hydraulic fracturing fluid" means the fluid, including the applicable base fluid. and all additives, used to perform a particular hydraulic fracturing treatment;
(8) "hydraulic fracturing treatment" means all stages of the treatment of a well by the application of hydraulic fracturing;
(9) "proppant" means treated sand, a manufactured ceramic material, or another solid material designed to keep a hydraulic fracture open during or after hydraulic fracturing treatment;
(10) "stage" means any separate interval treatment that initiates a new fracture within the wellbore;
(11) "water well" means a well producing freshwater that serves as a source of drinking water for human consumption or agricultural purposes.

20 AAC 25.285. Secondary well control for tubing workover operations: blowout prevention equipment requirements.

(a) This section applies to workover operations performed with the tree removed. These operations are also subject to the requirements of 20 AAC 25.527.
(b) The rated working pressure of the BOPE and other well control equipment must exceed the maximum potential surface pressure to which it may be subjected. If an approved Application for Sundry Approvals (Form 10-403) is required under 20 AAC 25.280, the commission will specify in that approved application the working pressure that the equipment must be rated to meet or exceed. However, the rated working pressure of the annular type preventer need not exceed 5,000 psi.
(c) Well control equipment must include
(1) at least one positive seal manual or hydraulic valve or BOPE blind ram and one set of BOPE pipe rams flanged to the wellhead;
(2) in rotary drilling rig operations,
(A) for an operation with a maximum potential surface pressure of 3,000 psi or less, at least three preventers, including
(i) one equipped with pipe rams that fit the size of drill pipe, tubing, liner or casing being used, except that pipe rams need not be sized to bottom-hole assemblies (BHAs) and drill collars;
(ii) one with blind rams, except that a subsea BOPE assembly must have blind/shear rams in place of blind rams; and
(iii) one annular type;
(B) for an operation, other than a casing or liner operation, with a maximum potential surface pressure of greater than 3,000 psi, at least four preventers, including
(i) two equipped with pipe rams that fit the size of the drill pipe or tubing being used, except that pipe rams need not be sized to BHAs and drill collars;
(ii) one with blind rams, except that a subsea BOPE assembly must have blind/shear rams in place of blind rams; and
(iii) one annular type; and
(C) for a casing or liner operation, with a maximum potential surface pressure of greater than 3,000 psi, at least four preventers, including
(i) one equipped with pipe rams that fit the size of the drill pipe or tubing being used, except that pipe rams need not be sized to BHAS and drill collars;
(ii) one equipped with pipe rams that fit the size of casing or liner being used;
(iii) one with blind rams, except that a subsea BOPE assembly must have blind/shear rams in place of blind rams; and
(iv) one annular type;
(3) in coiled tubing unit operations,
(A) for an operation with a maximum potential surface pressure of 5,000 psi or less,
(i) BOPE rams providing for pipe, slip, cutting, and blinding operations on the coiled tubing in service;
(ii) a high pressure pack-off, stripper, or annular type preventer;
(iii) if pressure deployment of tools is planned, a riser or lubricator sized to the BHA and providing for pressure integrity from the BOPE rams to the high pressure pack-off, stripper, or annular type preventer; and
(iv) at least one preventer equipped with pipe rams that fit the size of the tubing, liner, or casing being used, except that pipe rams need not be sized to BHAs and drill collars;

(B) for an operation, other than a casing or liner operation, with a maximum potential surface pressure of greater than 5,000 psi,

(i) BOPE rams providing for pipe, slip, cutting, and blinding operations on the coiled tubing in service;

(ii) two high pressure pack-offs, strippers, or annular type preventers;

(iii) if pressure deployment of tools is planned, a riser or lubricator sized to the BHA and providing for pressure integrity from the BOPE rams to the high pressure pack-off, stripper, or annular type preventer; and

(iv) at least two preventers equipped with pipe rams that fit the size of the tubing used, except that pipe rams need not be sized to BHAs and drill collars; and

(C) for a casing or liner operation with a maximum potential surface pressure of greater than 5,000 psi,

(i) BOPE rams providing for pipe, slip, cutting, and blinding operations on the coiled tubing in service;

(ii) two high pressure pack-offs, strippers, or annular type preventers;

(iii) if pressure deployment of tools is planned, a riser or lubricator sized to the BHA and providing for pressure integrity from the BOPE rams to the high pressure pack-off, stripper, or annular type preventer;

(iv) at least one preventer equipped with pipe rams that fit the size of the tubing being used, except that pipe rams need not be sized to BHAs and drill collars; and

(v) at least one preventer equipped with pipe rams that fit the size of casing or liner being used;

(4) if a tapered string is used, either an additional set of rams for each size of pipe being run or a variable ram, except if small diameter tubulars are used to perform a clean-out operation through a production packer or to clean out a liner where the casing has been top set;

(5) locking devices on the ram-type preventers;

(6) in rotary drilling rig operations, one complete set of operable remote BOPE controls on or near the driller's station, in addition to controls on the accumulator system;

(7) in coiled tubing operations, one complete set of operable remote BOPE controls on or near the operator's station and, if these controls are not in close proximity to the drilling platform floor, a second annular type preventer closing control located on the drilling platform floor;

(8) a hydraulic actuating system with

(A) sufficient accumulator capacity to supply 150 percent of the volume necessary to close all BOPs, except blind rams, while maintaining a minimum pressure of 200 psi above the required precharge pressure when all BOPs, except blind rams, are closed and all power sources are shut off; and

(B) an accumulator pump system consisting of two or more pumps with independent primary and secondary power sources and an accumulator backup system having sufficient capacity to close all BOPs and to hold them closed;

(9) a kill line and a choke line each connected to a flanged or hubbed outlet on a drilling spool or on the BOP body with two full-opening valves on each outlet, conforming to the following specifications:

(A) the outlets must be at least two inches in nominal diameter, except that for rotary drilling rig operations, if the operation has a maximum potential surface pressure of greater than 3,000 psi, the nominal diameter of the choke outlets must be at least three inches;

(B) each valve must be sized at least equal to the required size of the outlet to which it is attached;

(C) the outer valve on the choke side must be a remotely controlled hydraulic valve;

(D) the inner valve on both the choke and kill sides may not normally be used for opening or closing on flowing fluid; and

(10) a choke manifold equipped with

(A) two or more adjustable chokes, one of which must be hydraulic and remotely controlled from near the driller's station if the operation has a maximum potential surface pressure of greater than 3,000 psi;

(B) a line at least two inches in nominal diameter downstream of each choke;

(C) immediately upstream of each choke, at least one full-opening valve for an operation with a maximum potential surface pressure of 3,000 psi or less, or at least two full-opening valves for an operation with a maximum potential surface pressure of greater than 3,000 psi; and

(D) a bypass line, at least two inches in nominal diameter, with at least one full-opening valve for an operation with a maximum potential surface pressure of 3,000 psi or less, or at least two full-opening valves for an operation with a maximum potential surface pressure of greater than 3,000 psi.

(d) The rated working pressure of valves, pipes, rotary hoses, and other fittings, including all sections of the choke manifold that are subject to full wellhead pressure, must exceed the maximum potential surface pressure to which they may be subjected and may not be less than the required working pressure specified for the BOPE in an approved Application for Sundry Approvals, if any, under 20 AAC 25.280, except that the rated working pressure of lines downstream of the choke need not exceed 50 percent of the required working pressure of the BOPE.

(e) Kill and choke lines must

(1) be constructed of rigid steel pipe, fire-resistant rotary hose, or other conduit that has been approved by the commission as capable of withstanding the temperature and pressure of an ignited uncontrolled release;

(2) be as straight as practical;

(3) if constructed of rigid steel pipe, use targeted turns where the bend radius is less than 20 times the inside diameter of the pipe;

(4) be secured to prevent excessive whip or vibration;

(5) be sized to prevent excessive erosion or fluid friction; and

(6) be assembled without hammer unions or internally clamped swivel joints, unless the commission determines that those joints do not compromise the maintenance of well control.

(f) The BOPE must be tested as follows:

(1) when installed, repaired, or changed, and at least once a week thereafter, BOPE, including emergency valves and choke manifolds, must be function pressure-tested, using a non-compressible fluid, to the required working pressure specified in an approved Application for Sundry Approvals under 20 AAC 25.280 or, if that application is not required, to the maximum potential surface pressure to which the BOPE may be subjected, except that an annular type preventer need not be tested to more than 50 percent of its rated working pressure;

(2) if any BOP equipment components have been used for well control or other equivalent purpose, or when routine

use of the equipment may have compromised its effectiveness, the components used must be function pressure-tested before the next wellbore entry, using a non-compressible fluid, to the required working pressure specified in an approved Application for Sundry Approvals under 20 AAC 25.280 or, if that application is not required, to the maximum potential surface pressure to which that equipment may be subjected, except that an annular type preventer need not be tested to more than 50 percent of its rated working pressure;

(3) non-sealing equipment must be function-tested weekly, after a repair or change, and after an action that disconnects the hydraulic system lines from the BOPE, except that if the workstring is continuously in the well, function-testing must be performed as soon as possible after the workstring is pulled out of the well and the BHA clears the BOP;

(4) for each BOPE test during drilling and completion operations, variable bore rams must be function pressure-tested to the required pressure on the smallest outside diameter (OD) and largest outside diameter (OD) tubulars that may be used during that test cycle, except that variable bore rams need not be tested on BHAs and drill collars;

(5) after they are installed in the BOP stack, the rams for casing or liner must be function pressure-tested to the required pressure before running casing or liner;

(6) BOPE test results must be recorded as part of the daily record required by 20 AAC 25.070(1), and must be provided to the commission, in a format approved by the commission, within five days after completing the test;

(7) at least 24 hours notice of each BOPE function pressure test must be provided so that a representative of the commission can witness the test;

(8) the operator shall report to the commission within 24 hours any instance of BOPE use to prevent the flow of fluids from a well.

(g) In a rotary drilling rig operation, the operator shall have on location a copy of the approved Application for Sundry Approvals, if that application is required under 20 AAC 25.280, and shall post on the drilling rig floor any geologic hazard information obtained while drilling the well and a copy of the operator's standing orders specifying well control procedures. In a coiled tubing operation, the operator shall post in the operator's cab a copy of the approved Application for Sundry Approvals, if that application is required under 20 AAC 25.280, any geologic hazard information obtained while drilling the well, and a copy of the operator's standing orders specifying well control procedures. If an additional or separate substructure is used in a coiled tubing operation, the operator shall post a second set of standing orders on the drilling platform floor.

(h) Upon request of the operator, the commission will, in its discretion, approve a variance from the requirements of this section if the variance provides at least an equally effective means of ensuring well control.

20 AAC 25.286. Well control requirements for workstring service operations.

(a) This section applies to through-tubing operations that are not subject to the requirements of 20 AAC 25.036 or 20 AAC 25.285, and that are performed with coiled tubing, small diameter drill pipe, or small diameter tubing. These operations are also subject to the requirements of 20 AAC 25.527.

(b) The operator shall use a full lubricator system or open hole deployment type system.

(c) The rated working pressure of the blowout prevention equipment (BOPE) and other well control equipment must exceed the maximum potential surface pressure to which it may be subjected. If an approved Application for Sundry Approvals (Form 10-403) is required under 20 AAC 25.280, the commission will specify in that approved application the working pressure that the equipment must be rated to meet or exceed. However, the rated working pressure of the annular type preventer need not exceed 5,000 psi.

(d) Well control equipment must include

(1) at least one positive seal manual or hydraulic valve or blind ram flanged to the wellhead or tree;

(2) in rotary drilling rig operations,

(A) for an operation with a maximum potential surface pressure of 5,000 psi or less, at least three preventers, including

(i) one equipped with pipe rams that fit the size of drill pipe, tubing, or casing being used, except that pipe rams need not be sized to bottom-hole assemblies (BHAs) and drill collars;

(ii) one with blind rams, except that a subsea BOPE assembly must have blind/shear rams in place of blind rams; and

(iii) one annular type;

(B) for an operation, other than a casing or liner operation, with a maximum potential surface pressure of greater than 5,000 psi, at least four preventers, including

(i) two equipped with pipe rams that fit the size of the drill pipe or tubing being used, except that pipe rams need not be sized to BHAs and drill collars;

(ii) one with blind rams, except that a subsea BOPE assembly must have blind/shear rams in place of blind rams; and

(iii) one annular type; and

(C) for a casing or liner operation with a maximum potential surface pressure of greater than 5,000 psi, at least four preventers, including

(i) one equipped with pipe rams that fit the size of the drill pipe or tubing being used, except that pipe rams need not be sized to BHAs and drill collars;

(ii) one equipped with pipe rams that fit the size of casing or liner being used;

(iii) one with blind rams, except that a subsea BOPE assembly must have blind/shear rams in place of blind rams; and

(iv) one annular type;

(3) in coiled tubing unit operations,

(A) for an operation with a maximum potential surface pressure of 5,000 psi or less,

(i) BOPE rams providing for pipe, slip, cutting, and blinding operations on the coiled tubing in service;

(ii) a high pressure pack-off, stripper, or annular type preventer; and

(iii) if pressure deployment of tools is planned, a riser or lubricator sized to the BHA and providing for pressure integrity from the BOPE rams to the high pressure pack-off, stripper, or annular type preventer; and

(B) for an operation with a maximum potential surface pressure of greater than 5,000 psi,

(i) BOPE rams providing for pipe, slip, cutting, and blinding operations on the coiled tubing in service;

(ii) two high pressure pack-offs, strippers, or annular type preventers; and

(iii) if pressure deployment of tools is planned, a riser or lubricator sized to the BHA and providing for pressure integrity from the BOPE rams to the high pressure pack-off, stripper, or annular type preventer;

(4) a hydraulic actuating system with

(A) sufficient accumulator capacity to supply 150 percent of the volume necessary to close all BOPs, except blind rams, while maintaining a minimum pressure of 200 psi above the required precharge pressure when all BOPs, except blind rams, are closed, and all power sources are shut off; and

(B) an accumulator pump system;

(5) locking devices on the ram-type preventers;

(6) in rotary drilling rig operations, one complete set of operable remote BOPE controls on or near the driller's station, in addition to controls on the accumulator system;

(7) in coiled tubing operations, one complete set of operable remote BOPE controls on or near the operator's station and, if these controls are not in close proximity to the drilling platform floor, a second annular type preventer closing control located on the drilling platform floor; and

(8) a kill line capable of being attached with flanged or hubbed connections to the BOP body, drilling spool, tree, wellhead, or other well control equipment.

(e) The operator shall test the BOPE assembly as follows:

(1) at least once a week, and after each repair, change, or use for well control or other equivalent purpose, or when routine use of the equipment may have compromised its effectiveness, BOP equipment must be function pressure-tested, using a non-compressible fluid, to the required working pressure specified in an approved Application for Sundry Approvals under 20 AAC 25.280 or, if that application is not required, to the maximum potential surface pressure to which they may be subjected, except that the annular type preventer need not be tested to more than 50 percent of its rated working pressure;

(2) after each installation of BOPE or other well control equipment, the equipment must be pressure-tested, before wellbore entry, to the maximum potential wellhead pressure to which it may be subjected, except that when testing against the annular type preventer, pressure testing need not exceed 50 percent of the rated working pressure of the annular type preventer;

(3) non-sealing equipment must be function-tested weekly, after a repair or change, and after an action that disconnects the hydraulic system lines from the BOPE, except that if the workstring is continuously in the well, function-testing must be performed as soon as possible after the workstring is pulled out of the well and the BHA clears the BOP;

(4) after each well installation of the BOPE, the BOPE hydraulic connections to the rams must be visually verified before wellbore entry;

(5) for each BOPE test during drilling and completion operations, variable bore rams must be function pressure-tested to the required pressure on the smallest outside diameter (OD) and largest outside diameter (OD) tubulars that may be used during that test cycle, except that variable bore rams need not be tested on BHAs and drill collars;

(6) BOPE test results must be recorded as part of the daily record required by 20 AAC 25.070(1), and must be provided to the commission, in a format approved by the commission, within five days after completing the test;

(7) at least 24 hours notice of each BOPE function pressure test must be provided so that a representative of the commission can witness the test;

(8) the operator shall report to the commission within 24 hours any instance of BOPE use to prevent the flow of fluids from a well.

(f) In a rotary drilling rig operation, the operator shall have on location a copy of the approved Application for Sundry Approvals, if that application is required under 20 AAC 25.280, and shall post on the drilling rig floor any geologic hazard information obtained while drilling the well and a copy of the operator's standing orders specifying well control procedures. In a coiled tubing operation, the operator shall post in the operator's cab a copy of the approved Application for Sundry Approvals, if that application is required under 20 AAC 25.280, any geologic hazard information obtained while drilling the well, and a copy of the operator's standing orders specifying well control procedures. If an additional or separate substructure is used in a coiled tubing operation, the operator shall post a second set of standing orders on the drilling platform floor.

(g) Upon request of the operator, the commission will, in its discretion, approve a variance from the requirements of this section if the variance provides at least an equally effective means of well control.

20 AAC 25.287. Well control requirements for wireline operations.

(a) This section applies to workover or service operations performed with slickline or conductor line with the tree in place. These operations are also subject to the requirements of 20 AAC 25.527.

(b) Well control equipment must include

(1) a set of wireline rams suitable or sized for each diameter of wire passing through the wireline valve;

(2) a lubricator or pressure deployment system; and

(3) a high pressure pack-off, stripper, or greasehead with linewiper, stripper, or pack-off.

(c) The rated working pressure of the well control equipment must exceed the maximum potential surface pressure to which it may be subjected. If an approved Application for Sundry Approvals (Form 10-403) is required under 20 AAC 25.280, the commission will specify in that approved application the working pressure that the equipment must be rated to meet or exceed.

(d) The operator shall test the well control equipment as follows:

(1) at least once a month, wireline valves must be dismantled and rebuilt to ensure the integrity of the inner seals; following rebuild, the wireline rams must be closed and function pressure-tested before wellbore entry, using a non-compressible fluid, to the required working pressure specified in an approved Application for Sundry Approvals under 20 AAC 25.280 or, if that application is not required, to the maximum potential surface pressure to which that equipment may be subjected;

(2) after each installation of the well control equipment, that equipment must be pressure-tested, before wellbore entry, to the maximum potential wellhead pressure to which that equipment may be subjected;

(3) if the wireline valve rams have been used, repaired or changed, the wireline rams must be closed and function pressure-tested before wellbore entry, using a non-compressible fluid, to the required working pressure specified in an approved Application for Sundry Approvals under 20 AAC 25.280 or, if that application is not required, to the maximum potential surface pressure to which they may be subjected.

(e) The operator shall post in the operator's cab a copy of the approved Application for Sundry Approvals, if that application is required under 20 AAC 25.280, any geologic hazard information obtained while drilling the well, and a copy of the operator's standing orders specifying well control procedures.

(f) Upon request of the operator, the commission will, in its discretion, approve a variance from the requirements of this section if the variance provides at least an equally effective means of well control.

20 AAC 25.288. Well control requirements for other service operations.

For downhole service operations not covered by 20 AAC 25.285 - 20 AAC 25.287, the commission will approve alternate well control procedures and equipment, if the commission determines that the alternate procedures and equipment are adequate to ensure well control.

20 AAC 25.290. Operations producing hydrogen sulfide.

An operator of a well or pool that produces hydrogen sulfide gas shall install, operate, and maintain surface production equipment in conformance with API RP 55, Recommended Practices for Oil and Gas Producing and Gas Processing Plant Operations Involving Hydrogen Sulfide, 2d edition, February 15, 1995, which is adopted by reference.

Article 4
Reports

20 AAC 25.300. Request for information.

Notwithstanding any other provision of this chapter, if the commission requests that a person provide information or documentation regarding a matter within the commission's jurisdiction, that person must provide that information and documentation within 30 days of the date the request was sent or within another period of time specified by the commission.

20 AAC 25.310. Books and records.

Operators of oil and gas properties and units within the state shall make and maintain, for a period of not less than five years, books and records necessary to make and substantiate the reports required by this chapter.

20 AAC 25.320. Filing of forms.

Repealed.

Article 5
Enhanced Recovery

20 AAC 25.402. Enhanced recovery operations.

(a) Enhanced recovery operations involving the introduction of extraneous forms of energy into a pool by injection are prohibited, except as ordered by the commission under this section. In response to an application for injection filed by an operator, and upon the commission's determination that the requirements of this section and 20 AAC 25.412 are met, the commission will issue an order authorizing the injection of fluids that function primarily to enhance recovery of oil and gas and that are appropriate for enhanced recovery. Except as provided in (i) of this section, an order authorizing injection for an enhanced recovery project remains valid unless revoked by the commission.

(b) The operator has the burden of demonstrating that the proposed operation will not allow the movement of fluid into sources of freshwater. Injection wells must be cased, the casing cemented, and the wells operated in a manner that will isolate the injection zone and protect oil, gas, and freshwater. If wells, including freshwater, wells and other borings, are located within a one-quarter mile radius of an injection well, are a possible means for fluids to move into sources of freshwater and are under the control of

(1) the operator, the operator shall ensure that the wells are properly repaired, plugged, or otherwise modified to prevent the movement of fluids into sources of freshwater; or

(2) a person other than the operator, the commission will not issue an order under (a) of this section until the operator presents evidence to the commission's satisfaction that the person who controls the wells has properly repaired, plugged, or otherwise modified the wells to prevent the movement of fluids into sources of freshwater.

(c) An application for injection must include

(1) a plat showing the location of each proposed injection well, abandoned or other unused well, production well, dry hole, and other well within one-quarter mile of each proposed injection well;

(2) a list of all operators and surface owners within a one-quarter mile radius of each proposed injection well;

(3) an affidavit showing that the operators and surface owners within a one-quarter mile radius have been provided a copy of the application for injection;

(4) a full description of the particular operation for which approval is requested;

(5) the names, descriptions, and depths of the pools to be affected;

(6) the name, description, depth, and thickness of the formation into which fluids are to be injected, and appropriate geological data on the injection zone and confining zone, including lithologic descriptions and geologic names;

(7) logs of the injection wells if not already on file with the commission;

(8) a description of the proposed method for demonstrating mechanical integrity of the casing and tubing under 20 AAC 25.412 and for demonstrating that no fluids will move behind casing beyond the approved injection zone, and a description of

(A) the casing of the injection wells if the wells are existing; or

(B) the proposed casing program, if the injection wells are new;

(9) a statement of the type of fluid to be injected, the fluid's composition, the fluid's source, the estimated maximum

amounts to be injected daily, and the fluid's compatibility with the injection zone;

(10) the estimated average and maximum injection pressure;

(11) evidence to support a commission finding that each proposed injection well will not initiate or propagate fractures through the confining zones that might enable the injection fluid or formation fluid to enter freshwater strata;

(12) a standard laboratory water analysis, or the results of another method acceptable to the commission, to determine the quality of the water within the formation into which fluid injection is proposed;

(13) a reference to any applicable freshwater exemption issued under 20 AAC 25.440;

(14) the expected incremental increase in ultimate hydrocarbon recovery; and

(15) a report on the mechanical condition of each well that has penetrated the injection zone within a one-quarter mile radius of a proposed injection well.

(d) The commission will publish notice of the enhanced recovery application and provide the opportunity for a hearing in accordance with 20 AAC 25.540.

(e) The mechanical integrity of an injection well must be demonstrated under 20 AAC 25.412 before injection is begun and after a well workover affecting mechanical integrity is conducted. To confirm continued mechanical integrity, the operator shall monitor the injection pressure and rate and the pressure in the casing-tubing annulus during actual injection. The monitored data must be reported monthly on the Monthly Injection Report (Form 10-406).

(f) If an injection rate, operating pressure observation, or pressure test indicates pressure communication or leakage in any casing, tubing, or packer, the operator shall notify the commission by the next working day and shall implement corrective action or increased surveillance as the commission requires to ensure protection of freshwater.

(g) The commission will require additional mechanical integrity tests, if the commission considers them prudent for conservation purposes or protection of freshwater.

(h) The commission will, in its discretion, approve a modification to an existing or pending injection operation under 20 AAC 25.507, if the applicant proves to the commission, upon application containing sufficient detail for the commission to evaluate the proposed modification, that the modification will not allow the movement of fluids into sources of freshwater.

(i) If injection operations are not begun within 24 months after the date of the order authorizing enhanced recovery, that order expires unless a letter of application for extension is approved by the commission.

20 AAC 25.410. Injection wells.

Repealed 4/2/86.

20 AAC 25.412. Casing, cementing, and tubing of injection wells for enhanced recovery, disposal, and storage.

(a) A well used for injection must be cased and cemented in accordance with 20 AAC 25.030 to prevent leakage into oil, gas, or freshwater sources.

(b) A well used for injection must be equipped with tubing and a packer, or with other equipment that isolates pressure to the injection interval, unless the commission approves the operator's use of alternate means to ensure that injection of fluid is limited to the injection zone. The minimum burst pressure of the tubing must exceed the maximum surface injection pressure by at least 25 percent. The packer must be placed within 200 feet measured depth above the top of the perforations, unless the commission approves a different placement depth as the commission considers appropriate given the thickness and depth of the confining zone.

(c) Before injection begins, a well must be pressure-tested to demonstrate the mechanical integrity of the tubing and packer and of the casing immediately surrounding the injection tubing string. The casing must be tested at a surface pressure of 1,500 psig or at a surface pressure of 0.25 psi/ft multiplied by the true vertical depth of the casing shoe, whichever is greater, but the casing may not be subjected to a hoop stress that will exceed 70 percent of the minimum yield strength of the casing. The test pressure must show stabilizing pressure and may not decline more than 10 percent within 30 minutes.

(d) The operator shall provide a cement quality log or other well data approved by the commission to demonstrate isolation of the injected fluids to the approved interval.

(e) At least 24 hours notice of a pressure test required by (c) of this section must be given so that a representative of the commission can witness the test.

20 AAC 25.420. Notice of commencement and discontinuance of injection operations.

(a) At least 10 days before beginning an injection operation or program, the operator shall notify the commission of the intended injection date.

(b) Within 10 days after discontinuing an injection operation or program, the operator shall notify the commission of the date of discontinuance and the reasons for it.

20 AAC 25.430. Enhanced recovery records.

Each operator shall keep accurate records showing volumes of fluids produced, injected volumes, reservoir pressures, and injection pressures, by well and pool. Each operator shall retain these records for five years. The commission will, in its discretion, specify retention of these records for a longer time period. Upon reasonable notice, the commission must be given full access during normal business hours to all records.

20 AAC 25.432. Report of underground injection.

An operator that injects fluids into subsurface strata through a service well for any purpose, other than fracturing, acidizing, or other similar treatment, shall file with the commission

(1) monthly reports that show all injected volumes and other data, by well and pool, as required by the commission on the Monthly Injection Report (Form 10-406) and, if applicable, the Facility Report of Produced Gas Disposition (Form 10-422); and

(2) an annual report that shows annual and total cumulative volumes injected and produced and other data, for each pool or injection project area within the pool, as required by the commission on the Annual Report of Injection Projects (Form 10-413); the annual report must be submitted by April 1 unless pool rules established under 20 AAC 25.520 require the report to be included with a pool-specific annual surveillance report.

20 AAC 25.440. Freshwater aquifer exemption.

(a) Upon receipt of a letter of application, and in accordance with (b) of this section, the commission will, in its discretion, issue an order designating a freshwater aquifer or portion of it as an exempt freshwater aquifer, if the freshwater aquifer meets the following criteria:

(1) it does not currently serve as a source of drinking water, and it cannot now and will not in the future serve as a source of drinking water because

(A) it is hydrocarbon-producing or can be demonstrated by the applicant to contain hydrocarbons that, considering their quantity and location, are expected to be commercially producible;

(B) it is situated at a depth or location that makes recovery of water for drinking water purposes economically or technologically impractical; or

(C) it is so contaminated that recovery of water for drinking water purposes is economically or technologically impractical; or

(2) the total dissolved solids content of the ground water is more than 3,000 and less than 10,000 mg/l, and it is not reasonably expected to supply a public water system.

(b) To apply for exemption of a freshwater aquifer, an operator shall submit to the commission a letter of application that includes sufficient data to justify the proposal, including data to substantiate that the criteria in (a) of this section are met. The commission will provide 15 days legal notice and the opportunity for a public hearing on the matter in accordance with 20 AAC 25.540.

(c) Freshwater aquifers within the state that, as of June 19, 1986, are designated as exempt aquifers by the United States Environmental Protection Agency under 40 C.F.R. 147.102 are accepted as exempt aquifers by the commission.

(d) A commission order designating a freshwater aquifer or a portion of it as an exempt freshwater aquifer is not effective with respect to underground disposal or storage operations subject to 20 AAC 25.252 or injection operations subject to 20 AAC 25.402 until the United States Environmental Protection Agency has been provided the opportunity to review the order under 40 C.F.R. 144.7(b)(3) and has

(1) approved the order, if it was issued under (a)(1) of this section; or

(2) has allowed the applicable time period within which to disapprove the order to expire without acting on it, if the order was issued under (a)(2) of this section.

20 AAC 25.450. Underground injection control variances.

(a) If injection does not occur into, through, or above freshwater, the commission will, authorize requirements for a well or project that are less stringent than the requirements in this chapter for the radius of investigation established under 20 AAC 25.252(h) or 20 AAC 25.402(b), casing and cementing, the tubing and packer mechanical integrity, operation, monitoring, and reporting, to the extent that the commission determines that the reduction in requirements will not result in an increased risk of movement of fluids into freshwater.

(b) At the discretion of the commission, pilot projects for enhanced recovery using a technology not proved feasible under the conditions in which it is being tested may be operated with less stringent requirements for well construction, operation, monitoring, and reporting, if the project will not result in an increased risk of fluid movement into freshwater sources.

20 AAC 25.460. Area injection orders.

(a) Upon application under this section and subject to the provisions of 20 AAC 25.252 or 20 AAC 25.402, as applicable, the commission will, in its discretion, after notice and opportunity for public hearing in accordance with 20 AAC 25.540, issue an order permitting the underground injection of fluids on an area basis, rather than for each well individually, if the wells are

(1) described and identified by location in the application if they are existing wells, except that the commission will, in its discretion, accept a single description of wells with substantially the same characteristics;

(2) within the same field, facility site, reservoir, project, or similar area;

(3) operated by a single operator; and

(4) repealed 11/7/99.

(b) In the area injection order, the commission will specify

(1) the area and strata within which underground injections are authorized; and

(2) the requirements for drilling, completing, operating, monitoring, reporting, and abandoning all wells authorized by the order.

(c) In the area injection order, the commission will, in its discretion, authorize the operator to drill, complete, and operate, to convert, or to plug and abandon wells within the area if

(1) the operator files with the commission an application for a Permit to Drill (Form 10-401) or an Application for Sundry Approvals (Form 10-403), as appropriate, for commission approval before the operator starts work; and

(2) the cumulative effects of drilling and operating additional injection wells are considered by the commission during evaluation of the area injection order application and are acceptable to the commission.

(d) If the commission determines that a well drilled and operated under an area injection order does not satisfy all of the requirements of this section or an order issued under this section, the commission will take enforcement action to ensure compliance.

Article 6
General Provisions

20 AAC 25.505. Scope of regulations.

(a) This chapter generally consists of statewide regulations which apply to all wells, pools, fields, and oil and gas properties, unless the commission, in its discretion, issues an order in conformance with 20 AAC 25.540.

(b) An order issued in conformance with 20 AAC 25.540 prevails over this chapter except for those regulations which govern underground injection and the protection of freshwater.

20 AAC 25.507. Change of an approved program.

(a) Except as otherwise provided by 20 AAC 25.015, if an operator desires to make a substantive change in a program or

activity for which commission approval is required and has been obtained under AS 31.05 or this chapter, complete details of the well's current condition and the proposed change must be submitted to the commission with an Application for Sundry Approvals (Form 10-403). A change to an approved program or activity may not be undertaken without commission approval. The commission will condition its approval as the commission considers necessary or appropriate to ensure compliance with the standards on which the original approval was based.
(b) If operational necessity requires prompt action, oral approval of a change may be obtained from the commission. The required Application for Sundry Approvals must be submitted within three days for final approval by the commission. That application must set out the name of the person who provided approval and the date of the oral approval.

20 AAC 25.510. Commission seal.
(a) Repealed 11/7/99.
(b) Repealed 11/7/99.
(c) The official seal of the commission is reproduced below.
Click to view SEAL

20 AAC 25.515. United States government land.
A person, including a federal agency, drilling for or producing oil or gas or conducting underground injection activities related to the recovery and production of oil or gas on federal land subject to the state's police powers shall comply with all applicable regulations and orders of the commission.

20 AAC 25.517. Plan of reservoir development and operation.
(a) Before commencement of regular production from an oil or gas pool, the operator shall submit to the commission a plan of reservoir development and operation for the pool or the portion of the pool for which development is contemplated by the operator.
(b) Unless otherwise ordered by the commission, the operator shall submit to the commission annual progress reports under the plan of reservoir development and operation. Any amendments and updates to the plan also must be submitted at least annually.
(c) The plan of reservoir development and operation must provide for
(1) the prevention of waste;
(2) the protection of correlative rights; and
(3) a greater ultimate recovery of oil and gas.

20 AAC 25.518. Agreements integrating interests.
A voluntary agreement for the purpose of integrating interests under AS 31.05.110(a) must be filed with the commission no later than 30 days after that agreement is executed.

20 AAC 25.520. Field and pool regulation and classification.
(a) Upon the motion of the commission, or the request of an affected owner or operator at any time after the discovery of oil or gas in a field or pool, the commission will hold a hearing in accordance with 20 AAC 25.540, and the commission will issue an order, based upon the evidence presented, classifying the pool as an oil or gas pool in a field and prescribing rules to govern the proposed development and operation of the pool. In the pool order, the commission will establish requirements
(1) that the commission considers necessary to prevent waste, protect freshwater, protect correlative rights, and ensure a greater ultimate recovery of oil and gas; and
(2) based on the operating and technical data presented.
(b) The commission will, in its discretion, amend pool orders in accordance with the procedures set forth in 20 AAC 25.540.

20 AAC 25.525. Forms upon request.
Repealed 4/2/86.

20 AAC 25.526. Conduct of operations.
An operator shall carry on all operations and maintain the property at all times in a safe and skillful manner in accordance with good oil field engineering practices and having due regard for the preservation and conservation of the property and protection of freshwater.

20 AAC 25.527. General well control requirements for drilling, completion, workover, and service operations.
(a) This section applies to all well drilling, completion, workover, and service operations. The requirements of this section are in addition to the applicable requirements of 20 AAC 25.033 - 20 AAC 25.036 and 20 AAC 25.285 - 20 AAC 25.288.
(b) Equipment must be in good operating condition at all times and must be protected to ensure reliable operation under the range of weather conditions that may be encountered at the well site.
(c) Well control equipment and fluids must be installed, used, maintained, and tested in a manner that ensures well control and, except as otherwise provided in this chapter, that conforms with the applicable provisions of the following documents, which are adopted by reference:
(1) API RP 5C7, Recommended Practice for Coiled Tubing Operations in Oil and Gas Well Services, 1st edition, December 1996;
(2) API RP 13B-1, Recommended Practice Standard Procedure for Field Testing Water-Based Drilling Fluids, 2d edition, September 1997;
(3) API RP 13B-2, Recommended Practice Standard Procedure for Field Testing Oil-Based Drilling Fluids, 3d edition, February 1998;
(4) API RP 49, Recommended Practices for Safe Drilling of Wells Containing Hydrogen Sulfide, 2d edition, April 15, 1987;
(5) API RP 53, Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells, 3d edition, March 1997;

(6) API RP 57, Recommended Practices for Offshore Well Completion, Servicing, Workover, and Plug and Abandonment Operations, 1st edition, January 15, 1986;

(7) API RP 64, Recommended Practices for Diverter Systems Equipment and Operations, 1st edition, July 1, 1991;

(8) API RP 68, Recommended Practice for Oil and Gas Well Servicing and Workover Operations Involving Hydrogen Sulfide, 1st edition, January 1998.

(d) A toolpusher, driller or functional equivalent, or person-in-charge who participates in drilling operations or in workover operations involving the installation or removal of jointed tubulars must have received formal well control training sufficient to ensure the competent performance of the person's well control duties. The commission will recognize training and certification in a drilling well control curriculum by any of the following entities as meeting the requirements of this subsection:

(1) United States Department of the Interior, Minerals Management Service;

(2) International Association of Drilling Contractors;

(3) International Well Control Forum;

(4) International Alliance for Well Control.

(e) The persons-in-charge on a drill rig floor must have the authority and responsibility to shut in the well if it starts to flow.

(f) The operator shall keep records and reports of well drilling, workover, and repair operations, including BOPE test results, in accordance with 20 AAC 25.070(1) or, in the case of wireline work or other service operations, in the daily work log, which must be made available to the commission upon request.

20 AAC 25.528. Open pit storage of oil.

Repealed.

20 AAC 25.530. Cooperative agreements with other parties.

The commission will, in its discretion, from time to time enter into agreements with state and federal agencies, industry committees, or individuals, with respect to special projects, services, and studies relating to underground fluid injection and the conservation of oil and gas. If an agreement requires the commission to use procedures not covered in this chapter, the procedures necessary to carry out the intent of the agreement will be formulated and made available at the office of the commission after public notice and opportunity for public comment, in accordance with 20 AAC 25.540.

20 AAC 25.534. Tests, surveys, and inspections.

(a) As the commission considers necessary or advisable to carry out the purposes of AS 31.05 (Alaska Oil and Gas Conservation Act) and this chapter, the commission will require that tests or surveys be made to determine the

(1) quality of oil and gas produced;

(2) formation, casing, tubing, or other pressures;

(3) existence of any waste of oil, gas, or reservoir energy; or

(4) risk of fluid movement into freshwater.

(b) The commission will, in its discretion, exercise its statutory power to enter and conduct on-site investigations and inspections at reasonable times of facilities, equipment, practices, records, or operations for the purpose of ensuring compliance with the requirements of this chapter.

(c) For locations that are remote from the nearest commission office, the operator is responsible for transporting the commission inspector to and from the locations. In this section, unless the context requires otherwise, "remote" means the location cannot be accessed by a commission vehicle.

20 AAC 25.535. Enforcement.

(a) If the commission, as the result of an investigation or otherwise, considers that a person may have violated or failed to comply with a provision of AS 31.05, this chapter, or a commission order, permit, or other approval, the commission will, in its discretion, take enforcement action under this section against the person.

(b) If the commission proposes to take enforcement action under this section against a person, the commission will send the person a written notification by personal service or by certified mail, return receipt requested. The commission's written notification to the person will

(1) state the nature of the apparent violation or noncompliance;

(2) summarize the reasons why the commission considers a violation or noncompliance to have occurred;

(3) state the action that the commission proposes to take under (e) of this section; and

(4) inform the person of the person's rights and liabilities under (c) - (e) of this section.

(c) Within 15 days after receipt of a notification under (b) of this section, a person may file with the commission a written response that concurs in whole or in part with a proposed commission action, requests informal review, or requests a hearing under 20 AAC 25.540. The commission will, in its discretion, extend the 15-day response period for good cause shown. If a person fails to file a timely written response, the commission will consider the person to have accepted the proposed commission action by default. If a person requests a hearing, the commission will schedule a hearing under 20 AAC 25.540.

(d) If a person requests informal review under (c) of this section, the commission will provide an opportunity for the person to submit documentary material and make a written or oral statement. The commission will then issue a proposed decision or order. A proposed decision or order becomes final 11 days after it is issued unless within 10 days after it is issued the person files a written request for a hearing, in which case the proposed decision or order is of no effect. If the person requests a hearing, the commission will schedule a hearing under 20 AAC 25.540.

(e) If a person concurs in a proposed action under (c) of this section, or after an informal review or a hearing under (c) or (d) of this section, and if the commission finds that a person has violated or failed to comply with a provision of AS 31.05, this chapter, or a commission order, permit, or other approval, the commission will, in its discretion, order one or more of the following, as it determines to be applicable:

(1) corrective action or remedial work;

(2) revocation or suspension of a permit or other approval;

(3) payment under the bond required by 20 AAC 25.025;

(4) imposition of penalties under AS 31.05.150.

(f) The commission's action under (e) of this section after an informal review or a hearing is not limited to what the commission proposed under (b)(3) of this section, if the person has reasonable notice and opportunity to be heard as to the commission's action.

(g) An action by the commission under this section is in addition to any action the commission may take under AS 31.05.160.

(h) If an apparent violation or noncompliance described in a notification under (b)(1) of this section relates to the underground disposal of oil field wastes or the underground storage of liquid hydrocarbons requiring commission authorization under 20 AAC 25.252 or relates to the injection of fluids requiring commission authorization under 20 AAC 25.402 or 20 AAC 25.460, a person with an interest that is or may be adversely affected may intervene in proceedings under this section.

20 AAC 25.536. Geologic data and logs.

Repealed 4/2/86.

20 AAC 25.537. Public and confidential information.

(a) The commission will routinely make available to the public, by means of records or reports, in its offices or elsewhere, or by means of regular publication, the following information:

(1) surface and proposed bottom-hole locations of each well after approval of the Permit to Drill (Form 10-401);

(2) total depth, bottom-hole location and well status after the Well Completion or Recompletion Report and Log (Form 10-407) is filed;

(3) all reports and information required by this chapter for development and service wells;

(4) regular production data and regular production reports, as required to be filed by the operator each month;

(5) injection data and injection reports, as required to be filed by the operator each month; and

(6) all data filed on a well as required by this chapter upon expiration of the confidential period described in (d) of this section.

(b) Engineering, geologic, geophysical, and other commercial information not required by this chapter, but voluntarily filed with the commission will be kept confidential if the person filing the information so requests. This subsection does not apply to information submitted in a public hearing under 20 AAC 25.540.

(c) In this section, "well status" means the classification of a well as oil, gas, service, suspended, shut-in, or abandoned.

(d) Except as provided by (a) of this section, the reports and information required by this chapter to be filed by the operator for exploratory and stratigraphic test wells will be kept confidential by the commission for 24 months following the 30-day filing period after well completion, suspension, or abandonment unless the operator gives written and unrestricted permission to release all of the reports and information at an earlier date. Upon notification that the commissioner of the Department of Natural Resources has made a finding that the required reports and information from a well contain significant information relating to the valuation of unleased land in the same vicinity, the commission will hold the reports and information confidential beyond the 24-month period and until notified by the commissioner of the Department of Natural Resources to release the reports and information.

(e) Notwithstanding (b) or (d) of this section, any information obtained or used by the commission in the administration of its program under 42 U.S.C. 300h-4 (Safe Drinking Water Act of 1974, as amended, 42 U.S.C. 300f - 300j)

(1) will be made available to the public unless the material has been claimed confidential and has been determined by the commission to be entitled to confidential treatment; claims of confidentiality will be denied for the following:

(A) the name and address of any applicant for underground injection of fluids, and

(B) information that deals with the existence, absence, or level of contaminants in freshwater;

(2) will be made available to the United States Environmental Protection Agency upon request; if the information has been submitted to the commission under claim of confidentiality, the commission will submit that claim to the United States Environmental Protection Agency when providing the information.

20 AAC 25.538. Naming of fields and pools.

Repealed 4/2/86.

20 AAC 25.539. Emergency action.

(a) The commission will, in its discretion, issue a temporary emergency order without a hearing if necessary to protect against immediate harm to public health or safety. Before issuing a temporary emergency order, the commission will attempt to communicate with the operator about the circumstances and need for a temporary order.

(b) In support of a temporary emergency order, the commission will issue a written decision describing the factual and legal basis for the action, including the necessity for acting on an emergency basis. The commission will provide the decision to the operator within 24 hours of the issuance of the order.

(c) A temporary emergency order expires after 14 days unless

(1) an earlier expiration date is established in that order;

(2) the operator agrees to an extension; or

(3) within that time period the commission begins a hearing under (d) of this section, in which case that order remains in effect for an additional period not to exceed the shorter of 14 days after the date the hearing begins or three working days after the date the hearing ends; the commission will extend that period if necessary to protect against immediate harm to public health or safety.

(d) The commission will, in its discretion, make the temporary emergency order permanent or modify or extend that order after a public hearing. If the temporary emergency order constitutes an enforcement action under 20 AAC 25.535(e)(1) or (2), the procedures under 20 AAC 25.535(b)(4), (c), and (d) do not apply to a commission action under this subsection unless the operator agrees to an extension sufficient to implement those procedures. If the operator does not agree to an extension, the commission's written decision under (b) of this section satisfies the requirements of 20 AAC 25.535(a) and (b)(1) - (3). The provisions of 20 AAC 25.540 apply to a public hearing under this subsection, except that

(1) the commission will provide notice of that hearing at least 10 days before the date of that hearing; and

(2) the requirement in 20 AAC 25.540 that a person request a public hearing does not apply.

20 AAC 25.540. Hearings.

(a) On its own motion or if a written request is received to issue an order affecting a single well or a single field, the commission will publish notice in an appropriate newspaper as provided in AS 31.05.050(b). In the notice, the commission will set out the essential details of the requested order, provide an opportunity for public comment, tentatively specify the place, time, and date for a public hearing, and provide a telephone number that the public may use to learn if the commission will hold the tentative hearing. The commission will tentatively set a hearing date that is at least 30 days after the date of publication of the notice. A person may submit a written protest or written comments during that 30-day period. In addition, a person may request that the tentatively scheduled hearing be held by filing a written request with the commission within 15 days after the publication date of the notice. If the commission receives a timely request for hearing, or if the commission desires to hold a hearing, the commission will hold a hearing on the date and time specified in the notice. If a request for hearing is not timely filed, the commission will, in its discretion, issue an order without a hearing.

(b) On its own motion or if a written request for a public hearing is received concerning a matter within the jurisdiction of the commission under this chapter, the commission will publish notice in an appropriate newspaper as provided in AS 31.05.050(b). In the notice, the commission will provide the essential details of the matter and set out the place for the public hearing, the date, and the time for the public hearing. The commission will set a hearing date that is at least 30 days after the date of publication.

(c) Except as otherwise provided in (e) of this section, the following procedures apply to public hearings conducted under (a) or (b) of this section:

(1) the hearing will be called to order and the subject of the hearing, along with the date and place of public notice given for the hearing, will be read into the record;

(2) the commission will receive both sworn testimony and unsworn statements; it will give greater weight in its deliberations to sworn testimony;

(3) all persons wishing to testify will be sworn;

(4) each witness shall state the witness's name and whom the witness represents;

(5) each witness who wishes to give expert testimony shall state the witness's qualifications, and the commission will rule on whether the witness qualifies as an expert;

(6) the applicant will be asked to present testimony first; all others wishing to present testimony will be heard next; upon request, the commission will, in its discretion, allow cross-examination of witnesses;

(7) a person wishing to make an oral statement will be allowed to do so after the conclusion of all testimony;

(8) the commission will, in its discretion, ask questions of a witness;

(9) except as may be allowed under (6) of this subsection, a person may not ask questions of witnesses directly; to have a question directed to a witness, a person must provide the question in writing, along with the person's name and that of the witness, to a designated commission representative; before the end of the hearing, the commission will review these questions and ask those that it believes will be helpful in eliciting needed information; all questions will be included in the public record;

(10) if disclosure of otherwise confidential information is required, the commission will limit and condition disclosure to the extent necessary to comport with applicable constitutional, statutory, and common law doctrines that protect trade secrets within the meaning of AS 45.50.940 and other commercially sensitive, confidential, and proprietary information; in limiting or conditioning disclosure under this paragraph, the commission will, as necessary

(A) review confidential information in-camera; and

(B) redact commission decisions to protect confidential information;

(11) the hearing will be recorded and the recording included in the public record of the hearing;

(12) the commission will, in its discretion, allow pre-filed written testimony in place of or in addition to oral testimony.

(d) The commission will hold hearings on matters of statewide or general application under the applicable provisions of AS 44.62.

(e) In a hearing under 20 AAC 25.535, a party may be represented by counsel, call and examine witnesses, present relevant evidence unless unduly cumulative or repetitious, cross-examine witnesses, impeach witnesses, and rebut adverse evidence. The commission will base its decision with respect to contested issues of fact only on evidence presented during the hearing. The commission will establish a reasonable date before the hearing by which the commission will and each party must provide

(1) the names and addresses of persons known to have knowledge of relevant facts and, unless privileged,

(A) written or recorded statements by those persons; or

(B) summaries of statements by those persons;

(2) the name, address, and qualifications of each expert who will testify at the hearing, and a written description of the substance of the expert's proposed testimony, the expert's opinion, and the underlying basis of that opinion; and

(3) a copy of all documents and a description of all other tangible things intended to be used in the hearing.

(f) By means of a pre-hearing conference or otherwise, the commission will, in its discretion, establish additional procedures for a specific hearing consistent with the procedures in (c) or (e) of this section, as applicable, or as otherwise necessary to provide due process to a party.

20 AAC 25.545. Public mailing lists.

Public mailing lists will be maintained by the commission for the purpose of sending appropriate notices, orders, and publications to persons who request to be put on these lists.

20 AAC 25.550. Oaths.

Each member of the commission has the power to administer oaths to witnesses in any hearing, investigation, or proceeding conducted under AS 31.05 and this chapter.

20 AAC 25.555. Orders.

Repealed 4/2/86.

20 AAC 25.556. Orders.

(a) Orders of the commission require approval of at least two commissioners.

(b) Unless otherwise indicated in the order, each conservation order issued by the commission expires two years after activities authorized in that order cease.

(c) Unless otherwise indicated in the order, each enhanced recovery, area, storage, and disposal injection order issued by the commission expires

(1) two years after the date the order was adopted, if the operator has not commenced the injection operations authorized in the order; or

(2) two years after injection operations authorized in that order conclude.

(d) Upon proper application, or its own motion, and unless notice and public hearing are otherwise required, the commission may administratively waive or amend the requirements of any order issued by the commission if the change does not promote waste or jeopardize correlative rights, is based on sound engineering and geoscience principles, and will not result in an increased risk of fluid movement into freshwater aquifers.

20 AAC 25.557. Subpoenas.

(a) The commission will, in its discretion, issue subpoenas.

(b) Upon a written request, the commission will, in the commission's discretion, issue a subpoena for the production of books, records, papers, or other documents of any sort. The applicant must establish a proper relation to the matter, and must show the relevance of the evidence sought and the facts expected to be proved by that evidence.

(c) Upon a written request, the commission will, in the commission's discretion, issue a subpoena requiring the attendance of a witness for the purpose of taking oral testimony before the commission. The applicant must establish a proper relation to the matter and give the name and address of the desired witness.

20 AAC 25.560. Time.

If AS 31.05 or this chapter requires or permits a person to file or submit a document with the commission, the document is considered filed or submitted when it is received in the commission's office.

20 AAC 25.565. Plans submitted under AS 31.05.030(i).

(a) A written plan submitted under AS 31.05.030(i) must include an original and three copies of the following material:

(1) the identification of the lessee submitting the plan;

(2) the identification of the field covered by the plan;

(3) a general timetable and description of planned development activities;

(4) a general timetable and description of expected hiring and contracting decisions in connection with the development of the field;

(5) a detailed description of the best efforts that the lessee voluntarily agrees to use to employ residents of the state, consistent with law, and to contract with firms in the state for work in connection with the development of the field, including the fabrication and installation of required facilities, whenever feasible;

(6) the date the plan is submitted; and

(7) the lessee's certification of its voluntary agreement to use its best efforts as set out in the plan, including the name, title, and signature of the individual executing the certification on behalf of the lessee, which person must be authorized to bind the lessee.

(b) Upon receipt of a plan meeting the requirements of (a) of this section, the commission will promptly schedule a public hearing on the plan and give public notice of the hearing in accordance with AS 31.05.050(b). The hearing will be scheduled at least 10 days after the date of the public notice. The provisions of 20 AAC 25.540 do not apply to a hearing held under this section.

(c) In AS 31.05.030(i) and this section,

(1) "development" means all steps taken in the search for and the exploration, capture, and production of oil or gas;

(2) "firm in the state" means a firm or contractor that

(A) has held an Alaska business license for the preceding six months;

(B) maintains, and has maintained for the preceding six months, a place of business in the state that competently and professionally deals in supplies, services, or construction of the nature required for work in connection with development of an oil or gas field; and

(C) is

(i) a sole proprietorship and the proprietor is an Alaska resident;

(ii) a partnership and more than 50 percent of the partnership interest is held by Alaska residents;

(iii) a limited liability company and more than 50 percent of the membership interest is held by Alaska residents;

(iv) a corporation that has been incorporated in the state or is authorized to do business in the state; or

(v) a joint venture and a majority of the venturers qualify as firms in the state under this paragraph.

20 AAC 25.570. Definitions.

Repealed.

20 AAC 25.605. Calculation of regulatory cost charges.

(a) The formula for determining a person's regulatory cost charge under AS 31.05.093 is

RCC =VOP/VTOT*(A-L)

where

RCC = the regulatory cost charge;

VOP = the total volume of oil and gas produced from, and oil, gas, water, and other fluids injected into, during the most recently concluded calendar year, wells for which a Permit to Drill has been issued under AS 31.05.090, of which the person is the operator on the first day of the fiscal year, and that have not before that day been plugged and abandoned and reported as abandoned in accordance with this chapter;

VTOT = the total volume of oil and gas produced from, and oil, gas, water, and other fluids injected into, during the most recently concluded calendar year, all wells for which a Permit to Drill has been issued under AS 31.05.090 and that have

not before the first day of the fiscal year been plugged and abandoned and reported as abandoned in accordance with this chapter;
A = the appropriation, other than from federal receipts, made for the operating costs of the commission for the fiscal year;
L = the lapsed amount of a previous appropriation that is appropriated for the fiscal year under AS 31.05.093(d).
(b) For purposes of calculating regulatory cost charges, volumes of fluids produced from or injected into wells consist of the applicable volumes reported to the commission under 20 AAC 25.230(b) and 20 AAC 25.432, except that

(1) if an operator has failed to report a volume as required, if two or more reported volumes are inconsistent, or if the commission determines that a reported volume is otherwise unreliable, the commission will, in its discretion, calculate or estimate volumes as it considers appropriate;

(2) the commission will, in its discretion, add the volume of a substantial spill or other release of oil or gas that is not included in a report under 20 AAC 25.230(b) or 20 AAC 25.432.

(c) For purposes of AS 31.05.093(a) and this chapter, a well is considered plugged and abandoned and reported as abandoned in accordance with this chapter if the well has been abandoned in accordance with 20 AAC 25.105 and 20 AAC 25.112 and a complete well record for the well, including a description of plugging operations, on a Well Completion or Recompletion Report and Log (Form 10-407) as required by 20 AAC 25.070(3) has been filed with the commission after abandonment.

20 AAC 25.610. Estimated regulatory cost charges.

(a) Before determining regulatory cost charges for a fiscal year under 20 AAC 25.615, the commission will, in its discretion, establish estimated regulatory cost charges to be paid during the first quarter of the fiscal year. The amount of an estimated regulatory cost charge is one-fourth of the commission's reasonable estimate, based on information then available, of what the person's regulatory cost charge will be for that fiscal year.
(b) The commission will provide a person subject to an estimated regulatory cost charge with written notice of the amount of the charge and the payment date. The commission will set a payment date to be at least 20 days after the date of the notice. The person shall pay the estimated regulatory cost charge by the payment date.

20 AAC 25.615. Commission's determination of regulatory cost charges.

(a) After the later of the beginning of a fiscal year or the date of enactment of an appropriation for the operating costs of the commission for that fiscal year, the commission will provide to persons subject to a regulatory cost charge under AS 31.05.093 written notice of the proposed regulatory cost charges to be imposed on persons subject to regulatory cost charges for that fiscal year and the basis for the charges, in accordance with 20 AAC 25.605.
(b) Within 30 days after notice is issued under (a) of this section, a person subject to a regulatory cost charge may submit comments on, or request a revision to, the regulatory cost charges proposed by the commission. A request for a revision must be accompanied by an explanation of the basis for the requested revision. Before a hearing is held under (c) of this section, the commission will provide all persons subject to a regulatory cost charge with copies of comments and requests for revision received by the commission or with notice of the persons' right to inspect those comments and requests for revision.
(c) Within 60 days after notice is issued under (a) of this section, the commission will hold a public hearing in accordance with 20 AAC 25.540 on the proposed regulatory cost charges.
(d) Within 90 days after notice is issued under (a) of this section, the commission will issue an order determining the regulatory cost charges to be paid and the dates by which the charges must be paid. The commission will provide written notice to each person subject to a regulatory cost charge of the person's regulatory cost charge and payment dates.
(e) The commission will not determine or adjust previously determined regulatory cost charges based on fluid volume reports that are filed or amended, or on other fluid volume corrections that are made, after the deadline under (b) of this section for responding to the commission's notice of proposed regulatory cost charges, except if the commission finds that

(1) a person has grossly under-reported the person's VOP, as defined in 20 AAC 25.605(a);

(2) under-reporting as described in (1) of this subsection has caused or will cause others' regulatory cost charges to be materially excessive; and

(3) correcting the excessive regulatory cost charges is in the public interest.

20 AAC 25.620. Payment dates for regulatory cost charges.

(a) If the commission orders payment of estimated regulatory cost charges under 20 AAC 25.610, the commission will establish payment dates for regulatory cost charges during the second, third, and fourth quarters of the fiscal year. No later than each payment date, a person subject to a regulatory cost charge shall pay one-third of the difference between the person's regulatory cost charge and any estimated regulatory cost charge previously paid for the fiscal year, except that a regulatory cost charge may be prepaid, in part or in whole, at any time.
(b) If the commission does not order payment of estimated regulatory cost charges under 20 AAC 25.610, the commission will establish payment dates for regulatory cost charges during each quarter or each third of the fiscal year. No later than each payment date, a person subject to a regulatory cost charge shall pay one-fourth, if four payment dates are established, or one-third, if three payment dates are established, of the person's regulatory cost charge, except that a regulatory cost charge may be prepaid, in part or in whole, at any time.
(c) The commission will set the first payment date in a fiscal year to be at least 20 days after the date the commission provides notice under 20 AAC 25.615(d).

20 AAC 25.625. Supplemental appropriations.

In the case of regulatory cost charges based on a supplemental appropriation for a fiscal year,

(1) the commission will determine regulatory cost charges using the commission's determinations of fluid volumes and well operatorship previously made in connection with the regular appropriation for the fiscal year;

(2) in applying the formula set out in 20 AAC 25.605(a), the commission will set the variables "F" and "L" equal to zero;

(3) the commission will use the procedures set out in 20 AAC 25.615, except that the period

(A) for submitting comments or requesting a revision under 20 AAC 25.615(b) is 10 days instead of 30 days;

(B) within which a public hearing will be held under 20 AAC 25.615(c) is 20 days instead of 60 days; the commission will provide notice of that hearing at least 10 days before the date of that hearing; the 30-day notice requirement under 20 AAC 25.540 does not apply to a hearing held under this paragraph; and

(C) within which the commission will issue an order determining regulatory cost charges under 20 AAC 25.615(d) is 30 days instead of 90 days;

(4) 20 AAC 25.620 does not apply; and

(5) the commission will set the payment date for regulatory cost charges to be at least 10 days after the date the commission provides notice under 20 AAC 25.615(d).

20 AAC 25.630. Violations.

In addition to any other available remedy for nonpayment, a person's failure timely to pay a regulatory cost charge or estimated regulatory cost charge of which the person has been provided written notice by the commission subjects the person to enforcement action under 20 AAC 25.535.

Article 7
Geothermal Resources

20 AAC 25.705. Authority of commission.

All wells drilled in search of or in support of the recovery or production of geothermal resources must comply with the regulations contained in 20 AAC 25.705 - 20 AAC 25.740.

20 AAC 25.710. Applicability of regulations.

Unless otherwise specified in 20 AAC 25.705 - 20 AAC 25.740, the regulations in this chapter apply to wells drilled in search of or in support of the recovery or production of geothermal resources.

20 AAC 25.715. Variances.

Upon request of the operator for an action under 20 AAC 25.705 - 20 AAC 25.740 that has application to a single well or geothermal system, the commission may approve a variance from the commission's regulations, if

(1) the approval provides at least an equally effective means of accomplishing the requirement set out in the commission's regulation; or

(2) the commission determines that the request is more appropriate to the proposed operation than compliance with requirements of the regulation.

20 AAC 25.720. Calculation of regulatory cost charges for geothermal wells.

(a) The formula for determining a person's regulatory cost charge under AS 41.06.055 is

RCCg = Vgop/Vgtot *(Ag - Lg)

where

RCCg = the regulatory cost charge for geothermal wells;

Vgop = the total volume of geothermal resources produced from, and all fluids and substances injected into, during the most recently concluded calendar year, wells for which a Permit to Drill has been issued under AS 41.06.050, of which the person is the operator on the first day of the fiscal year, and that have not before that day been plugged and abandoned and reported as abandoned in accordance with this chapter;

Vgtot = the total volume of geothermal resources produced from, and all fluids and substances injected into, during the most recently concluded calendar year, all wells for which a Permit to Drill has been issued under AS 41.06.050 and that have not before the first day of the fiscal year been plugged and abandoned and reported as abandoned in accordance with this chapter;

Ag = the appropriation, other than from federal receipts, made for the operating costs related to activities under AS 41.06 of the commission for the fiscal year;

Lg = the lapsed amount of a previous appropriation that is appropriated for the fiscal year under AS 41.06.055(d).

(b) For purposes of calculating regulatory cost charges, volumes of geothermal resources produced from or injected into wells consist of the applicable volumes reported to the commission under 20 AAC 25.230(b) and 20 AAC 25.432, except that

(1) if an operator has failed to report a volume as required, if two or more reported volumes are inconsistent, or if the commission determines that a reported volume is otherwise unreliable, the commission may calculate or estimate volumes as it considers appropriate;

(2) the commission may add the volume of a substantial spill or other release of geothermal resources that is not included in a report under 20 AAC 25.230(b) or 20 AAC 25.432.

(c) For purposes of determining volumes under AS 41.06.055 and 20 AAC 25.705 - 20 AAC 25.740, 9,000 cubic feet of gaseous geothermal resources has a volume that is the equivalent of one barrel of liquid geothermal resources.

(d) For purposes of AS 41.06.055(a) and 20 AAC 25.705 - 20 AAC 25.740, a well is considered plugged and abandoned and reported as abandoned in accordance with this chapter if the well has been abandoned in accordance with 20 AAC 25.105 and 20 AAC 25.112 and a complete well record for the well, including a description of plugging operations, on a Well Completion or Recompletion Report and Log (Form 10-407) as required by 20 AAC 25.070(3) has been filed with the commission after abandonment.

20 AAC 25.725. Estimated regulatory cost charges for geothermal wells.

(a) Before determining regulatory cost charges for a fiscal year under 20 AAC 25.730 the commission may establish estimated regulatory cost charges for geothermal wells to be paid during the first quarter of the fiscal year. The amount of an estimated regulatory cost charge for geothermal wells is one-fourth of the commission's reasonable estimate, based on information then available, of what the person's total regulatory cost charge for geothermal wells will be for that fiscal year.

(b) The commission will provide a person subject to an estimated regulatory cost charge for geothermal wells with written notice of the amount of the charge and the payment date. The commission will set a payment date to be at least 20 days after the date of the notice. The person shall pay the estimated regulatory cost charges for geothermal wells by the payment date.

20 AAC 25.730. Commission's determination of regulatory cost charges for geothermal wells.

(a) After the later of the beginning of a fiscal year or the date of enactment of an appropriation for the operating costs of the commission for that fiscal year, the commission will provide to persons subject to a regulatory cost charge under AS 41.06.055 written notice of the proposed regulatory cost charges for geothermal wells to be imposed on persons subject to regulatory cost charges for geothermal wells for that fiscal year and the basis for the charges, in accordance with 20 AAC 25.720.

(b) No later than 30 days after notice is issued under (a) of this section, a person subject to a regulatory cost charge for geothermal wells may submit comments on, or request a revision to, the regulatory cost charges imposed for geothermal wells by the commission. A request for a revision must be accompanied by an explanation of the basis for the requested revision, and evidence in support of the request. Before a hearing is held under (c) of this section, the commission will provide all persons subject to a regulatory cost charge for geothermal wells with copies of comments and requests for revision received by the commission or with notice of the persons' right to inspect those comments and requests for revision.

(c) No later than 60 days after notice is issued under (a) of this section, the commission will hold a public hearing in accordance with 20 AAC 25.540 on the proposed regulatory cost charges for geothermal wells.

(d) No later than 90 days after notice is issued under (a) of this section, the commission will issue an order determining the regulatory cost charges for geothermal wells to be paid and the dates by which the charges must be paid. The commission will provide written notice to each person subject to a regulatory cost charge for geothermal wells of the person's regulatory cost charge for geothermal wells and payment dates.

(e) The commission will not determine or adjust previously determined regulatory cost charges for geothermal wells based on fluid volume reports that are filed or amended, or on other fluid volume corrections that are made, after the deadline under (b) of this section for responding to the commission's notice of proposed regulatory cost charges for geothermal wells, except if the commission finds that

(1) a person has grossly under-reported the person's Vgop, as defined in 20 AAC 25.720(a);

(2) under-reporting as described in (1) of this subsection caused or will cause others' regulatory cost charges for geothermal wells to be materially excessive; and

(3) correcting the excessive regulatory cost charges for geothermal wells is in the public interest.

20 AAC 25.735. Payment dates for regulatory cost charges for geothermal wells.

(a) If the commission orders payment of estimated regulatory cost charges under 20 AAC 25.725, the commission will establish payment dates for regulatory cost charges during the second, third, and fourth quarters of the fiscal year. No later than each payment date, a person subject to a regulatory cost charge under 20 AAC 25.725 shall pay one-third of the difference between the person's regulatory cost charge for geothermal wells and any estimated regulatory cost charge previously paid for the fiscal year, except that a regulatory cost charge for geothermal wells may be prepaid, in part or in whole, at any time.

(b) If the commission does not order payment of estimated regulatory cost charges under 20 AAC 25.725, the commission will establish payment dates for regulatory cost charges during each quarter or each third of the fiscal year. No later than each payment date, a person subject to a regulatory cost charge under 20 AAC 25.750 shall pay one-fourth, if four payment dates are established, or one-third, if three payment dates are established, of the person's regulatory cost charge, except that a regulatory cost charge for geothermal wells may be prepaid, in part or in whole, at any time.

(c) The commission will set the first payment date in a fiscal year to be at least 20 days after the date the commission provides notice under 20 AAC 25.730(d).

20 AAC 25.740. Supplemental appropriations.

For regulatory cost charges for geothermal wells on a supplemental appropriation for a fiscal year,

(1) the commission will determine regulatory cost charges using the commission's determinations of geothermal resources and well operatorship previously made in connection with the regular appropriation for the fiscal year;

(2) in applying the formula set out in 20 AAC 25.720(a), the commission will set the variable "Lg" equal to zero;

(3) the commission will use the procedures set out in 20 AAC 25.730, except that the period

(A) for submitting comments or requesting a revision under 20 AAC 25.730(b) is 10 days instead of 30 days;

(B) within which a public hearing will be held under 20 AAC 25.730(c) is 20 days instead of 60 days; the commission will provide notice of that hearing at least 10 days before the date of that hearing; the 30-day notice requirement under 20 AAC 25.540 does not apply to a hearing held under this paragraph; and

(C) within which the commission will issue an order determining regulatory cost charges under 20 AAC 25.730(d) is 30 days instead of 90 days;

(4) 20 AAC 25.735 does not apply; and

(5) the commission will set the payment date for regulatory cost charges to be at least 10 days after the date the commission provides notice under 20 AAC 25.730(d).

Article 8
Definitions

20 AAC 25.990. Definitions.

In this chapter, unless the context requires otherwise,

(1) "abandon" means to plug a well in accordance with 20 AAC 25.112 and without the commission's approval of well suspension under 20 AAC 25.110;

(2) "abnormally geo-pressured strata" means subsurface zones where the pore pressure exceeds a gradient of 0.50 psi/ft;

(3) "API" means the American Petroleum Institute;

(4) "API 5K" means an API-defined BOP configuration with a rated working pressure of 5,000 psi and as described in

API RP 53, adopted by reference at 20 AAC 25.527(c);

(5) "API number" means the number assigned by the commission under 20 AAC 25.040(b) for a well or well branch consistent with the API well numbering convention;

(6) "API RP" means API recommended practices;

(7) "barrel" means 42 U.S. gallons;

(8) "BHA" means bottom-hole assembly;

(9) "BOP" means blowout preventer, which is a casinghead assembly equipped with special gates or rams or other pack-offs that can be closed around the drill pipe, tubing, casing, or tools, and that completely close the top of the casing to control well pressure;

(10) "BOPE" means blowout prevention equipment;

(11) "bottom-hole location" means the subsurface point at the greatest measured penetration of a well or a well branch;

(12) "casing stub" means the remnant of a casing string when the upper portion of the casing has been cut and recovered;

(13) "commission" means the Alaska Oil and Gas Conservation Commission;

(14) "complete" means to equip and condition a well as an oil, gas, or service well so that it is capable of producing or injecting fluids; in the case of a well branch in a previously completed well, "complete" means to equip and condition a well branch so that it is capable of contributing to the well's production or injection of fluids;

(15) "completion operation" means work performed in a well after the casing and cementing of the wellbore; "completion operation" includes plugging, perforating, stimulating, testing, and equipping the well to produce or inject fluids;

(16) "conductor casing" means a casing string set before surface casing; depending on well configuration, "conductor casing" can be either the first or second string of casing set in a well and usually supports a diverter system;

(17) "day" means a calendar day;

(18) "development well" means a well drilled to a known productive pool;

(19) "displacement method" means pumping a cement slurry or other material into a well through a drillpipe or other tubular string and recovering displaced fluids on the surface;

(20) "diverter system" means an assembly of nipples, valves, and piping attached to a well's structural or conductor casing for venting a gas kick away from the drill rig;

(21) "downsqueeze method" means pumping a cement slurry or other material into a well through a drillpipe or other tubular string and forcing displaced fluids into a downhole formation;

(22) "drilling fluid" means any fluid used for the purpose of drilling a well;

(23) "drilling operations" means the penetration of ground below the setting depth of structural or conductor casing, using a drilling rig capable of performing the permitted well work, and for purposes other than setting structural or conductor casing; "drilling operations" includes the running of casing, cementing, and other downhole work performed ancillary to formation evaluation, and operations necessary to complete and equip the well so that formation fluids can be safely brought to the surface;

(24) "drilling unit" means an area of a pool

(A) established by the commission under AS 31.05.100, either by order or by regulation;

(B) to which no more than one oil or gas well may be drilled; and

(C) from which no more than one oil or gas well may produce;

(25) "exploratory well" means a well drilled to discover or to delineate a pool;

(26) "fluid" means any material or substance that flows or moves, whether in a semi-solid, liquid, sludge, gaseous, or other form or state;

(27) "freshwater" means water that

(A) has a total dissolved solids concentration of less than 10,000 mg/l, and occurs in a stratum not exempted under 20 AAC 25.440; or

(B) occurs in a stratum that serves as a source of drinking water for human consumption;

(28) "function pressure-test" means to actuate a component and demonstrate its ability to effect a pressure seal;

(29) "function-test" means to actuate a component to demonstrate its proper functioning without subjecting it to pressure;

(30) "gas well" means a well that produces predominantly gas at a gas-oil ratio over 100,000 scf/stb, unless on a pool-by-pool basis the commission establishes another ratio;

(31) "gas-oil ratio" means the cubic feet of gas, determined at 60° F and 14.65 psia, that are produced per stock tank barrel of oil produced;

(32) "injection" means the subsurface emplacement of fluid for enhanced recovery of oil or gas, disposal of oil field wastes, or underground storage of hydrocarbons;

(33) "intermediate casing" means a casing string run between the surface casing and the production casing or production liner and cemented in place to isolate abnormally geo-pressured strata, lost circulation zones, salt sections, or unstable shale sections;

(34) "junk" means debris lost in a hole; "junk" includes a lost bit, pieces of a bit, milled pieces of pipe, wrenches, or a relatively small object that impedes drilling;

(35) "landowner" has the meaning given in AS 31.05.170;

(36) "LEL" means lower explosive limit;

(37) "liner" means a string of casing that does not extend to surface but is

(A) hung inside the previous casing string, or

(B) set and cemented in place within the previous casing string;

(38) "meter curve" means a graph of the meter factor plotted against the flow rate, or of the pulse-per-unit-volume factor plotted against the flow rate, over the operating range of a meter;

(39) "meter factor" means the number obtained by dividing the gross standard volume of liquid passed through a meter, as measured by a prover during proving, by the corresponding meter-indicated volume at standard conditions;

(40) "mg/l" means milligrams per liter;

(41) "mscf" means thousand standard cubic feet;

(42) "mudline datum" means

(A) for a beach location, the plane of mean low water depth extended beneath the well site;

(B) for a location on a shifting natural island, the depth at which a horizontal plane through the toe of the island intersects the wellbore;

(C) for a location on an artificial island, the depth of the mudline as it existed before construction of the island; or

(D) for other offshore locations, the mudline;

(43) "multiple completion" means the completion of a well so as to permit production from more than one pool, with the production from each pool completely segregated;

(44) "offshore" means, in addition to its ordinary meaning, beach, artificial island, and shifting natural island locations;

(45) "oil well" means a well that produces predominantly oil at a gas-oil ratio of 100,000 scf/stb or lower, unless on a pool-by-pool basis the commission establishes another ratio;

(46) "operator" means an owner or a person authorized by an owner who is responsible for drilling, development, production, injection, disposal, storage, abandonment, and location clearance;

(47) "owner" has the meaning given in AS 31.05.170;

(48) "pilot gas" means gas routed to a safety flare system to maintain an ignition source;

(49) "ppm" means parts per million;

(50) "pressure-test" means to demonstrate the pressure integrity of a system without actuating its components;

(51) "production casing" means the casing installed from the wellhead to the top of or through the completion interval and cemented in place to seal off production or injection zones and water-bearing formations;

(52) "property" means a legally described tract of land, submerged or otherwise, to which a person has the right to drill, extract, remove, clean, process, and dispose of oil, gas, and associated substances;

(53) "psi" means pounds per square inch;

(54) "psia" means pounds per square inch absolute;

(55) "psi/ft" means pounds per square inch per foot, as a measure of pressure change with depth;

(56) "psig" means pounds per square inch gauge;

(57) "public water system" has the meaning given in 18 AAC 80.1990, as amended as of October 1, 1999, and as amended from time to time; 18 AAC 80.1990 is adopted by reference;

(58) "purge gas" means gas used to maintain forward flow and positive pressure in a safety flare system;

(59) "reservoir" means the same as "pool" in AS 31.05.170;

(60) "scf" means standard cubic feet;

(61) "service well" means a well used for injecting water, gas, or other fluids into a reservoir or producing formation in pressure maintenance, enhanced recovery, or storage operations, for disposing of oil field wastes, or for conducting other operations in support of oil or gas production;

(62) "shut in" means to close a well's surface, wellhead, or subsurface valves to halt flow from or into the well, with the completion interval remaining open to the tubing below the closed valves;

(63) "sidetrack operation" means a drilling operation conducted for the purpose of straightening the original hole, bypassing junk, or correcting mechanical difficulties in the original hole;

(64) "stabilizing pressure" means the pressure decline during the test shall trend toward a zero pressure differential;

(65) "standard cubic foot" has the meaning given to "cubic foot" in AS 31.05.170;

(66) "stb" means stock tank barrel;

(67) "stock tank barrel" means 42 U.S. gallons, measured at 60° F and 14.65 psia;

(68) "stratigraphic test well" means a hole drilled for the sole purpose of gaining structural or stratigraphic information to aid in exploring for oil and gas;

(69) "structural casing" means a short string of large diameter pipe that is set by driving, jetting, or drilling to support unconsolidated shallow sediments, provide hole stability for initial drilling operations, and provide anchorage for a diverter system;

(70) "surface casing" means a string of casing set and cemented in a well to prevent lost circulation while drilling deeper and to protect strata known or reasonably expected to serve as a source of drinking water for human consumption; usually "surface casing" is the first string of casing upon which BOPE is set;

(71) "suspend" means to plug a well in accordance with 20 AAC 25.110 and to reserve the option later to re-enter and

(A) redrill the well; or

(B) complete the well as an oil, gas, or service well;

(72) "tour" means a work shift in the drilling of a well;

(73) "underbalanced drilling" means drilling under conditions where the hydrostatic head of the drilling fluid column is intentionally designed to be lower than the pressure of the formation being drilled;

(74) "well"

(A) means a hole penetrating the earth, usually cased with steel pipe, and

(i) from which oil or gas, or both, or geothermal resources, is obtained or obtainable; or

(ii) that is made for the purpose of finding or obtaining oil, gas, or geothermal resources, or of supporting oil, gas, or geothermal resources production; and

(B) includes a well with multiple well branches drilled to different bottom-hole locations;

(75) "well branch" means that portion of a well drilled below the structural or conductor casing to access a given objective in a well with more than one bottom-hole location or whose bottom-hole location is being or has been changed by plugging back and redrilling; a well with multiple branches must feed into a designated primary wellbore;

(76) "working day" means a calendar day other than Saturday, Sunday, or a state holiday;

(77) "primary wellbore" means the active wellbore that is drilled from surface to the reservoir target, in which additional permitted branches are drilled; in the case of a sidetracked well, the new wellbore becomes the primary

wellbore.

(78) "surface owner" means a person who holds record title to the surface of the land as an owner.

Chapter 30
Alaska State Council on the Arts

Article 1
Operating Support Grants

20 AAC 30.010. Purpose.

The council may provide an annual, biennial, or triennial operating support grant to an arts organization to pay for a portion of the artistic or administrative function of the organization.

20 AAC 30.015. Grant conditions.

(a) An applicant for an operating support grant may request and the council will, in its discretion, award a grant in any amount. However,

(1) an application for an operating support grant may not be approved unless the grant applicant provided a cash match; and

(2) an operating support grant may not exceed 50 percent of the applicant's annual operating costs.

(b) If an operating support grant is awarded on a biennial or triennial basis, the grant amount payable during the second or third year may not be less than the grant amount paid during the first year, subject to a reduction in the amount of the grant that is proportional to the amount of the reduction of the annual appropriation made to the council for the support of the council's programs. The provisions of this subsection do not apply if payment of the second or third year of the grant is withheld by the council

(1) under 20 AAC 30.030(b) because of the grantee's failure to complete and submit a final report each year; or

(2) under 20 AAC 30.040(b) due to the grantee's failure to comply with the terms of the grant award letter.

20 AAC 30.020. General eligibility.

(a) Eligibility for an operating support grant is limited to an arts organization that:

(1) produces, presents, or administers a series of arts events or ongoing programs;

(2) has been determined by the Internal Revenue Service to qualify as an exempt organization under 26 USC 501(c)(3);

(3) has been incorporated for at least three years;

(4) is not a college or university; and

(5) has an annual budget of at least $50,000.

(b) An arts organization shall apply for an operating support grant on a biennial or triennial basis if the arts organization

(1) meets the eligibility requirements set out in (a)(1) - (4) of this section;

(2) has an annual budget of at least $150,000; and

(3) has received and successfully operated with at least two years of annual operating support grants; however, the council may waive the requirement of this paragraph and receive, review, and approve an application for an operating support grant on a biennial or triennial basis if the applicant meets the eligibility requirements of (1) and (2) of this subsection but has not successfully operated for at least two years with operating support grants.

(c) Except as provided in (b) of this section, an arts organization may only apply for and obtain an operating support grant on an annual basis.

20 AAC 30.025. Limitations.

(a) An arts organization submitting an application for an operating support grant is not eligible for any other annual grant.

(b) An arts organization may submit only one application for an operating support grant during a state fiscal year.

20 AAC 30.030. Application process.

(a) An arts organization applying for an operating support grant must

(1) complete an operating support grant application provided by the council in the guidelines and application form, adopted by reference in 20 AAC 30.983(1), for an operating support grant; and

(2) submit the following items, so that each is received or postmarked not later than the deadline established in the guidelines and application form described in (1) of this subsection:

(A) the completed application;

(B) any documentation requested in the guidelines and application form.

(b) To be eligible to receive payment of the grant during the second or third year of a biennial or triennial grant, the grantee shall complete and submit a final report each year. The final report must be

(1) made on a form provided by the council; and

(2) submitted to the council not later than the date set under 20 AAC 30.960.

20 AAC 30.040. Review criteria.

(a) The council will evaluate each application for an operating support grant

(1) as set out in the guidelines and application form, adopted by reference in 20 AAC 30.983(1), for an operating support grant, and using the following criteria:

(A) the quality of programs and services;

(B) the financial profile of the applicant;

(C) the applicant's outreach efforts to the community, and the relationship of the applicant and the program with the community;

(D) the applicant's administrative capability; and