20 AAC 25.265 is repealed and readopted to read:

20 AAC 25.265 Well Safety Valve Systems. (a) A completed well must be equipped with a functional safety valve system (SVS) 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) Every SVS 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, unless another type of surface safety valve system with that same capability is approved by the Commission.. For purposes of compliance with this section, a well flow line is that section of line between a well tree and the first piping manifold.

AOGA Comment: The 01/11/10 draft of this paragraph contained language specifically allowing the use of alternative surface safety valve systems with the capability to shut in a well when the flow line pressure drops below the required system actuating pressure. We request that specific language be included in this draft as well. We understand that the language may have been removed in anticipation that a request for a waiver of section 265 (b) requirements and approval of an alternative safety valve system may be considered by the Commission under proposed section 265 (o). While this is one possible method of seeking approval, we believe retaining the specific Commission approval language in section 265 (b) will streamline the process for approval.

(c) A SVS must meet the following requirements:

(1) the surface safety valve must be located within the ~~vertical run of a~~ well's tree or be located on the flow line adjacent to the tree;

AOGA Comment: Some existing wells are equipped with surface safety valves located immediately adjacent to the well's tree. The AOGCC has not indicated any issue with these systems and has allowed these wells to operate for many years. The addition of the qualifier "vertical line of a tree" will require either a waiver be granted to this section under 265 (o) and/or approval under proposed section 265 (c)(8). We request the language in this section include specific recognition of these systems that will allow these wells to continue to operate without any additional approvals.

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

(3) the SVS 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 wells that cycle between gas storage injection and production;

(5) in every well's SVS 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) structures containing multiple wells in a common area must have a gas detection system and a fire detection system that will immediately shut-in all wells located within the structure;

(7) SVS 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 SVS installed before {*effective date of regulation*} which do not meet the requirements of 20 AAC 25.265(c)(1) through (c)(7) require commission approval within one year to remain in operation.

(d) In addition to meeting the other requirements of 20 AAC 25.265, 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, unless another type of subsurface safety valve with that capability is approved by the Commission:

AOGA Comment: The 01/11/10 draft of this paragraph contained language specifically allowing the use of alternative subsurface safety valve systems with the capability to prevent an uncontrolled flow of fluid from the well's tubing. We request that specific language be included in this draft as well. We understand that the language may have been removed in anticipation that a request for a waiver of section 265 (d) requirements and approval of an alternative subsurface safety valve system may be considered by the Commission under proposed section 265 (o). While this is one possible method of seeking approval, we believe retaining the specific Commission approval language in section 265 (d) will streamline the process for approval.

(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 within one-eighth mile (660 feet) of:

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

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

(C) a ~~road accessible to the public~~government maintained road,

AOGA Comment: The common usage of the word "accessible" could be broadly applied to include unauthorized use of a lease roadway even if there are signs or barriers prohibiting access, or limited authorized use granted to specific members of the public. We request this section be changed to read "(C) a government maintained road".

(D) an operating railway,

(E) a government maintained airport runway,

(F) a coast line (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 CFR Part 329.4 with boundaries defined in 33 CFR 329.11; or

(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 (d) (2) of this section and equipped with an electric submersible pump or capillary string(s) run within the tubing is not required to be equipped with a subsurface safety valve.

(5) In addition to meeting the other requirements of 20 AAC 25.265, gas-only injection wells shall be equipped with either a subsurface safety valve as stated in 20 AAC 25.265(d) or an injection valve capable of preventing back flow. Wells cycling between gas storage injection and production shall be addressed by the commission 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 {*effective date of regulation*}, that is subject to the requirements of 20 AAC 25.265(d), 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 20 AAC 25.265(d) no later than the date that the well undergoes a tubing workover.

(g) Any subsurface safety valve required under 20 AAC 25.265 must be installed in the tubing string and located a minimum of 100 feet below original ground level (mudline datum for offshore wells), or if permafrost is present, below the permafrost.

AOGA Comment: As noted in previous comments submitted by AOGA, the provisions of these proposed regulations conflict in some instances with existing conservation orders. The example used was Conservation Order 458A (Northstar Oil Pool) which allows a minimum setting depth for tubing conveyed subsurface safety valves to be 500 feet which is above a permafrost interval. This proposed section requires subsurface safety valves to be set below the permafrost interval.

AOGCC staff testimony at the March 18 hearing recognized that there are field specific SVS related approvals embedded in about 35 conservation order pool rules. The staff recommended that about 15 of those orders should be maintained and the remainder rescinded. The staff also recommended that the Commission rescind all existing guidance documents, policies and commission letters written to provide clarification about well SVS requirements. Some items would be included in a new guidance document.

AOGA requests that industry be part of the process of developing the new guidance document to ensure current practices are understood and maintained. AOGA also requests individual operators be consulted prior to changing any conservation order SVS requirements.

(h) SVS testing is required; wells injecting water are exempt. SVS testing consists of function and performance tests. A function test is defined in 20 AAC 25.990(29). A performance test includes a function pressure test of the system's valves as defined in 20 AAC

25.990(28), and a function test of the mechanical or electrical actuating device. A SVS component fails a performance test when any test criteria in 20 AAC 25.265 (h)(9),(h)(10), (h)(11), or (h)(12) are not met on the first attempt. The SVS must be tested as outlined below:

(1) SVS performance testing 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 SVS components other than those listed in (h)(2), prior to or at the time of placing a well in service;

(4) a new well requiring a SVS shall not be operated unless it passes a performance test within 5 days of placing the well in service. The timing of all other SVS performance testing must be consistent with the requirements of 20 AAC 25.265 (i);

(5) performance tests 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 that is isolated from its well flow line or other production offtake mechanism need not be tested at the time of the required performance test stated in 20 AAC 25.265 (h), but the SVS must be performance tested within 5 days of the well’s return to stabilized production or injection;

(7) all performance test results must be verified by an operator's designated representative and submitted electronically to the commission no later than the 15th calendar day of the month following testing;

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

(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 SVS 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) within 2 minutes of 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) within 4 minutes of 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 prior 6 months shall be made available at the request of a commission representative; such records shall indicate the date and type of SVS maintenance completed.

(i) If a component of a SVS 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, within 24 hours, 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, within 48 hours, 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, within 14 days, 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, within 14 days, be repaired or replaced and performance tested, or the well must be shut-in;

(4) if the positive sealing device used to test a SVS leaks or otherwise precludes a successful SVS test, testing may continue with a substitute valve upon commission approval. The positive sealing device(s) must be repaired or replaced prior to the next required SVS 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 within 14 days of the date that the well is returned to service, and be tested within 5 days of ~~installation~~making the subsurface safety valve operable in accordance with 20 AAC 25.265 (h); and

AOGA Comment: We request this section be changed to acknowledge tubing retrievable subsurface safety valve installations where the time between installation of the equipment and the valve becoming operable could exceed 5 days.

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

(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 5 days in order to reach a stabilized condition prior to the test; and

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

(l) For purposes of 20 AAC 25.265(d), 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 within five minutes after a three-hour charted pressure build-up period; and

(2) the operator receives written confirmation (including confirmation by email 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 any required component of a well's SVS 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 SVS. The tag shall 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; and

(3) the name of the person 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 SVS test schedule is coordinated with the commission;

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

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

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

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

(o) Unless notice and hearing are required under this section, upon written request from the operator, the commission may approve a variance from a requirements of this section if the variance provides at least an equally effective means of complying with the requirement, or 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 any freshwater as defined under 20 AAC 05.990(27).

(Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am 11/7/99, Register 152; am ___/___/____, Register, ____)

Authority: AS 31.05.030 AS 31.05.095