Design, Installation, Operation, Test, and Redress of Subsurface Safety Valve Systems

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Introduction

This document has been developed by users/purchasers and suppliers/manufacturers of subsurface safety valve (SSSV) equipment intended for use in the petroleum and natural gas industry worldwide. This document is intended to give requirements and information to both parties on the design, operation, installation, and testing of subsurface safety valve system equipment and also the storage/transport, maintenance, and redress of the SSSV equipment.

Users of this document should be aware that further or differing requirements might be needed for individual installations, storage/transport and maintenance. This document is not intended to inhibit the user/purchaser from accepting alternative engineering solutions. This may be particularly applicable where there is innovative or developing well-completion technology.

Significant revisions to the document include the following.

— Many former recommendations (shoulds) have become requirements (shalls).

— Alternate technologies for SSSV operation have been included.

— Secondary tools used in the servicing of tubing-retrievable type SSSVs have been included.

— Subsurface injection safety valves (SSISV) have been included.

— Information on insert-type valves for tubing-retrievable type SSSVs has been expanded.

— The annex describing testing of SSSVs has been changed from informative to normative. Examples have been added to illustrate various methods of calculating leakage rate for both liquid and gas leakage.

— The testing interval of surface controlled SSSVs (SCSSVs) has been limited to a maximum frequency of 12 months.

Design, Installation, Operation, Test, and Redress of Subsurface Safety Valve Systems

1 Scope

This document establishes requirements and provides guidelines for subsurface safety valve (SSSV) system equipment. This includes requirements for SSSV system design, installation, operation, testing, redress, support activities, documentation, and failure reporting. SSSV system equipment addressed by this document includes control systems, control lines, SSSVs, and secondary tools as defined herein. SSSV types including surface controlled (SCSSV), sub-surface controlled (SSCSV), and sub-surface injection safety valves (SSISV) are included. Requirements for testing of SSSVs including frequency and acceptance criteria are included. Alternate technology SSSV equipment and systems are included in these requirements.

This document is not applicable to design, qualification, or repair activities for SSSVs. This document does not specify when a SSSV is required.

NOTE API 14A provides requirements for SSSV equipment design, qualification, and repair.

2 Normative References

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

API Specification 14A, *Specification for Subsurface Safety Valve Equipment*

API Recommended Practice 14C, *Recommended Practice for Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms*

API Recommended Practice 14E, *Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems*

API Recommended Practice 14F, *Design, Installation, and Maintenance of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities for Unclassified and Class I, Division 1, and Division 2 Locations*

API Specification 14L, *Specification for Lock Mandrels and Landing Nipples*

ISO 9000:2005 [1], *Quality management systems—Fundamentals and vocabulary*

ISO 9712:2012, *Non-destructive testing—Qualification and certification of NDT personnel*

ASNT SNT-TC-1A [2], *Personnel Qualification and Certification in Nondestructive Testing*

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1 International Organization for Standardization, 1, ch. de la Voie-Creuse, Case postale 56, CH-1211, Geneva 20, Switzerland, www.iso.org.

2 American Society for Nondestructive Testing, 1711 Arlingate Lane, P.O. Box 28518, Columbus, Ohio 43228, www.asnt.org.

3 Terms, Definitions, Acronyms, and Abbreviations

3.1 Terms and Definitions

For the purposes of this document, the terms and definitions given in ISO 9000 and the following apply.

3.1.1
alternate technology SSSVs
Designs such as but not limited to pressure charged systems, multiple hydraulic systems, indirect connection of the operator to the closure opening device, electric/electronically operated/induced activators, and control systems that include electrical and electronic signaling systems.

3.1.2
ambient-type valve
SSSV that is designed to close when tubing pressure drops below a pre-set level.

3.1.3
control line
Conduit utilized to transmit control signals to SCSSVs.

3.1.4
control system
Device or set of devices used to manage, command, direct, or regulate the behavior of the safety valve under normal operation and fail-safe conditions.

3.1.5
emergency shutdown system
System of stations which, when activated, initiate facility shutdown.

3.1.6
end sub
End component which provides connection between the tubing-retrievable safety valve (TRSV) and the tubing string and does not affect the functional operations of a TRSV.

3.1.7
equalizing feature
Mechanism which, when activated, permits the well pressure to bypass the SCSSV closure mechanism for the purposes of re-opening the SSSV.

3.1.8
fail-safe device
Device which, upon loss of the control signal, automatically shifts to a safe position.

3.1.9
fail-safe setting depth
Maximum true vertical depth at which an SCSSV can be installed and will close under worst-case hydrostatic conditions.

3.1.10
maintenance
Service operations performed on SSSV system equipment as part of routine operations.

3.1.11
manufacturer
Principal agent in the design, fabrication, and furnishing of original SSSV system equipment.

3.1.12
operating manual
Publication issued by the supplier/manufacturer which contains detailed data and instructions related to the installation, operation and maintenance of equipment.

3.1.13
operator
User of SSSV system equipment.

3.1.14
orifice (bean)
Designed restriction which causes the pressure drop in velocity-type SSCSVs.

3.1.15
packaging
Enclosure(s) of sufficient structural integrity to protect contents from damage or contamination, including impacts and environmental conditions encountered during the various phases of transport.

3.1.16
qualified part
Part manufactured under a recognized quality assurance program to meet the design and performance of the original part.

NOTE ISO 9001, API Spec Q1, and ISO TS29001 are examples of a recognized quality assurance program.

3.1.17
qualified person
Individual or individuals with characteristics or abilities gained through training or experience or both, as measured against established requirements, such as standards or tests that enable the individual to perform a required function.

3.1.18
rated working pressure
The lesser of:

a) the SSSV internal pressure rating; or

b) the differential rating with the valve closed.

3.1.19
redress
Any activity involving the replacement of **qualified parts** (3.1.16) within the limits described in Section 7.

3.1.20
repair
Any activity beyond the scope of **redress** (3.1.19) that includes disassembly, re-assembly, and testing with or without the replacement of qualified parts and may include machining, welding, heat-treating, or other manufacturing operations, that restores the equipment to its original performance.

3.1.21
safety valve landing nipple
SVLN
Any receptacle containing a profile designed for the installation of an SSSV lock mandrel.

NOTE SVLN may be ported for communication to an outside source for SSSV operation.

3.1.22
safety valve lock mandrel
Retention device used for SSSV equipment.

3.1.23
secondary tool
Tools and other equipment used with subsurface safety valves to perform a secondary function(s) or provide another intended design function.

NOTE Secondary tools may include communication, exercise, permanent lock open, temporary lock open, or other tools.

3.1.24
self-equalizing feature
SCSSV mechanism which, on initiation of opening sequence of the SSSV, permits the well pressure to automatically bypass the SCSSV closure mechanism.

3.1.25
storage
Act of retaining SSSV system equipment without damage or contamination, after processing is completed and prior to or after field use, including the transport process.

3.1.26
SSSV system equipment
Components which include the **control system** (3.1.4), **control line** (3.1.3), **SSSV** (3.1.30), **safety valve lock mandrel** (3.1.22), **safety valve landing nipple** (3.1.21), flow couplings, **secondary tools** (3.1.23) and other related downhole control components.

3.1.27
surface-controlled subsurface safety valve
SCSSV
Normally closed SSSV controlled from the surface by hydraulic, electrical, mechanical, or other means.

NOTE A normally closed SCSSV requires a signal to open. Upon loss of that signal, the valve closes.

3.1.28
subsurface-controlled subsurface safety valve
SSCSV
SSSV actuated by the characteristics of the well itself, such as velocity-type and ambient-type valves.

3.1.29
subsurface injection safety valve
SSISV
SSSV that is opened by injected flow and used to prevent back-flow.

NOTE These devices are usually actuated by the differential pressure through the SSISV (velocity type) or by tubing pressure at the SSISV (ambient type).

3.1.30
subsurface safety valve
SSSV
Device whose design function is to prevent uncontrolled well flow when closed.

NOTE SSSVs can be installed and retrieved by wireline or pump-down methods (wireline-retrievable) or be an integral part of the tubing string (tubing-retrievable).

3.1.31
surface safety valve
SSV
Automatic tree valve assembly which closes upon loss of power supply.

NOTE Where used in this document, the term Surface Safety Valve is understood to include an SSV valve and the SSV actuator.

3.1.32
system integration manual
Document issued by the operator (user/purchaser) which contains detailed data and instructions related to the configuration, preparation, installation, and operation of the SSSV system equipment.

3.1.33
transport
Actions required to ship SSSV system equipment from one geographic location to another.

3.1.34
underwater safety valve
USV
Automatic valve assembly (installed at an underwater wellhead location) which will close upon loss of power supply.

NOTE Where used in this document, the term is understood to include a USV valve and USV actuator.

3.1.35
velocity-type valve
SSSV that is designed to close when the flow velocity exceeds a pre-set value.

3.1.36
well test rate
Stabilized rate at which the well is produced on a routine basis.

3.2 Acronyms and Abbreviations

ESD	emergency shut-down
FSSD	fail-safe setting depth
NDE	non-destructive examination
OPD	oil per day
SCSSV	surface-controlled subsurface safety valve
SSCSV	subsurface-controlled subsurface safety valve
SSISV	subsurface injection safety valve
SSSV	subsurface safety valve

SSV	surface safety valve
SVLN	safety valve landing nipple
TFL	through flow line
TRSV	tubing-retrievable safety valve
TR-SCSSV	tubing-retrievable surface-controlled subsurface safety valve
USV	underwater safety valve
WRSV	wire-line retrievable safety valve

4 Design

4.1 SSSV System Equipment

4.1.1 General

Subsurface safety valve systems (see 3.1.26 and Figure 1) are designed and installed to prevent uncontrolled well flow when actuated.

The user/purchaser, when developing the system configuration, shall consider and document the pertinent elements, their basis for acceptance and their compatibility. These elements include, at a minimum, the following: control system, control line, wellhead/tubing hanger passages and connectors, control line protectors, control fluid (for SCSSV); SSSV; flow couplings; locking and sealing devices (for wireline safety valves); safety-valve landing nipples; secondary tools and exposed fluids.

Examples of basis for acceptance may include:

a) proven exploration and production experience or technology;

b) proven alternative industry experience or technology;

c) advanced design development, verification, and validation requirements;

d) required time for valve closure from signal conforming to user/purchaser or regulatory requirements; or

e) a combination of the previous elements.

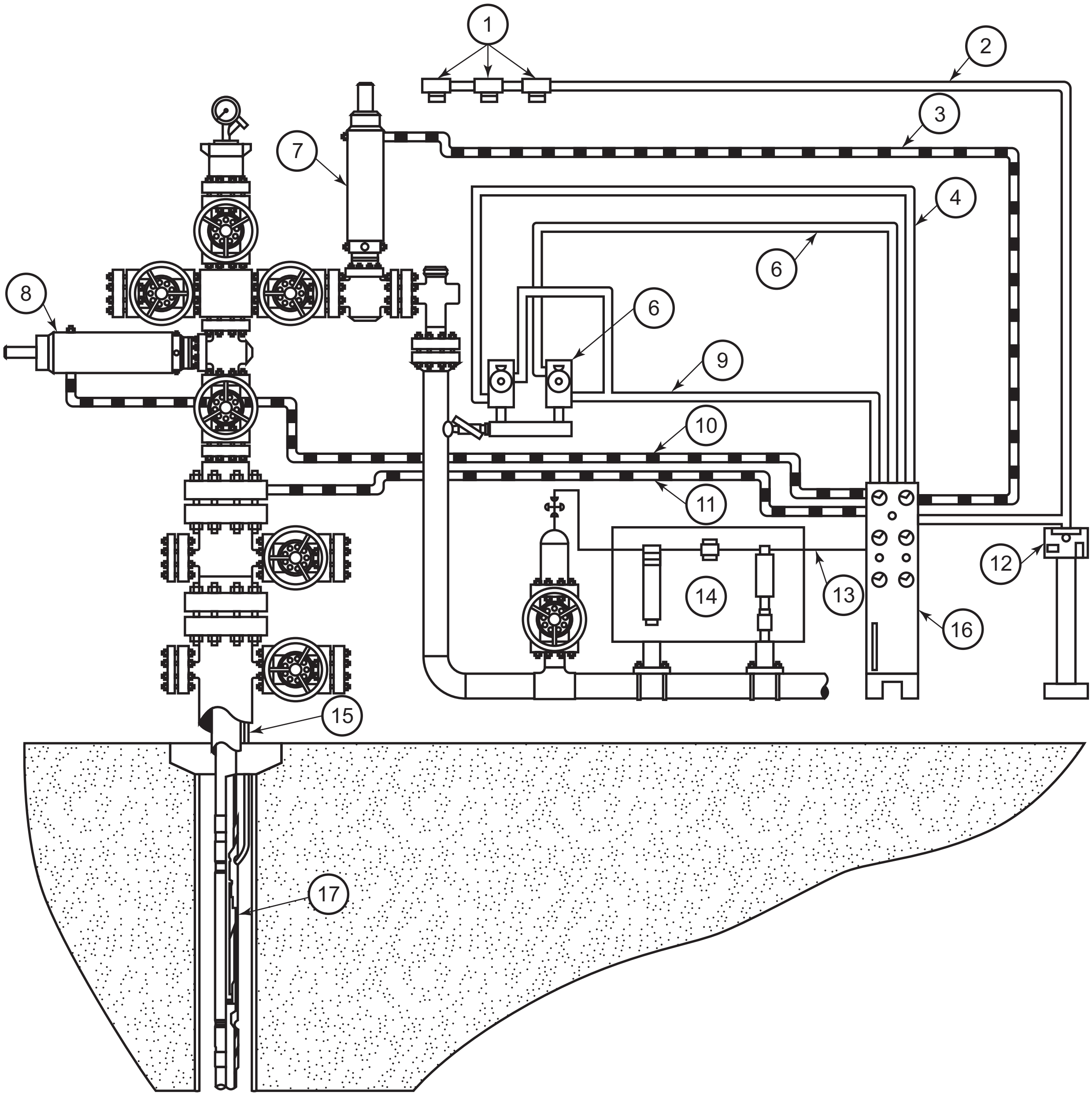
The user/purchaser shall assure that installation and installation testing of the SSSV system is performed and approved by a qualified person using documented procedures and acceptance criteria in accordance with the supplier/manufacturer's operating manual and operator's system integration manual. System configuration and installation testing results shall become a part of the well records (see 8.4).

4.1.2 Materials

The user/purchaser shall verify that the materials used in SSSV system equipment are suitable for the functional and technical requirements of the system and the application.

NOTE The functional and technical requirements include the intended environment

SSSVs that include alternate technologies (3.1.1) for the operation of SSSVs may require special efforts to align them with the requirements of this document. The performance requirements for SSSV systems utilizing alternate technologies shall conform to the requirements of this RP to the extent the technology is practical. Variances to the



Key

1 fusible plugs
2 ESD pressure line
3 hydraulic/pneumatic pressure line to wing valve
4 high pilot signal
5 low pilot signal
6 pilot box
7 wing SSV hydraulic or pneumatic actuator
10 hydraulic/pneumatic pressure to master SSV
11 hydraulic pressure line to SCSSV
12 manual remote emergency shutdown station
13 supply line
14 flowline scrubber assembly
15 hydraulic pressure line to the SCSSV
16 hydraulic/pneumatic control panel

Figure 1—Example: Surface-controlled Subsurface Safety Valve System in a Dry Tree Well

requirements of this RP shall be identified, justified, and documented by a qualified person and approved by a second qualified person. Such documentation shall become a portion of the system's permanent records (8.4).

4.1.3 Interfaces

Equipment shall be selected and verified as being compatible with the dimensions and configurations of: tubing and auxiliary conduit connections; tubing and casing drift diameters; related permanent well equipment and well-servicing tools; and control or other fluids in contact with the equipment.

4.1.4 Pressures/Temperatures/Flow Rates/Loads

Equipment shall be selected and verified to meet or exceed the anticipated pressure range, temperature range, maximum/minimum flow rates, and anticipated loading conditions.

4.2 Control System

4.2.1 General

All elements of the control system shall be analyzed for potential hazards that may render the system vulnerable to failure or may preclude safe use. For example, automatic resets shall not be incorporated in the control system since this feature may cause the SCSSV to reopen when it should remain closed. Systems shall be designed and operated to address potential hazards.

It is desirable to integrate the SCSSV control system with the surface safety system to ensure the operational sequence as recommended in Annex D. The integrated system shall be designed to allow independent signal supply and control of the SCSSV. This feature will allow for routine maintenance and troubleshooting.

For multiple-well installations, the control-system manifolding should include provisions for individual well and SCSSV isolation.

Emergency shut-down (ESD) controls shall be installed in strategic locations in accordance with API 14C, applicable regulations and sound engineering judgment. To avoid closure of the SCSSV under full well-flow conditions, a delay shall be incorporated between closure of the tree valves controlled by the ESD and the downhole SCSSV. The opening sequence should be reversed on returning production facilities to normal operations. This delay mechanism shall be analyzed and documented to verify that it does not create hazards that render the system vulnerable to failure.

NOTE API 17F contains information relating to subsea production control systems.

4.2.2 Sensors

Each installation shall be analyzed to determine applicable sensors. The sensor types used to signal the SCSSV may include heat sensors, pressure sensors, fluid level sensors, and other sensors, as applicable.

A high/low level sensor may be placed on the supply tank of hydraulic systems to warn of abnormal operating conditions, e.g. well flowing through control line or a leaking control line. A low-pressure pilot may also be installed on the control system pump discharge.

4.2.3 Power

The system shall be designed with sufficient capacity to operate all equipment to the defined conditions of the application.

The following requirements apply to various types of control systems:

a) Monitoring and controls shall be incorporated to prevent exceeding the limitations of the system.

b) The control conduit shall have adequate considerations for returned control signals upon closure of the SCSSV.

4.2.4 Guidelines for Selection of Control Fluid

The following shall be considered when selecting control fluids:

a) equipment supplier/manufacturer's recommendations;

b) flammability;

c) flash point;

d) lubricity;

e) physical/chemical compatibility: the fluid shall not degrade the sealing elements resulting in hardening, softening, swelling, or shrinking;

f) fluid property stability over expected temperature/pressure ranges and service life;

g) fluid cleanliness (solids content);

h) foam inhibition;

i) toxicity (including environmental impacts);

j) low corrosiveness;

k) oxidation stability;

l) viscosity and specific gravity at the operating temperatures.

4.2.5 Guidelines for Selection of Control Line

The following shall be considered when selecting the control line:

a) temperature at the SCSSV;

b) completion fluid (annulus);

c) anticipated operating pressures (maximum, minimum; internal, external);

d) working pressure of surface wellhead;

e) safety valve setting depth;

f) geometrical constraints;

g) control media, such as hydraulic fluid, pneumatic fluid, or an electric signal;

h) control line connector design, material and pressure rating;

i) control line manufacturing technique;

j) supplier/manufacturer's minimum bend radius;

k) well environment;

l) control line encapsulation/protection.

4.3 Wellhead/Tubing Hanger Passages and Connectors

Passages/connectors shall have a verified rating equal to or greater than the maximum anticipated control-system operating conditions at the tubing hanger and be compatible with the control media and environmental conditions (including pressure).

4.4 Control Line Protectors

Control line protectors should be used to protect the control line from possible damage (abrasion, flattening, etc.) that could occur during running/pulling operations after connecting the control line. When used, at least one protector for each tubing joint is recommended. The cross-coupling types are recommended to prevent the protector from moving on the tubing joint. Protectors shall have dimensions compatible with the tubing size and connection, with the control line size and type, and with the casing drift. It is recognized that there may be additional conduits which bypass the SSSV and may require consideration for protection.

4.5 SSSV

4.5.1 General

The following topics are prominent in the design selection of a SSSV. Each shall be applied as necessary to ensure the desired performance.

4.5.2 Considerations

SSSVs shall be selected that have been verified as being compatible with the dimensions and configurations of tubing and auxiliary conduit connections; tubing and casing drift diameters; related permanent well equipment and well-servicing tools; control or other fluids in contact with the equipment. The following shall be considered in determining the SSSV setting depth, operations, and testing intervals.

— Well effluents and producing characteristics including scale, paraffin and hydrate deposition are principal factors in selection and design.

— The temperature changes in a closed hydraulic system.

— Annulus pressure and its effects on valve operations for the life of the equipment.

4.5.3 Functional Characteristics

The user/purchaser shall consider for selection the following functional characteristics, as applicable: self-equalizing/non self-equalizing; selective/non-selective profiles; secondary communication; temporary/permanent lock-open; insert valve compatibility; reverse flow installations; setting depth capability.

NOTE For a more extensive list, see the functional specification requirements given in API 14A.

4.5.4 Determination of SCSSV Setting Depth

When determining the SCSSV setting depth, the following shall be considered, but not limited to:

a) actuation method;

b) communication system capabilities and limits;

c) maximum fail-safe setting depth according to the supplier/manufacturer's operating manual;

d) gradient and pressure of the annulus and control line fluids;

e) SSSV closing and opening pressure from the shipping report;

f) required design margins;

g) anticipated pressures (absolute and differential) and temperature ranges at valve depth;

h) paraffin, hydrate deposition, asphaltenes, pour point of well bore fluid, etc.;

i) well construction design such as wet or dry tree, permafrost, proximity to adjacent wells, etc.

4.5.5 Insert-type SSSV

An insert-type SSSV assembly typically consists of the lock mandrel, sealing devices, spacer tube, and wire-line retrievable SSSV. An equalizing assembly may be included for ease of retrieval.

The lock mandrel and external sealing device(s) as shown in Figure 2 shall meet the requirements of 4.7.

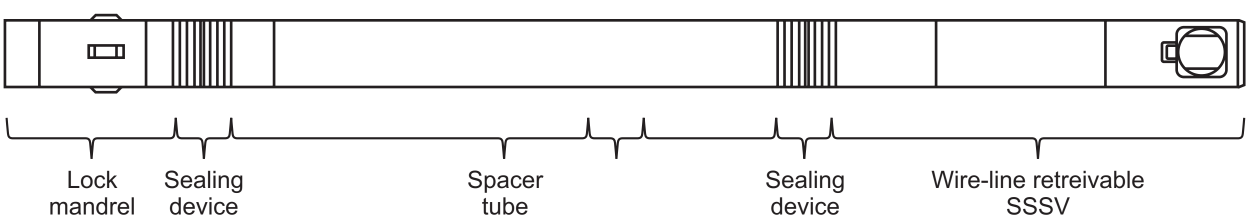


Figure 2—Example: Insert-type SSSV Assembly

The wire-line retrievable SSSV shall be in accordance to API 14A.

Each spacer tube, which is located between the lock mandrel and the wire-line retrievable SSSV, shall be documented and verified as compatible with the installation dimensions and be able to withstand the loading conditions and environment.

The installation of insert-type SCSSV assemblies into an existing tubing-retrievable safety valve (TRSV) potentially changes the performance ratings of the TRSV and/or limits the maximum control line pressure available to operate hydraulically operated insert-type SCSSV assemblies. An analysis of the following combination(s) of parameters shall be performed to determine if the planned operations are within the capabilities of the equipment and the planned well operations. This evaluation shall consider the following criteria as applicable:

1) maximum anticipated tubing pressure;

2) maximum anticipated load (tension and/or compression) on the TRSV;

3) annulus pressure outside the TRSV with the insert-type SCSSV assembly installed;

NOTE Assuming a zero annulus pressure may limit the maximum available control line pressure available for the insert-type SCSSV assembly.

4) maximum control line system pressure available to operate the insert-type SCSSV assembly;

5) maximum anticipated operating temperature and the temperature changes;

6) desired system design margin;

7) the capability ratings of each of the affected equipment which includes the TRSV.

NOTE Design load cases for the TRSV may be based on user/purchaser functional requirements, government regulations, field experience, reliability considerations, and/or other factors.

4.6 Flow Couplings

Flow entrance effects can impact SSSV performance and reliability. To reduce the resultant effects of turbulence during production, flow couplings should be considered an integral part of the tubing string, both upstream and downstream of the SSSV. Flow couplings should be compatible with the ID of the SSSV for an ample length prior to the SSSV entrance and at the exit. Typical industry practice has been to provide a minimum of 0.9 m (3 ft) in length provided it exceeds 8 to 10 times the ID of the tubing. In the case of TRSV installations, flow coupling length should take into account the dimensions and configurations of secondary tool usage.

4.7 Lock Mandrels, Safety Valve Landing Nipples, and Sealing Devices

Lock mandrels, safety valve landing nipples, and sealing devices shall be verified as compatible with the dimensions and configurations of related permanent well equipment and well-servicing tools. The applicable tools shall meet the requirements of API 14L.

4.8 Secondary Tools

Secondary tools shall be verified as compatible with the dimensions and configurations of related permanent well equipment and well-servicing tools.

5 Installation

5.1 General

The SSSV system equipment shall be installed according to the supplier/manufacturer's procedures and documented capabilities. See Annex C for guidelines on SSSV system equipment installation.

5.2 Control line

Prior to installation, the control line shall be verified as filled with the specified control fluid of the specified cleanliness. Monitor the control line during installation so no detrimental physical damage occurs. See 4.2.5 for control line selection criteria.

5.3 Lock Mandrels, Safety Valve Landing Nipples, and Sealing Devices

Installations and retrievals shall meet the requirements identified in the supplier/manufacturer's operating manual and, where applicable, the documented procedures of the user/purchaser as specified in API 14L.

5.4 Secondary Tools

Installations and retrievals shall meet the requirements identified in the supplier/manufacturer's operating manual and, where applicable, the documented procedures of the user/purchaser as specified in API 14A.

5.5 Equipment Verification

5.5.1 Prior to Installation

The opening and closing hydraulic pressures (or operating loads) shall be verified according to the specific supplier/manufacturer's operating manual. Verify the SCSSV will function fail-safe at the planned setting depth before installation by calculation of fail-safe setting depth (FSSD) in accordance with the supplier/manufacturer's operating manual, section 4.5.4 and API 14A.

SSCSVs and SSISVs shall be tested by a qualified person and in accordance with the supplier/manufacturer's operating manual to verify mechanical actuation, orifice sizing as applicable, and closure-mechanism pressure integrity. A mechanical device may be used to test the actuation mechanism.

SSSV system components should be functionally tested.

5.5.2 On Location

SSSV system equipment shall be inspected when received on location to:

a) verify that the part number and serial number on the SSSV equipment correspond to those recorded on the accompanying documents; and

b) verify the visible sealing elements and threads are not damaged, and that other visible features do not exhibit damage that may interfere with the SSSV equipment operation;

The supplied documentation including shipping report, operations manual, and any product data sheets shall be checked.

6 Operation and Test

6.1 General

The SSSV system equipment shall be operated according to the supplier/manufacturer's procedures and documented capabilities. When installed, the SSSV system equipment shall be tested by a qualified person to verify proper operation. System evaluations shall include testing procedures with acceptance criteria and documentation. See Annex D for operational guidelines and Annex A for testing requirements.

6.2 Control system

The construction, installation and operation of the control system should be in accordance with Annex C and Annex D. Additionally, where applicable, offshore control systems shall be in accordance with API 14C for surface safety systems, API 14E for piping systems and API 14F for electrical systems. It is recognized that additional regulations and company or local requirements may also apply. System components and connections shall have capability ratings that meet or exceed those anticipated of the system during its life cycle.

Control systems shall be installed in such a manner that they do not interfere with, nor are subject to damage by the normal operations performed at the facility. The location of the control unit, while not critical to its operation, should be chosen based upon convenience and safety considerations. The control unit enclosure shall be weatherproof and suitable for the selected environment.

All functions of the hydraulic, pneumatic, measurement, electric (electronic) systems shall be tested for proper operation and integrity at operating loads prior to their final connection to the SCSSV. Systems testing shall be in accordance with supplier/manufacturer's testing and operating procedures which include the applicable acceptance criteria. System tests shall include validation of the SCSSV closure after the system-defined delay.

The control system shall be tested at a maximum interval of every six months unless local regulations, conditions and/or documented historical evidence indicate a more frequent testing interval.

6.3 SCSSV Testing

After installation of the SCSSV in the well, the SCSSV shall be closed under minimum or no-flow conditions by operation of the control system. Verification of closure operation may be accomplished by pressure build-up/in-flow test. The SCSSV shall be reopened following the procedures in the supplier/manufacturer's operating manual.

SCSSVs shall be tested to the requirements in Annex A upon installation and at a maximum interval of every six months unless local regulations, conditions and/or documented historical evidence indicate a different testing interval not to exceed 12 months.

6.4 SSCSV and SSISV Testing

6.4.1 SSCSV and SSISV in situ Testing

SSCSVs and SSISVs that can be in situ tested shall be tested to the requirements in Annex A at a maximum interval of every six months unless local regulations, conditions and/or documented historical evidence indicate a different testing frequency not to exceed 12 months. Leakage rates in excess to the values specified in Annex A shall be cause for test rejection.

NOTE Contact the supplier/manufacturer to determine if the SSCSV is suitable for in situ testing.

6.4.2 SSCSV and SSISV that Cannot be in situ Tested

SSCSVs and SSISVs that cannot be in situ tested shall be retrieved, inspected, tested, and set to current well conditions in accordance with the supplier/manufacturer's recommendations at intervals not to exceed 12 months. More frequent inspection as dictated by field experience may be necessary for early detection of service wear or fouling. Pressure testing of the closure mechanism at the surface shall be at 1.38 MPa ±5 % (200 psi ±5 %) pressure differential. Leakage rates exceeding the criteria in Annex A.3.6 shall be cause for test rejection.

Reinstalled SSCSVs and SSISVs shall conform to the requirements of Section 7, Redress.

6.4.3 SSCSV and SSISV No-flow Condition Testing

For SSISVs installed in injection wells, where the well is incapable of flowing, the no-flow condition of the well shall be verified and documented at intervals not to exceed 12 months.

7 Redress

7.1 General

The redressed equipment shall conform to the current edition of the applicable national or international standard or the edition in effect at the time of original manufacture.

Redress of equipment shall be performed:

a) in accordance with the supplier/manufacturer's requirements and instructions, including the use of any specialized assembly equipment and tools;

b) with qualified part(s) (see 3.1.14) which have been installed by qualified person(s) (see 3.1.15);

c) with supplier/manufacturer-defined testing, including acceptance criteria and documentation.

7.2 SSSVs

7.2.1 TRSV Redress

The redress of TRSVs shall be limited to the replacement of seals such as tubing-thread seal rings, end subs and control line fittings or adapters which do not involve the disassembly of a body-joint connection. If any body-joint connection of the valve is disassembled, the procedure then becomes a repair and shall be performed in accordance with API 14A.

Replacement of validated end subs shall conform to the assembly requirements, operating manual's testing procedures, acceptance criteria and documentation requirements (see 8.4).

7.2.2 Wire-line Retrievable Safety Valve (WRSV) Redress

The redress of wire-line/through flow line (TFL)-retrievable SSCSVs and SSISVs shall be limited to the replacement of elastomeric and non-elastomeric seals, seal back-ups, wiper rings, and common hardware components such as pins or screws within the requirements for redress as defined in the supplier/manufacturer's operating manual.

If any pressure-containing connection involving the hydraulic or operating sections of the valve is disassembled, the connection shall be tested in accordance with the supplier/manufacturer's requirements. If any other action is performed, the procedure then becomes a repair process and shall be performed in accordance with API 14A.

7.3 Lock Mandrels and Secondary Tools

The redress of SSSV lock mandrels and secondary tools shall be limited to the replacement of qualified parts and common hardware components within the requirements of the supplier/manufacturer's operating manual. Repair of secondary tools shall be in accordance with API 14A. Repair of lock mandrels and landing nipples shall be in accordance with API 14L.

7.4 Inspection and Evaluation

All SSSV system equipment undergoing redress operations shall be inspected and evaluated by a qualified person for any deterioration in condition or functionality. Any equipment needing more than the redress within the limits described above shall be repaired according to the current edition of the applicable national or international standard or the edition in effect at the time of manufacture.

7.5 Reassembly

Reassembly of redressed SSSV system equipment shall be performed in accordance with the supplier/manufacturer's requirements and instructions, including the use of any specialized assembly equipment and tools.

7.6 Retest

All redressed SSSV system equipment shall be tested for mechanical and/or hydraulic functionality in accordance with the supplier/manufacturer's operating manual prior to installation.

7.7 SSSV Redress Documentation

To maintain traceability requirements of redressed SSSV equipment, documentation shall include SSSV equipment serial number, parts replaced, traceability of redress parts, name of the qualified person performing the redress and the date of redress.

For SSSV redress, records shall provide the following additional information, as applicable:

— opening pressure (maximum/minimum);

— closing pressure (maximum/minimum);

— leakage rate at 100 % working pressure;

— leakage rate at low pressure gas of 1379 kPa (200 psi) or less.

For SSCSV and SSISV redress, records shall provide the following additional information, as applicable:

— closing flow rates/pressure differentials/tubing pressures/opening flow rate range;

— orifice size;

— number and length of spacers;

— spring rate.

Testing results, pressures, and durations shall be documented per 8.4.1.

8 Support Requirements

8.1 General

This section provides minimum quality control requirements to meet this document. The quality control functions shall be controlled by documented instructions, which include acceptance criteria and results.

The user/purchaser shall establish and maintain documented procedures to control the SSSV system equipment documents and data that relate to the requirements of this document. These documents and data shall be maintained to demonstrate conformance to specified requirements. The documents and data shall be legible and shall be sorted and retained in such a way that they are readily retrievable in facilities that provide a suitable environment to prevent damage or deterioration and to prevent loss. Documents and data may be in any type of media, such as hard copy or electronic files.

Equipment shall be handled, transported, and stored in compliance with documented procedures of the supplier/manufacturer which are designed to prevent damage or deterioration in the anticipated environments. All equipment shall be transported and stored in such a manner as to preserve the integrity and operability of the equipment prior to well installation.

8.2 Handling

8.2.1 Packaging

SSSV equipment shall be packaged in such a way as to prevent damage or deterioration during transport and storage. Equipment which has exposed seals shall be protected from direct sunlight and/or other UV light sources, and shall be prevented from contact with contaminants such as: oils, vapors, solvents, etc. Materials provided as protection for storage or transport only, shall be clearly identified for removal prior to equipment use.

8.2.2 Storage

SSSV equipment shall be stored in conditions (temperature, etc.) which meet the supplier/manufacturer's specifications as defined in the equipment's operating manual. Equipment is typically stored vertically in an unstressed condition and shall be protected from the effects of abrasives and chemicals which may cause damage.

SSSV equipment containing elastomeric materials shall not be stored in areas where ozone is present or in the vicinity of radiation equipment. Storage of equipment containing elastomeric materials shall take into account the effects of shelf life and compression set of that material. For storage after transport the requirements and limits shall be as defined within the equipment's operating manual or data sheet.

8.2.3 Transport Before Installation

Equipment shall be packaged for transport per the written specifications of the equipment supplier/manufacturer to prevent normal handling loads and contamination from harming the equipment. These specifications shall address the protection of external sealing elements, sealing surfaces, and exposed threaded connections. All access port(s) shall be protected against contamination from fluids and/or debris.

Transportation regulations governing size, mass, hazardous materials, etc. as set forth by state, regional, or national authorities, and supplier/manufacturer recommendations shall be observed when shipping/transporting SSSV system equipment.

8.2.4 Transport After Recovery

Equipment shall conform to local requirements for the evaluation and removal of contaminants prior to transport. Transportation regulations governing size, mass, hazardous materials, etc. as set forth by state, regional, or national authorities and user/purchaser requirements shall be observed when shipping/transporting SSSV system equipment.

In the event any SSSV equipment requires evaluation and/or analysis, follow the user/purchaser's documented requirements for packaging and preparation for transport.

8.3 System Quality

8.3.1 Personnel Qualifications

All personnel performing installation, redress, testing, and inspection for acceptance shall be qualified in accordance with documented requirements. Additionally, personnel performing visual examinations shall be qualified in accordance with ISO 9712 vision requirements. Personnel performing non-destructive examination (NDE) shall be qualified in accordance with ASNT SNT-TC-1A or ISO 9712, to at least Level II or equivalent.

8.3.2 Calibration Systems

Measuring and testing equipment used for acceptance shall be identified, inspected, calibrated and adjusted at specific intervals in accordance with documented procedures and traceable to a national or international standard.

Calibration intervals for measuring devices shall be a maximum of three months until documented calibration history can be established. Calibration intervals shall then be established based on repeatability, degree of usage and documented calibration history. Calibration intervals shall not exceed one year.

Measuring devices used for final acceptance shall:

a) be readable to at least ±0.5 % of full-scale range;

b) be calibrated to maintain ±2 % accuracy of full-scale range;

c) be used only within the calibrated range; and

d) be calibrated with a master pressure-measuring device or a deadweight tester for pressure-measuring devices.

8.4 Documentation and Data Control

8.4.1 Retained Documentation

The user/purchaser (operator) shall retain documentation that provides objective evidence of conformance to the system configuration requirements of this document. As a minimum, this documentation shall include operating manuals; product data sheets; maintenance records; test reports (pre- and post-installation and system) and product-specific quality records.

All documentation shall be retained and available for a minimum of one year past the date of decommissioning of the SSSV equipment.

All records shall be endorsed by a qualified person and provide the following information, as a minimum:

— date;

— well identification;

— time summary and operations performed, including depth, pressures and equipment involved;

— all system equipment installed, removed, replaced and/or redressed;

— all equipment lost or left in the hole, and any restriction not previously reported;

— information required to complete failure-analysis reports.

8.4.2 Failure Reporting Documentation

Failure reporting shall be conducted in accordance with Annex B.

Annex A
(normative)

SSSV Testing

A.1 General

This annex includes the requirements for necessary procedures to perform in situ leakage testing of SSSVs to conform to the requirements of 6.3 and 6.4. A successful test requires completion of the steps defined below. SCSSVs that include alternate technology shall be tested to conform to the steps shown in this annex; however, the user/purchaser shall provide necessary variations in the measurements and methods thereof to perform this testing. The results of each test shall be recorded and maintained by the user/purchaser in accordance with 8.4.1.

When direct measurement is not feasible, this annex provides methods of testing that infers leakage rates by use of pressure build-up in a trapped cavity. Alternate methods to calculate such indirect leak measurement are acceptable when testing results conform to the defined requirements and documented procedures, provided they are verifiable and repeatable.

A.2 Procedure for Testing Installed SCSSVs

A.2.1 Record the control pressure.

A.2.2 Isolate the control system from the well to be tested.

A.2.3 Shut the well in at the wellhead.

A.2.4 Wait a minimum of 5 min or the duration required to establish a stable fluid phase at the SCSSV closure mechanism. Record the shut-in tubing pressure.

A.2.5 Isolate the control line pressure source from the SCSSV control line. Observe control line for increase or loss in pressure. If control line pressure changes are observed, investigate, record, and take corrective action as necessary.

A.2.6 Any leaks through the wing or flow-line valve shall be located, identified, measured, and considered during testing. Close the SCSSV by releasing the applied control line pressure. Close the control line system and observe for pressure build-up, which may indicate a faulty SCSSV system. If control line pressure changes are observed, further investigation shall be recorded and action may be taken.

A.2.7 Bleed the pressure off the tubing above the SSSV to the lowest practical pressure and then shut in the well at the wing or flow-line valve. Record the resulting tubing pressure and downstream cavity pressure. When possible, bleed flow-line header pressure down to or below tubing pressure and observe the flow-line and tubing for a change in pressure.

A.2.8 Conduct leakage test and document results. If the SCSSV failed to close or if the leakage rate exceeds 0.43 m^3/min (15 SCF/min) gas, or 400 cm^3/min (13.5 oz/min) liquid, the well shall remain shut-in until one of the following corrective actions has been performed:

a) remediate, repair, or replace the SSSV to conform to the acceptance criteria;

b) complete an approved documented risk assessment for continuing operations.

NOTE Continuing operations may require additional regulatory approvals.

A.2.8.1 For wells with gas below the SSSV where direct measurement is not possible, flow rates can be computed from pressure build-up by the following formula.

In SI units:

$$q = 2.84 \times 10^3 \left(\frac{P}{Z} - \frac{P_i}{Z_i}\right)\left(\frac{1}{t}\right)\left(\frac{V}{T}\right)$$

In USC units:

$$q = 35.37 \left(\frac{P}{Z} - \frac{P_i}{Z_i}\right)\left(\frac{1}{t}\right)\left(\frac{V}{T}\right)$$

where

q is the leakage rate, m^3/min (SCF/min);

P_i is the initial pressure at the commencement of test, MPa (psi);

P is the pressure after test has commenced at specific interval, MPa (psi);

Z_i is the initial compressibility factor;

Z is the compressibility factor at specific interval;

t is the build-up time, in min, to reach a target pressure;

V is the volume of gas in the tubing string above the SSSV, in m^3 (ft^3). This volume is dependent on the liquid level above the closure device;

T is the absolute temperature at the SSSV, in °C + 273 (°F + 460).

Example gas-leakage problem (SI and USC units):

In SI units:

P_i = 6.895 MPa

P = 7.93 MPa

t = 30 min

T = 93.3 °C + 273

Z_i = 0.935

Z = 0.928

V = 1.13 m^3

$$q = 2.84 \times 10^3 \left(\frac{P}{Z} - \frac{P_i}{Z_i}\right)\left(\frac{1}{t}\right)\left(\frac{V}{T}\right)$$

$$q = 2.84 \times 10^3 \left(\frac{7.93}{0.98} - \frac{6.895}{0.935}\right)\left(\frac{1}{30}\right)\left(\frac{1.13}{93.3 + 273}\right) = 0.34\,\mathrm{m}^3/\mathrm{min}$$

In USC units:

P_i = 1000 psi

P = 1150 psi

t = 30 min

T = 200 °F + 460

Z_i = 0.935

Z = 0.928

V = 40 ft^3

$$q = 35.37\left(\frac{P}{Z} - \frac{P_i}{Z_i}\right)\left(\frac{1}{t}\right)\left(\frac{V}{T}\right)$$

$$q = 35.37\left(\frac{1150}{0.98} - \frac{1000}{0.935}\right)\left(\frac{1}{30}\right)\left(\frac{40}{200+460}\right) = 12\text{scf/min}$$

A.2.8.2 For wells with liquid across the SSSV, the pressure build-up depends on the static liquid level and the amount of gas in the oil. If the liquid level is above the SSSV and no free gas exists in the tubing string up to the master valve, the leakage rate should be calculated using a single-phase liquid method such as below.

$$V = V_i\left(\frac{P - P_i}{M_B}\right) + V_i$$

$$q = \left(\frac{V - V_i}{t}\right)$$

where

q is the leakage rate, cm^3/min (oz/min);

Vi is the volume of liquid in the tubing string above the SCSSV in cm^3 (oz) prior to initiating test;

V is the volume of liquid in the tubing string above the SCSSV in cm^3 (oz) at specific time interval;

P_i is the initial pressure at the commencement of test, MPa (psi);

P is the pressure after test has commenced at specific interval, MPa (psi);

M_B is the bulk modulus of the fluid in the tubing string above the SCSSV, MPa (psi);

t is the duration of the test at specific interval, min.

NOTE 1 The single phase equations presented above represent a simplistic approach to estimating leakage rate based on pressure response at the wellhead. The associated degree of error will depend on multiple factors including pressure gauge/ transducer accuracy, as well as other input parameters.

NOTE 2 If free gas exists in the tubing string (i.e. if oil is below the bubble point pressure at any point in the tubing string), then other factors need to be taken into consideration such as gas expansion in the tubing as well as potential cooling effects of gas which will influence pressure to decrease simultaneously.

Example liquid-leakage problem (SI and USC units)

In SI units:

P_i = 6,894,759 Pa

P = 18,960,587 Pa

t = 15 min

Bulk Modulus = 2.35×10^9 Pa

V_i = 1.13 m^3

$$V = V_i\left[\frac{P - P_i}{M_B}\right] + V_i \rightarrow q = \frac{V - V_i}{t}$$

$$V = 1.13\left[\frac{18{,}960{,}587 - 6{,}894{,}759}{2.35 \times 10^9}\right] + 1.13 = 1.1358\text{m}^3$$

$$q = \frac{1.1358 - 1.13}{15}\left(1{,}000{,}000\frac{cc}{\text{m}^3}\right) = 386 \text{ cc/min}$$

In USC units:

P_i = 1000 psi

P = 2750 psi

t = 15 min

Bulk Modulus = 340,838.6 psi

V = 40 ft^3

$$V = V_i\left[\frac{P - P_i}{M_B}\right] + V_i \rightarrow q = \frac{V - V_i}{t}$$

$$V = 40\left[\frac{2750 - 1000}{340{,}839}\right] + 40 = 40{,}205 \text{ ft}^3$$

$$q = \frac{40.205 - 40}{15}\left(1728\frac{\text{in.}^3}{\text{ft}^3}\right)\left(0.554\frac{\text{oz}}{\text{in.}^3}\right) = 13.1 \text{ oz/min}$$

A.3 Procedure for Testing Installed SSCSVs and SSISVs

A.3.1 Close the SSSV using the method specified by the supplier/manufacturer in the operating manual. If the valve cannot be in situ tested, refer to 6.4.2.

A.3.2 Isolate the well from the flow line by shutting-in at, or near, the wellhead.

A.3.3 Bleed any remaining pressure off the wellhead to the lowest practical pressure and then shut in the well at the wing or flow line valve. When possible, bleed flow line header pressure down to or below wellhead pressure and observe the flow line and wellhead for a change in pressure which would indicate a faulty surface valve. Any measurable leaks through the wing or flow line valve shall be repaired before proceeding with the test.

A.3.4 Conduct leakage test and document results. For wells with gas below the SSSV, flow rates can be computed from pressure build-up by the formula given in A.2.8.1.

A.3.5 For wells with liquid across the SSSV, the pressure build-up depends on the static liquid level and the amount of gas in the oil. If the liquid level is below the SSSV, the formula for gas wells (see A.2.8.1) can be used. If the liquid level is above the SSSV, the liquid leakage rate should be calculated using a single-phase liquid method (see A.2.8.2).

A.3.6 If the SSSV failed to close or if the leakage rate exceeds 0.43 m^3/min (15 SCF/min) gas, or 400 cm^3/min (13.5 oz/min) liquid, the well shall remain shut-in until one of the following corrective actions has been performed:

a) remediate, repair, or replace the SSSV to conform to the acceptance criteria;

b) complete an approved documented risk assessment for continuing operations.

NOTE Continuing operations may require additional regulatory approvals.

Annex B
(normative)

Failure Reporting

B.1 Failure Reporting

The operator of SSSV equipment manufactured to API 14A shall provide to the supplier/manufacturer a notification of equipment failure. A failure report shall be submitted to the equipment supplier/manufacturer within 30 days of the discovery and identification of the failure. An investigation in the form of a failure analysis to define the cause of the failure shall be performed and the results documented.

The operator's options for performing failure analysis on failed equipment shall be as follows.

a) The operator removes the failed equipment from service and returns the equipment to the equipment supplier/manufacturer who, in cooperation with the operator, performs the failure analysis; or

b) the operator does not immediately remove the equipment from service. However, if the operator removes the equipment within five years of the date of the shipping/receiving report, the operator shall return the equipment to the equipment supplier/manufacturer for the failure analysis; or

c) the operator elects to perform an independent failure analysis.

The operator shall notify the equipment supplier/manufacturer of the option selected for failure analysis as part of the failure report. If option (c) is selected, a copy of the analysis report shall be sent to the equipment supplier/manufacturer within 45 days of completion of the analysis.

The supplier/manufacturer shall respond in accordance with the failure reporting requirements of API 14A.

B.2 Minimum Information for Failure Notification Report

The failure report should include, as a minimum, the following information:

I. Identification

Operator ______________________________

Date of installation ______________________________

Field and/or area ______________________________

Lease name and well number ______________________________

II. SSSV equipment identification

SSSV

Part Number ______________________________

Equipment mfr. ______________________________

Model ______________________________

Tubing Retrievable

Nipple profile______________________________

Packing Bore ______________________________

Wireline Retrievable ____ (SCSSV type) ____ (SSCSV type) ____ (SSISV type)

SSSV Lock ______________________________

SSSV Landing Nipple ______________________________

Serial Number ______________________________

Working Pressure ______________________________

Nominal Size ______________________________

Validation Grade or service class ______________________________

Redress history records

III. Well data

Well test rate ______________________________

Environmental conditions

Percent Sand ______________________________

H_2S ______________________________

CO_2 ______________________________

Other______________________________

Pressure and temperature

Surface ______________________________

Bottom Hole ______________________________

SSSV equipment setting depth ______________________________

SSSV equipment installation date ______________________________

Time equipment in service______________________________

Unusual operating conditions ______________________________

IV. Test Results

Furnished by operator and/or conducted by supplier/manufacturer

Failure Mode ____________________

Leakage Rate____________________

Control fluid ____________________

Operational data (opening and closing pressure, etc.)

V. Description of failure

Nature of failure ____________________

Observed conditions which could have caused failure ____________________

____

____

____

____

Date of last successful test ____________________

Date of failure____________________

Annex C
(informative)

Installation

C.1 General

The following recommended installation practices are intended as guides and are not all-inclusive, but cover the most common systems in use. They also provide information that may be utilized in other systems. A recommended SSSV test procedure is included in Annex A. Inspection of new SSSV equipment before installation is covered in 5.5. Installation requirements for specific valves shall be covered in the operations manual for the product.

Testing results, pressures, and durations shall be documented per 8.4.1.

C.2 Surface-controlled Subsurface Safety Valve

C.2.1 General

The installation steps following are only intended to highlight possible operational considerations and not intended to be prescriptive for every possible completion configuration. The user/operator and supplier/manufacturer should collaborate to insure the integrity of the system components before/during/after running the completion.

C.2.2 Control Line

Prior to installation, control line should be flushed and cleanliness level verified. Verify the control line contains the proper control line fluid. The spool should be pressure tested to the working pressure of the surface control system.

NOTE SAE AS4059 Table 1 or AIA NAS 1638 Table I contains information on cleanliness levels.

Verify there is sufficient control line on the spool to accommodate SSSV setting depth plus the length of control line required to reach from the rig floor to the sheave and back down to the spool leaving sufficient line on the core of the spool.

Verify the diameters of the sheaves used to run control line are larger than the minimum bend diameter specified by the control line supplier/manufacturer. Make certain sheaves and other control line handling equipment is properly fixed and secured to the rig structure prior to running.

Step 1. Run the production tubing until SCSSV position is reached. At this point, it is imperative that the well be fully under control, since it may be difficult to seal around both tubing and control line with blowout preventers. As an added safety precaution, a planned procedure for cutting the control line and closing in the well should be provided. Equipment to execute that procedure must be compatible with and compliant to rig floor environment. Special care should be taken to avoid excessive use of thread compound.

Step 2. Install safety valve landing nipple or tubing-retrievable valve with flow couplings if applicable and make-up to the production tubing.

Step 3. If control lines are passing the SSSV from below, make certain those lines align properly with the control line entry port(s) on the nipple or tubing-retrievable valve. Align and install the offset control line protector below the SSSV if applicable. Alignment is determined by offset protectors and cross-coupling protectors when used.

Step 4. Prior to control line connection, flush control line termination(s) with the required fluid to the specified cleanliness. Connect control line(s) to safety valve landing nipple or tubing-retrievable SCSSV. Follow the supplier/ manufacturer's operating manual to purge the tubing-retrievable SCSSV operating systems of air.

Step 5. Test control line(s) and connection(s). No visible leakage should be observed. The control fluid is critical and should be selected as described in 4.2.4.

The following procedures are recommended.

a) Wireline-retrievable: install dummy or block off control ports, if control ports are exposed to well fluid, and test to the rated working internal and external (if control line connection is capable) pressure of the system.

b) Tubing-retrievable: test to maximum internal and external (if control line connection is capable) pressure differential as recommended by the valve supplier/manufacturer's operating manual.

Step 6. Align and install the offset control line protector above the SSSV if applicable. Alignment is determined by position of control line entry ports, lower offset protector, and cross-coupling protectors when used.

Step 7. Run tubing and control line(s). When running a tubing-retrievable surface-controlled subsurface safety valve (TR-SCSSV), hold valve open with control line pressure according to the supplier/manufacturer's operating manual.

Precautions should be taken to:

a) prevent entry of well-bore contaminants into the control system (landing nipple design);

b) detect leaks in either control line operating system (when equipped) while running; and

c) prevent damage to the control line(s).

To aid in achieving these objectives, maintain pressure in the control line(s) when running according to the supplier/manufacturer's operating manual.

Step 8. Affix the control line(s) to the tubing with at least one fastener or control line protector (see 4.4) for each joint.

Step 9. Run tubing to completion design depth and space out, if required.

Step 10. Install tubing hanger and connect control line(s) to proper termination on the hanger (subsea completion) or proper pass-through port on the hanger (surface or platform completion). At this point special care should be taken to follow the wellhead supplier/manufacturer's written instructions for installing the wellhead assembly and assuring pressure continuity of the control line system.

Step 11. Pressure-test control line(s) and connection(s) at the tubing hanger in accordance with step 5 a) or step 5 b).

Step 12. The following procedures are recommended.

a) For wireline-retrievable installations, where the control port(s) are exposed to the wellbore fluid: pull dummy or open control ports and circulate a minimum of one (1) control line volume. Do not leave control line port open for prolonged periods; either install safety valve, reinstall dummy, close mandrel ports, or continuously pump small volumes of hydraulic fluid to keep foreign materials out of the control line.

b) For tubing-retrievable installations: test valve for proper operation as recommended by the supplier/manufacturer.

C.2.3 Control System

C.2.3.1 Installation of the control system should be made in accordance with API 14C for surface safety systems, in accordance with API 14E for piping systems and in accordance with API 14F for electrical systems, as applicable.

C.2.3.2 The control system should be installed in such a fashion that it does not interfere with nor is subject to damage by the normal production operations performed on the facility. The location of the control unit, while not critical to its operation, should be chosen for convenience and safety. Location of the control line pressure release valve should be as close as is practical to the SSSV to facilitate timely closure. The control unit enclosure should be weatherproof.

C.2.3.3 All functions, hydraulic, pneumatic, electric, or other actuation means should be tested for proper operation prior to the system's connection to the SCSSV. Systems should be tested in accordance with the supplier/manufacturer's recommended testing and operating procedures.

C.2.4 Subsurface-controlled Subsurface Safety Valves and Subsurface-controlled Injection Safety Valves—Application to Single and Multiple Completions

C.2.4.1 Run tubing with safety valve landing nipple and flow couplings, where used, positioned at designed SSCSV installation depth.

C.2.4.2 Additional safety valve landing nipples with flow couplings, where used, may be desirable to allow alternative SSCSV/SSISV placement.

C.2.4.3 Install the SSCSV/SSISV in accordance with the supplier/manufacturer's procedures.

Annex D
(informative)

Operations

D.1 General

The following recommended operation practices are intended as guidelines and are not all-inclusive, but cover the most common systems in use. They also provide information that may be utilized in other systems. Inspection of new valves before installation is covered in 5.5. Requirements for installation and operation of specific valves should be covered in the operations manual for that product.

Surface-controlled valves utilize valve elements that are normally closed. This fail-safe mode requires that the valve be opened by a signal. Loss of this signal results in the closing of the SCSSV. The signal to the valve is supplied from a control system, which is a part of the overall SCSSV system and managed by a safeguarding emergency shutdown (ESD) system.

The SSSV shall close in the event of an ESD. Closure of the SSSV under full-flow conditions should be avoided, and therefore a delay should be incorporated in the ESD system such that the SSV/USV closes before the SCSSV. The opening sequence should be reversed on returning production facilities to normal operations. This delay mechanism shall be carefully analyzed so that it does not create additional hazards that render the system more vulnerable to failure.

D.2 Operation and Testing

Because failure of a safeguarding system may not be obvious until the system is needed, it is important to check the instruments and the control system at defined intervals. Operation of the control system serves to keep moving parts free and functioning properly, and leads to early detection of failures. Additionally, more frequent checks should be made of gauges and other displayed controls. It is recommended that testing of the complete safeguarding system be carried out every six months unless local regulations, conditions and/or documented historical data indicate a different testing frequency.

Checking and testing should be carried out during:

— normal operations, using maintenance override switches; shutdown valves should not be actuated during normal operations;

— scheduled shutdowns, which could be initiated by actuating an individual shutdown device to test the system as a whole;

— unscheduled shutdowns initiated by any other cause.

When re-opening the SSSV, it is recommended to have the pressures above and below the closure mechanism equalized, regardless of whether the SSSV has equalizing feature(s).

D.3 Recommendations and Required Documentation

The following should be available:

— full system documentation including alarm and shutdown diagrams, loop diagrams, etc.;

— a comprehensive and updated testing procedure;

— all equipment should be correctly and clearly identified (tagged, labeled);

— all parties involved in the testing should be a qualified person and be familiar with the testing procedure.

Records should be kept of trips and test results (including spurious trips and failures to trip when required). The combination of above-mentioned checks should cover a complete ESD system including initiating devices, logic units and shutdown valves.

D.4 Review and Responsibilities of ESD System Testing

The procedure for testing of safeguarding systems should be reviewed to take into account testing results and to assess system reliability.

Reviews should involve personnel from engineering, operations, maintenance and safety.

The person responsible for testing the safeguarding system components should sign the test record to indicate that shutdown sensors and devices were satisfactorily checked, placed back in operation after testing, and overrides withdrawn.

D.5 Important Information on System Shutdown

No shutdown sensor or device in the safeguarding system should be left in the blocked or bypass position while the system or equipment that is being protected is in operation, unless full-time attendance is provided for the individual item of equipment on which the shutdown sensor or device is located.

Annex E
(informative)

Sizing of Subsurface-controlled Safety Valves and Subsurface-injection Safety Valves

E.1 General

This annex describes recommended sizing practices for SSCSVs and SSISVs. It is not all-inclusive, but covers the most common practices in use.

Two SSCSV-type designs are generally available: velocity-type (normally open) or ambient-type.

— Velocity-type SSCSVs used in production wells are designed to close when high well-effluent velocity causes a pressure differential across an orifice in the valve in excess of the design differential chosen by the user/purchaser.

— Ambient-type SSCSVs are designed to close when tubing pressure drops below a pre-set level.

Another type of flow-sensing SSSV is the injection-type (normally closed) referred to as SSISV.

— Injection-type SSISVs used in injection wells are similar to the velocity-type but are designed to open when injected flow through the SSISV occurs. Generally they are designed to close in the absence of injection.

It is recommended that the SSCSV and SSISV supplier/manufacturer be consulted regarding the specific design and setup of the provided equipment. Wells with possible erratic production flow (slugging) are generally not good candidate completions for SSCSVs due to the ever changing flowing conditions.

E.2 Velocity-type SSCSV

The following general procedure is recommended to size the velocity-type SSCSV.

Step 1. Obtain a representative well test rate. See Form E.1.

Step 2. Calculate or measure the flowing bottomhole pressure for the producing conditions of step 1. A suitable vertical flow correlation should be used in making the calculation. If an SSCSV was installed during the test, the pressure drop across the orifice should be calculated to determine the correct flowing bottomhole pressure.

Step 3. Calculate the well inflow performance from data obtained in step 1 and step 2. For oil wells, a PI or a Vogel [5] IPR should be calculated. The backpressure equation developed by Rawlins [4] for open-flow potential can be used for gas wells. Two or more different rate tests may be useful in determining the well inflow performance more accurately. Once the well inflow performance has been determined, flowing bottomhole pressures for other producing rates can be calculated.

Step 4. Select an orifice (bean) size or a desired pressure drop for a particular make, model and size of velocity-type SSCSV. The orifice size shall be small enough in diameter to create a sufficient pressure differential to close the SSCSV at the desired flow rate. In addition, the orifice size and material should be selected to minimize erosion. The supplier/manufacturer's recommended ranges of pressure differentials should be followed for each size and model of velocity-type SSCSV. The orifice is generally connected to the flow tube to control the SSCSV position (open or closed). Caution should be exercised if the orifice diameter exceeds 80 % of the flow tube diameter, since the pressure-drop calculations are less predictable. For gas wells, the calculated flow rate through the orifice shall not exceed the critical flow rate. To make reliable gas orifice calculations, the pressure drop through the orifice should not normally exceed 15 % of the value of the pressure immediately under the SSCSV. Appropriate orifice coefficient and pressure-drop correlations for the SSCSV and orifice should be obtained from the supplier/manufacturer.

Step 5. Select a closure-rate condition. The closure rate should be no greater than 150 % but no less than 110 % of the well test rate. For oil wells producing less than 63.6 m^3/day [400 barrels of fluid per day (BFPD)], the SSCSV should be designed to close at a rate no greater than 31.8 m^3/day (200 BFPD) above the well test rate. To avoid frequent nuisance closures and valve throttling, the closure rate shall be greater than the well test rate.

Step 6. Calculate the following for closure-rate conditions:

a) the flowing bottomhole pressure (use the well inflow performance obtained in step 3 to calculate this value);

b) the pressure immediately under the SSCSV (use a suitable vertical flow correlation);

c) the pressure drop or the orifice size (use the appropriate orifice correlation);

d) the flowing tubing wellhead pressure. Under closure-rate flow conditions, the surface tubing pressure should exceed 345 kPa (50 psi). If the calculated surface tubing pressure is less than 345 kPa (50 psi), select a reduced closure rate and recalculate.

Step 7. Calculate the required SSCSV closing force. The supplier/manufacturer will provide data, when applicable, to obtain the needed spring compression—normally by use of spacers. A spring with a particular spring-rate shall be selected and compression shall be applied which will keep the valve open under the well test rate but permit closure at the calculated closure rate. Verify that the requirements of step 4, step 5, and step 6 are met. If not, return to step 4 and select a different orifice size or pressure drop.

E.3 Ambient-type SSCSV

E.3.1 General

The SSCSV that is actuated by a decrease in the tubing pressure can be used in flowing oil and gas wells and in continuous gas-lift wells. Ambient-type SSCSVs are not suitable for intermittent gas-lift wells. As with the velocity-type SSCSV, the well test rate and closure-rate conditions shall be known to properly size the ambient-type SSCSV. Some wells may require the running of a pressure survey to determine more accurately the flowing pressure at the SSCSV. The ambient-type SSCSV can be sized using the following recommended procedure.

E.3.2 Flowing Oil and Gas Wells

Step 1. Obtain the well test rate.

Step 2. Calculate or measure the flowing pressure at the SSCSV depth and the flowing bottomhole pressure. Use an appropriate vertical flow correlation when making the calculations.

Step 3. Determine the well inflow performance. Use the same method given in step 3 for the velocity-type SSCSV.

Step 4. Determine the flowing temperature at the SSCSV. This temperature is required to accurately predict the closing pressure of the SSCSV. If direct measurement at the SSCSV depth is not available, a temperature prediction model or offset well data shall be used to determine the temperature.

Step 5. Select a closure-rate condition. The closure rate should be no greater than 150 % but no less than 110 % of the well test rate. For oil wells producing less than 63.6 m^3/day [400 barrels of fluid per day (BFPD)], the SSCSV should be designed to close at a rate no greater than 31.8 m^3/day (200 BFPD) above the well test rate. To avoid frequent nuisance closures and valve throttling, the closure rate shall be greater than the well test rate.

Step 6. Calculate the following for closure-rate conditions:

a) the flowing bottomhole pressure (use the well inflow performance obtained in step 3 to calculate this value);

b) the pressure at the SSCSV (use a suitable vertical flow correlation);

c) the flowing tubing wellhead pressure. The surface tubing pressure should exceed 345 kPa (50 psi) at closure-rate flow conditions. If the calculated flowing tubing wellhead pressure is less than 345 kPa (50 psi), select a reduced closure rate and recalculate.

Step 7. Set the ambient-type SSCSV to close at closure-rate condition. To avoid nuisance closures, the closure pressure should be at least 345 kPa (50 psi) less than the flowing pressure at valve depth.

E.3.3 Gas-lift Oil Wells

Step 1. Obtain the well test rate under gas-lifting producing conditions. Determine the injected gas volume and injection depths. Also, obtain a well test without gas injection. Form E.1 shows the required data.

Step 2. Determine the pressure at the SSCSV for the two well test rates obtained in step 1. Use a suitable vertical flow correlation when calculating the pressures. If the test pressure at the SSCSV without gas injection is within 345 kPa (50 psi) or greater than the test pressure for normal gas lifting conditions, the SSCSV is set too deep in the well or may not be suitable for use. Shallow settings of less than 305 m (1000 ft) are frequently required.

Step 3. Size the ambient-type SSCSV to close at valve depth with a pressure (a) less than the well test rate pressure, and (b) greater than the producing rate pressure without gas injection (flowing). The closure pressure should be at least 345 kPa (50 psi) less than the normal operating pressure at the valve to prevent nuisance closures. A temperature adjustment as outlined in step 4 of section E.3.2 for flowing oil and gas wells is required for these types of valves.

E.4 SSISV

The following general procedure is recommended to size the SSISV.

Step 1. Obtain a representative well injection rate. See Form E.1.

Step 2. Calculate or measure the upstream pressure for the injection conditions of step 1. A suitable vertical flow correlation should be used in making the calculation. If an SSISV was installed during the test, the pressure drop across the orifice shall be calculated to determine the correct upstream pressure.

Step 3. Select an orifice (bean) size or a desired pressure drop for a particular make, model and size of SSISV. The orifice size shall be small enough in diameter to create a sufficient pressure differential to fully open the SSISV at the desired flow rate. In addition, the orifice size and material should be selected to minimize erosion. The supplier/manufacturer’s recommended ranges of pressure differentials should be followed for each size and model of SSISV. The orifice is generally connected to the flow tube to control the SSISV position (open or closed). Caution should be exercised if the orifice diameter exceeds 80 % of the flow tube diameter, since the pressure-drop calculations are less predictable. Appropriate orifice coefficient and pressure-drop correlations for the SSISV and orifice should be obtained from the supplier/manufacturer.

Form E.1—Sample Sizing Data Form for Subsurface-controlled Subsurface Safety Valve

COMPANY________________________ DATE ________________________

LOCATION________________________ LEASE AND WELL ________________

1 Well Data—Oil Wells

Oil production (gas-lift/flowing)	____________	m^3 OPD (BOPD)
Water production	____________	m^3 WPD (BWPD)
Gas/oil ratio	____________	m^3/m^3 (cf/bbl)
Separator pressure	____________	MPag (psig)
Flowing tubing head pressure	____________	MPag (psig)
Crude gravity	____________	API
Bubble point pressure	____________	MPag (psig)
Gas injection volume (gas-lift only)	____________	Mm^3/d (MMCF/D)
Depth of gas injection (gas-lift only)	____________	m (ft)
Additional information	____________	

2 Well Data—Gas Wells

Gas production	____________	Mm^3/d (Bcf/d)
Condensate/gas ratio	____________	m^3/Mm^3 (bbl/Bcf)
Water/gas ratio	____________	m^3/Mm^3 (bbl/Bcf)
Flowing tubing head pressure	____________	MPag (psig)
Condensate gravity	____________	API
"*n*" Backpressure equation exponent	____________	

3 Completion and Reservoir Data

Depth of producing zone (TVD)	____________	m (ft)
Depth of SSSV (TVD)	____________	m (ft)
Tubing ID	____________	cm (in.)
Static bottom hole pressure	____________	MPa (psi)
Flowing BHP	____________	MPa (psi)
Pressure at/below SSSV	____________	MPa (psi)
Static bottom hole temperature	____________	°C (°F)
Flowing wellhead temperature	____________	°C (°F)

4 Standard Assumptions: (Oil/Gas)

Separator gas gravity (0.7/0.6 w/air = 1.0) ____________________

Water specific gravity (1.07/1.05) ____________________

Absolute pipe roughness (0.0018/0.0006) ____________________

Discharge coefficient of orifice (0.85/0.90) ____________________

Standard pressure 0.101325/0.101325 (14.696/14.696) ____________________ MPa (psi)

Standard temperature 15.6/15.6 (60/60) ____________________ °C (°F)

5 Deviated Hole Data:

MD _______ , _______ , ______ , _______, ________, _______, ________, ________m (ft)

TVD ______ , _______ , ______ , _______, ________, _______, ________, ________m (ft)

6 Existing SSSV Data (Where Applicable)

Orifice size ____________________ mm (in.)

Valve code or flow tube ID ____________________

7 Sizing Data

Valve code or valve type: (mfr. & description) ____

Orifice size: (1)______________ cm (in.), (2)_________________ cm (in.), (3) _________________ cm (in.)

OR

Pressure differential: (1)____________ MPa (psi), (2)_____________MPa (psi), (3) ___________ MPa (psi)

Ratio of calculated closure rate to the tested production rate:

(1)_______________ , (2)______________ , (3) ______________, (4) ______________, (5) ____________

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[1] API Specification 17F, *Specification for Subsea Production Control Systems*

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[4] Rawlins, E. L. and M. A. Schellardt: *Back-Pressure Data on Natural Gas Wells and Their Application to Production Practices*; Bureau of Mines Monograph 7, 1935, p. 168

[5] Vogel, J. V., "Inflow Performance Relationships for Solution Gas Drive Wells," *J. Petroleum Technol.*, January, 1968, pp. 8392

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