Recommended Practice for the Care and Handling of Sucker Rods

API RECOMMENDED PRACTICE 11BR
NINTH EDITION, AUGUST 2008

REAFFIRMED, MARCH 2015

AMERICAN PETROLEUM INSTITUTE

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Upstream Segment

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energy API

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Suggested revisions are invited and should be submitted to the Standards Department, API, 1220 L Street, NW, Washington, D.C. 20005, standards@api.org.

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Tables

Recommended Practice for Care and Handling of Sucker Rods

1 Scope

This recommended practice (RP) covers the care and handling of steel sucker rods, including guidelines on selection, allowable stress, proper joint makeup, corrosion control and used rod inspection.

2 References

This specification includes by reference, either in total or in part, the most recent editions of the following API, industry, and government standards, unless a specific edition is listed:

API Specification 11B, *Specification for Sucker Rods*

API Technical Report 11L, *Design Calculations for Sucker Rod Pumping Systems (Conventional Units)*

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

NACE MR0174 [2], *Selecting Inhibitors for Use as Sucker-Rod Thread Lubricants*

NACE SP0195, *Corrosion Control of Sucker Rods by Chemical Treatment*

3 Selection of API Steel Sucker Rods

3.1 General

The selection of API grade sucker rods for a beam pump installation depends on a variety of factors, including stress effects, environmental effects and rod grade.

3.2 Stress Effects

Sucker rods need to be selected based on applied stresses. API 11L, *Design Calculations for Sucker Rod Pumping Systems* provides a procedure for calculating the applied loads or stress on a sucker rod string design.

Sucker rod strength is limited by the fatigue performance of the rod's metal. This useful strength is dependent on the metal's tensile strength as shown by Goodman (Goodman, "Mechanics Applied to Engineering" and Kommers, "Effect of Range of Stress and Kind of Stress on Fatigue Life"). This relationship is the basis for Section 4 of this document. According to the Goodman diagram shown in Figure 1, sucker rods operating in a non-corrosive environment and in the proper stress range will theoretically exceed 10 million load reversals. However, the fatigue life can be dramatically decreased by improper installation, design, handling or operation even without corrosion.

3.3 Environmental Effects

Sucker rods will eventually fail, even if not stressed, when placed in a corrosive environment. There is a reduction in sucker rod and coupling life if placed in a corrosive environment. However, the life of the sucker rod can be extended by the use of an effective corrosion inhibition program. In that case the expected life of a sucker rod can potentially be the same as a rod in a non-corrosive environment.

[1] American National Standards Institute, 25 West 43rd Street, 4th floor, New York, New York 10036, www.ansi.org.
[2] NACE International (formerly the National Association of Corrosion Engineers), 1440 South Creek Drive, Houston, Texas 77218-8340, www.nace.org.

Another environmental concern is the use of the sucker rods in a production environment which contains hydrogen sulfide. A sucker rod placed in this environment can rapidly fail even though the corrosion effects are not readily apparent. NACE MR0175 has defined a hydrogen sulfide environment as “sour” when the hydrogen sulfide partial pressure is greater than 0.05 psi or 0.0034 atm (0.345 kPa). Materials placed in sour environments with hydrogen sulfide partial pressures equal to or greater than this value can fail prematurely due to hydrogen embrittlement unless the materials are sulfide stress cracking resistant or unless an effective corrosion inhibition program is maintained.

3.4 Sucker Rod and Coupling Grade Selection

3.4.1 General

Tables 1 and 2 identify the chemical composition and mechanical strength properties of steel sucker rods. For non-sour (sweet) environments, the applied stresses determine which grade of sucker rod is selected. However, a corrosion inhibition program may be required to combat the damaging effects of corrosion and its associated life reduction.

3.4.2 Grades

Materials which are not susceptible to sulfide stress cracking usually possess a Rockwell C scale hardness of less than 23. Thus, a Grade C sucker rod is the optimum sucker rod to be used if the applied stresses are within its capabilities and a sour environment exists.

If the applied stresses require Grade D sucker rods and a sour environment exists, then an effective corrosion inhibition program is required.

The Grade K rod is available for use when the other sucker rod grades have not performed satisfactorily in a corrosive environment.

The chemical composition of steel sucker roads and steel pony rods shall be any composition of AISI series steel, or international equivalent, listed in Table 1 which can be effectively heat treated to the mechanical property requirements of API Grades K, C, and D rods as shown in Table 2.

Table 1—Chemical Composition of Steel Sucker Rods

API Grade	Chemical Composition
K	AISI 46XX Series Steel [a]
C	AISI 10XX Series Steel [a] AISI 15XX Series Steel [a]
D Carbon	AISI 10XX Series Steel [a] AISI 15XX Series Steel [a]
D Alloy	AISI 41XX Series Steel [a]
D Special	Special—Special alloy shall be any chemical composition that contains a combination of nickel, chromium and molybdenum that total a minimum of 1.15% alloying content.

[a] Or an equivalent international series number steel.

Table 2—Mechanical Strength Properties of Steel Sucker Rods

API Grade	Minimum Yield 0.2% Offset psi (Mpa)	Minimum Tensile psi (Mpa)	Maximum Tensile psi (Mpa)
K	60,000 (414)	90,000 (620)	115,000 (793)
C	60,000 (414)	90,000 (620)	115,000 (793)
D	85,000 (586)	115,000 (793)	140,000 (965)

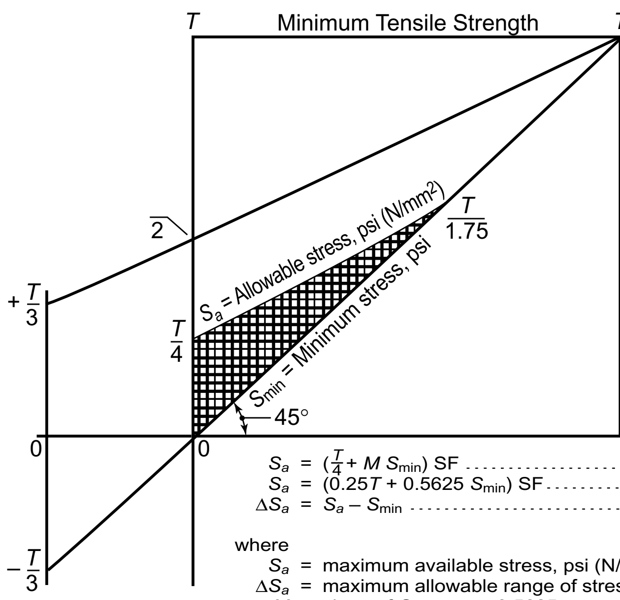
4 Allowable Sucker Rod Stress Determination Utilizing Range of Stress

4.1 General

In determining the allowable range of stress and allowable sucker rod stress for a string of sucker rods, it is recommended that the modified Goodman stress diagram shown in Figure 1 be used. This gives the basic or fundamental rating which can be used where corrosion is not a factor. Since all well fluids are corrosive to some degree, if not inhibited 100%, and since the corrosivity of well fluids varies greatly, it is of extreme importance that the stress values determined from this diagram be adjusted by an appropriate service factor, based on the severity of the corrosion. This service factor should be selected by each user as his experience indicates. It could be greater than one, although normally it will be less than one, varying inversely with severity of corrosion.

4.2 Stress Diagrams

In applying this information from Figure 1, separate diagrams can be prepared for each minimum tensile strength value. Separate diagrams showing load in pounds (KN) rather than stress can also be prepared for each grade and rod size. Alternately, the desire value can be obtained by using one of the equations shown in Figure 1.



$S_a = (\frac{T}{4} + M\ S_{min})$ SF 1

$S_a = (0.25T + 0.5625\ S_{min})$ SF 2

$\Delta S_a = S_a - S_{min}$ 3

where

S_a = maximum available stress, psi (N/mm^2)

ΔS_a = maximum allowable range of stress, psi (N/mm^2)

M = slope of S_a curve = 0.5625

S_{min} = minimum stress, psi (N/mm^2)(calculated or measured)

SF = service factor

T = minimum tensile strength, psi (N/mm^2)

Figure 1—Modified Goodman Diagram for Allowable Stress and Range of Stress for Sucker Rods in Non-corrosive Service

4.3 U.S. Customary (USC) Example

Assume a string of API Grade C rods with a minimum tensile strength of 90,000 psi (620 N/mm^2) is being used and that a minimum downstroke stress of 15,000 psi (103 N/mm^2) has been either measured or calculated. At what peak polished rod stress may we operate this string in non-corrosive service?

Refer to Figure 1, Equation (2).

$$S_a = (0.25T + 0.5625\ S_{min})$$

$$= (0.25 \times 90{,}000 + 15{,}000 \times 0.5625)$$

$$= 30{,}938 \text{ psi (non-corrosive)}$$

Converting to load for different size top rods, this would be:

$^5/_8$ in. ....30,938 × 0.307 = 9,498 lb

$^3/_4$ in. ....30,938 × 0.442 = 13,675 lb

$^7/_8$ in. ....30,938 × 0.601 = 18,594 lb

1 in. ....30,938 × 0.758 = 24,286 lb

4.4 Metric Example

$S_a = (0.25T + 05625\ S_{\min})$

$= 0.25 \times 620 + 0.5625 \times 103$

$= 213\ \text{N/mm}^2$

Converting to load for different size top rods, this would be:

15.9 mm..........213 × 197.9 = 42.2 KN

19.0 mm..........213 × 285.0 = 60.9 KN

22.2 mm.......... 213 × 387.9 = 82.6 KN

25.4 mm..........213 × 506.7 = 107.9 KN

The above values should then be adjusted by an appropriate service factor.

5 Slim Hole Sucker Rod Coupling Derating

5.1 Derating Factor History

The concept for reducing the allowable rod string stress when slim-hole couplings were used was originally published by Gipson et al., (Gipson, F.W and H.W. Swaim, “Beam Pump Fundamentals”).

It was discussed that the actual derating factor was not known. Original derating factors were developed based on the relationship between the slim-hole coupling cross sectional area divided by the cross sectional area of the corresponding sucker rod. However, it was known, based on field performance, that slim-hole couplings for 1-in. rods did not have a record of excessive failures. Thus, the derating factors were normalized based on the slim-hole area divided by the rod area for 1-in. rods. Derating factors were presented for the different slim-hole coupling sizes for use on all grades of sucker rods.

5.2 Modified Derating Factor

A more rigorous analysis of the cross sectional area relationships, stress concentration factor effects of the rod connection threads, and the use of the API Modified Goodman Diagram included here as Figure 1 was published by D.E. Hermanson (Hermanson, D.E., *Petroleum Engineering Handbook*).

These derating factors include the influence of the different allowable stress capabilities for the different rod and corresponding coupling size and API grade. These factors are presented in Table 9.8 of the above referenced handbook and are identified in Table 3 of this RP.

Table 3—Recommended Slim-hole Coupling Derating Factors, F_d

API Rod Size (in.)	API Rod Grade		
	K	C	D
5/8	—	0.97	0.77
3/4	—	—	0.86
7/8	0.93	0.88	0.69
1	—	—	0.89

These derating factors should be considered as a conservative allowable load or stress reduction to account for the "weakest link" design approach for sucker rod strings. Field experience may allow for modifications in these factors to either increase or decrease the amount of derating based on the individual well conditions. However, the use of a derating factor should be considered in the string design similar to that of rod stress determination.

6 Sucker Rod Joint Makeup Utilizing Circumferential Displacement

6.1 General

For optimum performance, it is imperative that all of the joints in the string of rods be made up to a given preload stress level in order to prevent separation between the pin shoulder and the coupling face during the pumping cycle.

Both test data and theoretical calculations show that circumferential displacement beyond hand-tight makeup of coupling and pin provides an accurate and repeatable means with which to measure and define the preload stress in a sucker rod joint.

Table 4—Sucker Rod Joint Circumferential Displacement Value Measurements
all dimensions in inches (followed by equivalent in mm)

1	2		3	
	Running New Grade D Displacement Valves		Rerunning Grades C, D and K Displacement Values	
Rod Size	Minimum	Maximum	Minimum	Maximum
5/8 (15.9)	8/32 (6.3)	9/32 (7.1)	6/32 (4.8)	8/32 (6.3)
3/4 (19.1)	9/32 (7.1)	11/32 (8.7)	7/32 (5.6)	17/64 (6.7)
7/8 (22.2)	11/32 (8.7)	12/32 (9.5)	9/32 (7.1)	23/64 (9.1)
1 (25.4)	14/32 (11.1)	16/32 (12.7)	12/32 (9.5)	14/32 (11.1)
1 1/8 (28.6)	18/32 (14.3)	21/32 (16.7)	16/32 (12.7)	19/32 (15.1)

NOTE: Above displacement values were established through calculations and strain gauge tests.

There are many inherent variables which affect joint makeup. Among these are the differences in materials, the smoothness of surface finishes, selection of an acceptable thread lubricant, and the lubricity of lubricants, as well as the operating characteristics and mechanical condition of the power tong equipment. As a result, applied torque has not proven to be the most accurate, nor the most practical means of measuring the preload stress level in a sucker rod joint.

NOTE NACE MR0174 has developed a tested procedure for possible thread lubricants that requires a single application of the thread lubricant to a pin, complete makeup and break-out using the appropriate makeup displacement for the rod size and grade and repeated for 10 complete cycles. After this procedure, the pin and coupling threads should be cleaned and inspected. An acceptable pin lubricant is one which results in no visible damage or galling of either thread forms.

In view of the foregoing, this RP provides, for field use, a comprehensive set of circumferential displacement values and procedures covering their use, including a method for the calibration of power tongs.

6.2 Circumferential Displacement Values

Circumferential displacement as used herein is the distance measured, after makeup, between the displaced parts of a vertical line scribed across the external surfaces of the box and pin when they are in a shouldered hand-tight relationship prior to makeup. See Figure 2 and Figure 3.

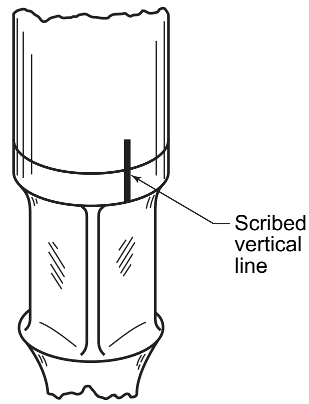


Figure 2—Hand-tight Joint

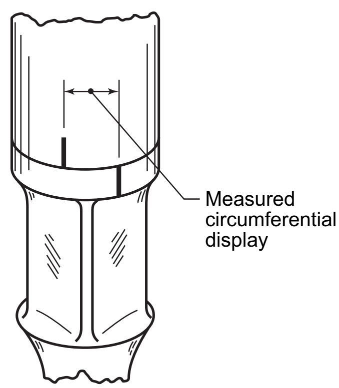


Figure 3—Made-up Joint

The circumferential displacement values shown in Table 4 are the necessary and recommended displacements required to achieve an optimum preload stress. Values for a combination of materials and their application are listed in the column headings. Choose the correct column.

Because the interface surfaces of the joint are burnished or smoothed out on initial makeup, the displacement values on initial makeup are greater than those on subsequent makeup. While this difference in displacement occurs in varying degrees with all rod grades, it is observed to be consistent only in the Grade D rod.

NOTE The tabulated values for use when rerunning Grade D rods are smaller than those for the initial makeup of new Grade D rods.

It is impractical to establish displacement values for the initial makeup of Grade C and K rods because of the inconsistency of observed test data with these materials. It is therefore recommended that new Grade C and K rod joints be made up and broken, in the field, prior to final makeup on initial installation.

When new couplings are installed on previously used rods regardless of their grade, the displacement values listed in Table 4, Column 2 should be used.

6.3 General Recommendations, Power Tongs

The use of a hydraulic power tong is recommended to assure best makeup results for all sizes of sucker rods. However, it is imperative the power tongs be maintained in accordance with the manufacturer's recommendations. It is recommended the hydraulic power oil system be circulated until a normal operating temperature is reached and that this temperature be maintained within a reasonable level through calibration and installation of rods.

6.4 Calibration of Power Tongs

6.4.1 General

Power tongs must be calibrated to produce recommended circumferential displacement makeup values shown by Table 4. After initial calibration, it is recommended the power tong calibration be checked each 1000 ft (300 m) and be calibrated for each change in rod sizes.

There are three different methods employed in calibrating power tongs for various API Grade rods and field conditions. It is imperative to select the recommended method to suit your field conditions.

6.4.2 Calibration Process for Power Tongs for New API Grade D Rods

The following process should be used for calibration of power tongs for new API Grade D rods.

a) Check condition outlined under 6.1.

b) Set the tongs operating pressure on the low side of the estimated value required to produce prescribed circumferential displacement value shown by Table 4.

c) Screw the first joint together hand-tight; scribe a fine vertical line across the pin and coupling shoulder to establish hand-tight reference as shown by Figure 2.

d) Loosen coupling to the normal running position then make up the joint with power tong operating with the tong throttle depressed to the fully open position. Do not hit the throttle a second time after joint shoulder and tongs have stalled.

e) Remove the tongs and measure the circumferential displacement between the scribed hand-tight vertical line as shown by Figure 3.

f) Increase or decrease the tong operating pressure to achieve the selected prescribed circumferential displacement as shown by Table 4.

g) Repeat Steps d) through f) until proper displacement is achieved. Check the calibration of tongs a minimum of four joints and for each 1000 ft thereafter, and at each change in rod sizes.

6.4.3 Calibration Process for Power Tongs for API Grade C and Grade K Rods

The following process should be used for calibration of power tongs for API Grade C and Grade K rods.

a) For the initial run of API Grade C and Grade K rods, a constant correction factor cannot be recommended because of inherent variables involved. Therefore, it is imperative to make up and break the connection prior to calibration and power tongs if proper preload is to be assured.

b) Once the joint is made up and broken follow the same procedure as outlined in 6.4.2, Steps a) through g), using the appropriate circumferential displacement values in Table 4, Column 3.

6.4.4 Calibration Process for Power Tongs for Rerunning of all Grades of API Rods and New Couplings

Employ values shown in Table 4, Column 3 and follow same procedure as outlined in 6.4.2, Steps a) through g).

6.5 Use of Rod Wrenches for Manual Makeup

6.5.1 General

The use of rod wrenches is not recommended for rod sizes larger than $^3/_4$ in. Application of rod wrenches to achieve the desired preload is as follows.

6.5.2 Manual Makeup of New API Grade D Rod Strings

The following process should be used for manual makeup of new API Grade D rod strings:

a) screw rod and coupling to a shouldered hand-tight position;

b) scribe a fine vertical line across the pin and coupling to establish a hand-tight reference as shown by Figure 2;

c) apply necessary mechanical force to achieve recommended displacement values as shown in Table 4, Column 2.

6.5.3 Mechanical Makeup of API Grade C and Grade K Rods

The following process should be used for mechanical makeup of API Grade C and Grade K rods:

a) apply mechanical force and make up joint once. Loosen and retighten to hand-tight position;

b) scribe a fine vertical line across the pin and coupling shoulder to establish a hand-tight reference as shown by Figure 2;

c) apply necessary mechanical force to achieve recommended displacement values as shown in Table 4, Column 3.

6.5.4 Mechanical Makeup of Used Rods and New Couplings

The following process should be used for mechanical makeup of use rods and new couplings:

a) bring coupling and rod pin to a hand-tight position;

b) scribe a fine vertical line across the pin and coupling shoulder to establish a hand-tight reference as shown by Figure 2;

c) apply mechanical force sufficient to achieve circumferential displacement as shown in Table 4, Column 3.

NOTE The hand-tight position as used in Section 6 is attained when full shouldered adjustment is made.

7 Installation of Polished Rod Clamp on Polished Rod

Installation of a polished rod clamp on a polished rod is as follows.

a) Install the polished rod clamp per manufacturer's instruction tag (see API 11B).

b) The polished rod must be void of dirt and grease where the clamp is located.

c) The polished rod clamp must be void of dirt and grease in the gripping area.

d) The hanger bar must be perpendicular to the wellhead in line with the well bore and void of dirt and grease.

e) Place the polished rod clamp in a clean area on polished rod and tighten nut (or nuts) to hand tight. Do not install on any sprayed metal part of the rod.

f) For proper torque, follow manufacturer's instruction tag attached to the clamp (see API 11B).

g) If a friction type polished rod clamp is used with a metal sprayed polish rod, the user should be aware that the O.D. has a +0.005, –0.040 tolerance between the pin end and start of metal spray (see API 11B).

8 Inspection of Used Sucker Rods and Couplings

8.1 General

8.1.1 Inspection Methods

Sucker rods and couplings should be inspected by using visual, electromagnetic, magnetic particle and dye penetrant testing methods and various dimensional gauging tools (Stuart and Lloyds). Any of the above methods or combinations of them can result in an adequate inspection as selected and defined by the user. API 11B has a listing of definitions for defects and details on measurement procedures to verify workmanship and finish.

All inspection and NDT equipment used by the methods stipulated in this RP should be calibrated in accordance with 8.1.3.

8.1.2 Personnel Qualification

Inspection personnel should be minimally Level 1 qualified according to ASNT SNT-TC-1A (*Recommended Practice, Personnel Qualification and Certification in Nondestructive Testing*).

8.1.3 Calibration Frequency

Inspection equipment calibration frequency should be adequate to assure accuracy of the equipment's measurements. The calibration status shall be recorded on the gauge and in a log book (or similar tracking method) with the date of the calibration and the initials of the person who performed the calibration. All calibration activities shall be traceable to NIST or equivalent.

8.1.4 Calibration References

Working gauges, API P6 and P8 "no-go" and "go" ring gauges used to inspect sucker rod pins and API B2 and B6 "go" and "no-go" box plug gauges for sucker rod couplings, shall be checked against Master Reference Gauges according to gauge certification specifications described in API 11B. Working master gauges P8 and P6 shall be checked against setting gauges P7 and P5, respectively, prior to running any rod order.

8.1.5 Feeler Gauges

The working area(s) of the feeler gauges shall be checked at the beginning of each shift with a calibrated micrometer. Feeler gauges shall be trimmed or replaced if they do not measure within –0.0002 in. of the actual value.

8.2 Visual Inspections

8.2.1 Preparations for Inspections

The rod body should be visually inspected for signs of damage, corrosion or wear by a qualified person. Rod guides should be removed before rods are inspected. This will enable visual inspection of the rods and improve cleaning to bare metal during shot cleaning. The area of the rod body near the location of the guides should be carefully inspected for obvious corrosion pitting or erosion.

Used rods should be shot-cleaned to remove surface deposits which may interfere with the inspection. The shot weight, size, shape and velocity should be such as to not shot-peen the rods, per the manufacturer's specifications. Thread protectors should be used to protect the pins from the shot-cleaning.

Rod length shall be measured to determine if the rod is within manufacturing tolerances of ±2 in. Measurements outside this tolerance are cause for rejection in all classes.

Couplings should be removed prior to visually inspecting rods. Rods visually rejected prior to coupling removal may be discarded as a single unit.

8.2.2 Bend Evaluations

Rods should be visually inspected for bends by rolling. Those with an apparent bend should be further checked following the procedure in API 11B. Severely bent or kinked rods (those exceeding the limits identified below) should be rejected without further inspection.

For rod bodies, the maximum allowable bend when using a 12 in. straight edge is 0.065 in. for all rod diameters. If a total indicated run-out (TIR) gauge is used, the maximum allowable TIR value is 0.130 in. The TIR methodology would be good to be detailed as variability of the process could cause differing results.

Rods with bends between 0.150 in. and 0.300 in. measured with a TIR can be cold straightened if the rods are downgraded to Class II. Rods with bends greater than 0.300 in. TIR can be cold straightened if desired by the customer. These rods should be downgraded to Class III.

Rod ends should not have more than 0.150 in. TIR when the rod body is supported 18 in. from the rod pin shoulder.

8.2.3 Mechanical Damage and Wear

Mechanical damage, such as hammer or wrench marks, is cause for rejection in all classes.

Signs of mechanical damage or rounding of wrench flats that cannot be repaired and meet API 11B dimensions are cause for rejection or downgrading as directed by the user.

Wear measuring up to 20% of the cross-sectional area or a pit between 0.020 in. and 0.040 in. are criteria to downgrade the rod to Class II. Wear between 20% and 30% reduction in cross-sectional area or corrosion pits of 0.040 in. to 0.060 in. shall be cause for rejection or downgrading to Class III.

8.2.4 Couplings

Couplings should be removed by a method that will not cause damage to either the rod or the coupling during the removal process. Couplings may be removed from rejected rods if the couplings pass a visual inspection for wear, corrosion or damage by a qualified person.

8.2.5 Threads

Pin threads should be visually inspected by a qualified person for thread damage and evidence of pulling. Evidence of pulled threads is cause for rejection in all classes.

Damage on the first three threads from the undercut end is cause for rejection. Minor damage on threads beyond the first three from the undercut end may not be cause for rejection if the damage can be repaired during the thread gauging process in 8.4.4.

8.3 Electromagnetic Inspections

8.3.1 Eddy Current Inspection

An Eddy Current Reference Standard should be used to ensure that the system is capable of detecting gross material variations.

Indicated wear that exceeds allowable diameter dimensional tolerances but is less than 20% of the rod cross-sectional area shall be downgraded to Class II or rejected. Indicated wear that exceeds 20% of the rod cross-sectional area but is less than 30% of the rod cross-sectional area shall be downgraded to Class III or rejected.

Gross material variation indications within individual rods that are detected by eddy current inspection require follow-up visual inspection before being rejected or downgraded.

NOTE Other methods may be used to identify changes in diameter as long as they have the demonstrated capability to identify the diameter variations described above.

8.3.2 Electromagnetic Flux Leakage Inspection

Calibrate the inspection equipment with a reference standard of the same diameter as the rods to be inspected. Run the reference standard at the start and end of each day, at any change in rod size, after any breakdown, after breaks and lunch and after every 100 rods. An electromagnetic flux leakage reference standard should be used to ensure that the system is capable of detecting the following artificial discontinuities.

a) A $^{1}/_{32}$ in. drilled hole, 0.020 in. deep.

b) Proof of system linearity shall be demonstrated by a series of $^{1}/_{16}$ in. diameter drilled holes with depths of 0.015 in., 0.020 in., 0.030 in., 0.040 in.and 0.050 in. The bottoms of the holes may have up to a 30° angle from the longitudinal axis of the rod.

c) Proof of system sensitivity shall be demonstrated by detection of transverse notches of 0.010 in. width with depths of 0.005 in., 0.010 in. and 0.020 in. The notches should be detectable using a minimum signal-to-noise ratio of 2:1. Notches should be machined with square sides.

d) All artificial discontinuities should be spaced a minimum of 18 in. apart and at least 2 ft from the end of the rod. All dimensions shall have a tolerance of –0.001 in. to +0.002 in.

A dynamic calibration shall be performed by inspecting the reference standard in four quadrants at line speed. The artificial discontinuities should produce linear indications on a strip chart or computer display.

In the event that calibration verification is found to differ by more than 15% from the previous calibration, all rods inspected since the previous calibration shall be reinspected.

During inspection, all indications exceeding the defect threshold as noted during calibration shall be cause for further examination by visual and/or magnetic particle methods.

a) All cracks shall be cause for rejection in all classes.

b) Mechanical damage that leaves sharp indications on the rod body shall be cause for rejection in all classes.

c) Loss of cross-sectional area due to corrosion, wear, defects, etc. greater than 0.020 in. shall be cause for downgrading to Class II or for rejection.

d) Wear between 20% and 30% reduction in cross-sectional area or corrosion pits of 0.040 in. to 0.060 in. shall be cause for rejection or downgrading to Class III.

e) After electromagnetic flux leakage inspection is completed, rods should be demagnetized to less than 30 gauss as measured with a Hall-effect electronic gauss meter. Measurements made with alternate instruments, such as a mechanical magnetometer, should be capable of making readings of equivalent accuracy.

8.4 Pin End Inspections

8.4.1 Preparation

Rod pin threads and shoulders shall be cleaned to bright metal.

8.4.2 Inspection Methods

The segment of the sucker rod pin end, upset area and rod body, not inspected by the electromagnetic system, should be inspected by fluorescent magnetic particle inspection, using a longitudinal magnetic field or other similar techniques mentioned in 8.1.1.

8.4.3 Pit Gauge

The depth of stampings, makeup marks, etc., should be confirmed with a pit gauge prior to rejection:

a) any corrosion found in the thread relief area with a depth greater than 0.005 in. shall be cause for rejection or downgrading as directed by the user;

b) wear measuring greater than 0.020 in. on the pin shoulder shall be cause for rejection or downgrading as directed by the user;

c) mechanical damage or wear on the upset areas of a rod shall be cause for rejection for all rods except for Class III rods.

8.4.4 Thread Gauging

Sucker rod pin threads should be checked with API P6 and P8 “go” and “no-go” ring gauges to verify that the threads are properly manufactured and a feeler gauge should be used to confirm the pin shoulder is in compliance with API 11B.

A coupling that has been verified on each shift with API B2 and B6 working gauges may be used to gauge pin threads of used sucker rods for complete make up. If shake is noted with the verified coupling, an API P6 working gauge shall be used to check for proper thread height.

At the end of each shift, the coupling used to gauge pin threads shall be reverified using API B2 and B6 working gauges. If the coupling is out of tolerance, all used sucker rod pin ends inspected since the previous coupling verification shall be reinspected to ensure proper pin make up dimensions.

Thread damage on the first three threads from the undercut end shall be cause for rejection except for Class III rods.

There can be no more than three threads in a plane with minor damage that can be repaired using a thread chaser or other similar implement. At no time are files to be used to dress thread areas.

8.5 Coupling Inspection

8.5.1 General

Sucker rod couplings should be visually examined for wear and/or corrosion. Wear that reduces the outside diameter of a T-type coupling to –0.010 in. of nominal OD of the outside diameter of the rod pin shoulder or wear through the spray metal coating of an SM coupling is cause for rejection.

8.5.2 Inspection Method

Sucker rod couplings should be magnetic particle inspected using a circular field or inspected using demonstratively comparable techniques. Any relevant magnetic particle indication is cause for rejection.

8.5.3 Gauges

API B2 and B6 “go” and “no-go” box plug gauges should be used to check coupling threads and parallelism in accordance with API 11B.

A rod pin end that is verified each shift using API P8 and P6 working gauges may be used to gauge coupling connections for complete makeup when inspecting used couplings.

At the end of each shift, the pin end used to gauge coupling connections shall be reverified using API P8 and P6 working gauges. If the pin is out of tolerance, all used sucker rod couplings inspected since the previous pin verification shall be reinspected to ensure proper coupling make up dimensions.

8.6 Acceptance Criteria

8.6.1 New Rods

New rods shall meet all requirements of API 11B. New rods may be inspected using the procedures in this section but rods failing the inspection process must be checked with inspection equipment that meets the requirements listed in API 11B before they can be rejected.

8.6.2 Used Rods

Used rods can be either downgraded or rejected by the inspection processes listed in this section. Downgraded rods can be used in less severe operating conditions at the discretion of the user.

8.7 Completion of Inspection

8.7.1 General

If there is a possible claim after the inspection company has finished inspecting rods and/or couplings, the user representative, together with the manufacturer’s representative and the inspection company’s personnel should examine all rejected sucker rods and/or couplings to confirm they do not meet test specifications. The user representative will then decide what action to take on the rejected sucker rods and/or couplings.

8.7.2 Rod Rejection

Rejected rods shall be segregated from acceptable rods and either bundled and tagged accordingly or marked within 18 in. of either pin shoulder with easily identifiable red paint.

8.7.3 Lubrication

The pin ends of good rods shall be lubricated with an anti-galling thread compound prior to the installation of pin protectors.

8.7.4 Corrosion Inhibitor

Rods that pass inspection shall be completely coated with an atmospheric corrosion inhibitor and allowed to dry.

8.7.5 Color Coding

Rods that pass inspection shall be color coded with paint within 18 in. of the pin shoulder to designate the rod grade and class:

a) for Class I rods, a single band shall be used;

b) class II rods shall have two bands;

c) class III rods shall have three bands;

d) for rods manufactured to API standards, color coding shall be consistent with API 11B as shown in Table 5;

e) a color coding scheme should be selected to uniquely identify the type and manufacturer of rods that are not manufactured to API 11B.

Table 5—Color Coding

Chemical Composition	Color
API Grade C	White
API Grade K	Blue
API Grade D [a]—Carbon Steel (AISI 10XX or 15XX)	Brown
API Grade D [a]—Chrome-Moly (AISI 41XX)	Yellow
API Grade D [a]—Special Alloy	Orange
[a] See 3.4.5 for chemical and mechanical properties.	

9 Corrosion Control

See Annex A for NACE SP0195-2007, *Corrosion Control of Sucker Rods by Chemical Treatment*.

10 Transportation and Handling, Storage, Running and Pulling

10.1 General

Rods should be inspected (see Section 8) on delivery and thereafter as necessary to ensure that damaged rods are not placed in regular storage or in service.

In all handling operations, care should be exercised to prevent sucker rods or rod ends from contacts which might cause nicks or bends, or injury to the threads by jamming of the thread protectors. Further, the sucker rods should never be handled in such a manner as to cause damage. Kinked, bent, or nicked rods are permanently damaged and require reinspection to determine their serviceability.

Packaged rods should be handled and stored as a packaged unit, until the rods are to be run in the well. When removing the rods from the package, care should be exercised to use proper tools to prevent damage, especially by nicking.

Sucker rods delivered from the manufacturer are provided with thread protectors on both the pin and coupling ends. Whenever observed to be without such protection, the sucker rod should be inspected and if undamaged, the protectors replaced. Protectors should not be removed, except for inspection purposes, until the rods are hung in the derrick or mast in preparation of running.

Thread protectors, couplings, upsets, and wrench squares should never be hammered for any reason. One hammer blow can so damage any part of a rod or coupling as to result in premature failure.

10.2 Handling

Care should be taken to avoid damaging the sucker rods when removing bulkheads and tie-downs used to secure the rods during shipment and transport. Cross supports, spacers and blocks contacting the sucker rods should be of material that is non-abrasive to the rods.

Sucker rods in packages should always be lifted and laid down with a handling device so designed as to support the package without damage to the rods.

Unpackaged sucker rods should be handled individually. They should never be thrown nor flipped from or onto a railway car truck or stack. During all handling operations, the sucker rods should be supported at least at two points to prevent excessive sagging and/or damaging contacts of any nature. Skids should be made of material not abrasive to the rod.

When rods are unloaded at the well, they should it is recommended they be placed on a transportable service rack. They should be located in such position they will not be damaged by a vehicles nor where heavy equipment may be set or dropped on the rods. Particular care should be taken to ensure the rods are not walked on by personnel.

10.3 Transportation

Transportation handling of packaged sucker rods should provide blockage directly under the crosswise supports of the package to ensure that the rods do not contact the blockage. Sucker rod packages should be stacked so that the bottom supports rest squarely on the top supports of the next lower package. Tie-down chains, straps, or cables should pass over the crosswise supports without contacting the rods.

Transportation handling of unpackaged sucker rods should provide cross supports near the rod ends and at least two other equally spaced intermediate positions. When flat beds are used, the supports should be of such thickness as to prevent the rod ends or couplings from resting directly on the bed. The spacers should be long enough to extend a few inches beyond the stack on both sides. If the spacers are not notched, the outside rods in each layer should be chocked with blocks to prevent the rods from rolling off the spacer. Tie-down chains, cables, or straps should pass over the ends of the spacers and should be prevented from contacting the sucker rods.

When sucker rods are loaded for transport for field distribution, the same precautions apply in loading, transporting, and unloading as for placing new rods in storage.

10.4 Storage

Rods should be stored separately according to grade and size. They should be stored in such locations and in such manner as to minimize deterioration from exposure to acid or other corrosive atmospheres. They should be stacked off the ground on racks or sills made of or surfaced with a material not abrasive to the rods.

For packaged rods, a rack or sill should be provided under each support of the package. The packages should be stacked so that the supports are in vertical alignment. See API 11B for packaging requirements.

For unpackaged rods, at least four rack or sill supports should be provided and the end supports should be located approximately one foot from the rod ends. The rod layers should be separated by spacers placed directly above the rack or sill. The spacers should be thick enough to prevent the rods from contacting those in adjacent layers. If the spacers are not notched, the outside rods in each layer should be chocked with blocks to prevent the rods from rolling off the spacers.

Stored rods should be inspected at regular intervals. Any rust should be removed with a wire brush and a suitable rust preventative which will not become fluid at less than 125°F (52°C) applied.

Sucker rods returned to storage after use should be cleaned, lubricated, and covered with clean, undamaged thread protectors. The sucker rod surfaces, including threads, should be covered with a rust preventative which will not become fluid at less than 125°F (52°C).

NOTE It is good practice to perform an inspection of sucker rods and couplings after use and before storage, see Section 10 for guidelines on this processing.

10.5 Running and Pulling

After removal of the thread protectors, inspect rods for damage and clean as necessary. If rods are being rerun the rod pin thread and face and, the coupling threads and faces should be thoroughly cleaned. Make certain that wire brushes are not used. Threads and faces of couplings and pins should be inspected for damage.

Running and pulling tools should be suitable for the job, in good condition and clean. These include but are not limited to: rod elevators, hooks and wrenches. They should be inspected regularly for wear and other damage, and be repaired or replaced when their use may result in damage to the rods. Special attention should be given to elevators and hooks to avoid dropping the rod string.

Single rods should be tailed into the mast. Special care should be taken to ensure they do not touch the ground, other rods, or any part of the mast. Also during tailing do not allow the rods to be raised with elevator latches. For maximum efficiency and to minimize the risk of damage to the rods, it is recommended suitable hangers be provided in the mast.

To help avoid cross threading, care should be taken that the handling equipment is positioned so that the rods, when hanging straight and free (without slack) in the rod elevators, are centered directly over the well bore. Should cross threading occur, the connection should be broken, a die run over the pin and a tap into the coupling; after which the threads should be cleaned, inspected and lubricated prior to storage or transport.

To obtain satisfactory results in makeup of rod connections, the joint must be clean, undamaged, properly lubricated and have a free-running fit to shoulder contact if applied circumferential displacement is to sufficiently preload the joint to prevent shoulder face separation during pumping. During makeup, the joint should be observed to determine that the coupling face makes proper contact with the shoulder face. When proper contact is not made, the joint should be broken, cleaned, inspected and re-lubricated.

In breaking the joints, care should be exercised that the threads and contact faces are not damaged. When breaking out connections, particularly with hand wrenches, the joint should never be hammered, and the proper coupling and rod wrenches, with the assist of cheater bars, should be used if a joint is unbreakable by ordinary procedure. Any hammered or over-torqued couplings should be discarded since hammering and over-torquing damages the coupling, faces, threads, and may result in premature failure.

Whenever rods are pulled, they should be carefully inspected for damage before being rerun. Kinked, bent, or nicked rods are permanently damaged and should be discarded. (See Section 8 and API 11B.) If a rod hanger is not provided, the rods should be pulled and laid down in singles. The same care should be exercised in handling and stacking the pulled rods as herein recommended for new rods.

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Annex A

NACE International SP0195, *Corrosion Control of Sucker Rods by Chemical Treatment* [3]

NACE International
NACE Standard SP0195-2007

Standard Practice
Corrosion Control of Sucker Rods by Chemical Treatment

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NACE Standard SP0195 Foreword

This standard practice presents corrosion inhibition, wear reduction, and corrosion prevention techniques for use from the manufacturing of bare steel sucker rods and couplings through installation and service in the well. Although aluminum, fiberglass, coated sucker rods, and high-alloy sucker rods are not specifically addressed in this standard, many recommendations contained herein may be applied to such sucker rods, as appropriate, at the user's discretion. Throughout this standard the words "sucker rod" or "rod" will be used in the above-described context.

This standard was originally prepared as NACE Publication 1D167 by NACE Task Group T-1D-3 for inclusion in API RP 11BR. Beginning in 1988 it was updated for the revision of API RP 11BR by NACE Task Group T-1D-35, a component of Unit Committee T-1D on Corrosion Monitoring and Control of Corrosion Environments in Petroleum Production Operations, for conversion to a standard practice, and this standard was originally issued in 1995. This standard was also balloted to and approved by API for inclusion in API RP 11BR. It was reaffirmed in 2001 and 2007 by Specific Technology Group (STG) 31 on Oil and Gas Production – Corrosion and Scale Inhibition and is issued by NACE International under the auspices of STG 31.

This standard represents a consensus of those individual members who have reviewed this document, its scope, and provisions. Its acceptance does not in any respect preclude anyone, whether he has adopted the standard or not, from manufacturing, marketing, purchasing, or using products, processes or procedures not in conformance with this statement. Nothing contained in this NACE International standard is to be construed as granting any right, by implication or otherwise, to manufacture, sell, or use in connection with any method, apparatus, or product covered by Letters Patent, or as indemnifying or protecting anyone against liability for infringement of Letters Patent. This standard represents minimum requirements and should in no way be interpreted as a restriction on the use of better procedures or materials.

In NACE standards, the terms *shall, must, should* and *may* are used in accordance with the definitions of these terms in the NACE *Publications Style Manual*, 4th ed., Paragraph 7.4.1.9. *Shall* and *must* are used to state mandatory requirements. *Should* is used to state something considered good and is recommended but not mandatory. *May* is used to state something considered optional.

NACE International
Standard Practice

Corrosion Control of Sucker Rods By Chemical Treatment

Contents

A.1 General

Corrosion can lead to serious multiple failures of oil well sucker-rod strings and other equipment. The use of chemical corrosion inhibitors has proved to be a cost-effective approach to minimize corrosion damage and to extend the life of the downhole equipment. This standard addresses corrosion control for atmospheric conditions and downhole environments, treatment procedures, inhibitor selection, and evaluation of corrosion inhibitor programs. Other factors to control failure of sucker-rod strings are addressed in API 11BR.

Corrosion inhibitors fall into many chemical classes that may be physical or health hazards. The handling precautions recommended by the manufacturer in the material safety data sheet (MSDS) shall be followed. In all cases, protection of the environment shall be considered.

In all operations discussed in this standard, corrosion inhibition is enhanced when sucker rod and coupling surfaces are free of scales and deposits.

Care should be taken to prevent air entry into the well to avoid oxygen-accelerated corrosion. Air entry can occur if casing vents are left open to the atmosphere or if the wellhead seals do not hold a vacuum.

A.2 Atmospheric Corrosion Control During Transportation and Storage

Hydrocarbon-removable coatings (HRC) [4] such as atmospheric corrosion inhibitors or temporary protective coatings should be used to prevent corrosion damage to sucker rods before they are placed in service. These coatings should be applied before transportation of the sucker rods and should be maintained during storage. HRC can also be used to minimize atmospheric corrosion during field service of the sucker rods.

The manufacturer should provide sucker rods and couplings free of mill scale and with a suitable HRC applied to all exposed surfaces. The HRC should be adequate to provide protection against corrosion for a minimum of one year under humid atmospheric conditions at the storage site [5]. Acceptable HRCs shall be readily removable using hydrocarbon solvents. HRCs that do not obscure manufacturer markings are preferred.

The vendor, supplier, or agent shall inspect shipments and warehouse stocks of sucker rods and couplings for visible signs of physical damage and corrosive attack. The vendor also shall take necessary action to clean rust spots and repair damage in the HRC.

The purchaser should inspect sucker rods and couplings upon receipt for physical damage and corrosion attack. The purchaser should also make periodic inspections of the sucker rods and couplings and maintain the HRC integrity during storage.

Used sucker rods that are stored for future service should be cleaned and coated for protection against atmospheric corrosion. Corrosion protection for less than one year can be obtained by dipping or spraying the rods and couplings with a suitable HRC atmospheric corrosion inhibitor. However, storage for more than one year requires the use of HRC similar to those recommended above.

A.3 Well Servicing

A.3.1 General

Sucker rods should be protected after removal from the well during well-servicing operations. This is especially important in areas where hydrogen sulfide (H_2S) and/or carbon dioxide (CO_2) is produced. However, the corrosion damage may frequently be caused by atmospheric oxidation. In some cases, protection from atmospheric oxidation can be achieved

[4] For the purposes of this standard, HRC refers to materials that are removed from the sucker-rod surface because they are soluble in produced hydrocarbon. The materials are not necessarily formulated in a hydrocarbon solvent.

[5] Performance assessment methods are available from standards-writing organizations such as the American Society for Testing and Materials (ASTM) International, 100 Barr Harbor Drive, West Conshohocken, PA 19428-2959.

by pumping oil with a high concentration of corrosion inhibitor into the tubing immediately before the rods are pulled. Alternatively, the rods may be coated with a mixture of oil and corrosion inhibitor after the rods are laid down.

A.3.2 Corrosion Inhibitor

Failures in threaded connections because of improper makeup or corrosion fatigue can occur when well fluids enter the couplings during pumping. Corrosion inhibitor should be applied during sucker-rod connection makeup to minimize corrosion inside the coupling. The couplings and pin ends can be dipped, brushed, or sprayed with a mixture of oil-soluble, film-forming corrosion inhibitor in refined oil or with inhibited grease. Sealants, such as thread dope, which contain a high level of solids, are not recommended for sucker-rod threads. The procedure for selecting an inhibitor can be found in NACE Standard MR0174, *Selecting Inhibitors for Use as Sucker-Rod Thread Lubricants*. The sucker-rod manufacturer may be consulted for assistance in selecting commercial lubricants. Use of too much inhibitor-oil mix in the coupling cavity interferes with proper makeup. The procedure for proper makeup of sucker-rods is found in API 11BR. Proper circumferential displacement develops sufficient sealing force at the shoulders, which tends to exclude well fluids from the threads.

A.3.3 Pulling and Running

When new rod string is run or each time the rods are pulled and rerun, the corrosion inhibitor film should be established (or reestablished) on downhole equipment. The rods should be examined for physical and corrosion damage each time they are run.

To provide initial protection to rods during and following installation, one approach is to add an oil-soluble corrosion inhibitor mixture [19 to 38 L (5 to 10 gal U.S.) of chemical in diesel or lease crude] to the tubing before running the rods (or to the casing before running tubing and rods). As the rods pass through this inhibitor mixture, a protective film is applied. If there is no packer, additional benefit may be obtained from the inhibitor by circulating one tubing volume of fluid into the annulus before the well is returned to production.

An alternate initial treating practice is to add 19 to 38 L (5 to 10 gal U.S.) of inhibitor to the casing/tubing annulus and circulate the well to displace the annular volume before beginning production to the battery.

A.3.4 Program Resumption

After the well is placed back on production, the selected treatment program should be resumed.

A.4 Downhole Corrosion Inhibition

A.4.1 General

There are many corrosion-inhibiting products and application techniques that are effective in protecting downhole production equipment. Selection of a particular method should be based on the specific application and the economics of the treatment program. These economic evaluations should consider the effectiveness of the treatment program as it relates to equipment replacement frequency and lost production.

A.4.2 Batch-and-flush Treatment

The batch-and-flush treatment is most widely used for rod-pumped wells. Normally in this technique, an oil-soluble, water-dispersible corrosion inhibitor is injected into the well annulus and flushed down to the fluid level. The flush fluids may be chemically oxygen-scavenged produced brine, chemically oxygen-scavenged fresh water, crude oil from a treater truck, or produced fluids bypassed from the well's flowline. Water-soluble inhibitors are generally less film-persistent than oil-soluble inhibitors, and therefore are normally not recommended for the batch-and-flush treatment.

Specific design of a treating program (i.e. inhibitor selection, inhibitor dosage, treating frequency) should include considerations such as oil/water ratio, fluid corrosiveness, fluid level above the pump, rod loading, etc. Inhibitor selection is covered in A.5. Typical inhibitor dosage and frequency are as follows.

a) One common practice for selecting inhibitor dosage for the initial program is to use an inhibitor concentration that is equal to 25 ppmv [6] based on the total fluid production between treatments. A minimum inhibitor volume of 4 L (1 gal U.S.) per treatment is recommended. For example, a well producing 64 m^3/d [400 barrels of fluid per day (BFPD)] would require about 11 L (3 gal U.S.) of inhibitor per week.

b) Treatment frequency usually varies with the well production rate. Typical treating frequencies are every other week for wells producing less than 16 m^3/d (100 BFPD), weekly for wells producing 16 to 48 m^3/d (100 to 300 BFPD), and twice weekly for wells producing 48 to 80 M^3/d (300 to 500 BFPD). When the total produced fluid is more than 80 M^3/d (500 BFPD), some operators consider continuous treatments.

c) Adjustments in dosage and frequency to optimize treatment effectiveness should be based on corrosion-monitoring results (see A.6 on Evaluation of Inhibitor Programs).

Flush volumes are often calculated based on well depth and annular pumping fluid level. For example, in low-fluid-level wells [less than 150 m (500 ft) above the pump], typical flush volumes are 80 to 160 L (0.5 to 1.0 bbl) of flush (produced water or oil) per 300 m (1000 ft) of well depth. Wells with more than 150 m (500 ft) of fluid above the pump may require more overflush. The goal is to displace chemical to the pump intake. The flush can be supplied by pump truck or the well can be circulated into the annulus (through a chemical pot if one is used) for a time to achieve the desired volume. Care should be taken not to introduce air into the well during the flush process. It may be necessary to chemically remove oxygen from the flush fluid when a pump truck is used. If this is done, sufficient time should be allowed for the oxygen-removal process to take place before the well is treated.

The casing and tubing annulus should be preflushed with the flush fluids before the inhibitor is introduced to ensure that the inhibitor reaches the fluid level.

If the well is pumped high (i.e., pump set well above the production zone) a tailpipe should be attached below the pump to ensure that the lower portion of the casing is exposed to the inhibitor treatment. However, this can significantly reduce the pump's volumetric efficiency if the liquids entering the tailpipe contain solution gas.

A.4.3 Batch-and-circulate Treatment

The batch-and-circulate treatment procedure is generally used to treat problem wells in which batch-and-flush treatments are not effective. This treatment procedure is the same as batch-and-flush treatment except that, rather than flushing after treatment, a large portion or all of the produced fluids are diverted from the flowline to the tubing/casing annulus for a specific circulation period. Production is delayed during the circulation period.

Although there are many variations of the batch-and-circulate treatment, the most common procedure is to circulate the well until the injected inhibitor slug reaches the surface and is returned to the annulus. The well is then placed on production.

The inhibitor volume required for this treatment varies according to the fluid volume in the annulus and the well depth. A basic goal is to contact well surfaces with an inhibitor concentration of more than 1000 ppmv for one hour or longer. The literature contains descriptions of other methods for determining inhibitor dosages and circulation times [*Cameron, et. al*]. Inhibitor concentration and treatment frequency are similar to those for the batch-and-flush treatment method described in A.4.2. Treatment dosage and frequency should be optimized to increase the effectiveness on each well.

[6] ppmv = parts per million by volume; 1 ppmv = 0.001 L/m^2 or 0.0042 gal U.S./100 bbl.

Possible disadvantages of the batch-and-circulate treatment are the manpower required to circulate the well and the delayed production. The batch-and-circulate treatment may not be practical for wells in which a long circulation time is required and/or a large delayed production volume results. Also, some wells build excessive pressure during circulation and are generally not treated using this method. In these cases, continuous treatment as described in A.4.5 should be considered.

A.4.4 Automated Treatment (Semi-batch)

Equipment is available for automatic injection of a preselected amount of inhibitor into the annulus, followed by produced fluid circulation for a preselected time. These devices permit treatment as often as desired. An economic analysis should be done to determine cost effectiveness.

A.4.5 Continuous Treatment with Bypass Flush

Typically, continuous flush is applied to wells with production exceeding 15 M^3/d (100 BFPD). In this procedure, a chemical feed pump is used to continuously inject inhibitor into a small volume of produced fluid continuously bypassed into the casing annulus. The inhibitor feed rate is typically 25 ppmv to 50 ppmv based on total produced fluid volume. Subsequent corrosion-monitoring results should be used to optimize the inhibitor dosage. The volume of produced fluid is not critical, as long as a positive flow is maintained down the annulus. Initial treatment in wells that do not pump off should include a large batch treatment [e.g., 19 L to 38 L (5 gal to 10 gal U.S.)] to ensure that the annulus is loaded with treated fluid.

A.4.6 Squeeze Treatment

Although it is not a common practice, effective and long-lasting treatments can sometimes be achieved by squeezing corrosion inhibitor mixtures into producing formations. A large volume of inhibitor mixed with crude or diesel is displaced into the formation. A portion of the inhibitor absorbs on the reservoir rock and subsequently desorbs over time to maintain the protective film. Normally, an oil-soluble inhibitor is used. Prior to any squeeze treatment, inhibitor compatibility with reservoir fluids and, more importantly with the formation, should be investigated to minimize formation damage and avoid a decrease in production. Core testing is one method used to assess the effect of the candidate squeeze inhibitor on the formation. Because of concerns such as inhibitor compatibility with formation rock and formation fluids, squeeze treatments are generally used when other treatment methods are not possible or practical. For example, squeeze treatments may be useful when tubing is set on a packer.

A.4.7 Continuous Downhole Injection

Continuous downhole injection utilizes a small-diameter tubing, generally a 6 mm to 13 mm (0.25 in. to 0.50 in.) OD, attached to the outside of the production tubing and connected to a downhole chemical injection mandrel and a chemical injection pump at the surface. This configuration allows a large amount of chemical to be injected in a short period of time to batch treat the production string. Thereafter, the dosage rate can be reduced to a maintenance treatment, typically 25 ppmv based on total fluid.

Adjustments in treatment rates to obtain optimum treatment effectiveness should be based on corrosion-monitoring results.

The inhibitor can be readily changed by flushing the old chemical from the tube ID with a suitable solvent followed by injecting the new chemical at a selected rate.

A.5 Inhibitor Selection

A.5.1 Types

Most inhibitors used in producing operations are polar organic compounds available in many different formulations. The inhibitor may either be oil-soluble, water-soluble, or water/oil dispersible. Regardless of the type, the inhibitor must:

a) match the application technique; i.e., the solubility and dispersibility must allow the inhibitor to reach the steel surface to form a protective film, and film persistency must be adequate for the selected treatment interval,

b) be compatible with other treating chemicals used,

c) not create an emulsion that is difficult to break, and

d) not exceed target levels for all carryover into injection water.

Thus, care must be taken in selecting the inhibitor.

A.5.2 Testing

Before using an inhibitor in a given field, laboratory and field tests for corrosion-mitigation effectiveness, compatibility with other chemicals, emulsion tendency, and water quality are generally a cost-effective investment. When dilution solvents are used, the tests should be performed using the actual chemical/solvent mixture.

A.6 Evaluation of Inhibitor Programs

The cost effectiveness of treating with the properly selected and applied inhibitor is normally high, with treatments providing excellent insurance against equipment failure and lost production. Proper corrosion control requires the following steps:

a) properly design and operate the beam pump lift system;

b) keep the rod string free of atmospheric corrosion before use;

c) protect the rod string immediately upon installation;

d) use a properly selected and applied corrosion inhibition method based on the well's corrosiveness;

e) continue treatment, monitor results (as described below), and adjust the corrosion control program as needed.

Various methods can be used to evaluate inhibitor programs. Well-failure history, visual inspection, changes in production characteristics, pump repair reports, and other equipment service records can be used to evaluate current program effectiveness. Often such records may indicate corrosion problems before the first rod failure occurs.

Other monitoring methods include the use of weight-loss [7] corrosion coupons, evaluation of weight loss of pony rods used as corrosion coupons, iron content analysis of produced fluids, copper-ion displacement tests, hydrogen sensors, galvanic probes, electrical resistance probes, and linear polarization probes.

The efficiency of the treating program should be evaluated by comparing monitoring data with actual well-failure history. It should be noted that surface-installed corrosion-monitoring tools only report corrosion rates for the condition

[7] In common terminology, "weight loss" is used to refer to a loss in mass.

at their point of installation. Often the development of a correlation between surface monitoring results and downhole corrosion is needed.

Assistance in evaluating inhibitor treatment programs can be obtained by consultation or study. Direct help can be obtained by consultation with recognized corrosion engineers, corrosion consultants, and chemical company service engineers.

A data and analysis system must be maintained to ensure the successful optimization of the corrosion control program.

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