



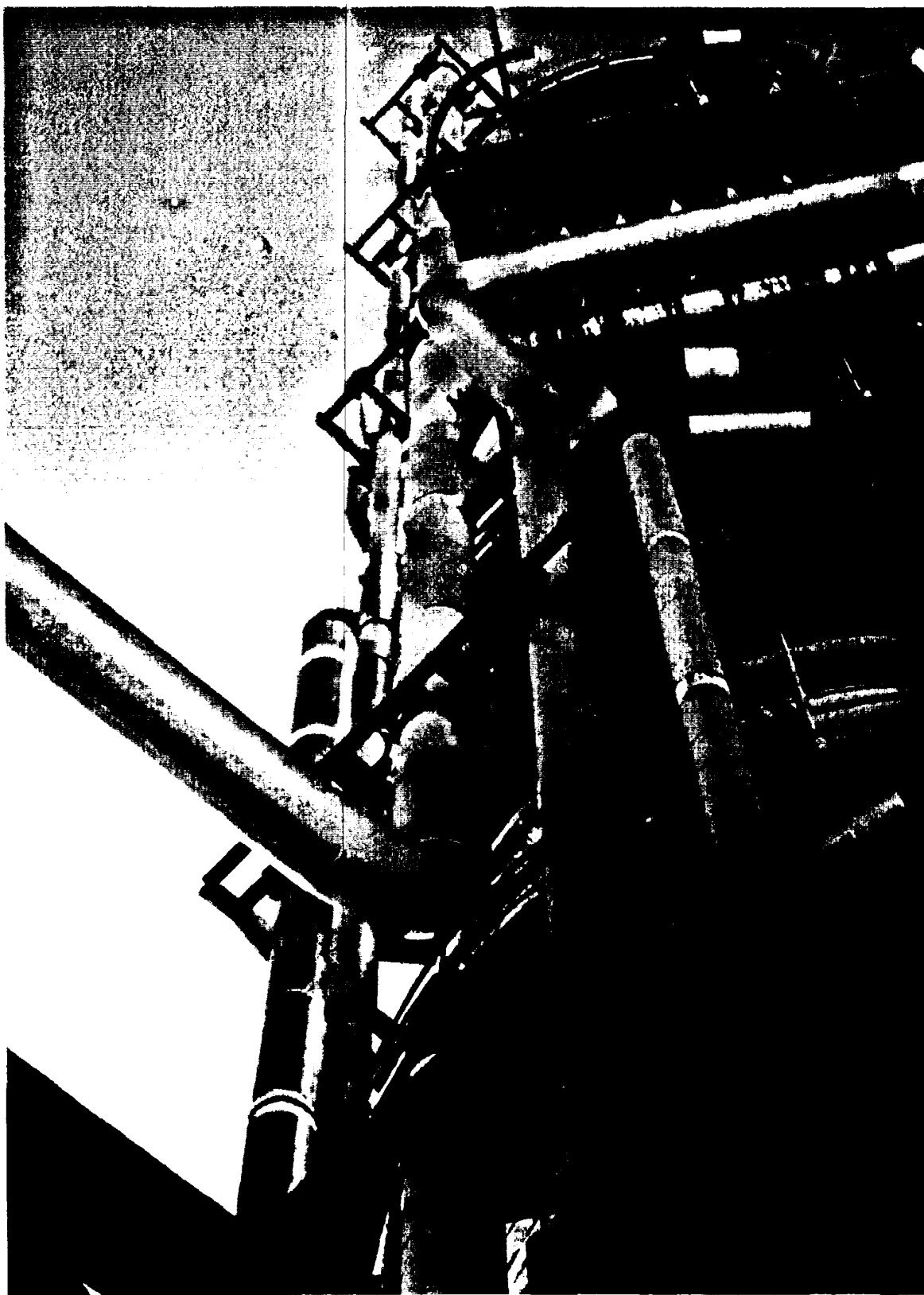
Engineering Report

SAER-5573

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Crude Distillation Unit Overhead Corrosion Study

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**CRUDE DISTILLATION UNIT
OVERHEAD CORROSION STUDY
SAER-5573**

Dhahran
E-7280 ♦ Tel: 874-6116 ♦ Fax: 873-8351
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FINAL REPORT ON CRUDE UNIT
OVERHEAD CORROSION CONTROL

SAER-5573

GENERAL MANAGER, Ras Tanura Refinery
MANAGER, Riyadh Refinery Department
MANAGER, Jeddah Refinery Department
MANAGER, Yanbu Refinery Department
MANAGER, Rabigh Refinery Department

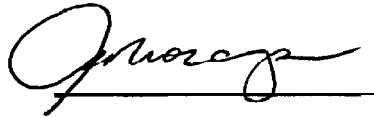
Following recurring corrosion problems and pinhole leaks in the crude unit overhead system at Yanbu Refinery, an Engineering Services multidisciplinary team comprised of representatives from Consulting Services, Process and Control Systems and Inspection Departments was formed to investigate the root causes of these failures and recommend remedial action. The objectives of this team were not only to analyze the Yanbu Refinery incidents but also to recommend other refinery specific corrosion control program improvements and to outline typical operating guidelines and "best practices". This was accomplished based on knowledge gained from site visits, review of major oil company operating procedures, and consultation with experts.

The study encompassed all Saudi Aramco domestic refineries: Jeddah, Rabigh, Riyadh, Yanbu and Ras Tanura. The team focused only on crude unit overhead system corrosion and did not address downstream corrosion concerns in stabilization or vacuum unit equipment. For the benefit of learning the industry practice outside the realm of Saudi Aramco, the team: sought **consultation** and advice on overhead system corrosion from Chevron Research and Technology Company experts, conducted a review of the **SASREF** joint-venture Refinery Crude Distillation Unit at Jubail, and reviewed SAMREF documentation on the very same subject. Nalco Chemicals technical representatives were also contacted to provide background on the current chemical treatment program proposed for the Saudi Aramco refinery operations.

During the course of this study (November, 1996 - March, 1997) and upon the completion of each refinery facility review, the team issued interim reports to the individual refineries focusing on three main areas: process, inspection, and corrosion control and monitoring programs. The interim reports covered in detail the team's observations, and immediate and long term recommendations specific to each refinery. The attached final report provides **generalized** philosophy, operating guidelines, and "best practices" along with the summarized recommendations.

Refer your questions, if any, to A. A. Abu Al Saud at 874-6549.

G. A. BARGAWI, Manager
Consulting Services Department



AMN
AMN:

attachments

cc: Vice President, Engineering Services (w/o attachments)
Vice President, Northern Area Manufacturing (w/o attachment)
Vice President, **Jeddah/Riyadh** Refining Operations (w/o attachment)
Executive Director, Yanbu Refining (w/o attachments)
Director, Domestic Joint Venture Coordination Dept.
Manager, R&D Technical Support Services Dept.
Manager, Process & Control System Dept.
Manager, Inspection Dept.
Technical Information Center (2 copies)
Coordinator, **ME&CCD/CSD**
Team Members
CSD L/B

EXECUTIVE SUMMARY

Corrosion of crude unit overhead equipment and associated piping is a common concern to all refineries and its causes have been well documented in the open literature. In practice, mitigation of corrosion in the overhead system functionally relates to the vigilant control of chlorides in the crude feed to the atmospheric crude tower. An effective corrosion control program for the overhead system always begins at the upstream end. Close attention to crude storage tank operations, in the form of adequate settling time, and periodic water drainage, and optimization of desalter operation, constitute important factors in the minimization of facility corrosion. Chemical injection requirements (caustic, neutralizer, filming amine), on the other hand, are dependent upon the effectiveness of upstream operations.

Domestic Refineries, that were the subject of the team review, have different system configurations and capabilities as well as operating philosophies. This covers a wide spectrum including: desalter single stage and two-stage designs, chemical injection hardware and location, wash water sources, overhead receiver reflux and product recovery arrangement, etc. All the domestic refineries are currently utilizing Nalco neutralizer and filming inhibitor chemicals.

Most of Saudi Aramco domestic refineries are now progressing towards a more expanded corrosion control program. The most important step has been the optimization of existing desalter operation. In the past, some of the refineries have bypassed their desalters due to fouling incidents. The reasons for this have been at least partially resolved and crude unit desalting capacity is now utilized at most domestic refinery locations. In addition, continuous overhead water wash systems are being evaluated and scoped along with expanded monitoring including on-line pH meter and corrosion probe readout.

Unlike the domestic Refineries, SASREF embraced a different approach to corrosion control. This approach is oriented towards relying on disciplined operational control and minimization of operating costs in a competitive environment. SASREF has vigilant crude tank management which involves frequent analysis, water settlement and drainage, and thorough caustic mixing. SASREF has no desalting equipment and depends on caustic injection and cheap ammonia neutralization for overhead corrosion control. There is no continuous wafer wash or filming inhibitor treatment. Corrosion coupons and probes are not installed, but instead, an organized corrosion loop inspection program based on “risk to failure” and “consequence” is in force. This approach has resulted in acceptable corrosion performance history. It is estimated that compared to a typical corrosion program involving full chemical treatment, the savings in chemicals alone would be approximately **\$700/MBPD/Yr**. This does not include the Operations & Maintenance (O&M) costs associated with the related corrosion control equipment. With diligence, Saudi Aramco could migrate at least part way towards this approach. **Some of the** major oil companies, such as Chevron, have enforced tighter operational control and try to rely solely on good desalter operation, caustic injection, cheap ammonia neutralization, and water wash to minimize overhead corrosion.

A real concern impacting the corrosion control program is the operation of refinery units significantly above original design. In some cases, crude unit desalter and other pertinent equipment capacities may be exceeded at crude charge rates of 25 - 30 % above design. Generally speaking, the desalters experience low incoming salt loads, but in some circumstances, may be hydraulically overloaded so that separation of the water and the associated dissolved salts is difficult. Elevated crude rates not only put demand on equipment performance but also may require resources exceeding supply, such as the need for clean wash water. Also good engineering practice might dictate further process limitations. Therefore, the push towards the implementation of a full corrosion control program may be limited by the need for additional capital expenditure for debottlenecking.

All the refineries to a certain degree lack the utilization of on-line pH and corrosion probe monitoring systems. These on-line systems can be used to respond more quickly to process upsets and can help to minimize costs through optimization of chemical usage. Some refineries have already started to adopt such systems. Consideration should be given to incorporate applicable new technology monitoring tools such as flush-mounted ER probes at certain vulnerable locations.

All Refinery Inspection Units have an On Stream Inspection (OSI) program using radiographic and ultrasonic thickness (UT) surveys on crude overhead systems. Most of the units were able to identify a corrosion problem and take the necessary action before failure occurred. However, some potentially vulnerable areas are not inspected due to the lack of access. In general, the present (OSI) test point locations and the techniques used may miss localized corrosion as seen on recent overhead line failures. Recommendations were made to provide at least temporary access and to conduct more comprehensive inspection work. The average (OSI) frequency on the overhead lines ranges between three and five years, mainly in line with T&I scheduling. In some cases the inspection frequency is not in compliance with the Saudi Aramco Engineering Practices (SAEP-20, Table-II guidelines). Locations with demonstrated high corrosion rates may require on-stream testing outside the T&I scheduled time window. Also, all the units are inadequately equipped to conduct thorough (OSI) at elevated on-stream temperatures. Designated chemical injection points are being inspected by all units; however, there is no documented chemical injection point inspection program that fully complies with the new API RP 570 inspection guidelines. For reference, the new guideline is furnished as an attachment to this final report.

RECOMMENDATIONS

Process

1. Evaluate, as a technology item, two-stage caustic mixing and injection for overhead chloride control. An effective caustic injection system can reduce neutralizer consumption and help mitigate downstream fouling tendencies. Consult with P&CSD/Process Engineering Division.

2. Carefully consider corrosion control program options in the light **of continued** high crude charge rates and the impacts on equipment capacity and system capabilities. **A** case in point is the installation of a continuous overhead water wash system and the effect on overhead equipment, liquid handling hydraulics, and overhead line velocity considerations. One example is the use of preheated boiler feed water as wash water which increases cooler duty and contributes to high overhead line velocity.
3. Overhead Wash Water System: (i) carefully specify the design if a continuous overhead wash water system is installed. The removable spray nozzle should be an atomizing type. The nozzle should be located for accessibility and a suitable distance away from dead legs. The overhead line should be insulated upstream of the water spray nozzle location; (ii) the overhead wash water source should be de-oxygenated, have low **TDS** (< 25 ppmw), and in general be filtered. If oxygenated sources are used, the receiver boot water should be checked for oxygen content. Target oxygen content is < 20 ppbw.
4. Provide appropriate overhead dew point margins to minimize dew point acid corrosion in the crude column overhead line. Theoretically, we recommend the margin target be set at **10 °C** or more. However, if there is evidence of persistent corrosion in cold spots defined by thermographic surveys, then the survey results should be incorporated appropriately and the target adjusted if ambient conditions dictate or heat sinks can not be eliminated.
5. The tail water chloride target in the overhead receiver **should** be set at **20 - 25** ppmw or less. With effective caustic injection, this should be possible given a desalted crude salt content of 1 - 2 PTB or less. If an outside source of wash water is used other than recycled receiver boot water, then this target should be lowered even further to, say, < 15 ppmw.
6. Desalter operation needs further improvement at some refineries. Desalter operations with low operating temperatures (< 120 °C) should be investigated. Where the desalter equipment is hydraulically limited, an internals revamp should be considered **or other** available capacity put into service. Where desalter makeup wash water supply is severely limited at high crude charge rate, the refinery should consider installing a recycle water system.
7. If tower top conditions are relatively dry and Monel tray materials and lining are specified, then the neutralizer injection point should be located in the overhead line upstream of the filming inhibitor injection point. This is recommended to prevent the possibility of salt buildup in stagnant areas in the top of the tower. To reduce any plugging tendencies when using neat neutralizer, steam injection can be used at the neutralizer injection point. Both Yanbu and Jeddah refineries inject neutralizer into the tower **reflux** stream.

8. Two-stage overhead systems should have special considerations in order to provide effective chemical treatment. **Jeddah** Refinery should consider separate inhibitor injection at the inlet of the second stage water coolers, if **OSI** data can support this. Also a commingled water sample from both stages should be used for control purposes.
9. Refineries reporting chemical usage outside the normal range expected for the given salt and overhead chloride quantities quoted should investigate their usage. (Refer to Table 3). All chemical usage needs to be positively measured by metering pump, meter, or gauge so that accurate daily consumption can be obtained. Diluent streams should also be quantified.
10. Initiate a formal monitoring program which can provide historical trends and set benchmark performance.

Inspection

1. Develop, as a technology item, high temperature (on-line) Ultrasonic scanning capability and/or on line continuous Ultrasonic thickness measurement techniques. Consult with ID/Operations Inspection Division.
2. On Stream Inspection Program: (i) implement **OSI** inspection frequencies per SAEP-20, Table-II guidelines; (ii) take multiple point **OSI** thickness readings in a **360°** band with a minimum of 8 - 12 readings per band on lines over 20 inches in diameter; (iii) provide permanent or temporary access to take **OSI** thickness readings at preferred locations per the appropriate **OSI** schedule; (iv) consider adopting a computerized **OSI** data management and analysis program, such as PIPE+ or **IDDEAL**; (v) re-evaluate the locations of the overhead system corrosion probes based on **OSI** corrosion rates.
3. Chemical Injection Point Inspection Program: (i) incorporate NACE, Corrosion 1996 Paper No. 588 (attachment 6) and the present API **RP 570** inspection guidelines (attachment 7). Saudi Aramco is in a process of adopting these inspection guidelines; (ii) consider water wash injection points as chemical injection points and inspect accordingly.
4. Ultrasonic Thickness Surveys: during T & I, remove the external insulation (if the line is insulated) and perform UT surveys in an approximately 1 meter wide **360°** band (i) around the overhead line at **1st**, **2nd**, **3rd** elbows and **1st** tee location plus all potential impingement locations; (ii) around the overhead line straight sections near chemical injection points, immediately down stream of **2nd** (vertical), and **3rd** (horizontal) elbows.
5. All thickness data should be evaluated first before it is permanently recorded. In case of doubt, the readings should be taken again or an alternative nondestructive testing (**NDT**) method should be considered.

6. Overhead line branch **connectinns** should be considered as dead legs and should be monitored accordingly.
7. **Thc** elevation profile of the horizontal sections of the overhead line should be evaluated and **OSI** testing should be selected accordingly.
8. Deviations Outside Corrosion Control Process Limits: (i) set up a **communication** system between Inspection and Operations, to notify Inspection every time the corrosion control process limits are violated. It would then be the Inspection Unit's responsibility to document the cumulative time outside the set control limits; (ii) the Refinery Inspection Unit should set up a procedure that defines when special action is required based on the length of operating periods outside the control limits.
9. If a very high short term corrosion is observed close to the main equipment (Column) the nearest nozzle should also be surveyed thoroughly.

Corrosion Monitoring & Materials

1. Upgrade all chemical injection quills to removable type in Monel 400, as soon as possible. Quills should be located at the top (12 o'clock) position of the horizontal line.
2. On-line Corrosion Monitoring Technique: (i) consider incorporating flush-mounted ER probes, or other suitable monitoring device, at certain vulnerable locations of the overhead line, such as downstream of elbows (in the 1" elbow upstream of the chemical **injection** points, downstream of 2nd elbow, in the 3rd elbow, and selected inlet headers to the aircoolers); (ii) consider installing corrosion probes and on-line **pH** meters on the receiver tail water for data management systems linked to the DCS. Refer to Attachment 4 (Process Options & Operational Guidelines).
3. Establish a **full** time dedicated corrosion engineering position with the responsibility for corrosion monitoring and control throughout the refinery.
4. Follow the misalignment limits for butt welds given in SAES-W-011, to improve blending at elbow girth welds (sites of increased erosion). This is also important for relief valve branch lines, to ensure proper drainage.

Typical Operational Guidelines

All Saudi Aramco "domestic" and "Joint Venture" refineries were surveyed to acquire operational experience and current process information. SAMREF was the only location which was not visited on site, however, their report on the Crude Unit corrosion control was reviewed by the team. This and information gained through discussion with a specialist **from** Chevron Research and Technology Company and Nalco technical staff form the basis for the team's establishment of the operational guidelines. This information is detailed on a PFD Attachment 4 (Process Options & Operational Guidelines) and Table 1 (Materials for

Crude Unit Trains and Fittings). These industry practical guidelines and targets are also supplemented by Saudi Aramco Standards & Engineering Practices.

INTRODUCTION

Review Team: Formation and Review Method

An Engineering Services multidisciplinary team was formed to review the subject of crude unit overhead corrosion control at all five domestic refineries (Jeddah, Riyadh, Rabigh, Yanbu, and Ras Tanura). Two unexpected failures in a refinery crude unit overhead line during 1996 suggested the need for an evaluation of current crude unit overhead corrosion control practices at all domestic refineries. The review team also took the opportunity to visit the SASREF joint-venture refinery in Jubail, to learn their approach to this subject. In addition, the team also reviewed a report titled 'SAMREF Experience in Crude Overhead System Corrosion' and sought international advice from a specialist with Chevron Research & Technology Company.

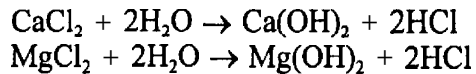
One significant team objective was to identify a common approach for crude unit overhead corrosion control and monitoring and use this as a company guideline. The review method adopted was to conduct site reviews with the aid of a checklist that identified important parameters and features related to crude unit process operation and corrosion control. The checklist was sent to each refinery as early as possible prior to each site visit and formed the basis for the site review and discussion with refinery engineers. Each refinery nominated a contact engineer, who was conversant with crude unit operation and corrosion control.

The team conducted refinery facility reviews during the period November 1996 through March 1997. The team's reviews specifically covered process, inspection and the present corrosion control program areas. Following each domestic refinery visit, an interim report was issued highlighting the team's principal findings and specific recommendations.

Overhead Corrosion: Mechanism and Control Methods

Corrosion of crude unit overhead equipment and associated piping is a common concern to all refineries and its causes have been well documented in the open literature. This section outlines the basic corrosion mechanism in crude unit overhead systems and considers corrosion control methods such as storage tank settling, the use of desalters, caustic injection, neutralizers, corrosion inhibitors (**filmers**) and the use of corrosion resistant alloys (**CRAs**).

The crude charge contains natural inorganic salts present within a dispersed water phase. Hydrolysis of calcium and magnesium chlorides occurs during heating leading to the formation of hydrochloric acid, described by the following chemical reactions:



Significant hydrolysis of magnesium chloride occurs at around 400 °F, well below the fired heater outlet temperature of 700 °F. Injection of well-dispersed caustic soda solution (sodium hydroxide) is utilized to neutralize hydrochloric acid (**HCl**) prior to fractionation in the atmospheric crude **column**. Any free HCl can enter the overhead as hydrogen chloride vapor, which, upon subsequent condensation at the water dew point, produces a strong acid that is very corrosive. Effective caustic additions, in crude unit preheat trains, thus reduce the quantity of overhead chemicals (neutralizer and inhibitor) needed to combat acid corrosion.

Effective corrosion control begins at the upstream end, paying close attention to crude storage tank operations. Adequate settling time and periodic water drainage are prerequisites to cutting the water (therefore chloride) content in the crude, as well as reducing suspended solids. An optimized desalter operation also reduces salt levels further, as well as bottom sediments. Caustic soda is used downstream of the desalter to neutralize the hydrochloric acid formed from the hydrolyzable salts. Finally, amine neutralizer and filming inhibitor chemicals (Nalco 5 151 and Nalco 5 186, respectively) are used for corrosion control in the overhead. Caustic, neutralizer and **filmer** chemicals must be introduced via engineered injection quills to promote proper dispersion. Monel alloys are used for the column top trays and top shell cladding and are also preferred for all chemical injection quills.

DISCUSSION

On stream Inspection

At present all inspection units have an On stream Inspection (**OSI**) program on crude overhead (O/H) systems. Most of the units were able to identify the corrosion problem before failure. At few locations, the **OSI** program was well documented and implemented in accordance with the established program. Some units are using the PIPE + computerized **OSI** program to record and analyze pipe wall thickness data and schedule inspection frequencies based on corrosion rate and remaining life calculations. All inspection units use isometric drawings of the overhead line to identify the Ultrasonic Test (UT) thickness measuring points. The average inspection (**OSI**) frequency on the overhead lines ranged between 3 and 5 years.

The internal corrosion in a crude overhead line is dependent on various process variables, such as:

1. Crude quality (salt and water in the crude),
2. Desalter operation,

3. Caustic injection type and location,
4. Crude column hydrocarbon and steam loading,
5. Velocity and turbulence,
6. Crude column overhead pressure, temperature and water dew point temperature,
7. Insulation of overhead line,
8. Overhead vapor neutralizing/filming amine chemicals injection type and locations,
9. Water wash rate, type and injection locations, or
10. Pooling of liquids in horizontal lines.

The corrosion of crude overhead lines is not uniform (general metal loss). During certain changes in the above process variables, the internal corrosion could be very aggressive at localized areas. The short term metal loss rate of 150 - 200 mpy is not uncommon at locations of impingement and turbulence when control limits are not maintained. Therefore, the selection of **OSI** test points and techniques used are very critical to locate localized corrosion.

Reviewing the present **OSI** programs on crude overhead lines, the following areas requiring improvement were identified:

- a) The inspection frequency shall be in compliance with the SAEP-20, Table-II guidelines.
- b) All Refinery Inspection Units need to have a documented chemical injection point inspection program that complies fully with present API RP 570 inspection guidelines.
- c) The water wash nozzle was not considered as a chemical injection point.
- d) Present **OSI** test point locations and the techniques used may miss localized corrosion as seen on recent overhead line failures. The **OSI** test point locations should cover all impingement locations (Tees and Elbows).
- e) Most of the wall thickness values are based on single point readings.
- f) Some units were able to take **OSI** thickness readings at preferred locations. Others were unable due to inaccessibility (no scaffolding or platform).
- g) In some units the **OSI** data management is still in manual format and data analysis and corrosion rates are not properly documented.
- h) In some units, **OSI** readings which showed high short term corrosion rates were ignored since they considered this as resulting from inaccurate thickness readings.
- i) Treat **O/H** line branch connections for the relief valves as dead legs.
- j) All elevation profiles of horizontal sections of the **O/H** line should be documented. This information is important when selecting **OSI** test points on the bottom of the line which may contain acidic liquid.
- k) All units should have a procedure that defines when special UT surveys must be performed based on the frequency and duration when process control limits are not maintained.
- l) All units are not adequately equipped to perform a thorough **OSI** program due to higher temperatures (130 °C) and equipment requirements.

- m) Corrosion rates measured by corrosion probes located in aircoolers showed much lower rates than OSI Ultrasonic readings.

Metallurgy and Corrosion Monitoring

Carbon steel is the major material of construction throughout the crude unit system (Table 1). Corrosion resistant alloys (CRAs) are used only sparingly as cladding or linings and for pre-heat exchanger tubing exposed to potential sulfur corrosion at higher temperatures. However, CRAs can be justified for injection quills and probes. Chemical injection quills should be made from a CRA such as Monel 400 (UNS N04400). AISI 300 series austenitic stainless steels are not recommended for quills in the overhead line since they are susceptible to stress corrosion cracking in hot chloride environments. Monel 400 is also used for the top trays in the crude column and as a cladding at the top of the column.

With effective control of crude unit overhead corrosion (e. g. chlorides in receiver water < 25 ppm), carbon steel is the normal material of choice for the overhead line. Although not normally regarded as necessary, CRA upgrades for the first section of the overhead line, e. g. up to water wash point, could include either Monel cladding or Incoloy 825 (UNS N08825). Both Mobil publications (below) and Nickel Development Institute personnel suggest Incoloy 825 for use in this service, the former recommending its use for column nozzles only. It is emphasized that such alloy upgrading is not normally a first choice, since there are both higher materials costs and possible procurement problems to be faced.

According to the Mobil Engineering Guide (EGE 55-B-1-1988) 'Materials Application - Crude Units', Shell and Tube Heat Exchangers are normally specified in carbon steels for hydrocarbon streams, with upgrades for tubes to 5½ Cr - ½ Mo or 410 (12 Cr) stainless steel for higher temperature (> 650 °F / 343 °C) or severe service. Our refineries (e. g. Jeddah and Yanbu) have incorporated heat exchanger tubing materials that are generally consistent with this approach.

Within the aircooler banks, corrosion monitoring with the use of ER probes, supplemented with corrosion coupons is practiced at all our refineries (see Corrosion Monitoring Summary Table 2). Some refineries are planning to increase coverage within the aircoolers to include ER probes at inlet, outlet and other locations. Stagnant and/or impingement areas within the aircooler banks should be identified for survey work. Location of probes should be supported by the results of comprehensive field survey work. This increased coverage will enable better mapping of corrosion activity, especially if the probes can be linked to DCS systems or other automated computerized systems located in the refinery control rooms. DCS integration of an on-line pH meter on the receiver tail water will provide a means of identifying excursions outside of control limits. Integration of an on-line pH meter should include alarms that are triggered automatically if the receiver wafer pH goes outside the control limits.

The present major weakness at all refineries is that there is no on-line corrosion monitoring within overhead lines. All that is performed at the moment are periodic on-stream inspections. Applicable new technology monitoring tools may help in the future. In the meantime, consideration should be given to incorporating flush-mounted ER probes (see Attachments **5a** and **5b**) at certain vulnerable locations of the overhead line, such as downstream of elbows (in the 1st elbow upstream of the chemical injection points, downstream of 2nd elbow, in the 3rd elbow and selected inlet headers to the aircoolers). We recognize that accessibility poses practical difficulties in introducing overhead line corrosion monitoring. Nonetheless, we believe that it is both feasible and necessary to perform on-line corrosion monitoring within the overhead line. An on-line integrated corrosion monitoring system is an ideal goal that may be feasible for some refineries. Equally important, the review team feels that each refinery could greatly benefit from an experienced resident Corrosion Engineer. The Corrosion Engineer would be able to give the complete perspective on corrosion activity throughout the refinery, by analyzing the problems and data from all sources.

For overhead line or overhead line elbow replacement, attention is drawn to the misalignment limits for butt welds (the applicable SAES-W-011 paragraph is reprinted below). Proper blending is especially important for the case of high overhead vapor velocities that increase erosion/impingement concerns. (SAES-W-011, **Para. 9.3**: "Internal misalignment of butt joints shall not exceed 1.5 mm. Internal tapering in accordance with **ASME B3 1.3** by machining, backwelding, or a combination may be used to correct the misalignment"). This is also important for relief valve branch lines, to ensure proper drainage. Relief valve branch lines are regarded as operational dead legs, where dew point corrosion conditions may occur.

Process Review

A survey of both domestic and joint-venture refineries has shown a wide spectrum of operating philosophies and capabilities concerning crude unit corrosion control. The most striking approach to corrosion control was exhibited by SASREF. **SASREF's** approach is oriented towards relying on disciplined operational control and minimization of operating costs in a competitive environment. SASREF has vigilant crude tank management which involves frequent analysis, water settlement and drainage, and thorough mixing. SASREF has no desalting equipment and depends on caustic injection and cheap ammonia neutralization for overhead corrosion control. There is no continuous water wash or filming inhibitor treatment. Corrosion coupons and probes are not installed, but instead, an organized corrosion loop inspection program based on "risk to failure" and "consequence" is in force. This approach has resulted in acceptable corrosion performance history. It is estimated that compared to a typical corrosion program involving full chemical treatment, the savings in chemicals alone would be approximately **\$700/MBPD/Yr**. This does not include the **O&M** costs associated with the related corrosion control equipment. With diligence, Saudi Aramco could migrate at least part way towards this approach. There is some risk associated with such an approach in that operational upsets are avoided, dry tower and overhead line conditions are insured, and chlorides into the system are **consistently**

minimized. Some of the major oil companies, such as Chevron, have enforced tighter operational control and try to rely solely on good desalter operation, caustic injection, ammonia neutralization, and water wash to minimize overhead corrosion.

Most of Saudi Aramco domestic refineries are now progressing towards a more expanded corrosion control program. The most important step has been the optimization of existing desalter operation. In the past, some of the refineries have bypassed their desalters due to fouling incidents. The reasons for this have been at least partially resolved and crude unit desalting capacity is now utilized at all domestic refinery locations with the exception of Riyadh refinery. In addition, continuous water wash systems are being evaluated and scoped along with expanded monitoring including on-line pH and corrosion probe readout.

A real concern impacting the corrosion control program is the operation of refinery units significantly above original design. In some cases, crude unit desalter and other pertinent equipment capabilities may be exceeded at crude charge rates of 25 - 30 % above design. Generally speaking, the desalters experience low incoming salt loads, but in some circumstances, may be hydraulically overloaded so that separation of the water and the associated dissolved salts is difficult. Elevated crude rates not only put demand on equipment performance but also may require resources exceeding supply, such as the need for clean wash water. Also good engineering practice might dictate further process limitations. Therefore, the push towards the implementation of a full corrosion control program may be limited by the need for additional capital expenditure for debottlenecking. One example of this is the employment of an overhead recycle wash water system. A recycle wash water system affects overhead equipment performance and may present erosional concerns at high velocities if not properly designed. Each refinery should carefully evaluate corrosion control options to weigh the perceived benefits against incremental costs and impacts to its operation.

Corrosion Control Process Options

The purpose of this section is to describe the various process system approaches utilized to control overhead system acid corrosion. Each of the described options has advantages and disadvantages, depending upon feedstock qualities, physical configuration, and envisioned operational risk. Each plant should carefully evaluate these options based on their own circumstances.

a) Caustic Addition

Overhead Chloride Control: Next to the desalting operation, caustic addition is probably the most important factor in mitigating hydrogen chloride production in the crude unit overhead system. The efficient reaction of caustic with the forming hydrochloric acid (HCl) is primary to corrosion control and can reduce neutralizer consumption costs. This is accomplished through dispersion and thorough mixing.

Usually, a dilute caustic (3 - 5 Be°) mixture is utilized to avoid stress corrosion cracking at elevated temperatures and to reduce fouling tendencies. The water source for the caustic solution should be of condensate quality. At 1 - 2 PTB of caustic addition, the volumetric ratio with crude charge would be about 1 : 10,000. In order to effectively accomplish this mixing, dilute caustic is first mixed with a crude slipstream representing approximately 1 vol. % of total charge and the resultant mixture is then injected into the desalted crude charge via a high velocity quill system.

Both Shell and Chevron employ a two-stage mixing approach for caustic injection and differ only in the mechanical means for slipstream mixing and the injection location. Two-stage mixing of dilute caustic solution is a proven approach for efficiently reducing residual chlorides in the desalted crude. For a given caustic injection rate, two-stage mixing seems to reduce overhead residual chloride levels over more conventional caustic injection systems. Conversely, this method of caustic injection can also result in decreased caustic usage for a given level of chloride concentration. Over-dosage of caustic much beyond the stoichiometric amount may also increase fouling tendencies. Shell utilizes a vortex mixing device, while Chevron uses a tee and restriction orifice combination. The biggest philosophical difference is the location of mixture injection. Chevron chooses to inject the pre-mixed caustic into the crude charge upstream of the charge heater, while the Shell injection point is more conventionally located after the desalter. The Chevron installation has the advantage that exchanger fouling is avoided but some plugging problems around the restriction orifice have been witnessed. Another alternative when a desalter booster pump is in place, is to use a recycle line from the pump discharge to the pump suction as the slipstream.

Desalter Water Effluent pH Control: Some of the refineries use injection of caustic upstream of the desalter for pH control of the water effluent. If this is not done carefully, preheat exchanger fouling and/or emulsion buildup in the desalter may be the result. If the desalter pH is too high, this might also release ammonia from the water phase into the crude, which would present further concern in the overhead system.

If the desalter vessel water phase area is lined and the integrity can be insured, then only the water effluent carbon steel piping needs to be protected. In this case, the preferred method is direct injection of dilute caustic into the water effluent piping just downstream of the desalter. If the desalter vessel is of concern, then caustic should be injected into the desalter makeup wash water. Uniform mixing may be more easily accomplished at the makeup wash water surge tank by injecting caustic into the makeup water pump suction.

b) Desalter

Configuration: The electrical desalting equipment is the most significant device used for controlling the amount of hydrolyzable chloride appearing as hydrogen chloride in the overhead system. The electrical desalter effectively removes salt containing water and

water-wet solids after thorough mixing with a clean wash water source. Removal of soluble sodium salts is also significant for downstream conversion units.

Two-stage desalting is utilized in situations involving **crudes** containing brines with high salt contents or when stringent specifications for the product crude are required. Riyadh and Yanbu refineries alone have two-stage desalting. The selection for Riyadh was probably based on supplying sales specification crude to SCECO for power generation. A typical specification for two-stage desalting would be: 0.1 vol. % **BS&W** maximum; and a maximum salt content of 1.0 PTB or 10 % of incoming charge salt, whichever is greater.

For the two-stage configuration, makeup wash water is routed in a counter-current manner to the second stage mix valve and the effluent water from the second stage is then pumped to the mix valve at the inlet of the first stage. If the availability of makeup water is limiting efficient desalting, then recycling part of the first stage desalter effluent water to the makeup surge drum on flow control might be considered. This can apply to single-stage configurations as well.

Wash Water: The desalter makeup wash water should be oxygen free and have a low level of dissolved solids. Ideally, the wash water should meet condensate or stripped sour water qualities. Makeup wash water can be split and a portion routed to the front-end of the preheat just downstream of the charge pumps while the remainder is routed upstream of the desalter mix valve. A typical split might be 2 vol. % and 3 vol. % of crude charge rate to the preheat and mixing valve, respectively. In the majority of the cases, splitting the wash water improves desalting and alleviates any fouling which might be present. However, if fouling is not evident, it is questionable whether or not any investment associated with splitting the makeup water would be justified. This could be supported **further** by a cheap field trial. If the availability of relatively cheap makeup water is lacking, then the refinery should investigate the use of water recycle. If possible, avoid sending recycle water to the preheat exchangers when splitting the wash water requirement. The cleanest source of water should be preferentially routed to this location.

Demulsifier: Emulsion breakers can be used to improve the separation of crude oil and water and reduce crude salt content. These chemicals are also capable of water wetting suspended solids which are then removed in the water phase. One strategy of emulsion breaker utilization is to optimize mixing valve pressure drop enabling a more efficient contact of the wash water with the oil. Because there is more shearing of the water-oil mixture, the water droplet size distribution is smaller and the emulsion breaker then comes into play by aiding the coalescence of the water phase.

After good overall desalter operation is established, emulsion breaker addition can be used as a polishing step. Emulsion breaker chemicals work best under steady operation with few upsets in incoming water content, **pH** control, and wash water quality. To date, the use of emulsion breakers in Saudi Aramco refineries has been unsuccessful. This statement is also based on recent trials at both Jeddah and Yanbu refineries.

c) Overhead Water Wash

Corrosion Control: Overhead water wash stabilizes pH control, helps to solubilize salts, and aids in flushing corrosion products and other solids from exchanger tubes. Solid salt formation is the first step in initiating under-deposit corrosion. The water wash is especially **valuable** when using ammonia as a neutralizer. If the overhead chloride content is relatively high, then ammonium chloride deposits can form at temperatures above the water dew point. Enough water is added as wash water near the top of the tower to raise the overhead vapor water dew point as quickly as possible in order to prevent salt deposits. This also results in partial condensation of the hydrocarbon phase which serves as additional carrier for the inhibitor chemical. In fact, some will recommend over-saturation to provide even better liquid distribution to each exchanger bank or bundle for dispersion of the inhibitor.

The value of continual water wash when utilizing amine based neutralizers is diminished somewhat. This is especially true if good desalter operation can be established so that overhead chloride targets are met on a continuous basis. Nalco 515 l's (a neutralizer) reaction product with hydrochloric acid is touted to be a non-deposit mobile salt. If this is the case, then the chances of salt deposition and resulting under-deposit corrosion should be considerably reduced. Continual water wash may present some process limitations and other risks as discussed below.

Process Limitations and Concerns: The introduction of a continual water wash system can present serious equipment limitations if water wash was not incorporated already as part of the original design concept. Possible limitations are:

1. Exchanger performance especially in regard to air coolers during summer time conditions,
2. Overhead receiver oil-water phase separation efficiency,
3. Overhead piping velocities and erosional concerns, and
4. Existing pump and piping hydraulics for delivery of wash water to the overhead line.

These limitations may be even more significant in view of the fact that many of the **refineries are running** notably above crude charge design capacity. An evaluation should be completed to determine the actual impact to unit performance. This evaluation along with any capital and maintenance expenditures envisioned should be weighed against the perceived benefits.

System Design: The typical and probably most economical approach is to use recycle from the overhead receiver as wash water. However, other external sources with low TDS and containing no oxygen can be used. Wash water should be injected on the vertical piping drop downstream of chemical injection. Dead legs near the injection point should be avoided. The water should be filtered and injected through a removable atomizing style of spray nozzle. The idea is to vaporize the water as quickly as possible by producing literally

a fog of water. This also produces a droplet size which minimizes possible erosional impingement near the injection point location.

d) Overhead Chemical Treatment

Description & Usage: Nalco products, 5151 (neutralizer) and 5186 (filming inhibitor), are used at all the Saudi Aramco refineries. The Nalco 5151 product is amine based (MEA & MOPA), completely soluble in water, and forms a non-deposit mobile salt when reacted with hydrogen chloride. This neutralizer is volatilized at top tower conditions. Nalco 5186 is aromatic based with an active ingredient of imidazoline and is oil soluble, and effective over a wide range of pH.

Configuration Considerations: Chemical system design depends on the overhead system configuration. Ras Tanura and Jeddah refineries both have two-stage overhead systems, but Ras Tanura has a cold refluxed system, while Jeddah has a hot refluxed system. Neutralizer added ahead of the first stage receiver is solubilized in the water formed. Ideally, this wafer should be pumped to the inlet of the second stage cooler. This is not the case for Jeddah refinery. Since Jeddah's first stage is on reflux service any inhibitor injected upstream is refluxed back to the tower. This essentially means that Jeddah's second stage is not receiving protection from the filming inhibitor injected. If OSI data support it, Jeddah refinery should consider inhibitor injection at both stages. Ras Tanura pumps all condensate formed in the first stage to the inlet of the second stage equipment.

System Design: Neutralizer and inhibitor are injected as near as possible to the top of the crude tower, usually in the horizontal run downstream of the first tower elbow. Both operators and vendors agree that injection of the amine-based neutralizer into the tower via return reflux or vapor streams should be avoided due to the possibility of salt accumulation in stagnant tray areas. Certainly there is no need if dry tower conditions can be somewhat guaranteed and/or the top tower section is lined and trays specified with monel materials. The neutralizer can be injected neat or in a mixture with water. To avoid plugging and to aid in vaporizing the neutralizer, a preferred approach is to inject steam with the neat chemical. The inhibitor needs to be dispersed to be effective and, therefore, is usually diluted with naphtha reflux before injection. The recommended minimum dilution ratio by volume is 50 : 1. Removable injection quills should be used in order to affect quick mixing. These quills should be located in the vertical position with a staggered separation and at an appropriate distance from elbows and major fittings. Neutralizer should be injected upstream of the inhibitor. All chemical injection streams should be positively metered or gauged and usage recorded on a daily basis.

Targets & Qualities

All Saudi Aramco "domestic" and "Joint Venture" refineries were surveyed to provide an operational comparison for benchmarking purposes. SAMREF was the only location which was not visited on site. However, information was obtained verbally and also from publicly

published documents. Table 3 is a comparison of significant corrosion control process parameters for each refinery operation.

The most important observation which is pertinent to successful corrosion control is the minimization of chlorides into the crude unit overhead system. If this is done on a consistent basis, pervasive corrosion and related maintenance costs are reduced considerably. Large or erratic swings in overhead chlorides should be avoided. This in turn causes bounces in pH control which can strip protective films and expose the system to more corrosion risk.

a) Incoming Crude Handling

For the most part, the Arab Light crude delivered by pipeline is dry and low in salt content. Usually, Arab Light crude from the Abqaiq stabilizers has a **BS&W** content of 0.1 vol. % or less and a salt content of less than 10 PTB. All refineries see the same quality of crude and differ only in the specific delivery system. Some of the differences reported in incoming crude qualities to the crude unit might be attributed to additional settling time in refinery tanks, RTR and SASREF have separate dedicated pipeline systems from the Abqaiq stabilizers. All the other refineries receive their crude via the East-West pipeline system. Yanbu and SAMREF can both receive crude from the Yanbu Crude Oil Terminal (COT) after further settling. Both Jeddah and Rabigh refineries tanker their crude from the Yanbu COT and the crude to these refineries is in general dry given the possibility of ballast water contamination.

b) Desalter Operation

The three main operating variables affecting water and salt removal efficiencies in the desalter are: wash water %, temperature, and residence time. Wash water quality, mixing valve pressure drop, and pH control affect efficiencies to a less extent. A wash water rate in the range of 5 - 7 vol. % of crude charge is considered to be reasonable. Wash water rates below 3 vol. % of crude charge may hamper performance. Surveyed operating temperatures ranged from 90 °C to the 140s °C. Jeddah and Riyadh refineries exhibited low temperatures, while SAMREF and RTR had the highest temperature range. There is nothing to indicate that the higher temperature at and above 140 °C is detrimental to water removal. Usually there are mechanical limitations to operating at elevated temperature, such as transformer bushings.

Riyadh's two-stage desalter was originally designed for low temperature desalting of crude bound for crude sales. Currently, very little desalted crude is routed to Riyadh No. 2 Refinery Crude Unit and the inside battery limits unit desalter is now acting as an oil-water separator. Riyadh refinery is now in the process of evaluating options for increasing desalter capability.

Overall, Yanbu refinery and, Jeddah refinery in particular, need to improve desalter operations. Both Yanbu and Jeddah refinery desalter performance is encumbered by crude charge rates in excess of 25 - 30 % above design. This represents a considerable reduction in available water **settling** time. At the high crude charge rates, Yanbu refinery operates their two-stage desalters with low wash water rate, < 3 vol. % of crude charge, due to pump capacity limitations. Jeddah refinery desalter operating temperature can be as low as 100 °C. This could be due to a revised heat exchange scheme and/or poorly performing preheat exchangers. Also, there is very little wash water preheat available. Jeddah refinery should investigate the low operating temperature and the possibility of revamping the existing desalter or putting into service other available capacity.

Desalter makeup wash water is usually condensate quality (< 25 ppmw TDS), with little dissolved acid gases and should contain no oxygen. Overhead receiver tail water and vacuum unit condensate are good in-plant candidates. Stripped sour water has been utilized successfully but its use should be limited as a secondary source and the qualities monitored regularly. Sour water sources should be avoided. Under certain circumstances, such as an upset, significant amounts of ammonia and hydrogen sulfide can migrate into the oil phase and cause additional problems in the overhead system as well as disturb desalter operation,

Ras Tanura refinery and, most recently, Rabigh refinery, both operate with desalter wash water recycle. This decision is usually an economic one based on the availability of cheap good quality makeup water. When recycling under high salt loadings, water effluent TDS may be high enough to affect salt removal efficiency and any water entrainment or carryover could cause downstream fouling.

c) Caustic Injection

Outside sources recommend that caustic injection not to exceed 5 PTB due to the risk of caustic embrittlement and fouling concerns. The refinery operations surveyed all show downstream caustic injection corresponding to less than 1.5 PTB. This is mainly due to relatively low incoming salt contents delivered via pipeline and tanker. If 1 PTB salt content as sodium chloride can be achieved leaving the desalter, then hydrolyzable chloride in the range of 20 - 100 % of this amount is neutralized by approximately 0.2 -0.7 PTB of sodium hydroxide in diluted caustic. Caustic use, for sure, should be less than double this amount, say 1.4 PTB. Based on this and the reported salt content, Rabigh refinery caustic use is high and should be investigated. Jeddah refinery should increase the caustic injection amount based on an overhead chloride target of 20 - 25 ppmw. However, Jeddah refinery has expressed concerns about downstream fouling above this level of injection. Jeddah refinery desalter operation should be improved prior to an effort to adjust caustic addition for overhead chloride control. SASREF, SAMREF, and Ras Tanura refineries seem to have the most effective caustic injection based on unit salt content residuals and the chlorides reported in the overhead. Two of these refinery locations are verified to have two-stage' caustic injection.

d) Overhead Corrosion Control Parameters

Tail Water Chlorides: The combination of good desalter operation and caustic injection should achieve a chloride level of less than 30 ppmw in the tail water. To put this in perspective, if 20 - 100 % of 1 PTB salt content in desalted crude is hydrolyzable and totally absorbed in the tail water, this would conservatively result in approximately 30 - 130 ppmw chlorides in the tail water. This assumes essentially no caustic addition. Certainly with caustic, the low end of this range or better should be achievable. A maximum concentration of 20 - 25 ppmw chloride in the tail water should be set as an operational target. This is somewhat arbitrary, but represents a compromise between practicality and exposure risk to front-end acid corrosion. If an outside water source is used for wash water in lieu of recycle from the receiver, then the tail water target of 20 -25 ppmw should be lowered further in relation to the dilution.

Neutralizer: If all the measured chloride at a concentration level of 30 ppmw represented hydrochloric acid, then the acidity of the tail water would be about $\text{pH} = 3.1$. Even at 1 ppmw the acidity level is $\text{pH} < 5$. This shows the need for neutralizer even with an efficient and effective desalter and caustic injection program. Based on total overhead volume, an addition of approximately 10 ppmv of Nalco 5151 would be required to completely neutralize 30 ppmw chlorides as hydrochloric acid in the tower generated tail water. With this in mind, the Rabigh refinery reported usage of 30 ppmv at < 30 ppmw chlorides in the tail water is excessive. Jeddah refinery neutralizer consumption at 5 ppmv is on the low side based on the reported 50 ppmw chlorides concentration in the tail water. Adjustment of neutralizer addition is done based on measured pH in the tail water. This is usually kept in the range of 5.5 - 6.5 per recommendation by Nalco technical staff.

Filming Inhibitor: Inhibitor needs can be dictated by the size and configuration of the piping and downstream equipment. Also process variables such as pH , temperature, and system velocities may contribute to effectiveness. The filming inhibitor is most effective under steady conditions at a nearly neutral pH and therefore is nearly always used in conjunction with neutralizers. High system velocities may strip the inhibitor barrier especially in areas of high turbulence. This could result in spotty results and higher application rates may be needed. The effectiveness of the inhibitor program is indicated by tail water iron content, corrosion probes, and thickness measurements. An iron content analysis is considered unreliable over the short term. However, a target of around 1 ppmw is usually set. The best tool for optimizing the inhibitor program is strategically placed on-line corrosion probes. In general, inhibitor consumption should be in the 3 - 5 ppmv range based on total overhead volumes. Both Jeddah and Riyadh refinery **consumptions** are significantly above this range. However, Riyadh's usage amount is a rough estimated figure.

Overhead Wash Water: Ideally, overhead wash water rate should be set so that the overhead vapor is slightly over-saturated. A rule of thumb is to fix the rate at 5 vol. % of the total overhead volume. If a simulator is available, then a nomograph could be constructed so that saturation can be targeted based on system variables. One way to positively measure

saturation is to install a thermocouple **sufficiently** downstream of the injection point after vaporization has occurred. Adding the wash water lowers the vapor temperature below tower top temperature. When the vapor is fully saturated, this quenching effect stops. Wash water should be condensate quality (< 25 ppmw TDS) and contain essentially no oxygen (< 20 ppbw). The presence of oxygen under acidic conditions will accelerate corrosion.

e) Crude Column Operation

The best means of protecting the tower top and overhead system piping is to operate with a dry system. That is, ~~conditions are set so that tower~~ top temperature is a comfortable margin above water dew point. ~~Shock condensation can take place on the top reflux tray area and, understandably, Monel materials are specified.~~ At high throughputs, entrainment can take place and any wet liquids present will attack the carbon steel fitting attached to the top tower flange. This kind of attack may have been evidenced at both Yanbu and Jeddah refineries. Entrainment was witnessed at the Yanbu refinery by opening up a vent just downstream of the first elbow.

²⁾
Directionally, ~~maximum~~ kerosene production (low naphtha end point) combined with low pressure operation represents the highest risk for water dew point acid corrosion. This situation produces the lowest dew point margin, ~~the difference between tower top temperature and water dew point temperature.~~ ^{Low to reflux} rates and high steam rates further exasperate the situation. This might be the case when operating with low crude charge rates. Computer simulations, using the operating ranges supplied, indicate that there is no particular dew point problem at any of the domestic refinery locations. Refer to Table 3 concerning calculated dew point margins. The lowest overhead dew point margins were calculated for the Rabigh refinery. High short term corrosion rates were measured at this site on the overhead line vertical drop. Where line corrosion rates are high and the corrosion is general in nature or localized at possible heat sinks and operational dead legs, we have recommended that thermographic surveys be completed to identify cold spots in the overhead piping. Ideally this survey should be done during winter conditions. The results of the survey can then be appropriately incorporated within the OSI program.

For facilities design work, the Saudi Aramco Standards limit vapor line velocity to 60 ft./sec. Overhead line vapor velocities are in general limited to 100 ft./sec. due to associated acoustical noise problems. One other aspect of a high velocity situation is accelerated corrosion rate due to erosion/corrosion. Some very high velocities in excess of 100 ft./sec. can be exhibited in the overhead piping. Refer to Table 3 for site specific information. This is mainly due to the fact that refinery crude charge rates have been pushed, in some cases, to 25 - 30 % or more above design. Regardless of the addition of continuous wash water, inspection of process piping and equipment may need to be expanded and made more comprehensive at elevated crude charge rates.

Program Monitoring and Laboratory Analysis

The effectiveness of the corrosion control program hinges upon the frequent and accurate monitoring of process equipment performance, chemical treatment, and process stream qualities. Once a baseline is established which represents good performance, trend plots can be used to indicate any deviant behavior and the corresponding reasons. Gathering process information from a DCS system and archiving data in a dedicated PC is a preferred method for accurate surveillance. On-line pH and corrosion probe information gathered from this same DCS system can be a great help in timely interpretation of process upsets and also can help optimize chemical treatment. Capturing a realistic view of the field not only rests with accurate process data but with good sampling and accurate sample analysis as well.

a) Program Monitoring

Scrutiny of the corrosion control program should include the following areas as a minimum:

1. Incoming crude - analysis (BS&W, salt content, suspended solids (SS), etc.).
2. Desalter operation - temperature, mixing valve pressure drop, crude & wash water rates, makeup and effluent water rates & qualities (TDS, SS, Cls, pH, dissolved gases, etc.), and desalted crude qualities (BS&W, salt content, etc.).
3. Chemical injection (caustic, neutralizer, and inhibitor) - daily chemical use, diluent rate, and chemical quality check.
4. Overhead tail water - rate, analysis (pH, Cls, Fe).
5. Overhead wash water - rate, and qualities as necessary.
6. Overhead conditions - tower top dew point margin, wash water saturation temperature.
7. Corrosion probe data - on-line or manually read.

For a given incoming crude and desalter makeup wash water rate and quality, the desalter effluent water analysis is probably the most important indicator of a change in desalter operation. The Total Dissolved Solids and chloride content are a qualitative measure of the washing efficiency of the system. More refining operations should add this to their routine laboratory analysis work.

Both water and salt removal efficiencies can be calculated for the desalter and plotted. However, the accuracy and benefit of doing so is questionable. Using the standard analytical methods, calculated salt removal efficiencies are highly inaccurate at low incoming salt contents. Water removal efficiencies are more accurate, but the important measurement is the desalted crude residual water content and the dissolved salts in this residual water.

Troubleshooting the desalter and caustic injection operation can be aided by performing a chloride balance. Samples of crude, makeup wash water and effluent water can be analyzed for chlorides and hydrolyzable salts estimated or identified. The objective is to quantify accurately the hydrolyzable salts exiting the desalter. Approximately 95 % and 15 % of the magnesium and calcium chloride, respectively, are hydrolyzed at crude unit heater

conditions. This **assumption then fixes the** maximum amount of chlorides that can appear in the overhead system without any caustic addition.

With a two-stage overhead system, the first stage water should be analyzed separately on an occasional basis as a check on neutralizer effectiveness. Program control should be done on the basis of a commingled water sample.

b) Laboratory Analysis

Measurement of salt content utilizing the ASTM conductivity procedure is recommended over an approximate range of 2 - 50 PTB. Even at 2 PTB the reported repeatability and reproducibility are **0.3 and 1.4 PTB**. Measurement of salt content at the 1 PTB level is highly suspect and accurately calculated salt removal efficiencies are out of the question. The accuracy of the centrifuge technique for water content determination is dependent on selection of solvent and emulsion breaker systems with a particular crude. A Karl Fischer titration method can be used as a check on measured water contents using the centrifuge method.

The chloride analysis involves titration of the water sample or water extract of the oil using silver nitrate. The **presence of a significant** amount of sulfides may interfere with the chloride determination and they must be removed beforehand.


A. A. Abu Al Saud (Team Leader)

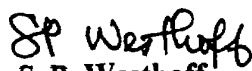
CSD/ME&CCD


G. R. Lobley

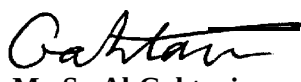
CSD/ME&CCD


O. S. Abdul Hamid

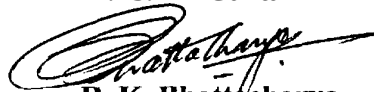
CSD/ME&CCD


S. P. Westhoff

P&CSD/PED


M. S. Al-Gahtani

ID/OID


R. K. Bhattacharya

ID/OID

Table 1: Materials for Crude Unit Trains and Fittings

UNIT/LOCATION or FITTING	MATERIAL
Crude Storage Tanks	Carbon Steel. Bottom and 1 meter up sides internally coated with epoxy-based coating to APCS 2A or 3.
Piping	Carbon Steel.
Desalter	Carbon Steel vessel. Bottom section may be internally lined with Corrosion Resistant Alloy (CRA) e. g. Incoloy 825 at RTR.
Pre-Heat Exchangers: tubes	Carbon Steel $\rightarrow 5\frac{1}{2}\text{Cr} - 1\frac{1}{2}\text{Mo} \rightarrow 9\text{Cr} - 1\text{Mo} \rightarrow \text{Type 410 (12 Cr)}$ stainless steel. Alloy upgrade steps for higher temperatures ($>650^{\circ}\text{F}/343^{\circ}\text{C}$), in contact with sulfur-containing oils.
Crude Column	Carbon Steel; top section clad with Monel 400. Top trays Monel.
Overhead Line	Carbon Steel.
Aircooler Tubes	Carbon Steel. CRA (e. g. Monel 400 or Incoloy 825) ferrules may be needed at the inlet section.
Injection Quills: (Caustic & Overhead Chemicals)	Monel 400. Austenitic Stainless Steels not recommended.
Probes for Corrosion Monitoring	Incoloy 825 preferred for probe body. Austenitic Stainless Steels not recommended.

The above table is based on general industry experience, supplemented by Saudi Aramco guidelines.

*Naphth. Corro
 (140
 ASS 316 or 317)

 475 embritt.
 (Limit use of 12 Cr
 in press. containing
 components)*

Table 2: Crude Unit Overhead Corrosion Monitoring Summary

Refinery	Crude Charge Rate MBPD	Overhead Line Size (Inches)	Corrosion Monitoring System	Probes Number/Type Location	Coupons Number/ Location	Comments	Injection Quill /Metallurgy
Yanbu	220	30	<i>Coritest</i> 4901 Corrosion Monitoring System	12 planned -----	One ER probe and a number of weight-loss coupons on OH condenser banks	New system, not yet fully installed/integrated. Erosion concerns with high OH vapor velocities (> 100 ft/s) and poor atomization of chemicals	No inhibitor quill. Monel OH injection quills recommended. <i>next on Ref. Unit</i> Monel for Caustic. CS water injection system.
Ras Tanura	250	48	cosasco (generic type)	6	None	Corrosion rates c 0.5 MPY. Probes to be linked to computer. ✓	OH injection quills 304/3 16, upgraded to Monel in 1992.
Riyadh	112 ✓	(Unit 1) 14 (Unit 2) 30	Rohrback Cosasco RC-1 Integrated Corrosion Monitoring System installed. Range of data can be displayed/printed from Control Room.	Refinery #2: 2 (D I/O of Fin Fan bank)	2 (D I/O of Fin Fan bank)	Plan to increase probes/coupons, as banks are re-tubed.	Currently, no quills at OH injection points. Monel quills for OH recommended.
Jeddah	43 (CV-201)	20	Rohrback ICMS/RCS-8: Reading in Control Room	2 ER (B1 inlet/outlet) Corrosometer ✓	2 (1C2 1; 1 E2 0)	Additional 6 probes & 8 coupons proposed (for 1997). Current corrosion rate: 6 mpy Need to consider OH line. Potential erosion concerns due to relatively high overhead vapor velocity.	Nalco "Nal-Quill" 304 SS inhibitor quills. Must be upgraded to Monel.
Rabigh	350 (325 design)	44	Cosasco: manual reading	4 in aircooler inlets (EA-01A-1 & 11, EA-OIB-13 & 22) ✓ 1 in desalter V-109B ✓	10 coupons: 4 in aircooler - ✓ 2 in inlet & 2 in outlet	Corrosion rates: aircooler 5.5 mpy (probe) & 4.5 mpy (coupon) Desalter: 0.29 mpy ✓	Quill metallurgy: for caustic & chemical injection is 304 ss. must be upgraded to Monel. Inconel 600 water spray nozzle ok.
SASREF, Jubail	300 (2x150)	30	None	None	None	SASREF's approach is based on maximizing water removal & paying special attention to optimal caustic mixing to cut Cl (Typical Cl < 10 ppm in OH). NH ₃ is neutralizer.	Monel for caustic

TABLE 3
Comparison of Refinery Corrosion Control Operating Parameters

Refinery	Tank Settl. Time Hrs.	Unit Incoming BS&W/Salt vol.%/PTB	Caustic Strength Be	U.S. Caustic Inject. PTB	D.S. Caustic Inject. PTB	Desalter Config. #/stgs.	Desalter Temp deg. C	Desalter Makeup Source	Desalter w.w. Tot/Recycle vol.%/vol.%	Desalter Mix Valve Kg/cm2	Desalter BS&W/Salt vol.%/PTB
SASREF	18	0.1/1.5	5	None	<1	None	N/A	N/A	N/A	N/A	N/A
SAMREF	0	0.05/4-5	4	None	0.5-0.7	2/s.s.	140-147	Strip. s.w.	7/No	0.8	0.3-0.5/1.5
YANBU	>48	<0.1/2-4	3	None	<1	4/t.s.	120-125	Proc., C.U. cond.	<3/No	0.8	0.1-0.2/1-2
RTR	0	0.4-2.0/3-10	3	None	0.5	2/s.s.	130-149?	Vac. Cond.	5.0/2.0	1.0	<1.0/1.0
RIYADH (1)	0	Trc./3-10	3	None	Unmeasured	2/t.s. (2)	90	Trtd., Strip. s.w., & C.U. cond.	3/No	0.9-1.2	Trc./0.8-1.8
JEDDAH	0	0.1/2-3	2-5	0.8	0.7	1/s.s.	102-112	Proc., C.U. cond.	4-5/No	1.0	0.3-1+/1-2
RABIGH	48	0.1/1-3	5	0.5	1.5	4/s.s.	131	Strip. s.w.	5/Yes	1.0	0.2/0.3-0.5

Notes: (1) Information listed for RR No. 2 Refinery only.
(2) Riyadh Refinery Desalter is used for crude sales and very little Crude Unit charge is desalted.

Refinery	Overhead Clis ppmw	Overhead pH	Inhibitor Usage type/ppmv/loc.	Neut. Usage type/ppmv/loc.	Tower Top Press. Kg/cm2	Tower Top Temp. deg. C	Overhead water wash type	Overhead water wash vol.%
SASREF	<10	7	None	3 wt.%NH3/ - /Ovhd.	1.9-2.3	135 max.	None	N/A
SAMREF	10-20	5.5-6.5	5186/3-5/Ovhd.	5151/2-5/Reflux	2.1	130	Unknown	Intermitt.
YANBU	<25	5.5-7	Dil. 5186/5/Ovhd.	Nt. 5151/15/Reflux	<0.7-1.95	110-140	Desltr. w.w.	5.0
RTR	2-14	5.5-6.5	Dil. 5186/3-5/Ovhd.	Nt. 5151/2/Ovhd.	1.1	132	Rcvr. Boot	5.0
RIYADH	<30 gen.	Variable	Dil. 5186/8-167/Ovhd.	Nt. 5151/Unmeas./Ovhd.	1.1	131	Desltr. w.w.	3.0
JEDDAH	50 avg.	5.5-7	Dil. 5186/10/Ovhd.	Wtr.Dil./5/Reflux	0.7-1.7	117-130	BFW	4.0
RABIGH	<30	5.5-6.5	Dil. 5186/3-4/Ovhd.	Nt. 5151/30/Ovhd.	1.1-1.6	114-127	Rcvr. Boot	Intermitt.

velocity
8/5

-
-
100

-
80-100
90

110-140

DP&Vels

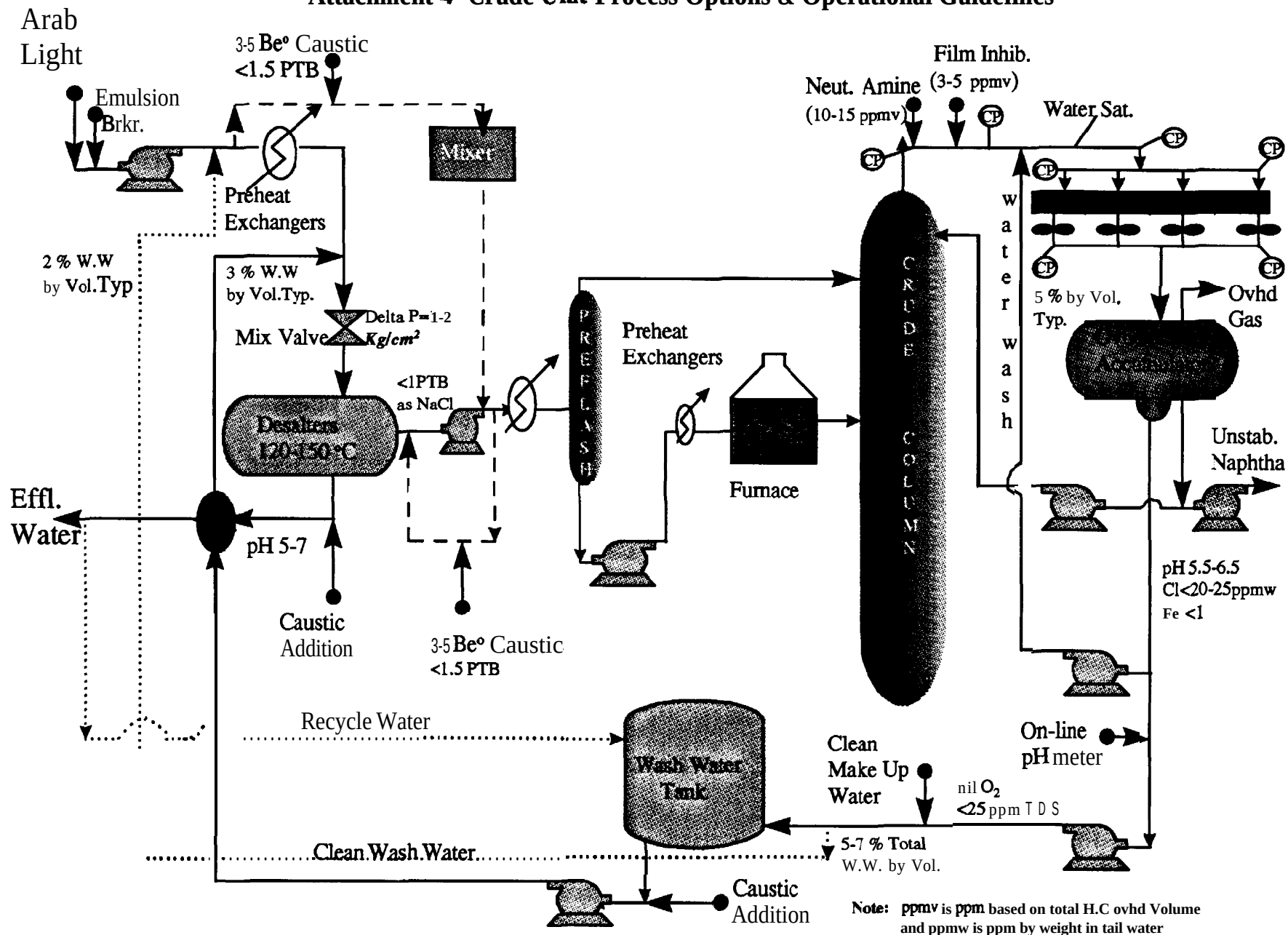
TABLE II
Comparison of Refinery Crude Unit Overhead Operating Conditions

Refinery	Crude Charge Rate M3/Hr.	Total Ovhd. Rate M3/Hr.	Tail Water Rate M3/Hr.	Inject. Water Rate M3/Hr.	Tower Top Press. Kg/cm ²	Tower Top Temp. deg. C	Ovhd. Line Diam. ins.	Ovhd. Vapor Velocity ft./sec.	Ovhd. Vapor D.P. Margin deg. C	State of Sat. Downstream of Inject.
YANBU	1556	358	20	19	0.7-1.95	110-140	30	>100 (2)	18-27	Sat.
RTR	2185	781	19	25	1.1	130	48	84	41	Undersat.
RIYADH	728	148	5.4	4.4	1.1	131	30	43	28	Undersat.
JEDDAH	285	100	4.2	5	0.8-1.3	117-128	20	78->100 (1)	33-37	Undersat.
RABIGH	2649	702	38	Intermitt.	1.1-1.6	114-127	44	100	16-24 (3)	N/A

Notes:

- (1) Range of velocities is upstream-downstream of water wash at stated overhead rates.
 (2) Corresponds to 54 MBPD net ovhd. product w/ tower top pressure of 1.3 Kg/cm².
 (3) Low end of range corresponds to low crude charge rate and high steam rates.

Attachment 4- Crude Unit Process Options & Operational Guidelines



Electrical Resistance Probes for Corrosion Monitorine in the Overhead Line

Based on expected process conditions of 120 °C, 14.2 psig, some HCl and a trace amount of H_2S , either flush mounted electrical resistance (ER) probes or flush mounted coupons can be utilized for corrosion monitoring in crude unit overhead. It is Saudi Aramco policy to utilize the 2 inch High Pressure 'Cosasco' type access fitting and plug for on-line' corrosion monitoring. With this system, a service valve and retriever are required for the installation and removal of probes and coupons.

ER probes generate on-line corrosion rate data and can detect changes in corrosivity over time. For example, if corrosion rates are in the range 5 mpy to 50 mpy, a flush strip ER probe with a 10 mil carbon-steel element would be able to detect a corrosion rate of 50 mpy in about 18 hours, and a rate of 5 mpy in about 7 days. ER probes however are unable to distinguish between pitting attack and uniform corrosion.

Coupons only provide data following removal from the system, and the corrosion rate determined is an average for the exposure period. However they are able to detect pitting and generally require a minimum exposure time of about 30 days to do this.

The material of construction for ER probes is usually 316 stainless steel. This alloy is susceptible to chloride-induced stress corrosion cracking, under conditions that may be encountered in the overhead line, especially if there are process upsets. We therefore recommend the use of a more corrosion resistant alloy, such as Incoloy 825 for the probe element body and connector.

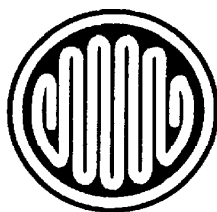
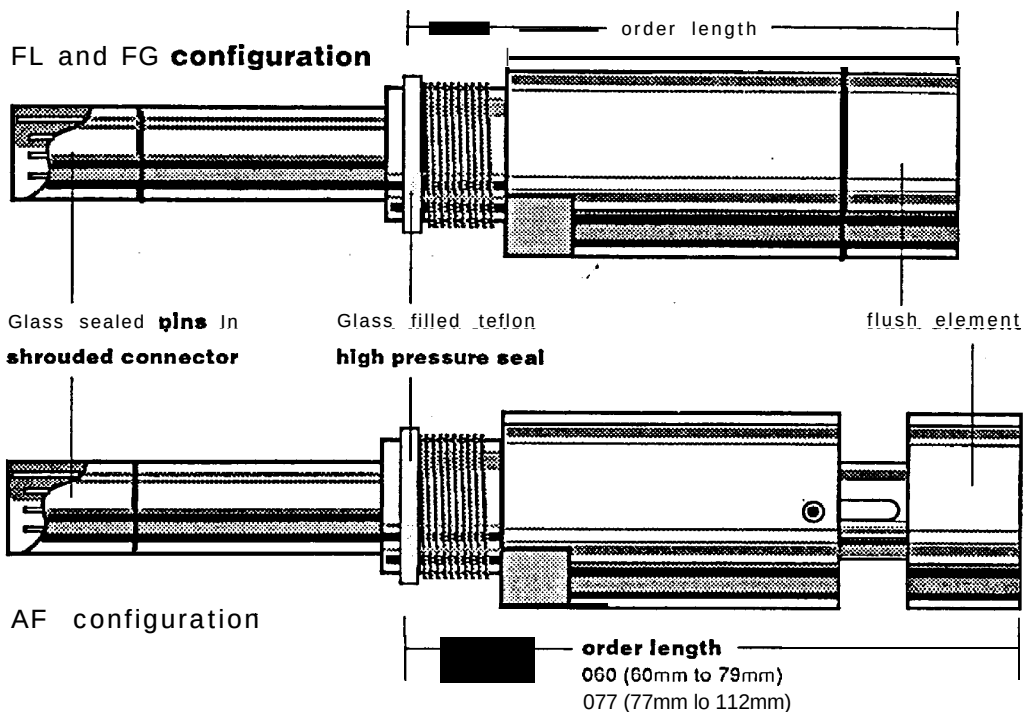
Probe: Electrical Resistance flush element & adjustable flush

cormon

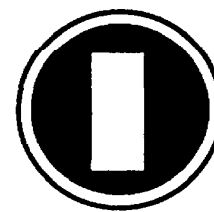
Data Sheet CMEI.011.1

For **use** with all 2" access high pressure fittings (**AC** series)

For monitoring in all types of locations, especially for bottom of line and pigged lines.
Not recommended for H_2S /scaling environments.*



long path epoxy
(FL + AF series)



CORMON LTD
CORROSION
MONITORING
SYSTEMS



BSI Reg
Q5877

See CormonBand Probe data sheet CMEP 008

Specifications and ordering information **overleaf**

CormonHouse,
Riverbank BusinessCentre,
Shoreham-by-Sea,
West Sussex BN43 5FL U.K.
Tel: +44 (0) 1273 441168
Telex: 87323 FSIG
Fax: +44 (0) 1273 441169

Retrieval Under Pressure

AC Series 2" Access System

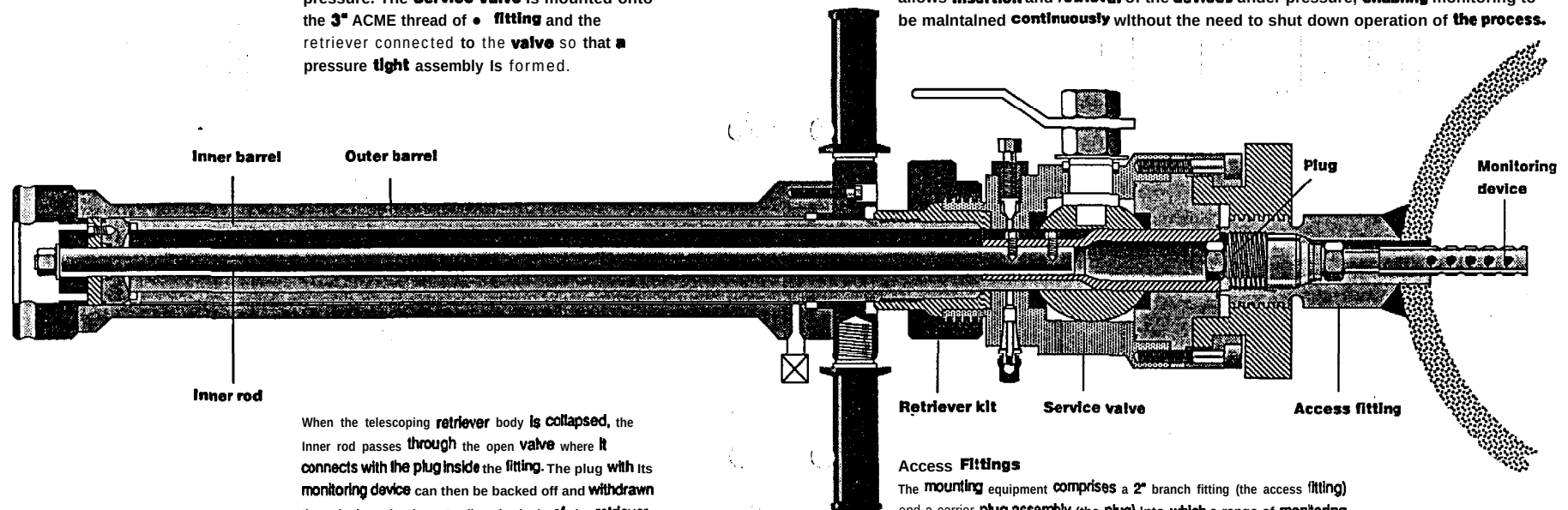


Data Sheet CMEF 001.1

High Pressure - up to 6000 psi 400 bar

By using a **Retriever Kit** and **Service Valve**, devices can be installed or retrieved under pressure. The **Service Valve** is mounted onto the **3" ACME** thread of a fitting and the retriever connected to the valve so that a pressure tight assembly is formed.

The 2" system is a widely used "industry standard" high pressure access method for mounting corrosion monitoring devices into pipework and vessels. The system allows insertion and retrieval of the devices under pressure, enabling monitoring to be maintained continuously without the need to shut down operation of the process.



When the telescoping retriever body is collapsed, the inner rod passes through the open valve where it connects with the plug inside the fitting. The plug with its monitoring device can then be backed off and withdrawn through the valve by extending the body of the retriever.

Once the plug assembly is clear of the valve it is closed and pressure is bled from the retriever which can then be dismantled from the valve allowing access to the plug assembly.

After servicing or changing the device in the carrier plug, re-installation is carried out using the reverse procedure. The alignment of the device is easily controlled by rotation of the plug.

The retriever is a pressure balanced design which will not telescope if pressure is released suddenly from the system. Care must be taken when specifying retrieval under pressure to ensure sufficient clearance exists for the extended tool to withdraw the device from the line. See the detailed data sheet on Retrievers.

Access Fittings

The mounting equipment comprises a 2" branch fitting (the access fitting) and a carrier plug assembly (the plug) into which a range of monitoring probes or other devices may be placed. Access fittings have an internal 1 1/4" 12 UNF parallel thread to receive the plug, below which is a taper shoulder which mates with the packing element of the plug. An external 3" ACME thread allows installation of the service valve used in making retrievals under pressure. When not in use for retrieval, the external thread is fitted with a cover to protect against corrosion and impact damage and in some cases to provide a secondary pressure barrier.

Fittings may be welded directly to the pipe or vessel using a butt weld or weldolet configuration; the weldolet version of the access fitting is commonly described as a Flareweld Fitting. Alternatively, a flanged fitting may be bolted to suitable contra flange, allowing the option to renew or replace the fitting at a later date. Access Fittings are generally rated at 6000 psi / 400 bar and are available in a wide range of materials to match those used in the system.

CORMON LTD

CORROSION
MONITORING
SYSTEMS

Cormon House,
Riverbank Business Centre
Shoreham-by-Sea
West Sussex BN43 5FL U.K.
Tel: +44 (0) 1273 441168
Telex: 87323 FSIG
Fax: +44 (0) 1273 441169

12 4 7
1 2 4 7

Probe: Electrical Resistance flush element and adjustable flush.

Specifications and ordering information

Pressure rating 3600psi
 Temperature rating 200°C (260°C FG series)
 Body material 316ss
 (for other options contact our sales office)

FL -Standard flush fixed length probe with long path element set in epoxy

AF -Adjustable flush probe with long path element set in epoxy. Allows exact length to be set on-site and reduces inventory required to cover replacements.

FG-Flush fixed length probe with glass sealed strip element.

All connectors are 6 pin mil spec with shroud, locator and glass sealed gold plated pins. An extension adaptor is required for use in 2" access fittings: order GEA PL 092 for portable and GEA SW 206 for permanent instrumentation.

Adjustable Flush Probes

The length of Common Adjustable Flush (AF) probes may be set in the field to ensure exactly flush installation. This is a particular advantage in many situations including waxy crudes where under-flush probes may give false readings, or pigged lines where over-flush probes may be damaged. The wide range of combined wall thickness and fin diameter which can be covered by a single AF probe allows operators to reduce inventory of replacement probes and simplifies ordering.

Our standard Short 060mm and Long 077mm probes between them cover a standard 5 1/4" flare weld access fitting on lines from 1/2" Schedule 5S to 20" Schedule 160. Common data sheet CMEP.013 gives full information on these probe lengths.

For longer probes please state the approximate fixed flush length required. This may be calculated using our probe length calculation data sheet CMEP.013. Probes longer than 77mm will have at least 35mm travel.

P E R	A C				
Probe Electrical Resistance	2"access mounting style	Length in mm see length calculation data sheet	Element configuration	Element thickness	Element material
			FL Flush - long path epoxy fixed length	40 0.040" (not FG series)	A07 carbon steel cs2
			AF Adjustable length. Flush - long path epoxy	20 0.020"	for other materials contact our sales office
			FG. Flush - glass sealed strip element -fixed length	10 0.010"	
				05 0.005" (FG only)	

Data Sheet CMEP.011.2

Paper No.
588

CORROSION96

The NACE International Annual Conference and Exposition

IMPLEMENTATION STRATEGIES FOR API 570 INJECTION POINT INSPECTION PROGRAMS

R. R. Konet
Amoco Corporation
P.O. Box 710
Whiting, In 48394

G. J. Honer
Ultramar Inc.
P.O. Box 93102
Long Beach, Ca 90809-3102

R. M. Thompson
Chevron Research and Technology Co.
P.O. Box 1627
Richmond, Ca 94802-0627

ABSTRACT

Several highly publicized refinery piping **failures** around injection points have made apparent the need for more detailed inspection requirements **in** these areas. This need was addressed by the American **Petroleum** Institute (API) with the first **edition** of the API 570 Piping Inspection Code. This paper discusses implementation of an inspection program that complies with API **570** injecttton point inspections and improves the overall reliability of injection systems. Four case histories are presented to illustrate the benefits of increased inspection efforts and to provide experiences to help improve existing inspection programs.

INTRODUCTION

Many **different** types of process **additives** are used to maintain reliability and to ensure optimum performance of refinery operations. An additive may be a proprietary chemical such as a corrosion inhibitor, antifoulant, antifoam, oxygen scavenger, or as simple as a water stream to **dissolve** salt deposition or dilute corrosive process components. Typically, these process **additives** are injected into

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refinery piping systems through small branch connections either directly or through a quill or spray nozzle. These locations are commonly referred to as injection points.

Several types of unique corrosion mechanisms associated with injection points have become apparent to refinery personnel over the years. Problems include impingement opposite the injection point or at downstream changes in pipe direction, corrosivity of the additive itself, and insufficient or excessive injection rates. Many of these problems result in highly localized deterioration.

In recent years, several well publicized piping failures associated with injection points have been discussed at industry forums such as NACE, API, etc. Probably the most widely known was the failure and resulting fire at the Shell Norco refinery. Upon discussion, it became apparent that existing piping inspection programs were not sufficient to detect localized corrosion problems at injection points and that more thorough programs specifically designed to identify the unique problems of injection points were required.

API 570 INSPECTION OF INJECTION POINTS

The need for more detailed inspection requirements was formally addressed industry-wide in June 1993 with the issuance of API 570, 'Inspection, Repair, Alteration, and Rerating of In-Service Piping Systems'. API 570 defines injection points as "locations where relatively small quantities of materials are injected into process streams to control chemistry or other process variables." Process mix points are specifically excluded. API 570 recommends more rigorous inspection of injection points due to the potential susceptibility to accelerated or localized corrosion.

Chemical Injection Circuit

An injection point circuit is defined by API 570 as the process piping:

- beginning 12" (30.5 cm) or 3D (3 times the nominal pipe diameter), whichever is greater, upstream of the injection point; and
- ending two changes in flow direction or 25' (7.6 m) beyond the first change in direction, whichever is less, downstream of the injection point.

If included in the circuit, the downstream endpoint can also be a piece of equipment such as a pressure vessel or heat exchanger. The injection nozzle and the injection piping are also included in the circuit definition.

This definition of the injection circuit focuses inspection efforts to the area considered most susceptible to failure. The circuit definition provides an initial sampling point that one could change if needed. For example, if corrosion is discovered which could extend beyond the circuit limit, the circuit should be expanded to define the extent of the problem and direct future inspection efforts.

Thickness Monitoring Locations (TMLs)

Some general guidance is provided in API 570 to help select TMLs for ultrasonic or radiographic inspection. As a minimum, TMLs are required on each fitting within the injection point circuit, the point of expected impingement at the actual injection location, and the upstream and downstream limits of

the circuit. API 570 further suggests **TMLs** on straight runs between fittings, but does not specify any particular spacing. For **ultrasonic** inspection, each TML by definition includes measurements at each of the four **pipe** or fitting quadrants.

STEPS TO IMPLEMENTING AN INSPECTION PROGRAM

Like implementing any program plant-wide, following some common steps have proven successful in maximizing both the value of the program and participation of key personnel. The primary goals are to determine the existing condition of the injection systems, if not known, and provide **a consistent set of** inspection guidelines that can be used on plantwide injection circuits. The following steps have been used successfully in Implementing an injection point inspection program

Audit Existing Installations

Existing injection installations are surveyed to identify the **type of** installations, their condition, susceptibility to corrosion problems, and access requirements to perform the inspection. The survey requires a multidisciplinary approach with input from Unit Operations, Maintenance, Inspection personnel, and representatives of the local suppliers of proprietary **chemicals**. A listing of data considered important in the audit are shown in Table 1. This includes data on the process and injection streams, **details on** the injection system hardware, properties of the chemical being injected, and inspection data like piping isometric drawings.

As a side benefit, the survey facilitates a review of potential deterioration mechanisms and process safety management issues associated with a given system. Examples of potential problems that can be **revealed are:**

- Lack of an injection quill -- Chemical may not disperse adequately resulting in accelerated corrosion downstream (either due to the chemical not being present or from the chemical itself).
- Lack of a diluent stream -- **Concentrated chemicals, for instance filming amines**, may cause accelerated corrosion at temperatures exceeding 300°F.
- Lack of backflow protection on chemical -- Process fluids can flow into the injection stream.
- Improper metallurgy for injection quill -- **A quill can corrode or environmentally crack either from the process side or injectant side if it is not of the proper metallurgy.**
- Fixed versus Retractable quill -- Reliance on a packing gland assembly to prevent leaks may be undesirable in some **process systems**, while failure of a fixed quill would necessitate an undesirable unit shutdown to repair. These safety and economic considerations need to be **weighed** on a **case-by-case** basis to help select appropriate hardware for a given system.
- Injection point located immediately upstream of a change in direction -- The injection stream can impinge upon the pipe fitting causing accelerated erosion or corrosion.
- Non-compatible chemistry of the additive and the process stream (including any diluent) or multiple chemicals injected through the same injection point.
- **Process stream temperature high enough for the additive to become corrosive.**

Establish Consistent Approach to TMLs

A consistent approach to defining **TMLs** in an injection point circuit aids in the inspection of these points at a plant. **An approach like this allows** engineers and inspectors to understand the requirements without **treating each circuit uniquely.** Depending upon the degree of confidence desired and the level of

inspection supported by the plant inspection budget, many approaches can be used. One approach that has been used successfully to define **TMLs** is as follows:

TMLs in an injection point circuit should be on the primary process piping and located at the:

- Upstream limit of the injection circuit, either **12"** (30.5 cm) or **3D**, where D is the pipe diameter),
- injection point 360° around the injection nozzle,
- Apparent impingement point on the process piping opposite the injection nozzle (e.g., injection is perpendicular at 12 o'clock, TML is located 180° from the injection **nozzle** at 6 o'clock),
- Points downstream of the injection point defined by: D, **5D**, **10D**, midway between the injection point and the first change in direction (if they are more than 25' (7.6 m) apart), the first change in direction, and the downstream limit of the injection circuit.

Create an Inspection Isometric Sketch

The injection point circuit should be identified as such on the piping inspection isometric drawing. Creating a unique piping isometric for injection circuits can help facilitate the more rigorous inspection required for these circuits. Typically, the isometric should include the diameter and piping **schedule** for the primary process piping and injection piping (or tubing) and the location of the **TMLs**.

Establish Inspection Requirements

inspection at **TMLs**. A TML is defined for our purposes as a band around the pipe rather than a single inspection point, except for the **TML** at the injection nozzle, which is a band around the nozzle. Thickness measurements taken with ultrasonics (UT) on a one inch spacing around the circumference is adequate. The lowest reading will be recorded for that TML. If the operating temperature of the **line** precludes the use of UT, radiography should be used to assess wall thickness in at least two quadrants of the pipe (preferably 90° apart). **TMLs** should be permanently identified on the piping to achieve meaningful future inspection results.

Detailed inspection ~~Between 12" (30.5 cm) upstream and 10D downstream~~ API 570 requires a more detailed inspection of the primary process piping located between **12"** (30.5 cm) upstream and **10D** downstream of the injection point. Experience has shown that localized corrosion damage in this **part** of the circuit could be missed when performing spot UT thickness measurements. Therefore, inspection of this area is best performed by scanning using **A, B** or C-scan ultrasonics. If the scan defines a local area of significant metal loss, it should be marked and defined as an additional TML for that circuit.

In addition, if the additive is being injected into a gas or two phase stream, the first change in direction should be scanned. The purpose for this scan is to **detect** any localized erosion or erosion corrosion present at the first obstruction (e.g. impingement location).

Aside from the additional expense, the only drawback to this type of inspection is that scanning equipment tends to be more sensitive to elevated temperature than spot **ultrasonic** inspection equipment. Depending on process temperatures, scanning may only be possible during downtime, limiting the ability to **effectively** plan maintenance activity.

● Set an Inspection Frequency

API 570 requires a **maximum inspection interval of three years for injection point circuits**. This interval is appropriate for many systems. However, for circuits where the industry has experienced significant **corrosion problems, such as water wash injection in hydrotreater reactor effluent streams or in catalytic cracker Light ends recovery units**, a much shorter interval **should** be used. An experienced corrosion engineer should be consulted to review process conditions and equipment history in order to help select an initial **inspection interval**. **After several cycles of inspection data have been collected, the inspection interval should be reviewed and increased or reduced as appropriate. However, in no case should the interval exceed the three year maximum.**

Keep Track of Changes to Injection Systems

The **"Management of Change" process should be used to identify** changes which could impact the inspection plan for a particular injection point circuit. Changes to the composition of the additive, location of the injection, and length of time the **additive** is injected can occur frequently. This is especially important when a trial program for an additive is initiated. Close **communication** between Operations, Engineering, and Inspection personnel regarding these types of changes will **help** prevent the development of problems due to an oversight in the inspection program. In addition, the same type of communication on new installations will help improve the effectiveness and minimize the cost impact of **the inspection program by addressing key issues such as hardware selection, inspection access, and potential corrosion problems.**

● FIELD CASES OF INJECTION POINT INSPECTIONS

Since API 570 was issued and required owner-users to address the specific inspection needs of injection points, **supplemental inspection programs have been implemented in many facilities. The common goal of these programs is to avoid piping failures and thereby improve plant safety, environmental performance, and unit reliability. The success of this approach has been made clear through experience identifying problems before they find the user.**

Reid cases are presented below which illustrate both positive and negative experience since the injection point inspection programs were implemented. Negative experiences have been presented to provide lessons to better improve existing programs. **Table 2 lists summary data on the chemical injection systems described in each of the four cases.**

Case 1: Water Wash In a Catalytic Cracker Gas Recovery Unit

A refinery has two catalytic crackers and two gas recovery **units**, GRU 1 and GRU 2. The vapor **downstream of the gas compressors on the Catalytic Cracker fractionator overhead is water washed with condensate to dissolve salts and dilute corrosive species. Water wash started in the 1960's, was discontinued in the mid 1970s, and was reinitiated in 1991. The water wash system is identical in configuration and hardware at both gas recovery units. The injection point is immediately upstream of the aftercooler heat exchanger.**

Concurrent with the development of API 570, the refinery initiated an audit of injection piping circuits. Table 2 shows the data gathered on the injection system during the audit. Initial recommendations based on the audit included:

- Create an injection point inspection piping isometric,
- Relocate the injection point further upstream (preferably 10 pipe diameters upstream of the elbow to avoid direct impingement), and
- **Install** an injection quill. At the time of the audit, water was being injected through a nozzle directly into the process stream.

Figure 1 shows the piping inspection isometric for GRU 1, labeled with both the historical **TMLs** and the new **TMLs** created specifically for the water injection circuit. Previously, the **TMLs** were thought to be representative of the piping components in the system. The inspection consisted of single UT thickness measurements taken at the **TMLs**. Corrosion rates were calculated between 0 and 0.13 mm/y (0 and 5 mpy) for the historical **TMLs**. Note that none of the previous **TMLs** were **located** at the water injection location.

The new **TMLs** were specifically positioned to address the potential for localized corrosion from the water injection point in response to API 570 section 3.2.1 guidelines. The basis for choosing new **TMLs** was primarily distance from the injection point and anticipated impingement areas.

Because industry experience has shown these particular water wash systems to be prone to corrosion, an annual inspection interval was **specified** on these water injection circuits. Sample thickness data obtained during the inspections are shown in Figure 1 for GRU 1. The measured corrosion rate between successive inspections was 1.22 mm/y (48 mpy) at the point immediately downstream of the injection nozzle. The inspection revealed a 7" (17.8 cm) long groove that initiated at the at the injection nozzle and propagated in the downstream direction. Pitting was also observed around the edges of the groove.

On **GRU 2**, a small leak developed while removing external corrosion scale around the injection nozzle to perform the initial inspection. The system was immediately taken off line and upon inspection, the elbow was found to be severely corroded at the downstream side of the **nozzle**. The most severe corrosion occurred where the nozzle penetrated the pipe wall.

Following repair, remedial action included installing an injection quill on these systems. After 2 years experience with a quill at GRU 2, corrosion of the piping has been eliminated. During the next scheduled maintenance shutdown, the water injection point will be relocated further upstream of the exchanger and elbow.

This case illustrates several benefits of implementing an injection point inspection program:

1. Audits are valuable for identifying inadequacies. In this case, a potential problem existed with the injection nozzle (lack of an injection **quill**) and a less than desirable injection location.
2. Piping inspection programs based upon random sampling of piping components is not appropriate in identifying **localized** corrosion problems. Locating **TMLs specifically** for an injection circuit is required as API 570 details.
3. A close and thorough inspection of injection points is justified to prevent significant failures.

Case 2: Water Wash In a Catalytic Cracker Gas Recovery Unit

At a catalytic cracker light ends recovery unit, cold condensate is injected into an insulated, 14" (35.6 cm) vertical carbon steel line on the inlet of a compressor interstage cooler. Similar to Case 1, the condensate is injected to dissolve salts and dilute corrosive species. The cold condensate is saturated with oxygen and contains a proprietary corrosion inhibitor at a concentration of 20 ppm. The water is injected directly into the line without a quill.

The historical inspection program included UT thickness measurements at designated **TMLs** previously chosen on representative piping components. **TMLs** were not located in the area of the water injection.

With the implementation of an injection point specific inspection program, 2" (5.1 cm) diameter holes were cut in the insulation for **TMLs** at the injection point. UT thickness measurements at the **TMLs** did not identify any measurable wall loss. In addition to the single point UT thickness measurements, profile radiography was performed in lieu of UT scanning, which would have required removal of a insulation. Unlike UT, profile radiography identified severe thinning where the wash water cascaded down the vertical section of the piping. Figure 2 shows the piping inspection isometric and a sketch depicting the corrosion loss.

This case illustrates the importance of a detailed inspection between the upstream limit of the injection circuit and **10D** downstream of the injection point as recommended in API 570. Single UT thickness readings did not identify a problem because they were not located at the exact area of wall loss. However, profile radiography and UT scanning techniques allow greater coverage (up to 100% of the area can be inspected), which can more successfully identify localized loss.

Another potential data interpretation pitfall can be encountered with computer programs used by some owner-users to statistically analyze the UT data obtained on a system. Care should be taken to ensure that the analysis does not mask localized corrosion loss obtained at a TML. Depending upon the analysis program, a point-by-point review may be more appropriate.

Case 3: Caustic Injection in an HF Alkylation Unit

At an HF Alkylation Unit, KOH is injected through a monel sparger into a 10" (25.4 cm) Monel 400 elbow on the vapor inlet of a Relief Gas Scrubber. The KOH is maintained at a **pH** of 8-10 and is saturated with oxygen. During the audit of the refinery's injection systems, plant personnel did not recognize this location as an injection circuit.

After 14 years service, a leak developed in the line where the injected fluid impinged upon the pipe wall from the sparger. **Data** collected from existing **TMLs** on the line did not identify the localized loss. The corrosion rate was estimated at 0.25 mm/y (**10** mpy) at the point of failure. Figure 3 shows an isometric drawing of the piping and a schematic of the failure.

This case again illustrates the importance of a thorough audit process in implementing an injection circuit inspection program. If this location had been recognized as an injection circuit, either ultrasonic scanning or profile radiographic inspection would have identified the problem prior to the line failure. In addition, this case clearly demonstrates the importance of assigning a TML where the chemical is anticipated to impinge on the pipe and recognizing that the design of a quill can significantly affect corrosion potential.

Case 4: Chemical Injection in a Hydroformer Unit

In a semi-regenerative hydroformer unit, a trial injection of a proprietary chemical into the 350°F (177°C), liquid feed stream of the debutanizer tower was initiated in 1991. The purpose of the chemical was to **control tower fouling and corrosion from salts. The chemical was injected neat through an existing 1" (2.5 cm) nozzle on the 6" (15.2 cm) diameter process line. A quill was not used for the trial.** A "Management Of Change" (MOC) process performed on the trial proposal identified this location as an injection circuit, however, the MOC did not identify a concern about injecting the **chemical neat or injecting directly through a nozzle during the trial period.** Operations, Engineering, inspection and the Chemical supplier were participants in the MOC.

The injection into the tower feed was discontinued after a few months. An injection circuit inspection was not performed due to the short duration of the trial and the fact that the **injection** was discontinued. After 15 months, a trial of a new chemical was initiated at the same location under the same conditions. The MOC again identified this location as an injection circuit requiring detailed inspection **during** a scheduled maintenance outage 6 months later. Figure 4 shows the inspection piping isometric of the injection circuit.

Prior to injecting the first chemical additive, the feed piping to the tower was monitored using TMLs considered **representative for the piping system.** During the maintenance outage, initial API 570 inspection of this injection circuit identified a **noticeable decrease in wall thickness throughout the feed inlet piping.** Figure 4 indicates the thickness measurements and calculated corrosion rates. The average short term corrosion rate changed from 0.08 mm/y (3 mpy) to 0.38 mm/y (15 mpy) between the 1986-1 990 and 1990-1 995 time periods.

This example shows the importance and value of a well conducted MOC. A detailed review of the **methodology involved in performing an effective MOC is beyond the scope of this paper, however,** in this case, the corrosivity of the chemicals being injected into the hot feed stream was not fully realized. Even during a "trial" period, significant corrosion can occur. Furthermore, "trial" periods may extend longer than originally anticipated. Following good injection practices from the start of any chemical injection regardless of the anticipated duration or purpose is appropriate. In this case, the API 570 inspection identified the corrosion loss early enough to prevent an on-stream leak. However, corrosion might have been minimized and maintenance expense avoided had good injection practices been followed.

SUMMARY

industry experience and API 570 Sections 3.2 and 3.2.1 detail the need for an inspection program designed specifically for injection points. As owner-users develop programs to comply with this Code, **they wrestle with how best to develop and implement such programs.**

The 'first step is to audit the existing injection points with the help of Operations, Maintenance and **Engineering personnel. The audit provides an effective way to assess the scope of the program and** identify potential problems with existing injection locations. The audit also serves to educate personnel on the value and need for an injection point specific inspection program.

The second step is to develop consistent inspection **guidelines** with **the flexibility to change the guidelines** for unique situations. Consistency helps ensure that the inspection program is fully adopted **throughout a facility and minimizes the chance of oversight at specific units. Locating TMLs in an injection circuit and specifying the appropriate inspection technique should be focused on identifying localized corrosion.**

Lastly, the success of the **program** depends on timely communication of changes made to injection systems. **Ideally any change in chemical type, injection rate or duration, or injection location should signal a need to analyze potential impact on the inspection program.**

Four field cases were presented which illustrate the importance and value of these various steps in **implementing an injection point inspection program. An inspection program can be developed which complies with API 570 section 3.2.1, however full benefit of a program probably cannot be achieved without the participation** of appropriate refinery personnel and establishing a formal program, Ultimately, the goal of the program is improved plant safety, environmental performance, and unit reliability.

REFERENCES

1. B. Wilde, Materials Performance **32, 6(1993):** p. 50.
2. American Petroleum Institute 570 Piping Inspection Code, **First Edition, June 1993.**

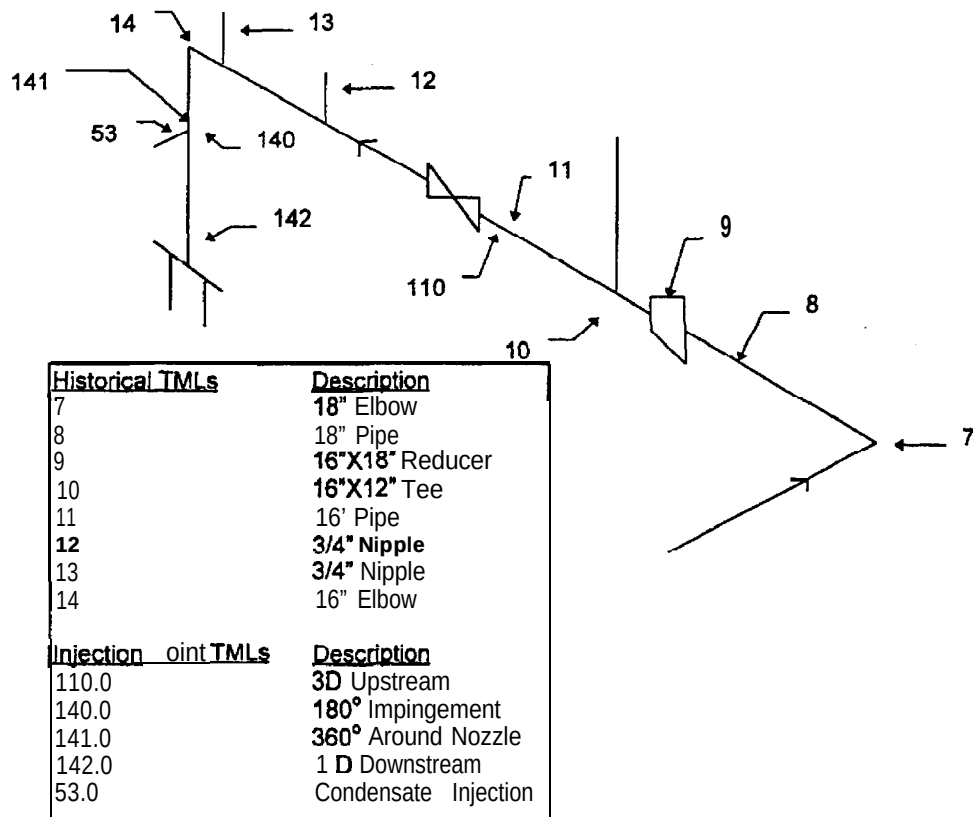
Table 1: Injection Point Data Reviewed In Audit Process

Unit
Line Number
Main Process Stream
Main stream phase
Nominal line size
Line metallurgy
Operating temperature
Operating pressure
Mainstream typical corrosion rate
Injection Stream
Nominal line size
Line metallurgy
Operating temperature
Operating pressure
Injection stream typical corrosion rate
Injection rate
Injection Point Detail
Injection point (quill , spray)
Injection point orientation into main pipe
Injection flow direction (upstream, downstream, cross flow)
Injection point metallurgy (injector)
Injection point metallurgy (main line if different from balance of line)
Distance from injection point to first change in direction
Chemical Data
Generic description
Injection purpose
Supplier
Product name
Injection start date
Inspection Data
Isometric sketch number
Inspection intervals
Inspection technique
Last inspection date
Next Inspection date
Corrosion Monitoring
Coupons or Probes and frequency monitored

Table 2: Injection Data Specific to Field Cases

FIELD CASE NO.	1	2	3	4
UNIT DATA				
Unit Name	Gas Recovery Unit	Gas Recovery Unit	HF Alkylation	Hydroformer
Process Stream Data	C1-C6, H2S, NH3	C1-C6, H2S, NH3		Heavy Naptha
Pressure	200 psi	75 psi	50 psi	200 psi
Temperature	225°F	150°F	100°F	350°F
Liq./Vap.	Liquid/Vapor	Liquid/Vapor	Vapor	Liquid
CHEMICAL DATA				
Generic Description	/Condensate	/Condensate	KOH	Chemical
Purpose of Injection	Water Wash	Cyanide control	Neutralize HF acid	Prevent fouling
Injection Start Date	1990	1981	1981	1991
INJECTION DATA				
Injection Rate	30 gpm	72 gpm	4 gpm	
Diluent Stream	N/A	N/A	N/A	No
INJECTION SYSTEM				
Injection Quill	None	None	Yes	No
Metallurgy			Monel 400	
Design			Sparger	
Location in Pipe	Vertical run	Vertical run	Vertical run	Vertical run
INSPECTION DATA				
Process Pipe Metl.	Carbon Steel	Carbon Steel	Monel 400	
Inspection Frequency	Annual	Biannual	Biannual	
Inspection Technique				
RT		Yes	Yes	
UT	Yes	Yes	Yes	Yes

Figure 1: Piping Inspection Isometric of Water Wash System



Sample Thickness and Corrosion Data on Injection Circuit TMLs

Unit: Gas Recovery									
Unit Name:		Unit		Inspection Date:		May-93	Nov-94	Oct-95	
TML No.	Size	Nominal Thickness	Minimum Allowable Thickness	Measured Thickness	Measured Thickness	Measured Thickness	Short Term Corrosion Rate (mpy)	Long Term Corrosion Rate (mpy)	Retire Date
53.0	1.5" NOZZLE	0.20"	0.06"	0.15"	0.15"	0.15"	0	0	--
110.0	3D @ 60"	0.375"	0.13"	0.48"	0.48"	0.48"	0	0	--
140.0	180 DEG	0.375"	0.13"	0.38"	0.39"	0.39"	0	0	--
141.0	360 DEG.	0.375"	0.13"	0.39"	0.28"	0.26"	24	59	12/1997
142.0	1D	0.375"	0.13"	0.39"	0.38"	0.24"	168	68	5/1996

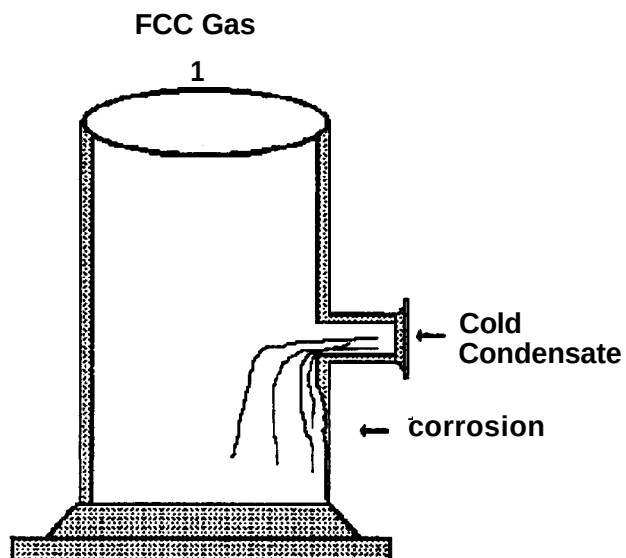


Figure 2: Schematic showing corrosion damage in Case 2 condensate wash system.

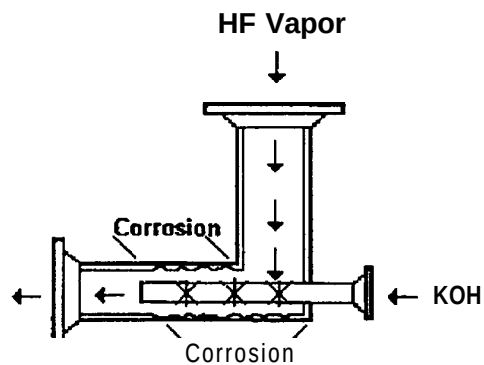
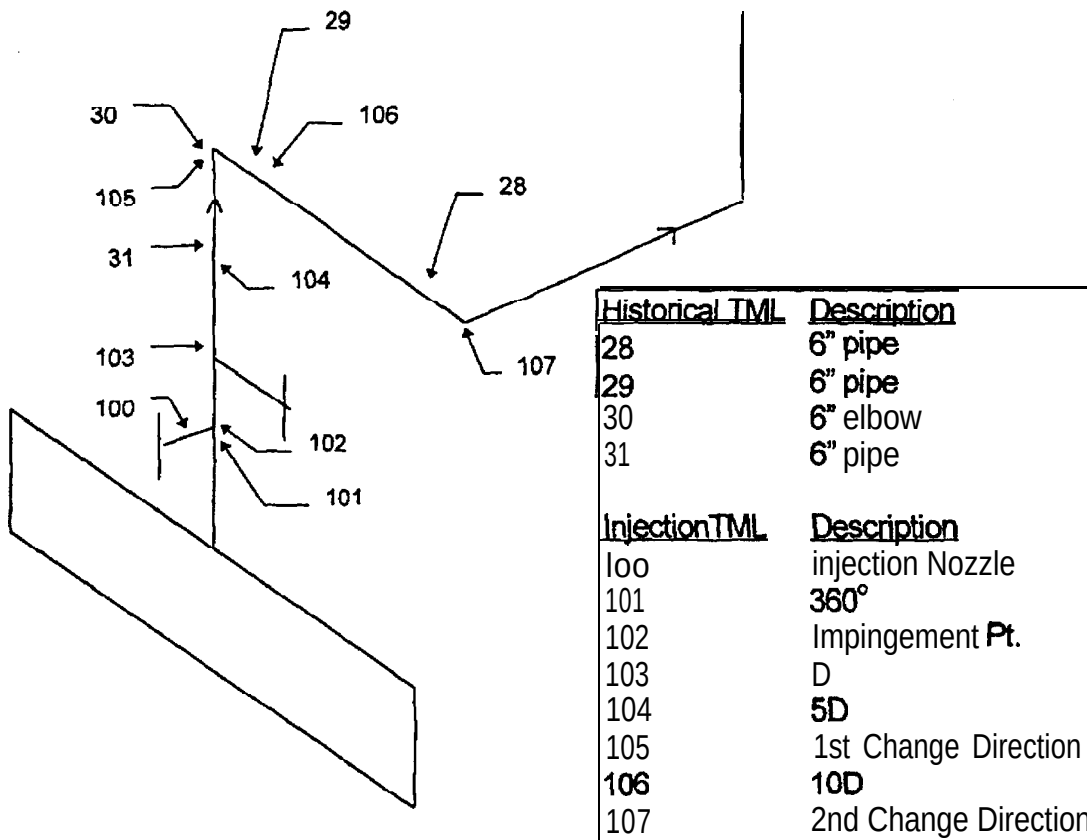


Figure 3: Schematic showing corrosion loss associated with sparger in Case 3 KOH injection.

Figure 4: Piping Inspection Isometric of Chemical Injection Circuit at Hydroformer Debutanizer Tower



Thickness and Corrosion Data of Inlet Piping TMLs

Unit Name: Hydroformer									
			Inspection Date:	Apr-86	Mar-90	Mar-95			
TML No.	Size	Nominal Thickness	Minimum Allowable Thickness	Measured Thickness	Measured Thickness	Measured Thickness	Short Corrosion Rate (mpy)	Long Corrosion Rate (mpy)	Retire Date
28.0	6"	0.28"	0.11"	0.29"	0.27"	0.18"	18	12	1/1999
29.0	6"	0.28"	0.11"	0.29"	0.29"	0.24"	10	6	3/2008
30.0	6"	0.28"	0.11"	0.30"	0.30"	0.22"	16	9	1/2002
31.0	6"	0.28"	0.11"	0.28"	0.24"	0.16"	16	13	4/1998
32.0	6"	0.28"	0.11"	—	—	0.15"	—	14	1/1998

Piping Inspection Code

Inspection, Repair, Alteration, and Rerating Of In-Service Piping Systems

API 570
FIRST EDITION, JUNE 1993

American Petroleum Institute
1220 L Street, Northwest
Washington, D.C. 20005



Piping Inspection Code

Inspection, Repair, Alteration, and Rerating Of In-Service Piping Systems

Manufacturing, Distribution and Marketing Department

API 570

FIRST EDITION, JUNE 1993

American
Petroleum
Institute



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FOREWORD

The *Piping Inspection Code* is a result of a need for an inspection code applicable to piping systems constructed in accordance with ASME B3 1.3, *Chemical Plant and Petroleum Refinery Piping*, and other piping code sections. This publication complements API 5 10, *Pressure Vessel Inspection Code*, and API Standard 653, *Tank Inspection, Repair, Alteration, and Reconstruction*, by setting forth practices for piping systems associated with pressure vessels and atmospheric storage tanks.

It is the purpose of the *Piping Inspection Code* to establish requirements and guidelines that will allow owners and users of piping systems to maintain the safety and integrity of the systems after they have been placed into service.

It is the intent of the American Petroleum Institute to periodically revise this publication. All owners and operators of piping systems are invited to report their experiences inspecting and repairing piping systems whenever such experiences suggest a need for revision or expansion of the practices set forth herein.

API publications may be used by anyone desiring to do so. Every effort has been made by the Institute to assure the accuracy and reliability of the information contained in them; however, the Institute makes no representation, warranty, or guarantee in connection with this publication and hereby expressly disclaims any liability or responsibility for loss or damage resulting from its use or for the violation of any federal, state, or municipal regulation with which this publication may conflict.

Suggested revisions, reports, comments, and requests for interpretations are invited and should be submitted to the director, Manufacturing, Distribution and Marketing Department, American Petroleum Institute, 1220 L Street, N.W., Washington, D.C. 20005. See Appendix C for further information regarding inquiries about API 570.

IMPORTANT INFORMATION CONCERNING USE OF ASBESTOS OR ALTERNATIVE MATERIALS

Asbestos is specified or referenced for certain components of the equipment described in some API standards. It has been of great usefulness in minimizing fire, hazards associated with **petroleum processing**. It also has **been** a universal sealing material, compatible with most refining fluid services.

Certain serious adverse health effects are associated with asbestos, among them the serious and often fatal diseases of lung cancer, **asbestosis**, and mesothelioma (a cancer of the chest and abdominal linings). The degree of exposure to asbestos varies with the product and the work practices involved.

Consult the most recent edition of the Occupational Safety and Health Administration (**OSHA**), U.S. Department of Labor, Occupational Safety and Health Standard for Asbestos, Tremolite, Anthophyllite, and Actinolite, **29 Code of Federal Regulations** Section 1910.001; the U.S. Environmental Protection Agency, National Emission Standard for Asbestos, **40 Code of Federal Regulations** Sections 6.1.140 through 6.1.156; and the proposed rule by the U.S. Environmental Protection Agency (EPA) proposing labeling requirements and phased banning of asbestos products, published at **51 Federal Register 3738-3759** (January 29, 1986; the most recent edition should be consulted).

There are currently in use and under development a number of substitute materials to replace asbestos in certain applications. Manufacturers and users are encouraged to develop and use effective substitute materials which can meet the specifications for, and operating requirements of, the equipment to which they would apply.

SAFETY AND HEALTH **INFORMATION** WITH RESPECT TO PARTICULAR PRODUCTS OR MATERIALS CAN BE OBTAINED FROM THE EMPLOYER, THE MANUFACTURER OR SUPPLIER OF THAT PRODUCT OR MATERIAL, OR THE MATERIAL SAFETY DATA SHEET.

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Piping Inspection Code-Inspection, Repair, Alteration, and Rerating of In-Service Piping Systems

SECTION I-GENERAL

1.1 Scope

1.1.1 GENERAL APPLICATION

1.1.1.1 Coverage

API 570 covers inspection, repair, alteration, and rerating procedures for metallic piping systems that have been in-service.

1.1.1.2 Intent

API 570 was developed for the petroleum refining and chemical process industries but may be used, where practical, for any piping system. It is intended for use by organizations that maintain or have access to an authorized inspection agency, a repair organization, and technically qualified piping engineers, inspectors, and examiners, all as defined in Appendix A.

1.1.1.3 Limitations

API 570 shall not be used as a substitute for the original construction requirements governing a piping system before it is placed in-service; nor shall it be used in conflict with any prevailing regulatory requirements.

1.1.2 SPECIFIC APPLICATIONS

1.1.2.1 Included Fluid Services

Except as provided in 1.1.2.2, API 570 applies to piping systems for process fluids, hydrocarbons, and similar flammable or toxic fluid services, such as the following:

- a. Raw, intermediate, and finished petroleum products.
- b. Raw, intermediate, and finished chemical products.
- c. Catalyst lines.
- d. Hydrogen, natural gas, fuel gas, and Rare systems.
- e. Sour water and hazardous waste streams above threshold limits, as defined by jurisdictional regulations.
- f. Hazardous chemicals above threshold limits, as defined by jurisdictional regulations.

1.1.2.2 Excluded and Optional Piping Systems

The fluid services and classes of piping systems listed below are excluded from the specific requirements of API 570 but may be included at the owner's or user's (owner-user's) option.

a. Fluid services that are excluded or optional include the following:

1. Hazardous fluid services below threshold limits, as defined by jurisdictional regulations.
2. Water (including fire protection systems), steam, steam-condensate, boiler feed water, and Category D fluid services, as defined in ASME B3 1.3.
- b. Classes of piping systems that are excluded or optional are as follows:
 1. Piping systems on movable structures covered by jurisdictional regulations, including piping systems on trucks, ships, barges, and other mobile equipment.
 2. Piping systems that are an integral part or component of rotating or reciprocating mechanical devices, such as pumps, compressors, turbines, generators, engines, and hydraulic or pneumatic cylinders where the primary design considerations and/or stresses are derived from the functional requirements of the device.
 3. Internal piping or tubing of fired heaters and boilers, including tubes, tube headers, return bends, external crossovers, and manifolds.
 4. Pressure vessels, heaters, furnaces, heat exchangers, and other fluid handling or processing equipment, including internal piping and connections for external piping.
 5. Plumbing, sanitary sewers, process waste sewers, and storm sewers.
 6. Piping or tubing with an outside diameter not exceeding that of NPS ½.
 7. Nonmetallic piping and polymeric or glass-lined piping.

1.2 Glossary

Definitions of technical terms used throughout this document may be found in Appendix A.

1.3 Referenced Publications

The most recent editions of the following standards, codes, and specifications are cited in API 570.

- API
510 *Pressure Vessel Inspection Code*
RP 571¹ *Recognition of Conditions Causing Deterioration or Failure*

¹API Guide for Inspection of Refinery Equipment, Chapter II, "Conditions Causing Deterioration or Failures," is under revision and will be reissued as API Recommended Practice 57 1.

- RP 574** *Inspection of Piping, Tubing, Valves, and Fittings*
 Std 598 *Valve Inspection and Testing*
RP 651 *Cathodic Protection of Aboveground Petroleum Storage Tanks*
 RP 750 *Management of Process Hazards*
Publ 920 *Prevention of Brittle Fracture of Pressure Vessels*
Publ 2201 *Procedures for Welding or Hot Tapping on Equipment Containing Flammables* (under revision)
- ASME²**
 B16.34 *Valves—Flanged, Threaded, and Welding End*
 B31.3 *Chemical Plant and Petroleum Refinery Piping*
B31G *Manual for Determining the Remaining Strength of Corroded Pipelines*
Boiler and Pressure Vessel Code, Section VIII. "Pressure Vessels." Division; 1 and 2; S&on IX, "Welding and Brazing Qualifications"
- ASTM³**
G57 *Method for Field Measurement of Soil Resistivity Using the Wenner Four-Electrode Method*
- NACE⁴**
 RPO169 *Control of External Corrosion on Underground or Submerged Metallic Piping System*
 RPO170 *Protection of Austenitic Stainless Steels from Polythionic Acid Stress Corrosion Cracking During Shutdown of Refinery Equipment*
 RP0274 *High-Voltage Electrical Inspection of Pipeline Coatings Prior to Installation*
- RP0275** *Application of Organic Coatings to the External Surface of Steel Pipe for Underground Service*
- NFPA⁵**
 704 *Identification of the Fire Hazards of Materials*

1.4 Responsibilities

1.4.1 OWNER-USER

The owner-user of a piping installation within the scope of API 570 shall have overall responsibility for compliance with API 570 and for establishing requirements for inspection, repair, alteration, and rerating.

1.4.2 PIPING ENGINEER

The piping engineer is responsible to the owner-user for activities involving design, engineering review, analysis, or evaluation of piping systems covered by API 570.

1.4.3 REPAIR ORGANIZATION

The repair organization shall be responsible to the owner-user and shall provide the materials, equipment, quality control, and workmanship necessary to maintain and repair the piping systems in accordance with the requirements of API 570.

1.4.4 INSPECTOR

The inspector shall be responsible to the owner-user for determining that the requirements of API 570 for inspection, examination, and testing are met.

1.4.5 OTHER PERSONNEL

Operating, maintenance, or other personnel who have special knowledge or expertise related to particular piping systems shall be responsible for promptly making the inspector or piping engineer aware of any unusual conditions that may develop and for providing other assistance, where appropriate.

²American Society of Mechanical Engineers, 345 East 47th Street, New York, New York 10017.

³American Society for Testing and Materials, 1916 Race Street, Philadelphia, Pennsylvania 19103-1187.

⁴National Association of Corrosion Engineers, P.O. Box 218340, Houston, Texas 77218.

⁵National Fire Protection Association, 1 Batterymarch Park, P.O. Box 9101, Quincy, Massachusetts 02269-9101.

SECTION P-OWNER-USER INSPECTION ORGANIZATION

2.1 General

An owner-user of piping systems shall exercise **control** of the piping system inspection program, inspection **frequencies**, and maintenance and is responsible for **the** function of an authorized inspection agency in accordance with the **provisions** of **API 570**. **The owner-user inspection** organization also shall control activities relating to the **rerating**, repair, and alteration of its piping systems.

2.2 Authorized Piplng Inspector Qualllfcation

Authorized piping inspectors shall have education and **ex-perience** equal to **at** least one **of the** following:

a. A degree in engineering plus one year of experience in the design, **construction**, repair, operation, or inspection of piping systems.

b. **A 2-year certificate in engineering or technology** from a technical college plus 2 years of experience in the design, construction, repair, operation, or inspection of **pip-ing** systems.

c. The equivalent of a high school education plus 3 years of experience in the design, construction, repair, **operation, or inspection** of piping systems.

d. **Five years of experience inspecting in-service** piping systems.

Whenever the **term** inspector is used in this document, it refers to an authorized **piping inspector**.

SECTION 3—INSPECTION AND TESTING PRACTICES

3.1 Preparation

Because of the products carried in piping systems, safety precautions are important when the system is inspected, particularly if it is opened for examining internal surfaces.

Procedures for segregating piping systems, installing blanks (blinds), and testing tightness should be an integral part of safety practices. Appropriate safety precautions shall be taken before any piping system is opened and before some types of external inspection are performed. In general, the section of piping to be opened should be isolated from all sources of harmful liquids, gases, or vapors and purged to remove all oil and toxic or flammable gases and vapors.

Before starting inspection, inspection personnel should obtain permission to work in the vicinity from operating personnel responsible for the piping system.

Protective equipment shall be worn when required by regulations or by the owner-user.

Nondestructive testing equipment used for inspection is subject to the operating facility's safety requirements for electrical equipment.

In general, inspectors should familiarize themselves with prior inspection results and repairs in the piping systems for which they are responsible. In particular, they should briefly review the history of individual piping systems before making any of the inspections required by API 570. (See Section 6 of API Recommended Practice 574 for supplementary recommended practices.)

3.2 Inspection for Specific Types of Corrosion and Cracking

Note: For more thorough and complete information, see API Recommended Practice 571.

Each owner-user should provide specific attention to the need for inspection of piping systems that are susceptible to the following specific types and areas of deterioration:

- a. Injection points.
- b. Deadlegs.
- c. Corrosion under insulation (CUI).
- d. Soil-to-air (S/A) interfaces.
- e. Service specific and localized corrosion.
- f. Erosion and corrosion/erosion.
- g. Environmental cracking.
- h. Corrosion beneath linings and deposits.
- i. Fatigue cracking;
- j. Creep cracking.
- k. Brittle fracture.
- l. Freeze damage.

Other areas of concern are noted in API Recommended Practice 571 and 8.1 of API Recommended Practice 574.

3.2.1 INJECTION POINTS

Injection points are sometimes subject to accelerated or localized corrosion from normal or abnormal operating conditions. Those that are may be treated as separate inspection circuits, and these areas need to be inspected thoroughly on a regular schedule.

When designating an injection point circuit for the purposes of inspection, the recommended upstream limit of the injection point circuit is a minimum of 12 inches (305 millimeters) or three pipe diameters upstream of the injection point, whichever is greater. The recommended downstream limit of the injection point circuit is the second change in flow direction past the injection point, or 25 feet (7.6 meters) beyond the first change in flow direction, whichever is less. In some cases, it may be more appropriate to extend this circuit to the next piece of pressure equipment, as shown in Figure 1.

The selection of thickness measurement locations (TMLs) within injection point circuits subject to localized corrosion should be in accordance with the following guidelines:

- a. Establish TMLs on appropriate fittings within the injection point circuit.
- b. Establish TMLs on the pipe wall at the location of expected pipe wall impingement of injected fluid.
- c. TMLs at intermediate locations along the longer straight piping within the injection point circuit may be required.
- d. Establish TMLs at both the upstream and downstream limits of the injection point circuit.

The preferred methods of inspecting injection points are radiography and/or ultrasonics, as appropriate to establish the minimum thickness at each TML. Close grid ultrasonic measurements or scanning may be used, as long as temperatures are appropriate.

For some applications, it is beneficial to remove piping spools to facilitate a visual inspection of the inside surface. However, thickness measurements will still be required to determine the remaining thickness.

During periodic scheduled inspections, more extensive inspection should be applied to an area beginning 12 inches (305 millimeters) upstream of the injection nozzle and continuing for at least ten pipe diameters downstream of the injection point. Additionally, measure and record the thickness at all TMLs within the injection point circuit.

3.2.2 DEADLEGS

The corrosion rate in deadlegs can vary significantly from adjacent active piping. The inspector should monitor wall thickness on selected deadlegs, including both the stagnant end and at the connection to an active line. In hot piping sys-

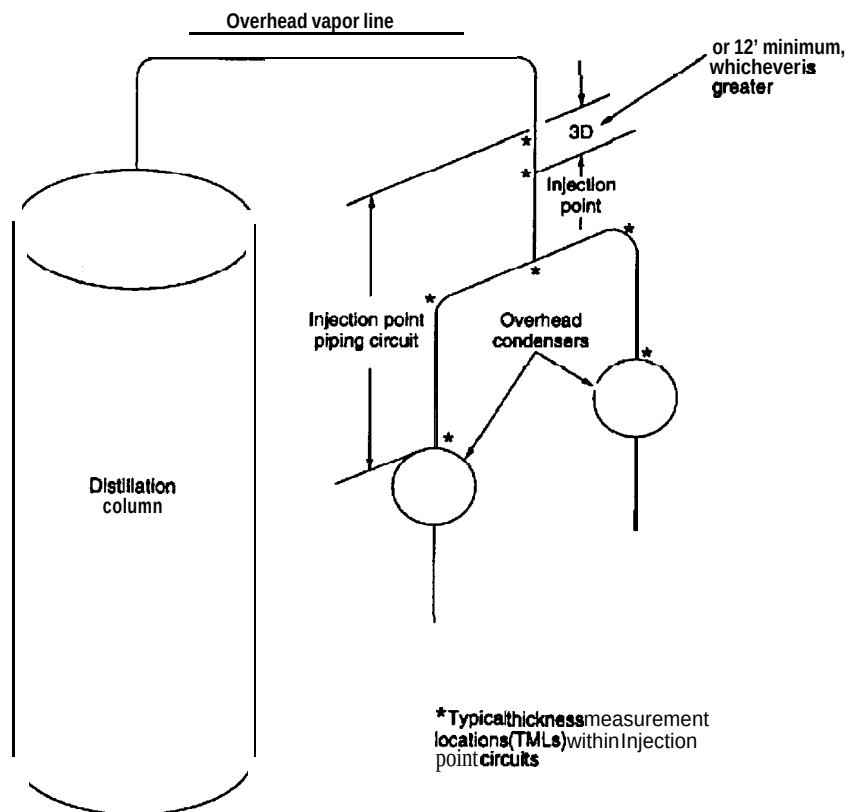


Figure 1—Typical Injection Point Piping Circuit

terms, the high-point area may corrode due to convective currents set up in the **deadleg**. Consideration should be given to removing **deadlegs** that serve no further **process** purpose.

3.2.3 CORROSION UNDER INSULATION

External inspection of insulated piping systems should include a **review of the integrity of the insulation system** for conditions that could lead to corrosion under insulation (**CUI**) and for signs of ongoing **CUI**. Sources of moisture may include rain, **water** leaks, condensation, and **deluge** systems. The most common forms of CUI are localized corrosion of carbon steel and chloride stress corrosion cracking of austenitic stainless steels.

This section **provides guidelines for identifying potential CUI** areas for inspection. The extent of a CUI inspection program may vary depending on the local climate-warmer, marine locations may require a very active **program**; whereas cooler, drier, **midcontinent** locations may not need as extensive a program.

3.2.3.1 h-mutated Piping Systems Susceptible to CUI

Certain areas and **types** of piping systems are potentially more **susceptible** to **CUI**, including the following:

- a. Areas exposed to mist overspray from cooling water towers.
- b. Areas exposed to steam vents.
- c. Areas **exposed to deluge systems**.
- d. Areas subject to process spills, ingress of moisture, or acid vapors.
- e. **Carbon** steel piping systems, including those insulated for personnel protection, operating between **25°F** and 250°F (-4°C and 120°C). CUI is particularly aggressive where **operating temperatures** cause **frequent or continuous condensation** and **re-evaporation** of atmospheric moisture.
- f. **Carbon** steel piping systems that normally operate in-service above **250°F (120°C)** but are in intermittent service.
- g. **Deadlegs** and attachments that protrude from insulated piping and operate at a different temperature than the **operating** temperature of the active line.

- h. Austenitic stainless steel piping systems operating between **150°F** and **400°F** (**65°C** and **204°C**). (These systems are susceptible to **chloride stress** corrosion cracking.)
- i. Vibrating piping systems that have a tendency to inflict damage to insulation jacketing providing a path for water ingress.
- j. Steam traced piping systems that may experience tracing leaks, especially at tubing fittings beneath the insulation.
- k. **Piping systems with deteriorated coatings and/or wrappings.**

3.2.3.2 Common Locations on Piping Systems Susceptible to CUI

The areas of piping systems listed in 3.2.3.1 may have **specific locations within them** that are more susceptible to CUI, including the following:

- a. **All** penetrations or breaches in the insulation jacketing systems, such as:
 1. Deadlegs (vents, drains, and other similar items).
 2. Pipe hangers and other supports.
 3. **Valves** and fittings (irregular insulation surfaces).
 4. Bolted-on pipe shoes.
 5. Steam tracer tubing penetrations.
- b. Termination of insulation at flanges and other piping components.
- c. Damaged or missing insulation jacketing.
- d. Insulation jacketing seams located on the top of horizontal piping or improperly lapped or sealed insulation jacketing.
- e. Termination of insulation in a **vertical pipe**.
- f. Caulking that has hardened, has separated, or is missing.
- g. Bulges or staining of the insulation or jacketing system or missing bands. (Bulges may indicate corrosion product buildup.)
- h. Low points in piping systems that have a **known** breach in the insulation system, including low points in long unsupported piping runs.
- i. Carbon or low-alloy steel flanges, bolting, and other components under insulation in high-alloy piping systems.

Locations where insulation plugs have been removed to permit piping thickness measurements on insulated piping should receive particular attention. These plugs should be promptly replaced and sealed. Several types of removable plugs are commercially available that permit inspection and identification of inspection points for future reference.

3.2.4 SOIL-TO-AIR INTERFACE

Soil-to-air (S/A) interfaces for buried piping without adequate cathodic protection shall be included in scheduled external piping inspections. Inspection at grade should check for coating damage, bare pipe, and pit depth measurements. If significant corrosion is noted, thickness measurements and

excavation may be required to assess whether the corrosion is localized to the S/A interface or may be more pervasive to the buried system. Thickness readings at S/A interfaces may expose the metal and accelerate corrosion if coatings and wrappings are not properly restored. If the buried piping has satisfactory cathodic protection as determined by monitoring in accordance with Section 7, excavation is required only if there is evidence of coating or wrapping damage. If the buried piping is uncoated at grade, consideration should be given to excavating 6 inches to 12 inches (152 millimeters to 305 millimeters) deep to assess the potential for hidden damage.

At concrete-to-air and asphalt-to-air interfaces of buried piping without cathodic protection, the inspector should look for evidence that the caulking or seal at the interface has deteriorated and allowed moisture ingress. If such a condition exists on piping systems over 10 years old, it may be necessary to inspect for corrosion beneath the surface before re-sealing the joint.

3.2.5 SERVICE-SPECIFIC AND LOCALIZED CORROSION

An effective inspection program includes the following three elements, which help identify the potential for service-specific and localized corrosion and select appropriate TMLs:

- a. An inspector with knowledge of the service and where corrosion is likely to occur.
- b. Extensive use of nondestructive examination (NDE).
- c. Communication from operating personnel when process upsets occur that may affect corrosion rates.

A few examples of where this type of corrosion might be expected to occur include the following:

- a. Downstream of injection points and upstream of product separators, such as in hydroprocess reactor effluent lines.
- b. Dew-point corrosion in condensing streams, such as overhead fractionation.
- c. Unanticipated acid or caustic carryover from processes into nonalloyed piping systems or caustic carryover into steel piping systems that are not postweld heat treated.
- d. Ammonium salt condensation locations in hydroprocess streams.
- e. Mixed-phase flow and turbulent areas in acidic systems.
- f. Mixed grades of carbon steel piping in hot corrosive oil service [**450°F** (**232°C**) or higher temperature and sulfur content in the oil greater than 0.5 percent by weight]. Note that nonsilicon killed steel pipe, such as A-53 and API 5L, may corrode at higher rates than does silicon killed steel pipe, such as A-106, especially in high-temperature sulfidic environments.
- g. Underdeposit corrosion in slurries, crystallizing solutions, or coke producing fluids.

h. Chloride carryover in catalytic reformer regeneration systems.

i. Hot-spot **corrosion** on piping with external heat tracing. In services **that** become much more corrosive to **the** piping with increased temperature, such as caustic in carbon steel, corrosion or **stress corrosion cracking (SCC)** can occur at hot spots that develop under low-flow conditions.

3.2.6 EROSION AND CORROSION/EROSION

Erosion can be defined as the removal of surface material by the action of numerous individual impacts of solid or liquid particles. It can be characterized by grooves, rounded **holes, waves, and valleys in a directional** pattern. Erosion usually occurs in areas of turbulent flow, such as at changes of direction in a piping system or downstream of control valves where vaporization may take place. Erosion damage is usually increased in streams with large quantities of solid or liquid particles flowing at high **velocities**. A combination of corrosion and erosion (corrosion/erosion) results in significantly greater metal loss than can **be expected** from **corrosion** or erosion alone. This type of corrosion occurs at high-velocity and high-turbulence areas.

Examples of places to inspect include the following:

- a. Downstream of control valves, especially when flashing is occurring.
- b. Downstream of orifices.
- c. Downstream of pump discharges.
- d. At any point of flow direction change, such as the inside and outside radius of elbows.
- e. **Downstream of piping configurations (such as welds, thermowells, and flanges) that produce turbulence**, particularly in velocity sensitive systems such as ammonium hydro-sulfide and sulfuric acid systems.

Areas suspected of having localized corrosion/erosion **should** be inspected using appropriate NDE methods that will yield thickness data over a wide **area**, such as ultrasonic scanning, radiographic profile, or eddy current.

3.2.7 ENVIRONMENTAL CRACKING

Piping system construction materials are normally selected to resist the various **forms** of stress corrosion cracking (**SCC**). However, **some** piping systems may be susceptible to environmental cracking due to upset process conditions. **CUI**, unanticipated condensation, or exposure to wet hydrogen sulfide or carbonates.

Examples of environmental cracking include:

- a. Chloride SCC of austenitic stainless steels due to moisture and chlorides under insulation, under deposits, under gaskets, or in crevices.
- b. **Polythionic acid SCC of sensitized austenitic alloy steels due to exposure to sulfide, moisture condensation, or oxygen.**

c. Caustic SCC (sometimes known as caustic **embrittlement**).

d. **Amine SCC in piping systems that are not stress relieved.**

e. **Carbonate SCC.**

f. SCC in environments where wet hydrogen sulfide exists, **such as systems containing sour water.**

g. **Hydrogen blistering and hydrogen induced cracking (I-UC) damage.**

When the inspector suspects or is advised that specific circuits may be susceptible to environmental cracking, the inspector should schedule supplemental inspections. Such inspections can take the form of surface NDE (**liquid-penetrant testing (PT)** or wet fluorescent magnetic-particle testing (**WFMT**)) or ultrasonics (UT). Where available, suspect spools may be removed from the piping system and split open for internal surface examination.

If **environmental cracking is detected during internal inspection** of pressure vessels and the piping is considered equally susceptible, the inspector should designate appropriate piping spools upstream and **downstream of** the pressure vessel for environmental cracking inspection. When the potential for environmental cracking is suspected in piping circuits, inspection of selected spools should be scheduled prior to an **upcoming turnaround**. Such inspection should provide information **useful** in forecasting turnaround maintenance,

3.2.8 CORROSION BENEATH LININGS AND DEPOSITS

If external or internal coatings, refractory linings, and corrosion-resistant linings are in good condition and there is no reason to suspect a deteriorated condition behind them, it is usually not necessary to remove them for inspection of the piping system.

The effectiveness of corrosion-resistant linings is greatly reduced due to breaks or holes in the lining. The linings should be inspected for separation, breaks, holes, and blisters. If any of these conditions **are** noted, it may be necessary to remove portions of the internal lining to investigate the effectiveness of the lining and the **condition** of the **metal** piping beneath the lining. Alternatively, ultrasonic inspection from the **external** surface can be used to measure wall **thickness** and detect separation, holes, and blisters.

Refractory linings may **spall** or crack in-service with or **without** causing any significant problems. **Corrosion** beneath refractory linings can result in separation and bulging of the refractory. If **bulging** or separation of the refractory lining is detected, portions of the **refractory** may be removed to permit **inspection of the piping beneath** the refractory. Otherwise, **ultrasonic** thickness measurements may be made from the external **metal** surface.

Where operating deposits, such as coke, are present on a pipe surface, it is particularly important to determine whether such deposits have active corrosion beneath them. This may require a thorough inspection in selected areas.

Larger lines should have the deposits removed in selected **critical** areas for spot examination. Smaller lines may require that selected spools be removed or that NDE methods, such as radiography, be performed in selected areas.

3.2.9 FATIGUE CRACKING

Fatigue cracking of piping systems may result from excessive cyclic stresses that are often well below the static **yield strength** of the material. The cyclic stresses may be imposed by pressure, mechanical, or thermal means and may result in low-cycle or high-cycle fatigue. The onset of low-cycle fatigue cracking is often directly related to the number of **heat-up** and cool-down cycles experienced. Excessive piping system vibration (such as machine or flow-induced vibrations) also can cause high-cycle fatigue damage. (See 3.3.4 for vibrating piping surveillance requirements and 5.5 for design requirements associated with vibrating piping.)

Fatigue cracking can typically be **first** detected at points of **high-stress intensification** such as **branch connections**. Locations where metals having different coefficients of thermal expansion are joined by welding may be susceptible to thermal fatigue. (See 4.5.3 for fatigue considerations relative to threaded connections.) Preferred NDE methods of detecting fatigue cracking include liquid-penetrant testing (PT) or magnetic-particle testing (MT). Acoustic emission also may be used to detect the presence of cracks that are activated by test pressures or stresses generated during the test.

It is important that the owner-user and the inspector understand that fatigue cracking is likely to cause piping failure before it is detected with any NDE methods. Of the total number of fatigue cycles required to produce a failure, the vast majority are required to initiate a crack and relatively **fewer cycles are required to propagate the crack to failure**. Therefore, proper design and installation in or to prevent the initiation of fatigue cracking are important.

3.2.10 CREEP CRACKING

Creep is dependent on time, temperature, and stress. Creep cracking may **eventually occur** at design conditions, since **some piping code allowable stresses are in the creep range**. Cracking is accelerated by creep and fatigue interaction when operating conditions in the creep range are cyclic. **The inspector should pay particular attention to areas of high stress concentration**. If excessive temperatures are encountered, mechanical property and microstructural changes in metals **also** may take place, which may permanently weaken equipment. Since creep is dependent on time, temperature, and stress, the **actual or estimated** levels of these parameters shall be used in any evaluations. An example of where creep cracking has been experienced in the industry is in 1% Cr steels above 900°F (482°C).

NDE methods of detecting creep cracking include liquid-penetrant testing, magnetic-particle testing, ultrasonic test-

ing, radiographic testing, and in-situ metallography. Acoustic emission testing also may be used to detect the presence of cracks that are activated by test pressures or stresses generated during the test.

3.2.11 BRITTLE FRACTURE

Carbon, low-alloy, and other ferritic steels may be susceptible to brittle failure at or below ambient temperatures. **Brittle fracture usually is not a concern with relatively thin-wall piping**. Most brittle fractures have occurred on the first application of a particular stress level (that is, the first hydrotest or overload) **unless critical defects are introduced during service**. The potential for a brittle failure shall be considered when rehydrotesting or more carefully evaluated when testing equipment pneumatically or when adding any other additional loads. Special **attention** should be given to low-alloy steels (**especially** 2% Cr-Mo material), because they may be prone to temper embrittlement, and to ferritic stainless steels.

API Publication 920, which contains information on the prevention of brittle fracture in pressure vessels, may be useful in assessing brittle fracture potential in piping systems.

3.2.12 FREEZE DAMAGE

At subfreezing temperatures, water and aqueous solutions in piping systems may freeze and cause failure because of the expansion of these materials. After unexpectedly severe freezing weather, it is important to check for freeze damage to exposed piping components before the system thaws. If rupture has occurred, leakage may be temporarily prevented by the frozen fluid. Low points, driplegs, and deadlegs of piping systems containing water should be carefully examined for damage.

3.3 Types of Inspection and Surveillance

Different types of inspection and surveillance are appropriate depending on the circumstances and the piping system (see note). These include the following:

- a. Internal visual inspection.
- b. Thickness measurement inspection.
- c. External visual inspection.
- d. Vibrating piping inspection.
- e. Supplemental inspection.

Note: See Section 4 for frequency and extent of inspection.

3.3.1 INTERNAL VISUAL INSPECTION

Internal visual inspections are not normally performed on piping. When possible and practical, internal visual inspections may be scheduled for systems such as large-diameter transfer lines, ducts, catalyst lines, or other large-diameter piping systems. Such inspections are similar in nature to

pressure vessel inspections and should **be conducted** with methods and procedures similar to those outlined in API 5 **10**. Remote visual inspection techniques can be helpful when inspecting piping too small to enter.

An additional opportunity for internal inspection is **provided** when piping flanges are disconnected, allowing visual inspection of internal surfaces with or without the use of NDE. Removing a section of piping and splitting it along its centerline also permits access to internal surfaces where there is **need** for such inspection.

3.3.2 THICKNESS MEASUREMENT INSPECTION

A thickness measurement inspection is performed to determine the internal condition **and** remaining thickness of the piping components. Thickness measurements may be **obtained** when the piping system is in or **out** of operation and shall be performed **by** the inspector or examiner.

3.3.3 EXTERNAL VISUAL INSPECTION

An external visual inspection is performed to determine the condition of **the** outside of the piping, insulation system, painting and coating **systems**, and associated hardware; **and to check** for signs of misalignment, vibration, and leakage. When corrosion product buildup is noted at pipe support contact areas, lifting off such supports may **be required** for inspection. When doing this, **care** should be exercised if the piping is in-service.

External piping inspections may be made when the piping system is in-service. Refer to API Recommended Practice 574 for information helpful in conducting external inspections. A checklist to assist in conducting external piping inspections is provided in Appendix E.

External inspections shall include surveys for the condition of piping hangers and supports. Instances of cracked or broken hangers, "bottoming out" of **spring** supports, support shoes displaced from support members, or other improper restraint conditions shall **be reported** and corrected. **Vertical** support dummy legs also shall be checked to confirm that they have not **filled** with **water** that is causing external **corrosion** of the pressure piping **or** internal corrosion of the support leg. Horizontal support dummy legs also shall be checked to determine that slight displacements from horizontal are not causing moisture traps against the external **surface** of active piping components.

Bellows expansion joints should be **inspected** visually for unusual deformations, misalignment, or displacements that may **exceed** design.

The inspector should examine the piping system for the presence **of** any field modifications or temporary repairs not previously recorded on the piping drawings and/or records. The inspector also should **be** alert to the presence of any components in the service that may be unsuitable for **long-**

term operation, such as improper flanges, temporary repairs (clamps), modifications (flexible hoses), or valves of improper specification. Threaded components that may be more easily **removed** and installed deserve particular attention **because** of their higher potential for installation of **improper components**.

The periodic external inspection called for in 4.3 should normally be conducted by the inspector, who also shall be responsible for record keeping and repair inspection. Qualified operating or maintenance personnel also may conduct external inspections, when acceptable to the inspector. In such cases, the persons conducting external piping inspections in accordance with API 570 shall be qualified through an appropriate amount of training.

In addition to these scheduled external inspections that are documented in inspection records, it is beneficial for **personnel** who frequent the area to report deterioration or changes **to the inspector**. (See Appendix E and 8.2 of API Recommended Practice 574 for examples of such deterioration.)

3.3.4 VIBRATING PIPING AND LINE MOVEMENT SURVEILLANCE

Operating personnel should report vibrating or swaying piping to engineering or inspection personnel for assessment. Other significant line movements should be reported that may have **resulted** from liquid hammer+ liquid slugging in vapor **lines**, **or** abnormal thermal expansion. At junctions where vibrating piping systems are restrained, periodic magnetic-particle testing or liquid-penetrant testing should be considered to **check** for the **onset** of fatigue cracking. **Branch** connections should receive special attention.

3.3.5 SUPPLEMENTAL INSPECTION

Other inspections may **be** scheduled as appropriate or **necessary**. Examples of **such inspections** include **periodic** use of radiography and/or thermography to check for fouling or internal plugging, **thermography** to check for **hot spots in refractory** lined systems, or inspection for environmental cracking. Acoustic emission, acoustic leak detection, and thermography can be used for remote leak detection and surveillance. Ultrasonics and/or radiography can be used for detecting localized corrosion.

3.4 Thickness Measurement Locations

3.4.1 GENERAL

Thickness measurement locations (**TMLs**) are specific areas along the piping circuit where inspections are to be made. The nature of the TML varies according to its location in the piping system. The selection of **TMLs** shall consider the potential for **localized** corrosion and **service-specific** corrosion as **described** in 3.2.

3.4.2 TML MONITORING

Each piping system shall be monitored by taking thickness measurements at **TMLs**. Piping circuits with high potential consequences if failure should occur and those subject to higher corrosion rates or localized corrosion will normally have more **TMLs** and be monitored more frequently (see 4.2). **TMLs** should be distributed appropriately throughout each piping circuit. **TMLs** may be eliminated or the number reduced under certain circumstances, such as olefin plant cold side piping, anhydrous ammonia piping, clean noncorrosive hydrocarbon product, or high-alloy piping for product purity. In circumstances where **TMLs** will be substantially reduced or eliminated, persons knowledgeable in corrosion should be consulted.

The minimum thickness at each TML can be located by ultrasonic scanning or radiography. Electromagnetic techniques also can be used to identify thin areas that may then be measured by ultrasonics or radiography. When accomplished with ultrasonics, scanning consists of taking several thickness measurements at the TML searching for localized thinning. The thinnest reading or an average of several measurement readings taken within the area of a test point shall be recorded and used to calculate corrosion rates, remaining life, and the next inspection date in accordance with Section 5.

Where appropriate, thickness measurements should include measurements at each of the four quadrants on pipe and fittings, with special attention to the inside and outside radius of elbows and tees where corrosion/erosion could increase corrosion rates. As a minimum, the thinnest reading and its location shall be recorded.

TMLs should be established for areas with continuing CUI, corrosion at S/A interfaces, or other locations of potential localized corrosion as well as for general, uniform corrosion.

TMLs should be marked on inspection drawings and on the piping system to allow repetitive measurements at the same **TMLs**. This recording procedure provides data for more accurate corrosion rate determination.

3.4.3 TML SELECTION

3.4.3.1 In selecting or adjusting the number and locations of **TMLs**, the inspector should take into account the patterns of corrosion that would be expected and have been experienced in the process unit. A number of corrosion processes common to refining and petrochemical units are relatively uniform in nature, resulting in a fairly constant rate of pipe wall reduction independent of location within the piping circuit, either axially or circumferentially. Examples of such corrosion phenomena include high-temperature sulfur corrosion and sour water corrosion (provided velocities are not so excessive as to cause local corrosion/erosion of elbows, tees, and other similar items). In these situations, the number of

TMLs required to monitor a circuit will be fewer than those required to monitor circuits subject to more localized metal loss. In theory, a circuit subject to perfectly uniform corrosion could be adequately monitored with a single TML. In reality, corrosion is never truly uniform, so additional **TMLs** may be required. Inspectors must use their knowledge (and that of others) of the process unit to optimize the TML selection for each circuit, balancing the effort of collecting the data with the benefits provided by the data.

3.4.3.2 More **TMLs** should be selected for piping systems with any of the following characteristics:

- Higher potential for creating a safety or environmental emergency in the event of a leak.
- Higher expected or experienced corrosion rates.
- Higher potential for localized corrosion.
- More complexity in terms of fittings, branches, deadlegs, injection points, and other similar items.
- Higher potential for CUI.

3.4.3.3 Fewer **TMLs** can be selected for piping systems with any of the following three characteristics:

- Low potential for creating a safety or environmental emergency in the event of a leak.
- Kelatively noncorrosive piping systems.
- Long, straight-run piping systems.

3.4.3.4 **TMLs** can be eliminated for piping systems with either of the following two characteristics:

- Extremely low potential for creating a safety or environmental emergency in the event of a leak.
- Noncorrosive systems, as demonstrated by history or similar service, and systems not subject to changes that could cause corrosion.

3.5 Thickness Measurement Methods

Ultrasonic thickness measuring instruments usually are the most accurate means for obtaining thickness measurements on installed pipe larger than NPS 1. Radiographic profile techniques are preferred for pipe diameters of NPS 1 and smaller. Radiographic profile techniques may be used for locating areas to be measured, particularly in insulated systems or where nonuniform or localized corrosion is suspected. Where practical, ultrasonics can then be used to obtain the actual thickness of the areas to be recorded. Following ultrasonic readings at **TMLs**, proper repair of insulation and insulation weather coating is recommended to reduce the potential for CUI. Radiographic profile techniques, which do not require removing insulation, may be considered as an alternative.

When corrosion in a piping system is nonuniform or the remaining thickness is approaching the minimum required thickness, additional thickness measuring may be required.

Radiography or ultrasonic scanning are **the** preferred methods in such cases. **Eddy** current devices **also** may be used.

When **ultrasonic** measurements **are taken above 150°F (66°C)**, instruments, couplants, and procedures should be used that will result in accurate measurements at the higher temperatures. Measurements should be adjusted by the appropriate temperature correction factor.

Inspectors should be aware of possible sources of measurement inaccuracies and make every effort to eliminate their occurrence. As a general rule, each of the NDE techniques will have practical limits with respect to accuracy. Factors that can contribute to reduced accuracy of ultrasonic measurements include the following:

- a. Improper instrument calibration.
- b. External coatings or scale.
- c. Excessive surface roughness.
- d. **Excessive "cocking" of the probe (on the curved surface).**
- e. Subsurface material flaws, such as laminations.
- f. Temperature effects [at temperatures above 150°F (66°C)].
- g. Small flaw detector **screens**.
- h. Thicknesses of less than $\frac{1}{4}$ inch (3.2 millimeters) for typical digital thickness gauges.

In addition, it must be kept in mind that the pattern of corrosion can be nonuniform. For corrosion rate determinations to be valid, it is important that measurements on the thinnest point **be repeated** as closely as possible to the same location. Alternatively, the minimum reading or an average of several readings at a test point may **be** considered.

When piping systems are out of service, thickness measurements may be taken through openings using calipers. Calipers are useful in determining approximate thicknesses of castings, forgings, and valve bodies, as well as **pit depth approximations from CUI** on pipe.

Pit depth measuring devices also may be used to determine the depth of localized metal loss.

3.6 Pressure Testing of Piping Systems

Pressure tests are not normally conducted as part of a routine inspection. (See 6.2.6 for pressure testing **requirements** for repairs, alterations, and rerating.) Exceptions to this include requirements of the United States Coast Guard for overwater piping and requirements of local jurisdictions, after **welded alterations or when specified by the inspector or piping engineer**. When they are conducted, pressure tests shall be performed in accordance with the requirements of **ASME B3 1.3**. Additional considerations are provided in **API Recommended Practice 574** and **API Recommended Practice 920**. Lower pressure tests, which are used only for tightness of piping systems, may be conducted at pressures designated by the owner-user.

The test fluid should be water unless there is the possibility of damage due to freezing or other adverse effects of water on the piping system or the process or unless the test water will become contaminated and its disposal will present environmental problems. In either case, another suitable nontoxic liquid may be used. If the liquid is flammable, its flash point shall be at least 120°F (49°C) or greater, and consideration shall be given to the effect of the test environment on the test fluid.

Piping fabricated of or **having components of 300 series stainless** steel should be **hydrotested** with a solution **made up** of potable water (**see** note) or steam condensate. After testing is completed, the piping should be thoroughly drained (**all** high-point vents should be open during draining), air blown, or otherwise dried. If potable water is **not** available or if immediate draining and drying is not possible, water having a very low chloride level, higher **pH (>10)**, and inhibitor addition may be considered to reduce the risk of pitting and **microbiologically** induced corrosion.

Note: Potable water in this context follows U.S. practice, with 250 parts per million maximum chloride, sanitized with chlorine or ozone.

For sensitized austenitic stainless steel piping subject to polythionic stress corrosion cracking, **consideration** should be **given** to using an alkaline-water solution for pressure testing (see NACE **RP01 70**).

If a pressure test is to be maintained for a period of time and the test fluid in the system is subject to **thermal** expansion, precautions shall be taken to avoid excessive pressure.

When a pressure test is required, it shall be conducted after any heat treatment.

Before applying a hydrostatic **test** to piping systems, **consideration** should be given to the supporting structure design.

A pneumatic pressure test may be used **when it is impracticable** to hydrostatically test due to temperature, structural, or process limitations. However, the potential risks to personnel and **property** of pneumatic testing shall be considered when carrying out such a test. As a minimum, the inspection **precautions** contained in **ASME B31.3** shall **be** applied in any pneumatic testing.

During a pressure test, where the test pressure will exceed the set pressure of the safety valve on a piping system, **the** safety relief valve or valves should be removed or blanked for the duration of the test. As an alternative, each valve disk must be held down by a suitably designed test clamp. The application of **an** additional load to the valve spring by **turning** the adjusting screw is not recommended. **Other** appurtenances that are incapable of withstanding the test pressure, such as gage glasses, pressure gages, expansion joints, and rupture disks, should be removed or blanked. Lines containing expansion joints that cannot be removed or isolated may be tested at a reduced pressure in accordance with the principles of **ASME B31.3**. If block valves are used to isolate a

piping system for a pressure test, caution should be used to not exceed the Permissible seat pressure as described in ASME B 16.34 or applicable valve manufacturer data.

Upon completion of the pressure test, pressure relief devices of the **proper** settings and other appurtenances removed or made **inoperable during the pressure test** shall **be** reinstalled or reactivated.

3.7 Material Verification and Traceability

During repairs or **alterations** of low- to high-alloy piping systems, the inspector shall verify the installation of the correct new materials. At the discretion of the owner-user or **the** inspector, this verification can be either by **100-percent** checking or **testing in certain** critical situations or by sampling a Percentage of the materials. Testing can be accomplished by the inspector or the examiner with the use of suitable portable methods, such as chemical spot testing, optical **spectrographic** analyzers, or X-ray fluorescent **analyzers**. **Checking** can involve verifying test reports on **materials**, markings on piping **components** and bolting, and key dimensions.

If a piping system component should fail because an incorrect material was inadvertently substituted for **the proper** piping material, the inspector shall consider the need for further verification of existing piping materials. The extent of further verification will depend upon circumstances such as the consequences of failure and **the** likelihood of further material errors.

3.8 Inspection of Valves

Normally, thickness measurements are not routinely taken on valves in piping circuits. **The** body of a valve is normally thicker than other piping components for design reasons. However, when valves are dismantled for servicing and repair, the shop should be attentive to any unusual corrosion patterns or thinning and, when noted, **report** that information to the inspector. Bodies of valves that are exposed to steep temperature cycling (for example, catalytic reforming unit regeneration and steam cleaning) should be examined periodically for thermal fatigue cracking.

If gate valves are known to be or are suspected of being exposed to corrosion/erosion, thickness readings should be taken between the seats, since this is an area of high turbulence and high stress.

Control valves or other throttling valves, particularly in high-pressure **drop-and-slurry** services, can be susceptible to **localized corrosion/erosion** of the body downstream of the orifice. If such metal loss is suspected, the valve should be removed from the line for internal inspection. The inside of the downstream mating flange and piping also should be inspected for local metal loss.

When valve body and/or closure pressure tests are performed **after** servicing, they should be conducted in accordance with API Standard **598**.

3.9 Inspection of Welds In-Service

Inspection for piping weld quality is normally accomplished as a part of the requirements for new construction, repairs, or alterations. However, welds are often inspected for corrosion as part of a radiographic profile inspection or as part of internal inspection. **When** preferential weld **corrosion** is noted, additional welds in the same circuit or system should be examined for corrosion.

On occasion, **radiographic** profile examinations may reveal what appears to be imperfections in the weld. If **crack-like** imperfections are detected while the piping system is in operation, further inspection with weld quality radiography and/or ultrasonics may be used to assess the magnitude of **the imperfection**. Additionally, an effort should be made to determine whether the crack-like imperfections are from original weld fabrication or may be from an environmental cracking mechanism.

Environmental cracking shall be assessed by the piping engineer.

If the noted imperfections are a result of original weld fabrication, inspection and/or engineering analysis is required to assess the impact of the weld quality on piping integrity. This analysis may be one or more of the following:

- a. Inspector judgment.
- b. Certified welding inspector judgment.
- c. Piping engineer judgment.
- d. Engineering fitness-for-service analysis.

Issues to consider when assessing the quality of existing welds include the following:

- a. Original fabrication inspection acceptance criteria.
- b. Extent, magnitude, and orientation of imperfections.
- c. **Length** of time in-service.
- d. Operating versus design conditions.
- e. Presence of secondary piping stresses (residual and thermal).
- f. Potential for fatigue loads (mechanical and thermal).
- g.** Primary or secondary piping system.
- h. Potential for impact or transient loads.
- i. **Potential** for **environmental** cracking.
- j. Weld hardness.

In many cases for in-service welds, it is not **appropriate** to **use the random** or spot radiography acceptance criteria for weld quality in ASME B3 1.3. These acceptance criteria are intended to apply to new construction on a sampling of welds, not just the welds examined, in order **to** assess **the** probable quality **of all welds (or welders)** in the system.

Some welds may exist that will not meet these criteria but will still perform satisfactorily in-service after being **hydrotested**. This is especially true on **small branch** connections that are normally not examined during new construction.

3.10 Inspection of Flanged Joints

The markings on a **representative** sample of **newly installed** fasteners and **gaskets** should be examined to determine whether they **meet** the material specification. The markings are **identified** in the applicable **ASME** and **ASTM** standards. Questionable fasteners should be verified or renewed.

Fasteners should extend completely through their nuts. Any fastener failing to do **so** is considered acceptably engaged **if** the lack of complete engagement is not more than **one thread**.

If installed flanges are excessively bent, their **markings** and **thicknesses** **should be** checked against engineering **requirements** before taking corrective action.

Flange and valve bonnet fasteners should be examined visually for corrosion.

Flanged and valve bonnet joints should be examined for evidence of leakage, such as stains, deposits, or drips. Process leaks onto flange and bonnet fasteners may result in corrosion or environmental cracking. This examination should include those flanges enclosed with flange or **splash-and-spray** guards.

Flanged joints that have been clamped and pumped **with sealant** should be checked for leakage at the bolts. Fasteners subjected to such leakage may corrode or crack (caustic cracking, for example). If repumping is contemplated, affected fasteners should **be renewed first**.

Fasteners on instrumentation that are subject to process pressure and/or temperature should be included in the scope of these examinations.

See API Recommended Practice 574 for recommended practices when flanged joints are opened.

SECTION 4—FREQUENCY AND EXTENT OF INSPECTION

4.1 Piping Service Classes

All process piping systems shall be categorized into different classes. Such a classification system allows extra inspection efforts to be focused on piping systems that may have the highest potential consequences if failure or loss of containment should occur. In general, the higher classified systems require more extensive inspection at shorter intervals in order to affirm their integrity for continued safe operation. Classifications should be based on potential safety and environmental effects should a leak occur.

Owner-users shall maintain a record of process piping fluids handled, including their classifications. API Recommended Practice 750 and NFPA 704 provide information that may be helpful in classifying piping systems according to the potential hazards of the process fluids they contain.

The three classes listed below in 4.1.1 through 4.1.3 are recommended.

4.1.1 CLASS 1

Services with the highest potential of resulting in an immediate emergency if a leak were to occur are in Class 1. Such an emergency may be safety or environmental in nature. Examples of Class 1 piping include, but are not necessarily limited to, those containing the following:

- Flammable services that may auto-refrigerate and lead to brittle fracture.
- Pressurized services that may rapidly vaporize during release, creating vapors that may collect and form an explosive mixture, such as C_2 , C_3 , and C_4 streams.
- Hydrogen sulfide (greater than 3 percent weight) in a gaseous stream.
- Anhydrous hydrogen chloride.
- Hydrofluoric acid.
- Piping over or adjacent to water and piping over public thoroughways. (Refer to Department of Transportation and U.S. Coast Guard regulations for inspection of underwater piping.)

4.1.2 CLASS 2

Services not included in other classes are in Class 2. This classification includes the majority of unit process piping and selected off-site piping. Typical examples of these services include those containing the following:

- On-site hydrocarbons that will slowly vaporize during release.
- Hydrogen, fuel gas, and natural gas.
- On-site strong acids and caustics.

4.1.3 CLASS 3

Services that are flammable but do not significantly vaporize when they leak and are not located in high-activity areas are in Class 3. Services that are potentially harmful to human tissue but are located in remote areas may be included in this class. Examples of Class 3 service are as follows:

- On-site hydrocarbons that will not significantly vaporize during release.
- Distillate and product lines to and from storage and loading.
- Off-site acids and caustics.

4.2 Inspection Intervals

The interval between piping inspections shall be established and maintained using the following criteria:

- Corrosion rate and remaining life calculations.
- Piping service classification.
- Applicable jurisdictional requirements.
- Judgment of the inspector, the piping engineer, the piping engineer supervisor, or a corrosion specialist, based on operating conditions, previous inspection history, current inspection results, and conditions that may warrant supplemental inspections covered in 3.35.

The owner-user or the inspector shall establish inspection intervals for thickness measurements and external visual inspections and, where applicable, for internal and supplemental inspections.

Thickness measurements should be scheduled based on the calculation of not more than half the remaining life determined from corrosion rates indicated in 5.1.1 or at the maximum intervals suggested in Table 1, whichever is shorter. Shorter intervals may be appropriate under certain circumstances. Prior to using Table 1, corrosion rates should be calculated in accordance with 5.1.3.

Table 1 contains recommended maximum inspection intervals for the three categories of piping services described in 4.1, as well as recommended intervals for injection points and S/A interfaces.

The inspection interval must be reviewed and adjusted as necessary after each inspection or significant change in operating conditions. General corrosion, localized corrosion, pitting, environmental cracking, and other forms of deterioration must be considered when establishing the various inspection intervals.

Table 1--Recommended Maximum Inspection Intervals

Type of Circuit	Thickness Measurements	visual External
Class 1	5 Years	5 Years
Class 2	10 Years	5 Years
class3	10 Years	10 Years
Injection points ^a	3 Years	By class
Soil-to-air interfaces ^b	—	By class

Note: Thickness measurements apply to systems for which TMLs have been established in accordance with 3.4.

^aSee 3.2.1.

^bSee 3.2.4.

4.3 Extent of External and CUI Inspections

External inspections should be conducted at the maximum intervals listed in Table 1 using the checklist in Appendix E.

Inspection for potential corrosion under insulation (CUI) should be conducted on all piping systems susceptible to CUI listed in 3.2.3.1. For first time CUI inspection on Class 1 and Class 2 systems, the examination should include at least 50 percent of all suspect areas and 50 percent of all areas of damaged insulation. Radiographic examination or insulation removal and visual inspection is normally required. Other NDE methods may be used where applicable.

For Class 3 systems, the examination should include at least 10 percent of all suspect areas and areas of damaged insulation. When inspection of a percentage of suspect areas has located significant CUI, additional suspect areas should be examined and, where warranted, up to 100 percent of the circuit should be inspected.

Piping systems that are known to have a remaining life of over 10 years or that are protected against external corrosion need not have insulation removed for the periodic external inspection. However, the condition of the insulating system or the outer jacketing, such as the cold-box shell, should be observed periodically by operating or other personnel. If deterioration is noted, it should be reported to the inspector. The following are examples of these systems:

- Piping systems insulated effectively to preclude the entrance of moisture.
- Jacketed cryogenic piping systems.
- Piping systems installed in a cold box in which the atmosphere is purged with an inert gas.
- Piping systems in which the temperature being maintained is sufficiently low or sufficiently high to preclude the presence of water.

4.4 Extent of Thickness Measurement Inspection

To satisfy inspection interval requirements, each thickness measurement inspection should obtain thickness readings on a representative sampling of TMLs on each circuit (see 3.4). This representative sampling should include data for all the various types of components and orientations (horizontal and vertical) found in each circuit. This sampling also must include TMLs with the earliest renewal date as of the previous inspection. The more TMLs measured for each circuit, the more accurately the next inspection date will be projected. Therefore, scheduled inspection of circuits should obtain as many measurements as necessary.

The extent of inspection for injection points is covered in 3.2.1.

4.5 Extent of Small-Bore, Auxiliary Piping, and Threaded-Connections Inspections

4.5.1 SMALL-BORE PIPING INSPECTION

Small-bore piping (SBP) that is primary process piping should be inspected in accordance with all the requirements of this document.

SBP that is secondary process piping has different minimum requirements depending upon service classification. Class 1 secondary SBP shall be inspected to the same requirements as primary process piping. Inspection of Class 2 and Class 3 secondary SBP is optional. SBP deadlegs (such as level bridles) in Class 2 and Class 3 systems should be inspected where corrosion has been experienced or is anticipated.

4.5.2 AUXILIARY PIPING INSPECTION

Inspection of secondary, auxiliary SBP associated with instruments and machinery is optional. Criteria to consider in determining whether auxiliary SBP will need some form of inspection include the following:

- Classification.
- Potential for environmental or fatigue cracking.
- Potential for corrosion based on experience with adjacent primary systems.
- Potential for CUI.

4.5.3 THREADED-CONNECTIONS INSPECTION

Inspection of threaded connections will be according to the requirements listed above for small-bore and auxiliary piping. When selecting TMLs on threaded connections, include only those that can be radiographed during scheduled inspections.

Threaded connections associated with machinery and **subject** to fatigue damage should **be** periodically assessed and considered for **possible** renewal with a thicker wall or **upgrading** to welded components. The schedule for such **renewal** will depend on several issues, including the following:

- a. Classification of piping.
- b. Magnitude and frequency of vibration.

- c. Amount of unsupported weight.
- d. Current piping wall thickness.
- e. Whether or not the system can be maintained on-stream.
- f. Corrosion rate.
- g. Intermittent service.

SECTION 5—INSPECTION DATA EVALUATION, ANALYSIS, AND RECORDING

5.1 Corrosion Rate Determination

5.1.1 REMAINING LIFE CALCULATIONS

The remaining life of the piping system shall be calculated from the following formula:

$$\text{Remaining life (years)} = \frac{t_{\text{actual}} - t_{\text{minimum}}}{\text{corrosion rate}} \\ \text{[inches (millimeters) per year]}$$

Where:

t_{actual} = the actual minimum thickness, in inches (millimeters), determined at the time of inspection as specified in 3.5.

t_{minimum} = the minimum required thickness, in inches (millimeters), for the limiting section or zone.

The long term (L.T.) corrosion rate of piping circuits shall be calculated from the following formula:

$$\text{corrosion rate (L.T.)} = \frac{t_{\text{initial}} - t_{\text{last}}}{\text{time (years) between last and initial inspections}}$$

The short term (S.T.) corrosion rate of piping circuits shall be calculated from the following formula:

$$\text{corrosion rate (S.T.)} = \frac{t_{\text{previous}} - t_{\text{last}}}{\text{time (years) between last and previous inspections}}$$

Long-term and short-term corrosion rates should be compared to see which results in the shortest remaining life. (See 4.2 for inspection interval determination.)

5.1.2 NEWLY INSTALLED PIPING SYSTEMS OR CHANGES IN SERVICE

For new piping systems and piping systems for which service conditions are being changed, one of the following methods shall be employed to determine the probable rate of corrosion from which the remaining wall thickness at the time of the next inspection can be estimated:

- A corrosion rate for a piping circuit may be calculated from data collected by the owner-user on piping systems of similar material in comparable service.
- If data for the same or similar service are not available, a corrosion rate for a piping circuit may be estimated from the owner-user's experience or from published data on piping systems in comparable service.
- If the probable corrosion rate cannot be determined by either method listed in Item a or Item b, the initial thickness

measurement determinations shall be made after no more than 3 months of service by using nondestructive thickness measurements of the piping system. Corrosion monitoring devices, such as corrosion coupons or corrosion probes, may be useful in establishing the timing of these thickness measurements. Subsequent measurements shall be made after appropriate intervals until the corrosion rate is established.

5.1.3 EXISTING PIPING SYSTEMS

Corrosion rates shall be calculated on either a short-term or a long-term basis. For the short-term calculation, readings from the two most recent inspections shall be used. For the long-term calculation, wall thicknesses from the most recent and initial (or nominal) inspections shall be used. In most cases, the higher of these two rates should be used to estimate remaining life and to set the next inspection interval.

If calculations indicate that an inaccurate rate of corrosion has been assumed, the rate to be used for the next period shall be adjusted to agree with the actual rate found.

5.2 Maximum Allowable Working Pressure Determination

The maximum allowable working pressure (MAWP) for the continued use of piping systems shall be established using the applicable code. Computations may be made for known materials if all the following essential details are known to comply with the principles of the applicable code:

- Upper and/or lower temperature limits for specific materials.
- Quality of materials and workmanship.
- Inspection requirements.
- Reinforcement of openings.
- Any cyclical service requirements.

For unknown materials, computations may be made assuming the lowest grade material and joint efficiency in the applicable code. When the MAWP is recalculated, the wall thickness used in these computations shall be the actual thickness as determined by inspection (see 3.5 for definition) minus twice the estimated corrosion loss before the date of the next inspection (see 4.2). Allowance shall be made for the other loadings in accordance with the applicable code. The applicable code allowances for pressure and temperature variations from the MAWP are permitted provided all of the associated code criteria are satisfied.

Table 2 contains two examples of calculations of MAWP illustrating the use of the corrosion half-life concept.

Table P-Two Examples of the Calculation of Maximum Allowable Working Pressure (MAWP) Illustrating the Use of the Corrosion Half-Life Concept

Example 1:

Design pressure/temperature	500 psig/400°F (204°C)
Pipe description	NPS 16, standard weight, A 106-B
Outside diameter of pipe, <i>D</i>	16 in. (406 mm)
Allowable stress	20,000 psi
Longitudinal weld efficiency, <i>E</i>	1.0
Thickness determined from inspection	0.32 in. (8.13 mm)
Observed corrosion rate (see 5.1.1)	0.01 in./yr. (.254 mm/yr.)
Next planned inspection	3 yrs. --
Estimated corrosion loss by date of next inspection	$= 3 \times 0.01 = 0.03 \text{ in. (1.27 mm)}$
MAWP	$= \frac{2SEt}{D}$ $= \frac{2 \times 20,000 \times 1.0 \times (0.32 - (3 \times 0.01))}{16}$ $= 550 \text{ psig}$
Conclusion:	OK

Example 2:

Next planned inspection	7 yrs.
Estimated corrosion loss by date of next inspection	$= 7 \times 0.01 = 0.07 \text{ in. (1.78 mm)}$
MAWP	$= \frac{2SEt}{D}$ $= \frac{2 \times 20,000 \times 1.0 \times (0.32 - (7 \times 0.01))}{16}$ $= 450 \text{ psig}$
Conclusion:	Must reduce inspection interval or determine that normal operating pressure will not exceed this new MAWP during the seventh year, or renew the piping before the seventh year.

Notes:

1. psig = pounds per square inch gauge; psi = pounds per square inch.
2. The formula for MAWP is from ASME B31.3, Equation 3b, where *t* = corroded thickness.

5.3 Minimum Required Thickness Determination

The minimum required pipe wall thickness, or retirement thickness, shall be based on pressure, mechanical, and structural considerations using the appropriate design formulae and code allowable stress. Consideration of both general and localized corrosion shall be included. For services with high potential consequences if failure were to occur, the piping engineer should consider increasing the required minimum thickness above the calculated minimum thickness to provide for unanticipated or unknown loadings, undiscovered metal loss, or resistance to normal abuse.

5.4 Evaluation of Locally Thinned Areas

Locally thinned areas may be evaluated by the piping engineer using one of the following methods:

- a. In accordance with the latest edition of ASME B31G.
- b. Detailed numerical stress analysis (such as finite element analysis) of the area to determine adequacy for continued service. The results of this analysis shall be evaluated as described in the ASME Boiler and Pressure Vessel Code, Section VIII, Division 2, Appendix 4, Article 4-1. The basic allowable stress from the applicable code shall be used in

place of S_m in Division 2, but in no case shall the allowable stress used in this evaluation be greater than two-thirds of the specified minimum yield strength (SMYS) at temperature. At design temperatures in the creep range of the material, additional considerations beyond the scope of Division 2 are necessary, such as the effects of creep-fatigue interaction.

c. An independent calculation using the appropriate weld joint factor when a longitudinal weld having a joint factor of less than 1.0 is corroded as well as surfaces remote from the weld. This calculation must be made to determine if the thickness at the weld, or remote from the weld, governs the allowable working pressure. For the purpose of this calculation, the surface at a weld includes 1 inch (2.5 centimeters) of parent metal on either side of the weld or twice the minimum measured thickness on either side of the weld, whichever is greater. Alternatively, the weld joint factor may be increased by radiographic examination in accordance with the principles of ASME B31.3.

d. Corroded areas of pipe caps may be evaluated in accordance with Paragraph 3.7, Item h, of API 510.

5.5 Piping Stress Analysis

Piping must be supported and guided so that (a) its weight is carried safely, (b) it has sufficient flexibility for thermal

expansion or contraction, and (c) it does not vibrate excessively. Piping flexibility is of increasing concern the larger the diameter of the piping and the greater the difference between ambient and operating temperature conditions.

Piping stress analysis to assess system flexibility and support adequacy is not normally performed as part of a piping inspection. However, many existing piping systems were analyzed as part of their original design or as part of a rerating or modification, and the results of these analyses can be useful in developing inspection plans. When unexpected movement of a piping system is observed, such as during an external visual inspection (see 3.3.3), the inspector should discuss these observations with the piping engineer and evaluate the need for conducting a piping stress analysis.

Piping stress analysis can identify the most highly stressed components in a piping system and predict the thermal movement of the system when it is placed in operation. This information can be used to concentrate inspection efforts at the locations most prone to fatigue damage from thermal expansion (heat-up and cool-down) cycles and/or creep damage in high-temperature piping. Comparing predicted thermal movements with observed movements can help identify the occurrence of unexpected operating conditions and deterioration of guides and supports. Consultation with the piping engineer may be necessary to explain observed deviations from the analysis predictions, particularly for complicated systems involving multiple supports and guides between end points.

Piping stress analysis also can be employed to help solve observed piping vibration problems. The natural frequencies in which a piping system will vibrate can be predicted by analysis. The effects of additional guiding can be evaluated to assess its ability to control vibration by increasing the system's natural frequencies beyond the frequency of exciting forces, such as machine rotational speed. It is important to determine that guides added to control vibration do not adversely restrict thermal expansion.

5.6 Reporting and Records for Piping System Inspection

Any significant increase in corrosion rates shall be reported to the owner-user for appropriate action.

The owner-user shall maintain appropriate permanent and progressive records of each piping system covered by API 570. These records shall contain pertinent data such as piping system service: classification; identification numbers: inspection intervals; and documents necessary to record the name of the individual performing the testing, the date, the types of testing, the results of thickness measurements and other tests, inspections, repairs (temporary and permanent), alterations, or reratings. Design information and piping drawings may be included. Information on maintenance activities and events affecting piping system integrity also should be included. The date and results of required external inspections shall be recorded. (See API Recommended Practice 574 for guidance on piping inspection records.)

The use of a computer-based system for storing, calculating, and analyzing data should be considered in view of the volume of data that will be generated as part of a piping test-point program. Computer programs are particularly useful for the following:

- Storing the actual thickness readings.
- Calculating short- and long-term corrosion rates, retirement dates, MAWP, and reinspection intervals on a test-point by test-point basis.
- Highlighting areas of high corrosion rates, circuits overdue for inspection, circuits close to retirement thickness, and other information.

Algorithms for the analysis of data from entire circuits also may be included in the program. Care should be taken to ensure that the statistical treatment of circuit data results in predictions that accurately reflect the actual condition of the piping circuit.

SECTION 6--REPAIRS, ALTERATIONS, AND RERATING OF PIPING SYSTEMS

6.1 Repairs and Alterations

The principles of ASME B31.3 or the code to which the piping system was built shall be followed.

6.1.1 AUTHORIZATION

All repair and alteration work must be done by a repair organization as defined in Appendix A and must be authorized by the inspector prior to its commencement. Authorization for alteration work to a piping system may not be given without prior consultation with, and approval by, the piping engineer. The inspector will designate any inspection hold points required during the repair or alteration sequence. The inspector may give prior general authorization for limited or routine repairs and procedures, provided the inspector is satisfied with the competency of the repair organization.

6.1.2 APPROVAL

All proposed methods of design, execution, materials, welding procedures, examination, and testing must be approved by the inspector or by the piping engineer, as appropriate. Owner-user approval of on-stream welding is required.

Welding repairs of cracks that occurred in-service should not be attempted without prior consultation with the piping engineer in order to identify and correct the cause of the cracking. Examples are cracks suspected of being caused by vibration, thermal cycling, thermal expansion problems, and environmental cracking.

The inspector shall approve all repair and alteration work at designated hold points and after the repairs and alterations have been satisfactorily completed in accordance with the requirements of API 570.

6.1.3 WELDING REPAIRS (INCLUDING ON-STREAM)

6.1.3.1 Temporary Repairs

For temporary repairs, including on-stream, a full encirclement welded split sleeve or box-type enclosure designed by the piping engineer may be applied over the damaged or corroded area. Longitudinal cracks shall not be repaired in this manner unless the piping engineer has determined that cracks would not be expected to propagate from under the sleeve. In some cases, the piping engineer will need to consult with a fracture analyst.

If the repair area is localized (for example, pitting or pinholes) and the specified minimum yield strength (SMYS) of the pipe is not more than 40,000 pounds per square inch (275,800 kilopascals), a temporary repair may be made by fillet welding a properly designed split coupling or plate

patch over the pitted area. (See 6.2.3 for design considerations and Appendix D for an example.) The material for the repair shall match the base metal unless approved by the piping engineer.

For minor leaks, properly designed enclosures may be welded over the leak while the piping system is in-service, provided the inspector is satisfied that adequate thickness remains in the vicinity of the weld and the piping component can withstand welding without the likelihood of further material damage, such as from caustic service.

Temporary repairs should be removed and replaced with a suitable permanent repair at the next available maintenance opportunity. Temporary repairs may remain in place for a longer period of time only if approved and documented by the piping engineer.

6.1.3.2 Permanent Repairs

Repairs to defects found in piping components may be made by preparing a welding groove that completely removes the defect and then filling the groove with weld metal deposited in accordance with 6.2.

Corroded areas may be restored with weld metal deposited in accordance with 6.2. Surface irregularities and contamination shall be removed before welding. Appropriate NDE methods shall be applied after completion of the weld.

If it is feasible to take the piping system out of service, the defective area may be removed by cutting out a cylindrical section and replacing it with a piping component that meets the applicable code.

Insert patches (flush patches) may be used to repair damaged or corroded areas if the following requirements are met:

- Full-penetration groove welds are provided.
- For Class 1 and Class 2 piping systems, the welds shall be 100 percent radiographed or ultrasonically tested using NDE procedures that are approved by the inspector.
- Patches may be any shape but shall have rounded corners [1 inch (2.5 centimeters) minimum radius].

6.1.4 NONWELDING REPAIRS (ON-STREAM)

Temporary repairs of locally thinned sections or circumferential linear defects may be made on-stream by installing a properly designed and fabricated bolted leak clamp. The design shall include control of axial thrust loads if the piping component being clamped is (or may become) insufficient to control pressure thrust. The effect of clamping (crushing) forces on the component also shall be considered.

During turnarounds or other appropriate opportunities, temporary leak sealing and leak dissipating devices, including valves, shall be removed and appropriate actions taken to

restore the original integrity of the piping system. The inspector and/or piping **engineer shall** be involved in determining repair **methods and** procedures.

Procedures that include leak sealing fluids ("pumping") for process piping should be reviewed for acceptance by the inspector or piping engineer. The review should take into consideration the compatibility of the sealant with the **leak-**ing material; the pumping pressure on the clamp (especially when repumping); the risk of sealant affecting downstream flow meters, relief valves, or machinery; the risk of subsequent leakage at bolt threads causing corrosion or stress corrosion cracking of bolts; and the number of times the seal area is **repumped**.

6.2 Welding and Hot Tapping

All repair and alteration welding shall be done in accordance with the principles of **ASME B3 1.3** or the **code** to which the piping system was built.

Any welding conducted on piping components in operation must **be** done in accordance with API Publication **2201**. The inspector shall use as a minimum the "Suggested Hot Tap Checklist" contained in API Publication 2201 for hot tapping performed on piping components.

6.2.1 PROCEDURES, QUALIFICATIONS, AND RECORDS

The repair organization shall use welders and welding procedures qualified in accordance with **ASME B3 1.3** or the code to which the piping was built.

The repair organization shall maintain records of welding procedures and welder performance qualifications. These records shall be available to the inspector prior to the start of welding.

6.2.2 PREHEATING AND POSTWELD HEAT TREATMENT

6.2.2.1 Preheating

Preheat temperature **used** in making welding repairs shall be in accordance with the applicable code and qualified welding **procedure**. Exceptions for temporary repairs must be approved by the piping engineer.

Preheating to not less than 300°F (150°C) may be considered as an alternative to **postweld** heat treatment (PWHT) for alterations or repairs of piping systems initially **postweld** heat treated as a code **requirement** (see note). This applies to piping constructed of the P-1 steels listed in **ASME B31.3**. P-3 steels, with the exception of Mn-Mo steels, also may receive the 300°F (150°C) minimum preheat alternative when the piping system operating **temperature** is high enough to provide **reasonable** toughness and when there is no identifiable hazard associated with pressure testing, shutdown, and startup. The inspector **should** determine that the minimum preheat **temper-**

ature is measured and maintained. After welding, the joint should immediately be covered with insulation to slow the cooling rate.

Note: Preheating **may not** be considered as an alternative to **environmental** cracking prevention.

Piping systems constructed of other steels initially requiring **PWHT** normally are **postweld** heat treated if alterations or repairs involving pressure retaining welding are **per-**formed. The use of the preheat alternative requires **consulta-**tion with the piping engineer who should consider the potential for environmental cracking and whether the welding procedure will provide adequate toughness. Examples of situations where **this alternative** could **be** considered include seal **welds**, weld metal buildup of thin areas, and welding support clips.

6.2.2.2 Postweld Heat Treatment

PWHT of piping system repairs or alterations should be **made using the applicable requirements of ASME B3 1.3 or the code** to which the piping was built. See 6.2.2.1 for an alternative preheat procedure for some PWHT requirements. Exceptions for temporary repairs must be approved by the piping engineer.

Local PWHT may be substituted for **360-degree** banding on local repairs on all materials, provided the following precautions and requirements are applied:

- The application is reviewed, and a procedure is developed by the piping **engineer**.
- In evaluating the suitability of a procedure, consideration shall be given to applicable factors, such as base metal thickness, thermal gradients, material properties, changes resulting from **PWHT**, the need for **full-penetration** welds, and **surface and volumetric examinations after PWHT**. Additionally, the overall and **local** strains and distortions resulting from **the** heating of a local restrained area of the piping wall **shall** be considered in developing and evaluating PWHT **procedures**.
- A preheat of 300°F (150°C), or higher as **specified by specific** welding procedures, is maintained while welding.
- The required PWHT **temperature shall be maintained for a distance of not less than two times the base metal thickness** measured from the weld. The PWHT temperature shall be monitored **by a suitable** number of thermocouples (a minimum of two) **based** on the size and shape of the area **being** heat treated.
- Controlled heat also shall be applied to any branch connection or other attachment within the PWHT **area**.
- The **PWHT** is performed **for code compliance and not for environmental cracking resistance**.

6.2.3 DESIGN

Butt joints shall be full-penetration groove welds.

Piping components shall be replaced when repair is likely to be inadequate. **New connections** and replacements shall be designed and fabricated according to the principles of the applicable code. The design of temporary enclosures and repairs shall be approved by the piping engineer.

New connections may be installed on piping systems provided the design, location, and method of attachment conform to the principles of the applicable code.

Fillet welded patches **require special design considerations**, especially relating to weld-joint efficiency and crevice corrosion. Fillet welded patches shall be designed by the piping engineer. A patch may be applied to the external surfaces of piping, provided it is in accordance with 6.1.3 and **meets** either of the following requirements:

- a. The proposed patch provides design strength equivalent to a reinforced opening designed according to the applicable code.
- b. The proposed patch is designed to absorb the membrane strain of the part in a **manner** that is in accordance with the principles of the applicable code, if the following criteria are met:
 1. The allowable membrane stress is not exceeded in the piping part or the patch.
 2. The strain in the patch does **not** result in fillet weld stresses exceeding allowable stresses for such welds.
 3. An overlay patch shall have rounded corners (see Appendix D).

6.2.4 MATERIALS

The materials used in making repairs or alterations shall be of known weldable quality, shall conform to the applicable code, and shall be compatible with the original material. For material verification requirements, see 3.7.

6.2.5 NONDESTRUCTIVE EXAMINATION

Acceptance of a welded repair or alteration shall include NDE in accordance with the applicable code and the owner's specification, unless otherwise specified in API 570.

6.2.6 PRESSURE TESTING

After welding is completed, a pressure test in accordance with 3.6 shall be performed if practical and deemed necessary by the inspector. Pressure tests are normally required after alterations and major repairs. When a pressure test is not necessary or practical, NDE shall be utilized in lieu of a pressure test. Substituting special procedures for a pressure test after an alteration or repair may be done only after consultation with the inspector and the piping engineer.

When it is not practical to perform a pressure test of a final closure weld that joins a new or replacement section of

piping to an existing system, all of the following requirements shall be satisfied:

- a. The new or replacement piping is pressure tested.
- b. The closure weld is a full-penetration butt weld between a weld neck flange and standard piping component or straight sections of pipe of equal diameter and thickness, axially aligned (not miter cut), and of equivalent materials. For design cases up to Class 150 and 500°F (260°C), slip-on flanges are acceptable alternatives.
- c. Any final closure butt weld shall be of 100-percent radiographic quality; or angle-beam ultrasonics flaw detection may be used, provided the appropriate acceptance criteria have been established.
- d. MT or PT shall be performed on the root pass and the completed weld. Fillet welds must have PT.

6.3 Rerating

Rerating piping systems by changing the temperature rating or the MAWP may be done only after all of the following requirements have been met:

- a. Calculations are performed by the piping engineer or the inspector.
- b. All reratings shall be established in accordance with the requirements of the code to which the piping system was built or by computation using the appropriate methods in the latest edition of the applicable code.
- c. Current inspection records verify that the piping system is satisfactory for the proposed service conditions and that the appropriate corrosion allowance is provided.
- d. Rerated piping systems shall be leak tested in accordance with the code to which the piping system was built or the latest edition of the applicable code for the new service conditions, unless documented records indicate a previous leak test was performed at greater than or equal to the test pressure for the new condition. An increase in the rating temperature that does not affect allowable tensile stress does not require a leak test.
- e. The piping system is checked to affirm that the required pressure relieving devices are present, are set at the appropriate pressure, and have the appropriate capacity at set pressure.
- f. The piping system rerating is acceptable to the inspector or piping engineer.
- g. All piping components in the system (such as valves, flanges, bolts, gaskets, packing, and expansion joints) are adequate for the new combination of pressure and temperature.
- h. Piping flexibility is adequate for design temperature changes.
- i. Appropriate engineering records are updated.
- j. A decrease in minimum operating temperature is justified by impact test results, if required by the applicable code.

SECTION 7-INSPECTION OF BURIED PIPING

Inspection of **buried** process piping (not regulated by the Department of Transportation) is different from other **process** piping inspection because significant external deterioration can be caused by corrosive soil conditions. Since **the** inspection is hindered **by** the inaccessibility of the affected areas of the piping, **the** inspection of **buried** piping **is** treated in a separate section of API 570. important, nonmandatory references for underground piping inspection are the following NACE documents: **RP0169, RP0274, and RPO275**; and Section 9 of API Recommended Practice 651.

7.1 Types and Methods of Inspection

7.1.1 ABOVE-GRADE VISUAL SURVEILLANCE

Indications of leaks **in** buried piping may include a change in the surface contour of the ground, discoloration of the **soil**, softening of paving asphalt, pool formation, bubbling water puddles, or noticeable odor. Surveying **the** route of buried piping is one method of identifying problem areas.

7.1.2 CLOSE-INTERVAL POTENTIAL SURVEY

The close-interval potential survey performed at ground level over the buried pipe can be used to locate active **corrosion points on** the pipe's surface.

Corrosion cells can form on both bare and coated pipe where the bare steel contacts the soil. Since **the potential** at **the** area of corrosion will **be** measurably different from an adjacent area on the pipe, the location of the corrosion activity can be determined **by** this survey technique.

7.1.3 PIPE COATING HOLIDAY SURVEY

The pipe coating holiday survey can be used to locate coating defects on buried coated pipes, and **it can be** used on newly constructed pipe systems to **ensure that** the coating is intact and holiday-free. More often it is used to evaluate coating serviceability for buried piping that has been **in-service** for an extended period of time.

From survey data, **the** coating effectiveness and rate of coating deterioration can be determined. This information is used **both** for predicting corrosion activity in a **specific** area and for forecasting replacement of the coating for corrosion control.

7.1.4 SOIL RESISTIVITY

Corrosion of **bare** or Poorly coated piping **is** often caused by a mixture of **different** soils in contact with the pipe surface. The corrosiveness of the soils can be determined by a measurement of the soil resistivity. Lower levels of **resistivity** are relatively more corrosive than higher levels, especially in areas where the pipe is exposed to significant changes in **soil** resistivity.

Measurements of soil resistivity should be performed using the Wenner Four-Pin Method in accordance with **ASTM G57**. In cases of parallel pipes or in areas of intersecting pipelines, **it** may be **necessary to use the Single-Pin Method** to accurately measure **the** soil resistivity. For measuring **resistivity** of soil samples from auger holes or excavations, a soil box **serves** as a convenient means for obtaining accurate results.

The **depth** of the piping shall be considered in selecting the method to be used and the location of samples. The testing and evaluation of results should be performed by **personnel** trained **and** experienced in soil resistivity testing.

7.1.5 CATHODIC PROTECTION MONITORING

Cathodically protected buried piping should be monitored regularly to assure adequate **levels** of **protection**. Monitoring should include periodic measurement and analysis of pipe-to-soil Potentials by personnel trained and experienced in cathodic protection system operation. More frequent monitoring of critical cathodic protection components, such as impressed current rectifiers, is required **to** ensure **reliable** system operation.

Refer to NACE RPO169 and Section 9 of API Recommended Practice 651 for guidance applicable to inspecting and maintaining cathodic protection systems for buried piping.

7.1.6 INSPECTION METHODS

Several inspection methods are available. Some methods can indicate **the** external or wall condition of the piping, whereas **other methods indicate only the internal condition**. **Examples** are as follows:

- a. Intelligent pigging. **This** method involves the movement of a device (pig) through the piping either while it **is** in-service or after it has been **removed** from service. Several types of devices are available employing different methods of inspection. The time to be evaluated must be free from restrictions that would cause **the** device **to** stick within **the** line. Five diameter **bends** arc usually required since standard 90 degree pipe ells may not Pass a pig. The line must also have facilities for launching **and** recovering the pigs.
- b. Video cameras. Television cameras are available **that** can be inserted into the piping. These cameras may provide visual inspection information on **the** internal condition of **the** line.
- c. Excavation. In many **cases**, the only available inspection **method that** can be performed is unearthing the piping in order to visually **inspect the** external condition of **the** piping and to **evaluate** its thickness and internal condition using the methods discussed in 3.3.2. Care should be exercised in **re-**

moving soil from above and around the piping to prevent damaging the line or line coating. **The** last few inches of soil should be removed manually to avoid this possibility. If the excavation is sufficiently deep, the sides of the trench should be properly shored to prevent their collapse, in accordance with OSHA regulations, where applicable. If the coating or wrapping is deteriorated or damaged, it should be removed in that area to inspect the condition of the underlying metal.

7.2 Frequency and Extent of Inspection

7.2.1 ABOVE-GRADE VISUAL SURVEILLANCE

The owner-user should, at approximately **6-month** intervals survey the surface conditions on and adjacent to each pipeline path (**see** 7.1.1).

7.2.2 PIPE-TO-SOIL POTENTIAL SURVEY

A close-interval potential survey on a cathodically protected line may be used to verify that the buried piping has a protective potential throughout its length. For poorly coated **pipes** where cathodic protection potentials are **inconsistent**, the survey may be conducted at **5-year** intervals for **verification** of continuous corrosion control.

For piping with no cathodic protection or in areas where leaks have occurred due to external corrosion, a pipe-to-soil potential survey may be conducted along **the** pipe route. The pipe should be excavated at **sites** where **active corrosion cells** have been located to determine the extent of corrosion damage. A continuous potential profile or a close-interval survey may **be** required to locate active corrosion cells.

7.2.3 PIPE COATING HOLIDAY SURVEY

The frequency of pipe coating holiday surveys is usually based on indications that other forms of **corrosion** control are ineffective. For example, on a coated pipe where there is gradual loss of cathodic protection potentials or an external corrosion **leak occurs** at a coating **defect**, a **pipe** coating holiday survey may **be** used to evaluate the coating.

7.2.4 SOIL CORROSIVITY

For piping buried in lengths greater than **100 feet** (30 meters) and not cathodically protected, evaluations of soil **corrosivity** should be performed at 5-year intervals. Soil resistivity measurements **may be used** for relative classification of the soil **corrosivity** (see 7.1.4). Additional factors that may **warrant** consideration are changes in soil chemistry and **analyses** of the polarization resistance of the soil and piping interface.

7.2.5 CATHODIC PROTECTION

If **the** piping is cathodically protected, the system should **be** monitored at intervals in accordance with Section 10 of

NACE **RP0169** or Section 9 of API Recommended Practice 65 1.

7.2.6 EXTERNAL AND INTERNAL INSPECTION INTERVALS

If internal corrosion of buried piping is expected as a result of inspection on the **above-grade** portion of **the** line, inspection intervals and methods for the buried portion should **be** adjusted accordingly. The inspector should be aware of and consider the possibility of accelerated internal corrosion in **deadlegs**.

The external condition of buried piping that is not **cathodically** protected should be determined by either pigging, which can measure wall thickness, or by excavating according to the frequency given in Table 3. Significant external corrosion detected by pigging **or** by **other** means may **require** excavation **and** evaluation even if the piping is cathodically protected.

Piping inspected periodically by excavation shall be inspected in **lengths of 6** feet to 8 feet (1.8 meters to 2.4 **meters**) at one or more locations judged to **be** most susceptible **to** corrosion. Excavated piping should be inspected **full** circumference for the type and extent of corrosion (pitting or general) and the condition of the coating.

If inspection reveals damaged coating or corroded piping, additional piping shall be excavated until the extent of the condition is identified. If the average wall **thickness** is at or below retirement thickness, it shall be **repaired** or replaced.

If the piping is contained inside a casing pipe, the condition of the casing should be **inspected to determine** if water and/or soil has entered the casing. The inspector should verify the following: (a) both ends of the casing extend beyond the ground line; (b) the ends of the casing arc scaled if the casing is not **self-draining**; and, (c) **the pressure** carrying pipe is properly **coated** and wrapped.

7.2.7 LEAK TESTING INTERVALS

An alternative or supplement to inspection is leak testing with liquid at a pressure at least **10** percent greater than maximum operating pressure at intervals one-half the length of those shown in Table 3 for piping not cathodically protected and at the same intervals as shown in Table 3 for **cathodically** protected piping. The leak **test** should be maintained

Table 3—Frequency of Inspection for Buried Piping Without Effective Cathodic Protection

Soil Resistivity(ohm-cm)	Inspection Interval(years)
<2,000	5
2,000 to 10,000	10
>10,000	15

for a period of 12 hours. Six hours after the initial **pressurization** of the piping system, the pressure should be noted and, if necessary, the line repressurized **to original** test pressure and isolated from the pressure source. If, during the **remainder** of the test period, the pressure **decreases** more than **5** percent, the piping should be visually inspected externally **and/or inspected internally** to find the leak **and assess** the extent of corrosion. Sonic measurements **may be helpful** in locating leaks during leak testing.

Buried piping also may **be** surveyed for integrity by removing the line from service and performing a leak test. This inspection method typically involves pressurizing the line with a tracer gas (such as helium **or** sulfur **hexafluoride**), allowing time for the tracer gas to diffuse to the surface, and **surveying the** buried line with a **gas-specific detector to detect** the tracer gas.

7.3 Repairs to Buried Piping Systems

7.3.1 REPAIRS TO COATINGS

Any coating removed for inspection shall be renewed and inspected appropriately.

For coating repairs, the inspector should be assured that the coating meets the following criteria:

a. It has sufficient adhesion to the pipe to prevent **underfilm** migration of moisture.

- b. It is sufficiently ductile to resist **cracking**.
- c. It is free of voids and gaps in the coating (holidays).
- d.** It has sufficient strength to resist damage due to handling **and soil stress**.
- e. It can **support** any supplemental cathodic protection.

In **addition**, coating repairs may be tested using a **high-voltage** holiday detector. The detector voltage shall be adjusted to the appropriate **value** for the coating material **and** thickness. Any holidays found shall be repaired and retested.

7.3.2 CLAMP REPAIRS

If piping leaks are clamped and reburied, the location of the clamp shall be logged in the inspection record and may be surface **marked**. **Both** the marker and the record shall note the **date of** installation **and** the location of the clamp. **All** clamps shall **be** considered temporary. The piping should **be** permanently repaired at the first opportunity.

7.3.3 WELDED REPAIRS

Welded repairs shall be made in accordance in 6.2.

7.4 Records

Record systems for buried piping should be maintained in accordance **with** 5.6. In addition, a record of the location and date **of** installation of **temporary** clamps shall be maintained.

APPENDIX A-GLOSSARY

This glossary defines terms and acronyms for the purposes of this publication.

1. An **alteration** is a physical change in **any** component that has design implications affecting the pressure containing capability or flexibility of a piping system beyond the scope of its **design**. The following are not considered alterations: comparable or duplicate replacement, the addition of any reinforced branch connection equal to or less than the size of existing reinforced branch connections, and the addition of branch connections not requiring reinforcement.

2. The **applicable code** is the code, code section, or other recognized and generally accepted engineering standard or practice to which the piping system was built or which is deemed by the owner or user or the piping engineer to be most appropriate for the situation, including but not limited to the latest edition of **ASME B31.3**.

3. **ASME 631.3** is a shortened form of **ASME B31.3, Chemical Plant and Petroleum Refinery Piping**, published by the American Society of Mechanical Engineers. **ASME B3 1.3** is written for design and construction of piping systems. However, most of the technical requirements on design, welding, examination, and materials also can be applied in the inspection, rerating, repair, and alteration of operating piping systems. When **ASME B31.3** cannot be followed because of its new construction coverage (such as revised or new material specifications, inspection requirements, certain heat treatments, and pressure tests), the piping engineer or inspector shall be guided by **API 570** in lieu of strict conformity to **ASME B3 1.3**. As an example of intent, the phrase "principles of **ASME B3 1.3**" has been employed in **API 570**, rather than "in accordance with **ASME B3 1.3**."

4. An **authorized inspection agency** is defined as any of the following:

- The inspection organization of the jurisdiction in which the piping system is used.
- The inspection organization of an insurance company that is licensed or registered to write insurance for piping systems.
- An owner or user of piping systems who maintains an inspection organization for activities relating only to his equipment and not for piping systems intended for sale or resale.
- An independent inspection organization employed by or under contract to the owner or user of piping systems that are used only by the owner or user and not for sale or resale.
- An independent inspection organization licensed or recognized by the jurisdiction in which the piping system is used and employed by or under contract to the owner or user.

5. An **authorized piping inspector** is an employee of an authorized inspection agency who is qualified to perform the

functions specified in **API 570**. A nondestructive examination (NDE) examiner is not required to be an authorized piping inspector. Whenever the term inspector is used in **API 570**, it refers to an authorized piping inspector.

6. **Auxiliary piping** is instrument and machinery piping, typically small-bore secondary process piping that can be isolated from primary piping systems. Examples include flush lines, seal oil lines, analyzer lines, balance lines, buffer gas lines, drains, and vents.

7. **CUI** stands for corrosion under insulation, including stress corrosion cracking under insulation.

8. **Deadlegs** are components of a piping system that normally have no significant flow. Examples include the following: blanked branches, lines with normally closed block valves, lines with one end blanked, pressurized dummy support legs, stagnant control valve bypass piping, spare pump piping, level bridles, relief valve inlet and outlet header piping, pump trim bypass lines, high-point vents, sample points, drains, bleeders, and instrument connections.

9. A **defect** is an imperfection of a type or magnitude exceeding the acceptable criteria.

10. The **design temperature** of a piping system component is the temperature at which, under the coincident pressure, the greatest thickness or highest component rating is required. It is the same as the design temperature defined in **ASME 831.3** and other code sections and is subject to the same rules relating to allowances for variations of pressure or temperature or both. Different components in the same piping system or circuit may have different design temperatures. In establishing the design temperature, consideration shall be given to process fluid temperatures, ambient temperatures, heating and cooling media temperatures, and insulation.

11. An **examiner** is a person who assists the inspector by performing specific nondestructive examination (NDE) on piping system components but does not evaluate the results of those examinations in accordance with **API 570**, unless specifically trained and authorized to do so by the owner or user. The examiner need not be qualified in accordance with **API 570** or be an employee of the owner or user but shall be trained and qualified in the applicable procedures in which the examiner is involved. In some cases, the examiner may be required to hold other certifications as necessary to satisfy owner or user requirements. Examples of other certification that may be required are American Society for Non-Destructive Testing **SNT-TC-1 A** or **CP 189** or American Welding Society Welding Inspector certification. The examiner's employer shall maintain certification records of the examiners employed,

including dates and results of personnel qualifications, and shall make them available to the inspector.

12. **Hold point** is a point in the repair or alteration process beyond which work may not proceed until the required inspection has **been** performed and documented.

13. **Imperfections** are flaws or other discontinuities noted during inspection that may be subject to acceptance criteria during an engineering and inspection analysis.

14. An **indication** is a response or evidence resulting from the application of a nondestructive evaluation technique.

15. **Injection points** are locations where relatively small quantities of materials are injected into process streams to control chemistry or other process variables. Injection points do not include locations where two process streams join (mixing tees). Examples of injection **points** include **chlorine in reformers**, **water injection in overhead systems**, **polysulfide injection in catalytic cracking wet gas**, **antifoam** injections, inhibitors, and neutralizers.

16. In-service **refers** to piping systems that have been placed in operation, as opposed to new construction prior to being placed in service.

17. The term **inspector** refers to an authorized piping inspector.

18. A **jurisdiction** is a legally constituted government administration that may adopt rules relating to piping **systems**.

19. A level bridle is a level gauge **glass** piping assembly attached to a vessel.

20. **The maximum allowable working pressure (MAWP)** is the maximum internal pressure permitted in the piping system for **continued operation at the most severe condition** of coincident internal or external pressure, and temperature (minimum or maximum) expected during service. It is the same as the design pressure, as defined in **ASME B3 1.3** and other code sections, and is subject to the same rules relating to allowances for variations of pressure or temperature or both.

21. A **mixing tee** is a piping component that combines two process streams of differing composition and/or temperature.

22. MT stands for magnetic-particle testing.

23. **NDE is nondestructive examination.**

24. **NPS** means nominal pipe size (followed, when appropriate, by the specific **size** designation **number** without an inch symbol).

25. **On-stream** refers to piping containing any amount of process fluid.

26. An **owner-user** is an owner or user of piping systems who exercises **control** over the operation, engineering, in-

spection, repair, alteration, testing, and **rerating** of those piping systems.

27. An **owner-user inspector** is an authorized inspector employed by an owner or user.

28. **PT** is short for **liquid-penetrant** testing.

29. **Pipe** refers to a pressure-tight cylinder **used** to convey a fluid or to transmit a fluid pressure and is ordinarily designated **"pipe"** in applicable material **specifications**. (Materials designated "tube" or "tubing" in the specifications are treated as pipe when intended for pressure service.)

30. A **piping circuit** is a section of piping that has all parts exposed to an environment of similar corrosivity and that is of similar design conditions and construction material. Complex process units or piping systems are divided into piping circuits to manage the necessary inspections, calculations, and record keeping. When establishing the boundary of a particular piping circuit, the inspector may also size it to provide a practical package for record keeping and performing field inspection.

31. **The piping engineer shall be one of more persons** or organizations acceptable to the owner or user who are knowledgeable and experienced in the engineering disciplines associated with evaluating mechanical and material characteristics affecting the integrity and reliability of piping components and systems. The piping engineer, by consulting with appropriate specialists, **should be** regarded as a composite of all entities necessary to properly address a technical requirement.

32. **Piping system** refers to an assembly of **interconnected** piping that is subject to the same set or sets of **design** conditions and is used to convey, distribute, mix, separate, discharge, meter, **control**, or snub fluid flows. Piping system also includes pipe-supporting elements but does not include support structures, such as **structural** frames and foundations.

33. **Primary process piping** is process piping in normal, active service **that** cannot be valved off or, if it were valved off, would significantly affect unit operability. Primary process piping normally includes all process piping greater than **NPS 2**.

34. **PWHT** stands for **postweld** heat treatment.

35. Renewal is activity that discards an existing component and replaces it with new or existing spare materials of the same or better qualities as the original component.

36. A **repair** is the work necessary to restore a piping system to a condition suitable for safe operation at the design conditions. **If** any of the restorative changes result in a change of design **temperature** or pressure, the **requirements for rerating** also shall be satisfied. Any welding, cutting, or grinding operation on a pressure-containing piping component not specifically considered an alteration is considered a repair.

37. A **repair organization** refers to any of the following:

- a. An owner or user of piping systems who repairs or **alters** his or her own equipment in accordance with API 570.
- b. A contractor whose qualifications are acceptable to the owner or user of piping **systems** and who **makes** repairs or alterations in accordance with API 570.
- c. One who is authorized by, acceptable to, or otherwise not **prohibited** by the jurisdiction and who makes repairs in accordance with API 570.

38. **Rerating** is a change in either or both the design temperature or the maximum allowable working pressure of a **piping system**. A rerating may consist of an increase, a decrease, or a combination of both. Derating below original design conditions is a means to provide increased corrosion allowance.

39. **Secondary process piping** is small-bore (less than or equal to NPS 2) process piping downstream of normally closed **block valves**.

40. **Small-bore piping (SBP)** is piping that is less than or equal to NPS 2.

41. **Soil-to-air (S/A)** interface is an area in which external corrosion may occur on partially buried pipe. The zone of the corrosion will vary depending on factors such as moisture, oxygen content of the soil, and operating **temperature**. The zone generally is considered to be from 12 inches

(305 millimeters) **below** to 6 inches (152 millimeters) above the soil surface. **Pipe running** Parallel with the soil surface that contacts the soil is included.

42. Spool refers to a section of **piping** encompassed by flanges or other connecting fittings such as unions.

43. **Temper embrittlement** is defined as a loss of ductility and notch toughness in susceptible low-alloy **steels, such as 1% Cr and 2¼ Cr**, due to prolonged exposure to **high-temperature service [700°F to 1070°F (370°C to 575°C)]**.

44. **Temporary repairs** are repairs made to piping systems in order to **restore** sufficient integrity to **continue safe operation** until permanent repairs can be scheduled and accomplished within a time **period acceptable to the inspector or piping engineer**.

45. A **test point** is an area defined by a circle having a diameter **not** greater than 2 inches (50 millimeters) for a line diameter not exceeding 10 inches (254 millimeters), or not greater than 3 inches (76 millimeters) for larger lines. **Thickness** readings may be averaged within this area. A test point **shall** be within a thickness measurement location.

46. **Thickness measurement locations (TMLs)** are designated areas on piping systems where periodic inspections and thickness **measurements** are conducted.

47. **WFMT** stands for **wet fluorescent magnetic-particle testing**.

APPENDIX B-INSPECTOR CERTIFICATION

This appendix is reserved for **future** material to be appended to this document.

APPENDIX C-TECHNICAL INQUIRIES

C.1 Introduction

API will consider written requests for interpretations of API 570. API staff will make such **interpretations** in writing **after consultation, if necessary, with** the appropriate **committee** officers and **the committee** membership. The **API** committee **responsible** for maintaining API 570 meets regularly to consider written requests for interpretations and revisions **and** to develop new criteria as dictated by technological development. The committee's activities in this regard are limited strictly to interpretations of API 570 or **to** the consideration of revisions to API 570 based on the new data or technology. As a matter of policy, API **does not approve, certify,** rate, or endorse any item, construction, proprietary device, or **activity**; and accordingly, inquiries requiring such consideration will be returned. Moreover, API does not act as a consultant on specific engineering problems or **on** the general **understanding** or application of the rules. If, **based** on the inquiry information submitted, it is the opinion of the committee that the inquirer should seek engineering or technical assistance, **the inquiry will be** returned with the recommendation that such assistance **be** obtained.

All inquiries that **do not** provide the information needed for full understanding will be returned.

C.2 Inquiry Format

Inquiries shall be limited strictly to requests for interpretation of API 570 or to the consideration of revisions to API 570 based on new data or technology. Inquiries shall be submitted in the following format:

- a. Scope-The **inquiry** shall involve a single subject or closely related **subjects**. An inquiry letter concerning unrelated subjects will be returned.
- b. Background--The inquiry letter shall state the purpose of the inquiry, which shall be either to obtain an interpretation of API 570 or to propose consideration of a revision to API 570. The letter shall provide concisely the information needed for complete understanding of the inquiry (with sketches, as necessary) and include references to the applicable edition, revision, paragraphs, figures, and tables.
- c. Inquiry-The inquiry shall be **stated** in a condensed and precise question format, omitting superfluous background information and, where appropriate, composed in such a way that "yes" or "no" (perhaps with provisos) would be a suitable reply. This inquiry statement should be technically and editorially **correct**. The inquirer shall state what he or she believes API 570 requires. If in the opinion of the inquirer a revision **to** API 570 is needed, the inquirer shall provide recommended wording.

Submit the inquiry in typewritten form; however, legibly handwritten inquiries will be **considered**. Include the name and the mailing address of the inquirer. Submit the proposal to the following address: Director, Manufacturing, Distribution and Marketing Department, American Petroleum Institute, 1220 L Street, **N.W.**, Washington, D.C. 20005.

APPENDIX D-EXAMPLES OF REPAIRS

D-1 Repairs

Manual welding utilizing the gas metal-arc or shielded metal-arc processes may be used. When the temperature is below 50°F (10°C), low-hydrogen electrodes, AWS E-XX16 or **E-XX18**, shall be used when welding materials conforming to ASTM A-53, Grades A and B; A-106, Grades A and B; A-333; A-334; API SL; and other similar material. These **electrodes** should also be used on lower grades of material when the temperature of the material is below **32°F (0°C)**. The piping engineer should be consulted for cases involving different materials.

When AWS E-XX 16 or E-XX 18 electrodes are used on weld numbers 2 and 3 (see Figure D-1 below), the beads shall be deposited by starting at the bottom of the assembly and welding upward. The diameter of these electrodes should not exceed $\frac{3}{8}$ inch (4.0 millimeters). Electrodes huger that $\frac{3}{8}$ inch (4.0 millimeters) may be used on weld number 1 (see **Figure D-1**), **but the diameter should not exceed $\frac{3}{4}$ inch (4.8 millimeters)**.

The longitudinal welds (number **1**, Figure D-1) on the reinforcing sleeve shall be fitted with a suitable tape or mild steel backing strip (see note) to avoid fusing the weld to the side wall of the pipe.

Note: If the original pipe along weld number 1 has been checked thoroughly by ultrasonic methods and it is of sufficient thickness for welding, a backing strip is not necessary.

All repair and welding procedures for on-stream lines must conform to API Publication 220 1.

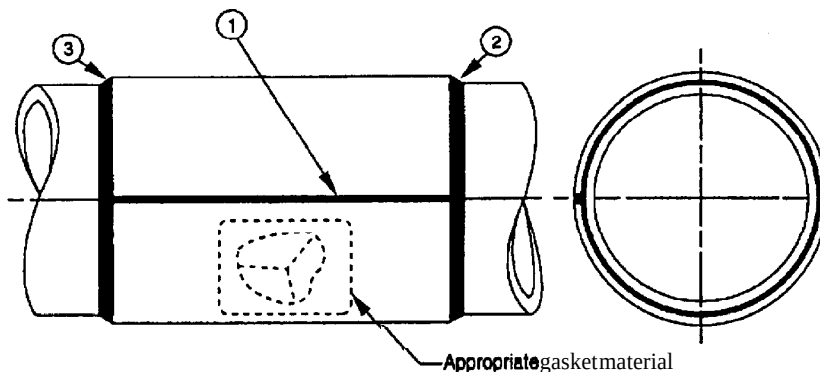


Figure D-1-Encirclement Repair Sleeve

(text continued on page D-2)

D-2 Small Repair Patches

The diameter of electrodes should not exceed $\frac{3}{8}$ inch (4.0 millimeters). When the temperature of the base material is below **32°F** (0°C), low-hydrogen **electrodes** shall be used. **Weaving** of weld beads deposited with low-hydrogen electrodes should be avoided.

All repair and welding procedures for on-stream lines must conform to API **Publication 2201**.

Examples of small repair patches are shown below in Figure D-2.

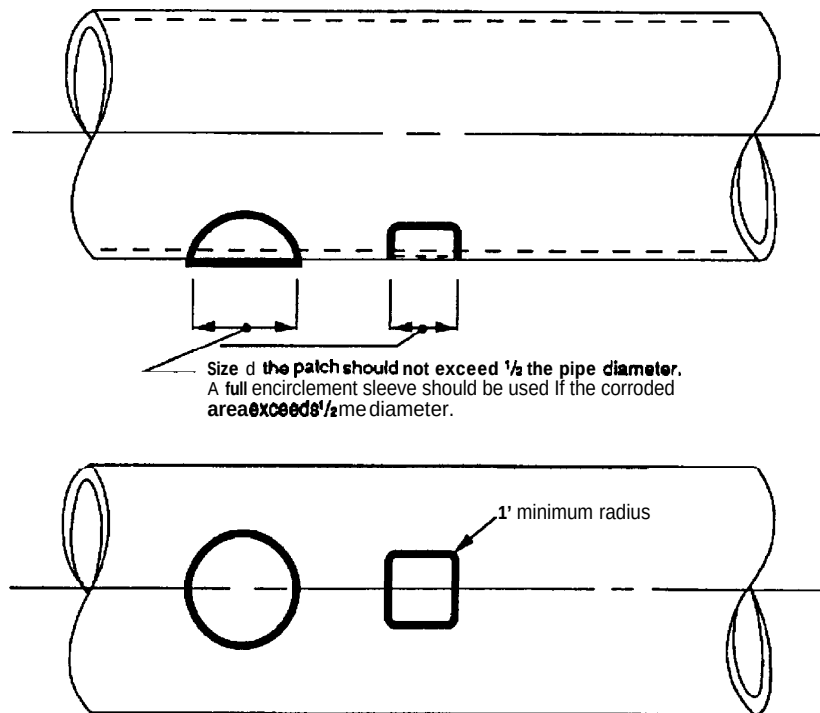


Figure D-2-Small Repair Patches

APPENDIX E-EXTERNAL INSPECTION CHECKLIST FOR
PROCESS PIPING

EXTERNAL INSPECTION CHECKLIST FOR PROCESS PIPING

Hem	Date Inspected	Inspected By	status
1. Leaks			
a. Process			
b. Steam Tracing			
c. Existing Clamps			I--
2. Misalignment			
a. Piping misalignment/restricted movement			
b. Expansion joint misalignment			
3. Vibration			
a. Excessive overhung weight			
b. Inadequate support			
c. Thin, small-bore, or alloy piping			
d. Threaded connections			
e. Loose supports causing metal wear			
4. Supports			
a. Shoes off support			
b. Hanger distortion or breakage			
c. Bottomed out springs			
d. Brace distortion/breakage			
e. Loose brackets			
f. Slide plates/rollers			
g. Counter balance condition			
h. Support corrosion			
5. Corrosion			
a. Bolting support points under clamps			
b. Coating/Painting deterioration			
c. Soil-to-air interface			
d. Insulation interfaces			
e. Biological growth			
6. Insulation			
a. Damage/penetrations			
b. Missing jacketing/insulation			
c. Sealing deterioration			
d. Bulging			
e. Banding (broken/missing)			

API RP*570 93 0732290 0513455 974

Order No 22-57000

1-1400—8/93—2.5M (1E)

American Petroleum Institute
1220 L Street Northwest
Washington, D.C. 20005



DP&Vels

TABLE II
Comparison of Refinery Crude Unit Overhead Operating Conditions

Refinery	Crude Charge Rate M3/Hr.	Total Ovhd. Rate M3/Hr.	Tail Water Rate M3/Hr.	Inject. Water Rate M3/Hr.	Tower Top Press. Kg/cm2	Tower Top Temp. deg. C	Ovhd. Line Diam. ins.	Ovhd. Vapor Velocity ft./sec.	Ovhd. Vapor D.P. Margin deg. C	State of Sat. Downstream of Inject.
YANBU	1556	358	20	19	0.7-1.95	110-140	30	>100 (2)	18-27	Sat.
RTR	2185	781	19	25	1.1	130	48	84	41	Undersat.
RIYADH	728	148	5.4	4.4	1.1	131	30	43	26	Undersat.
JEDDAH	285	100	4.2	5	0.8-1.3	117-128	20	78->100 (1)	33-37	Undersat.
RABIGH	2649	702	38	Intermitt.	1.1-1.6	114-127	44	100	16-24 (3)	N/A

Notes:

- (1) Range of velocities is upstream-downstream of water wash at stated overhead rates.
 (2) Corresponds to 54 MBPD net ovhd. product w/ tower top pressure of 1.3 Kg/cm2.
 (3) Low end of range corresponds to low crude charge rate and high steam rates.