Inspection of Fired Boilers and Heaters

RECOMMENDED PRACTICE 573
SECOND EDITION, FEBRUARY 2003

American Petroleum Institute

**Helping You
Get The Job
Done Right.**[SM]

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Downstream Segment

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Inspection of Fired Boilers and Heaters

1 Scope

This recommended practice covers the inspection practices for fired boilers and process heaters (furnaces) used in petroleum refineries and petrochemical plants. The practices described in this document are focused to improve equipment reliability and plant safety by describing the operating variables which impact reliability, and to ensure that inspection practices obtain the appropriate data, both on-stream and off-stream, to assess current and future performance of the equipment.

2 References

To the extent specified in this recommended practice, the most recent edition or revision of the following standards, codes, and specifications shall form a part of this recommended practice:

API

Std 530	*Calculation of Heater Tube Thickness in Petroleum Refineries*
RP 534	*Heat Recovery Steam Generators*
RP 535	*Burners for Fired Heaters in General Refinery Services*
RP 556	*Fired Heaters and Steam Generators*
Std 560	*Fired Heaters for General Refinery Services*
RP 572	*Inspection of Pressure Vessels, Heat Exchangers, Condensers, and Coolers*
RP 576	*Inspection of Pressure Relieving Devices*
RP 578	*Material Verification Program for New and Existing Alloy Piping Systems*
RP 579	*Fitness-For-Service*
RP 580	*Risk Based Inspection*

Guide for Inspection of Refinery Equipment, Chapter II, "Conditions Causing Deterioration or Failures"

> Note: This publication is out of print. To obtain a copy please inform the person taking your order that you require this publication for the API 510 Inspector Certification Exam.

AISC[1]

M015L	*Manual of Steel Construction, Load and Resistance Factor Design*
M016	*Manual of Steel Construction, Allowable Stress Design*

ASME[2]

B16.9	*Factory-Made Wrought Steel Buttwelding Fittings*
B16.28	*Wrought Steel Buttwelding Short Radius Elbows and Returns*
B31.1	*Power Piping*
B31.2	*Fuel Gas Piping*
B31.3	*Chemical Plant and Petroleum Refinery Piping*
B31.4	*Liquid Transportation Systems for Hydrocarbons, Liquid Petroleum Gas, Anhydrous Ammonia, and Alcohols*
B31.5	*Refrigeration Piping*
B31.8	*Gas Transmission and Distribution Piping Systems*
B31.9	*Building Services Piping*
B31.11	*Slurry Transportation Piping Systems*
B31 Guide	*Corrosion Control for ANSI3 B31.1 Power Piping Systems*
B31G	*Manual for Determining the Remaining Strength of Corroded Pipelines: A Supplement to B31, Code for Pressure Piping*

ASME Boiler and Pressure Vessel Code

Section I	*Power Boilers*
Section IV	*Heating Boilers*
Section VI	*Recommended Rules for Care and Operation of Heating Boilers*
Section VII	*Recommended Guidelines for Care of Power Boilers*

NB[3]

NB-23	*National Board Inspection Code*

ASTM[4]

A 297	*Steel Castings, Iron-Chromium and Iron-Chromium-Nickel, Heat-Resistant, for General Application*

NACE[5]

RP0170	*Protection of Austenitic Stainless Steel From Polythionic Acid Stress Corrosion Cracking During Shutdown of Refinery Equipment*

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3   Definitions

3.1   anchor: A metallic or refractory device that holds the refractory or insulation in place.

3.2   applicable code: The code, code section or other recognized and generally accepted engineering standard or practice to which the system/equipment was built or which is deemed most appropriate for the situation.

3.3   arch: A flat or sloped portion of the heater radiant section opposite the floor.

3.4   attemperator: An apparatus for reducing and controlling the temperature of a superheated steam.

3.5   backup layer: Any refractory layer behind the hot face layer.

3.6   breeching: The heater section where the flue gases are collected after the last convection coil for transmission to the stack or the outlet duct work.

3.7   bridgewall: A division or gravity wall which separates two adjacent heater zones.

3.8   butterfly damper: A single-blade damper pivoted about its center.

3.9   casing: The metal plate used to enclose the fired heater.

3.10   castable: An insulating concrete poured or gunned in place to form a rigid refractory shape or structure.

3.11   ceramic fiber: A fibrous refractory insulation composed primarily of silica and alumina that can comes in various forms like blanket, board, module, rigidized blanket, and vacuum-formed shapes.

3.12   chelate: An organic compound used in boiler water treatments which bonds with free metals in solution. Chelates help prevent metals from depositing upon tube surfaces.

3.13   convection section: The portion of the heater in which the heat is transferred to the tubes primarily by convection.

3.14   corbel: A projection from the refractory surface generally used to prevent flue gas bypassing the convection section tubes.

3.15   corrosion allowance: The additional metal thickness added to allow for metal loss during the design life of the component. It is the corrosion rate times tube design life, expressed in inches or millimeters.

3.16   corrosion rate: The reduction in the material thickness due to the chemical attack from the process fluid or flue gas or both, expressed in mils per year or millimeters per year.

3.17   crossover: The interconnecting piping between any two heater coil sections.

3.18   damper: A device for introducing a variable resistance for regulating volumetric flow of gas or air.

3.19   downcomer: Boiler tubes where the fluid flow is away from the steam drum.

3.20   duct: A conduit for air or flue gas flow.

3.21   economizer: A section of the boiler where incoming feedwater temperature is raised by recovery of the heat from flue gases leaving the boiler.

3.22   erosion: A reduction in material thickness due to mechanical attack from a fluid, expressed in inches or millimeters.

3.23   examiner: A person who performs specific NDE on equipment but does not evaluate the results of those examinations, unless specifically trained and authorized to do so by the owner or user. The examiner may be required to hold certificatioins as necessary to satisfy the owner or user requirements. Examples of other certification are American Society for Nondestructive Testing SNT-TC-1A.

3.24   extended surface: Refers to the heat transfer surface in the form of fins or studs attached to the heat absorbing surface.

3.25   fire tube boiler: A shell and tube heat exchanger in which steam is generated on the shell side by heat transferred from hot gas/fluid flowing through the tubes.

3.26   flue gas: The gaseous product of combustion including the excess air.

3.27   guillotine blind: A single blade device that is used to isolate equipment or heaters.

3.28   header or return bend: The common term for a 180-degree cast or wrought fitting that connects two or more tubes.

3.29   header box: The internally insulated structural compartment, separated from the flue gas stream, which is used to enclose a number of headers or manifolds. Access is afforded by means of hinged doors or removable panels.

3.30   heat pipe HRSG: A compact heat exchanger consisting of a pressure vessel and a bundle of heat pipes. The heat pipes extract heat from a hot fluid and transport it into a pressure vessel where steam is generated.

3.31   heat recovery steam generator (HRSG): A system in which steam is generated and may be superheated or water heated by the transfer of heat from gaseous products of combustion or other hot process fluids.

3.32   hot face layer: The refractory layer exposed to the highest temperatures in a multilayer or multicomponent lining.

3.33   ID: Inside diameter.

3.34   jurisdiction: A legally constituted government administration that may adopt rules relating to equipment.

3.35   louver damper: A damper consisting of several blades each pivoted about its center and linked together for simultaneous operation.

3.36   manifold: A chamber for the collection and distribution of fluid to or from multiple parallel flow paths.

3.37   monolithic lining: A single-component lining system.

3.38   mortar: A refractory material preparation used for laying and bonding refractory bricks.

3.39   MT: Refers to magnetic-particle testing.

3.40   mulitcomponent lining: A refractory system consisting of two or more layers of different refractory types; for example, castable and ceramic fiber.

3.41   NDE: Non-destructive examination.

3.42   OD: Outside diameter

3.43   on-stream: Equipment in operation containing process liquids/gases such that entry would not be possible.

3.44   PASCC: Polythionic acid stress corrosion cracking.

3.45   pass: A flow circuit consisting of one or more tubes in series.

3.46   pilot: A smaller burner that provides ignition energy to light the main burner.

3.47   plenum: A chamber surrounding the burners that is used to distribute air to the burners or reduce combustion noise.

3.48   plug header: A cast return bend provided with one or more openings for the purpose of inspection, mechanical tube cleaning, or draining.

3.49   protective coating: A corrosion-resistant material applied to a metal surface; for example, on casing plates behind porous refractory materials to protect against sulfur in the flue gases.

3.50   PT: Liquid penetrant testing.

3.51   radiant section: Portion of the heater in which heat is transferred to the tubes, primarily by radiation.

3.52   repair: Work necessary to restore equipment to a condition of safe operation at the design conditions.

3.53   riser: Boiler tubes where the fluid flow is toward the steam drum.

3.54   SCC: Stress corrosion cracking.

3.55   setting: The heater casing, brickwork, refractory, and insulation, including the tiebacks or anchors.

3.56   sootblower: A mechanical device for discharging steam or air to clean heat-absorbing surfaces.

3.57   spoilers: See strakes.

3.58   stack: A vertical conduit used to discharge flue gas to the atmosphere.

3.59   strakes: The metal stack attachments that prevent wind-induced vibration.

3.60   target wall: A vertical refractory firebrick wall which is exposed to direct flame impingement on one or both sides.

3.61   terminal: A flanged or welded projection from the coil providing for inlet or outlet of fluids.

3.62   thickness monitoring location (TML): Designated areas on equipment where periodic inspections and thickness measurements are conducted.

3.63   tieback: See anchor.

3.64   TOFD: Time-of-flight diffraction ultrasonic inspection technique.

3.65   tube guide: A component which restricts the horizontal movement of vertical tubes while allowing the tube to expand axially.

3.66   tube support: Any device used to support tubes such as hangers or tubesheets.

3.67   tubercles: Localized corrosion product appearing in the form of knob-like mounds covering pits often associated with oxygen corrosion in boiler systems.

3.68   vapor barrier: A metallic foil placed between layers of refractory as a barrier to flue gas flow.

3.69   vertical shell and tube watertube HRSG: A shell and tube heat exchanger in which steam is generated in the tubes by heat transferred from a hot fluid on the shell side.

3.70   water tube boiler: A multiple tube circuit heat exchanger within a gas-containing casing in which steam is generated inside the tubes by heat transferred from a hot gas flowing over the tubes.

3.71   water tube low pressure casing HRSG: A multiple tube circuit heat exchanger within a gas-containing casing in which steam is generated inside the tubes by heat transferred from a hot gas flowing over the tubes.

3.72   water tube pipe coil HRSG in a pressure vessel: A tube or pipe coil circuit within a pressure vessel in which steam is generated inside the tubes by heat transferred from a high-temperature fluid or fluidized solids surrounding the tube circuits.

3.73   WFMT: Wet fluorescent magnetic-particle testing.

3.74   windbox: See plenum.

4   Common Heater and Boiler Designs

4.1   TYPES OF HEATERS

4.1.1   General

There are a variety of designs for fired tubular heaters. Some of the more commonly used designs are the box, cylindrical, and cabin designs. Typical heater designs are represented in Figure 1. The tubes in the radiant section of the heater are called radiant tubes. The heat pickup in these tubes is mainly through radiation from the heating flame and the incandescent refractory. The shock or shield tubes are located at the entrance to the convection section. Because these tubes absorb both radiant and convective heat, they usually receive the highest heat flux.

Beyond the shock bank is the convection section where heat pickup comes from the combustion gases, primarily through convection. Convection tubes are commonly finned or studded to increase the surface area for heat transfer. Sometimes, the lowest rows of these extended surface tubes can absorb more heat per unit bare tube surface area than the radiant tubes.

4.1.2   Box-type Heaters

A box-type heater is a heater whose structural configuration forms a box. There are many different designs for box-type heaters. These designs involve a variety of tube coil configurations, including horizontal, vertical, and arbor configurations.

Figure 2 shows a typical box-type heater with a horizontal coil and identifies the main heater components. This type of heater can have locations or zones of different heat densities.

The size and arrangement of the tubes in a box-type heater are determined by the type of operation the heater is meant to perform; for example, crude oil distillation or cracking, the amount of heating surface required, and the flow rate through the tubes. Box-type heaters are usually updraft, with gas- or oil-fired burners located in the end or side wall, the floor or downdraft with the roof. After the process convection section tubes, auxiliary tubes are often added to preheat combustion air or to generate or superheat steam. In Figure 2, the convection section is centered in the upper portion of the box-type heater and the radiant tubes are on the two side walls.

4.1.3   Heaters with Vertical Coils

A vertical coil heater may be positioned cylindrical or in a rectangular (box-type heater). Most vertical coil heaters are bottom fired, with the stack mounted directly on top of the heater. Downdraft vertical heaters have also been used.

4.1.4   Heaters with Helical Coils

Helical coil heaters are cylindrical with the surface of the radiant section in the form of a coil that spirals up the wall of the heater. They do not usually have a convection section, but if one is included, the convection surface may be in the form of a flat spiral or a bank of horizontal tubes. The stack of a helical coil heater is almost always mounted directly on top of the heater.

4.1.5   Heaters with Arbor Coils

Heaters with arbor or wicket coils are used extensively in catalytic reforming units for preheat and reheat service and as heaters for process air or gases. These heaters have a radiant section that consists of inlet and outlet headers connected with inverted or upright L or U tubes in parallel arrangement. The convection sections consist of conventional horizontal tube coils.

4.1.6   Heaters Used in Steam/Methane Reforming

Heaters used in steam/methane reforming—the vaporized feed may vary in content from methane to any light hydrocarbon—usually have many rows of parallel vertical tubes that operate from 1500°F (816°C) to 1800°F (982°C). Figure 3 shows a steam/methane-reforming heater. These heaters are normally down fired from the roof or side fired at many levels to achieve even heat distribution across the entire length of the radiant tubes. The tubes may be made of wrought high-strength materials, including Alloy 800 and Alloy 800H, or of cast materials, including HK40, HP, and their proprietary modifications. Typically, small diameter pipe, called pigtails, connect the tubes to the inlet and outlet headers. Most outlet pigtails are of Alloy 800H or similar wrought materials since they operate at about 1400°F (760°C). Inlet pigtails operate at lower temperatures and can be a low Cr-Mo material.

Heater outlet headers have various designs. Some headers and outlet lines are made of carbon steel, C-Mo steel, or low-Cr-Mo steel and have refractory lining inside. Those that are internally uninsulated have been made of cast materials conforming to ASTM A 297, Grade HT or HK, or of wrought materials, including Alloy 800H.

4.1.7   Pyrolysis Heaters

Pyrolysis heaters are similar to steam/methane-reforming heaters. The same materials are often used for both. There are a few notable differences. Both Ys and U-bends are used in pyrolysis heaters and suffer erosion. The reaction in the tubes is usually carburizing and requires that the surfaces be smooth from boring or honing and that the material be more resistant to carburization. The material used in pyrolysis heat-

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A Box heater with arbor coil   **B** Cylindrical heater with helical coil   **C** Cabin heater with horizontal tube coil

D Box heater with vertical tube coil   **E** Cylindrical heater with vertical coil   **F** Box heater with horizontal tube coil

Figure 1—Typical Heater Types

ers is often a modification of a high-strength material that is adequate in reforming heaters.

4.1.8 Tube Metallurgy

The selection of materials for heater tubes is based on the design temperature and pressure of the tubes and the corrosivity of the process. The economics associated with the materials can not be overlooked as well. Suitable materials are evaluated looking at the total installed cost, including availability of the material, fabrication and heat treatment requirements.

Carbon steel, Cr-Mo steels, and austenitic stainless steels are common tube metallurgies. Carbon steel is limited to the low temperature applications. Many companies choose to limit carbon steel to applications below 800°F (427°C) to prevent problems from spheroidization and graphitization. The addition of chromium and molybdenum improve high-temperature strength, resistance to spheroidization, and resistance to oxidation and some corrosion mechanisms. Austenitic stainless steels are often used for tube applications where temperatures exceed about 1300°F (704°C) or the corrosivity of the process requires its use.

The common tube materials, corresponding ASTM tube or pipe specification, and the maximum design metal temperature limits per API Std 530 are listed in Table 1. The design
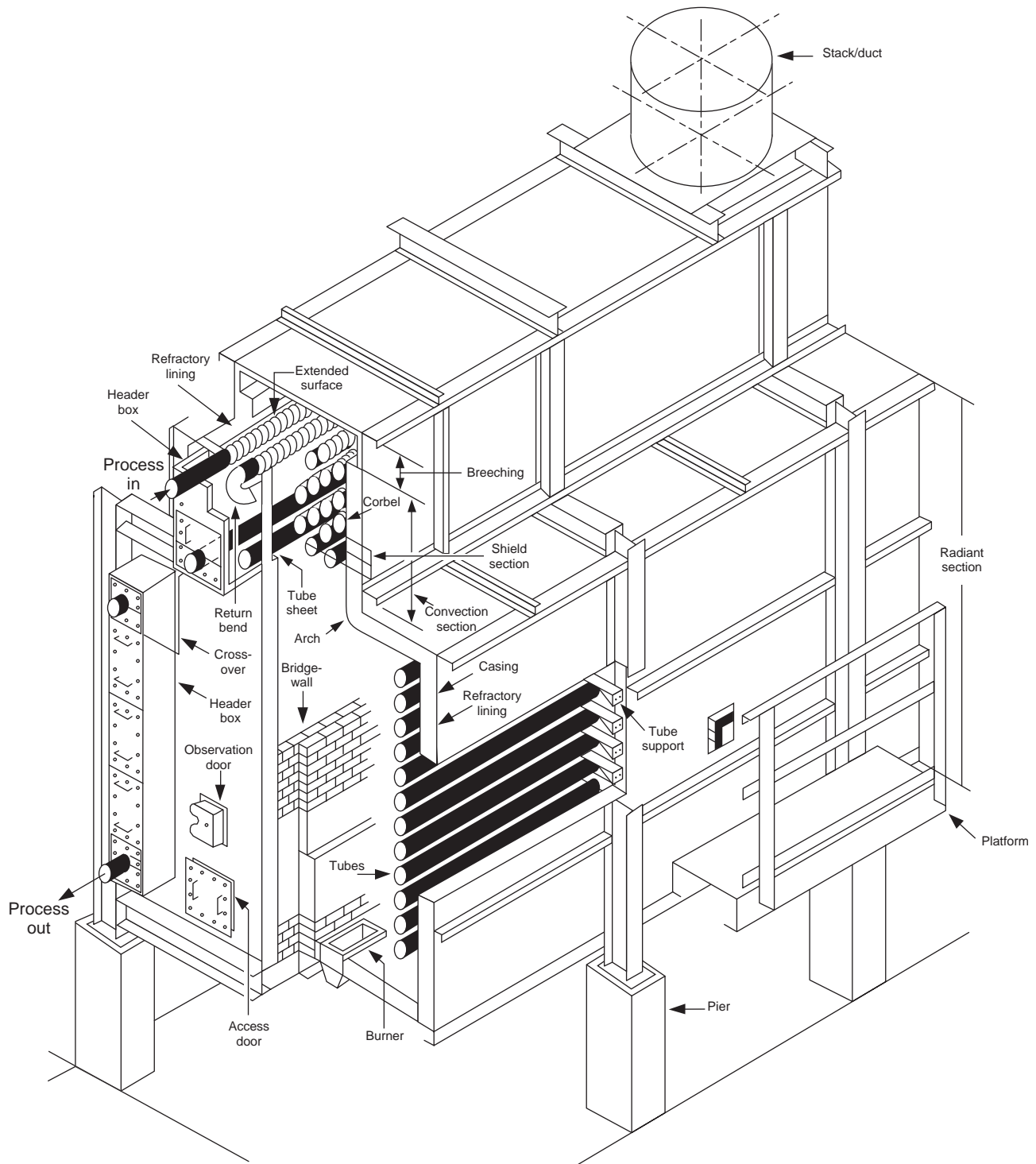
Figure 2—Box-type Heater with Horizontal Tube Coil Showing Main Components

Figure 3—Steam/Methane-reforming Heater

metal temperature shown is the upper limit for rupture strength. Tube wall calculations per API Std 530 should be completed to determine tube life at these temperatures. Other factors such as hydrogen partial pressure and resistance to oxidation often result in lower temperature limits.

4.2 TYPES OF BOILERS

4.2.1 General

Fired boilers are boilers in which fuel is burned in a combustion chamber associated with the boiler. The heat of combustion is absorbed by the boiler to heat the water and convert it to steam. Fired boilers that are most prevalent in industry are either fire tube boilers or water tube boilers.

4.2.2 Fire Tube Boiler

A fire tube boiler consists of a drum with a tube sheet on each end in which the fire tubes are fastened. Water is contained within the drum surrounding the fire tubes. Fuel is burned in a combustion chamber associated with the boiler and arranged in such a manner that the heat and products of combustion (flue gases) pass through the inside of the fire tubes to heat the water surrounding them. The combustion chamber may be a refractory-lined box located against one end of the drum or a steel chamber located within the drum

Table 1—Common Tube Metallurgies

Material	Seamless Tube Specification	Seamless Pipe Specification	Design Metal Temperature Limit Per API Std 530
Carbon steel		A106	1000°F
1-$\frac{1}{4}$Cr-$\frac{1}{2}$Mo	A213 T11	A335 P11	1100°F
2-$\frac{1}{4}$Cr-1Mo	A213 T22	A335 P22	1200°F
5Cr-$\frac{1}{2}$Mo	A213 T5	A335 P5	1200°F
9Cr-1Mo	A213 T9	A335 P9	1300°F
Type 304H	A213 TP304H	A312 TP304H	1500°F
Type 316	A213 TP 316	A312 TP 316	1500°F
Type 321	A213 TP 321	A312 TP 321	1500°F
Type 347	A213 TP347	A312 TP347	1500°F
HK		A351 HK-40	1850°F
HP		A297 HP	**

** HP alloy is not recognized in API Std 530.

and surrounded on all but one side by the water in the drum. In the first instance, the boiler may be described as externally fired; in the second, as internally fired.

Horizontal-return-tube boilers were popular in the early refineries. The Scotch marine boiler is of a fire tube design commonly employed in refinery package-type sulfur plants.

4.2.3 Water Tube Boiler

A water tube boiler usually has one or more drums and an external bank or banks of tubes connecting the two ends of the drum of a single-drum boiler or of the drums of a multi-drum boiler. In water tube boilers, the water is contained within the drums and tubes. The fuel is burned in a combustion chamber arranged so that radiant heat and convection heat is transferred to the outside of the water tubes to heat the water within.

Water tube boilers may be either straight tube boilers or bent tube boilers. The tubes of most straight tube boilers are connected into headers, which in turn are connected to the boiler drums. Water tube boilers are always used when large steam capacities are needed. They are also used for high pressures and temperatures. They have been built in sizes up to 5,000,000 lb. (2,268,000 kg) of steam per hour, at pressures up to 5000 psi gauge (34,474 kPa) and temperatures of up to approximately 1200°F (649°C).

Bent tube boilers are made in a variety of arrangements. They are similar to straight tube boilers, but they are almost always multidrum, and the tubes are connected directly into the boiler drums. The tubes are bent to allow them to enter the drums radially, to facilitate installation, to allow for expansion and contraction, and to allow for flexibility in design. Figures 4 and 5 illustrate typical bent tube boilers. Bent tube boilers may be either balanced draft boilers or positive pressure boilers.
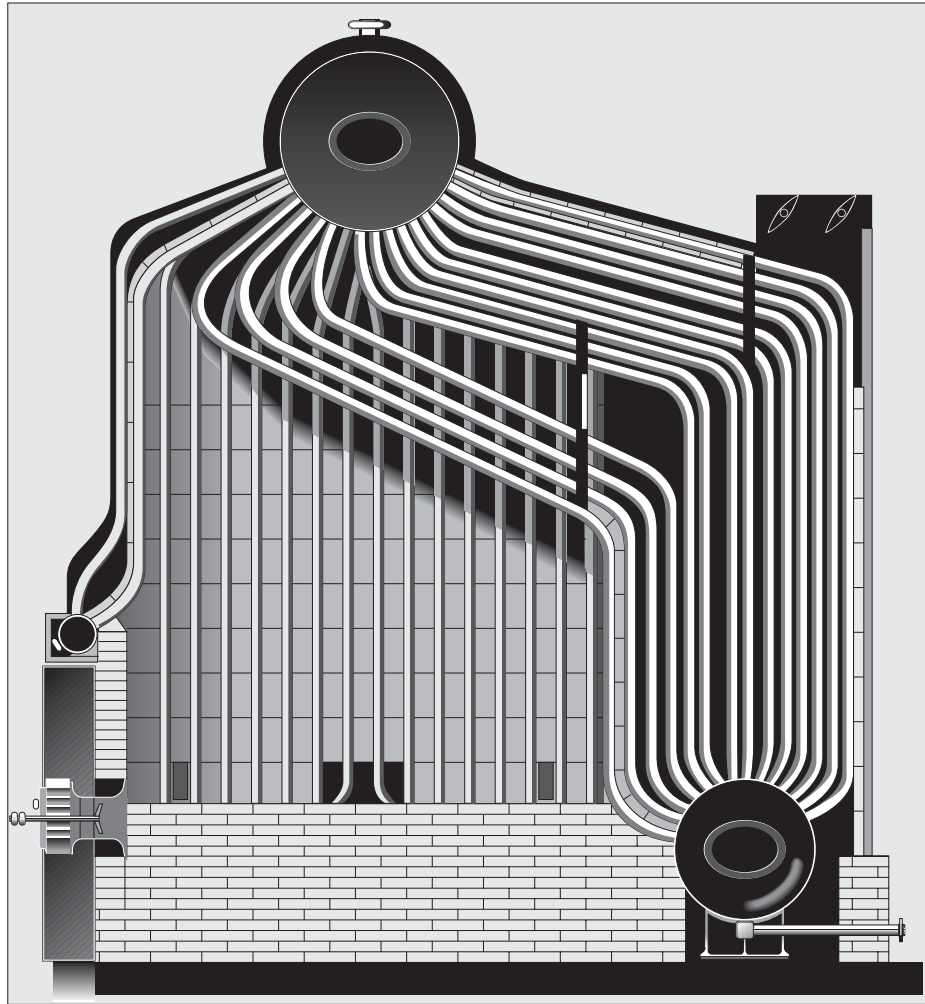
Figure 4—Typcial Vertical Oil- or Gas-fired Water Tube Boiler

Some boilers are fired using hot process waste gas streams, including fluid catalytic cracking unit (FCCU) regenerator flue gas as fuel to recover both sensible heat and fuel value. Carbon monoxide boilers can still be found in some refineries. Figure 6 illustrates one type of carbon monoxide boiler. Some refineries also use the combined cycle system, which utilizes the hot exhaust from gas turbines as combustion air in the boilers.

4.2.4 Waste Heat Boiler (Heat Recovery Steam Generators)

Waste heat boilers can be either a fire tube or water tube design and can have nearly identical configurations to their "fired" counterparts. However, waste heat boilers generate steam by transferring heat from high-temperature gaseous products of combustion or products of chemical reaction or other hot process fluids. These boilers can often be found on units with high-temperature streams and are used to recover the heat and cool the stream. They are described here simply because the types of deterioration and inspection are similar to the fired boilers.

4.2.5 Economizers and Air Preheaters

Economizers and air preheaters are heat exchangers used by some boilers as auxiliaries to recover more heat from the flue gases, heat that otherwise would be lost up the stack.

An economizer normally consists of a bank of tubes located in the path of the flue gases downstream of the steam-generating surfaces in the boiler. The low-temperature boiler feedwater is pumped through the tubes in this tube bank and is heated before passing into the boiler.

Air preheaters raise the temperature of air before it enters the combustion chamber. There are two basic types of air preheaters: recuperative and regenerative. The recuperative type is similar in principle to a conventional heat exchanger with the hot flue gases on one side of the heat transfer surface and the cool air on the other side. The most common recuperative type
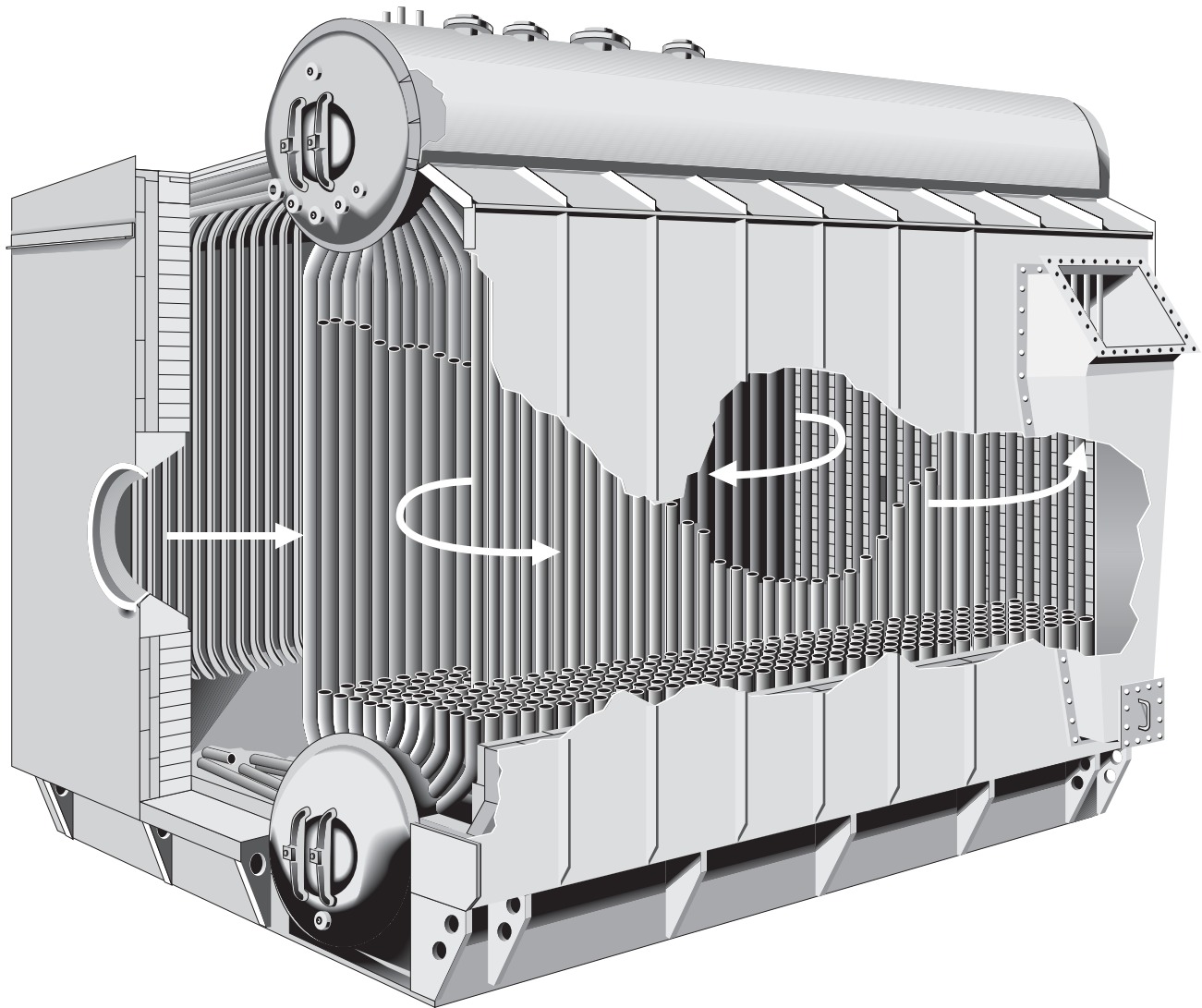
Figure 5—Another Variation of a Two-drum Bent Tube Boiler

is the tubular air preheater, which consists of a tube bank with the tubes rolled into a stationary tube sheet at the top of the unit and a floating tube sheet at the bottom. Flue gas flows on the outside of the tubes and air flows on the inside of the tubes. The use of a floating tubesheet accommodates the difference in expansion caused by temperature differences between the tubes and the casing. In this type, the hot gases flow through the tubes, and the air passes around the tubes. Another recuperative type is made up of plates arranged with passages for the flue gas on one side of the plates and passages for air on the other side. Figure 7 illustrates a recuperative type of air preheater.

The most common regenerative type is called a rotating heat transfer wheel and is made up of many closely spaced sheets of metal. This metal absorbs heat as it rotates through the flue-gas compartment of its housing and gives up heat as it rotates through the air compartment (see Figure 8). The heat transfer wheel is rotated at approximately 3 rpm by driving a

motor through a reduction gear. Diaphragms and seals divide the unit lengthwise to separate the hot flue gases from the air, which flow through the preheater in opposite directions.

The preheating of combustion air has high economic value. In the conventional air preheater, cold air from the forced-draft fan flows through the air preheater and extracts heat from the flue gases as they flow to the stack. Economizers or air preheaters are used when fuel savings justify them.

4.2.6 Superheaters

Superheaters consist of a bank of tubes located within the boiler setting, through which saturated steam flows from the steam drum and is superheated by the same flue gas that generates steam in the boiler. They may be of the radiant design, convection design, or a combination of both, depending on the manner in which heat is transferred from the heater gases to steam.
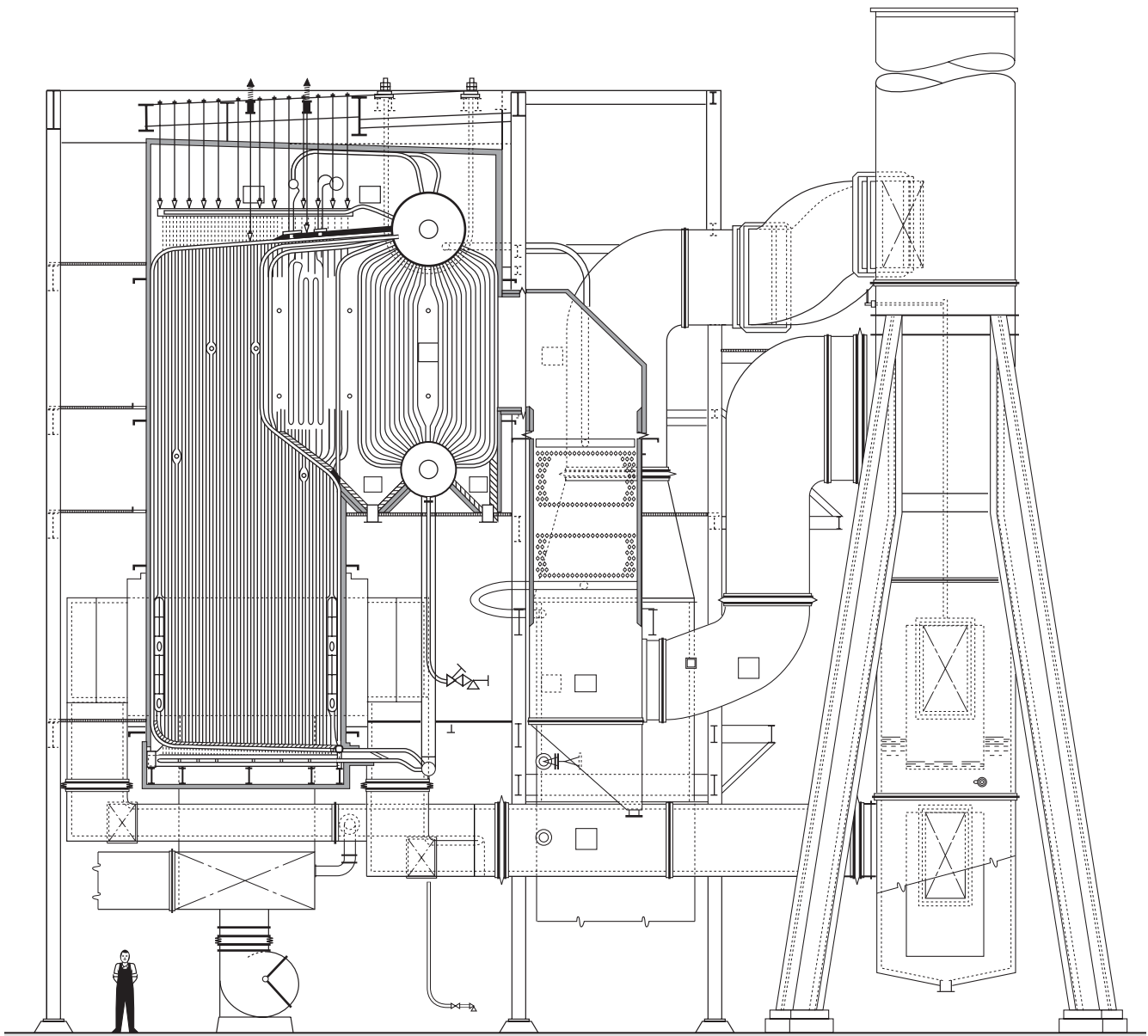
Figure 6—Typical Carbon Monoxide Boiler

Superheaters may have tubes in hairpin loops connected in parallel to inlet and outlet headers. They may also be of the continuous tube design in which each element has tube loops in series between inlet and outlet headers. In either case, they may be designed for drainage of condensate or may be in nondrainable pendent arrangements.

Nondrainable or pendent arrangements are very susceptible to tube failure due to overheating on start-up. Water collected in the pendent must be slowly vaporized to assure a flow path for the steam. If the boiler is heated too rapidly, some pendents will not clear of liquid; therefore, steam will not flow and the tube will overheat and fail. Special start-up instructions should be taken into consideration with this type of arrangement. Both straight and pendent arrangement superheaters are susceptible to failure due to steam impurities. When steam is used in processing operations, superheated steam may be required to obtain the desired process temperature. Most of the large-capacity, high-pressure steam generators, especially those used for power production, are equipped with superheaters.

Superheated steam is also necessary for the most efficient production of power, especially when used in high-pressure, high-speed steam turbine drives.

4.2.7 Tube Metallurgy

Boiler tubes are generally carbon steel, 1-$1/4$Cr-$1/2$Mo and 2-$1/4$Cr-1Mo steel. The material selection depends on the temperature and pressure of the application. Typically, the governing criteria is the oxidation rate of the material being evaluated. Carbon steel is often used in the water-filled and steam-generating tubes where the metal temperature is below 800°F (427°C). Tubes used in the steam superheat section can be higher alloys for improved strength and resistance to external oxidation. Again, the selection depends on the metal temperature and operating stress of the tube.

4.2.8 Flue Gas Stacks

Flue gas stacks vent the flue gas produced as part of the combustion process of the burners to the atmosphere. They are typically located directly above the heater or boiler or located nearby and connected to them by ductwork. Flue gas stacks are generally constructed of carbon steel and internally lined with refractory. The stack may have an organic coating to protect the steel from internal corrosion beneath the refractory lining. Stacks may be either self-supporting or guyed, and their height should be above that of nearby platforms.

5 Heater and Boiler Mechanical Reliability

5.1 RELIABILITY PROGRAMS

Reliability programs have evolved from inspection during unit maintenance outages to integrity management programs encompassing on-stream tube life monitoring, continual heater and boiler efficiency analyses and detailed and varied inspections during maintenance opportunities. In the simplest programs, heater and boiler reliability focus on preventing failures of the pressure boundary. The strategy is to prevent leaks and ruptures of the tubes and in the case of boilers, the drums too. Further refinements to these programs consider the operations of the heater and boiler and associated hardware to ensure they are operating optimally and at design levels. Oftentimes, poor performance or failure of associated hardware can lead to deterioration of the tubes.

Tube failures result from progressive deterioration from a variety of deterioration mechanisms. Therefore, one needs to understand the active and potential mechanisms in a particular heater and boiler in order to prevent them from causing a failure. For example, in elevated temperature services like boiler and heater tubes, creep and stress rupture are potential deterioration mechanisms. The tube operating variables which affect tube creep life/stress rupture life include: the base metal creep/stress rupture properties, tube metal temperatures, applied stress from internal operating pressure and from mechanical loading (i.e., from supports or lack of supports), and time operating at each unique combination of stress and metal temperature. Each deterioration mechanism
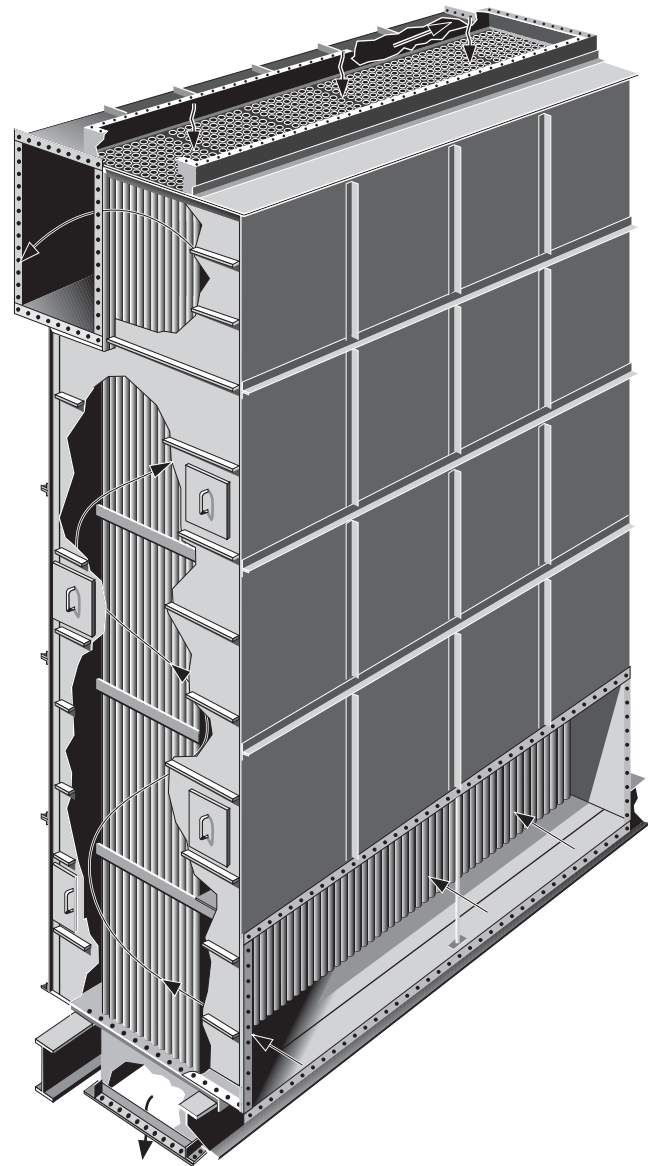
Figure 7—Tubular Air Preheater

should be understood similarly and will be discussed more fully in Section 6.

Tube reliability not only requires an understanding of the mechanisms by which the tubes can fail, but also requires data on how the previous operating history has impacted tube life, predictions of deterioration rate, how the future operation will impact tube life, and finally, monitoring of operations and deterioration to ensure the analyses and predictions are accurate and appropriate. Historically, inspection data gathered during outages assessed the immediate condition of the tubes with varying degrees of accuracy or success. Typical inspections included a visual examination for bulges in tubes and thickness measurements of accessible tubes. Now, inspections can also include detailed strapping/gauging for bulges, internal UT pigs to gather detailed tube wall thickness
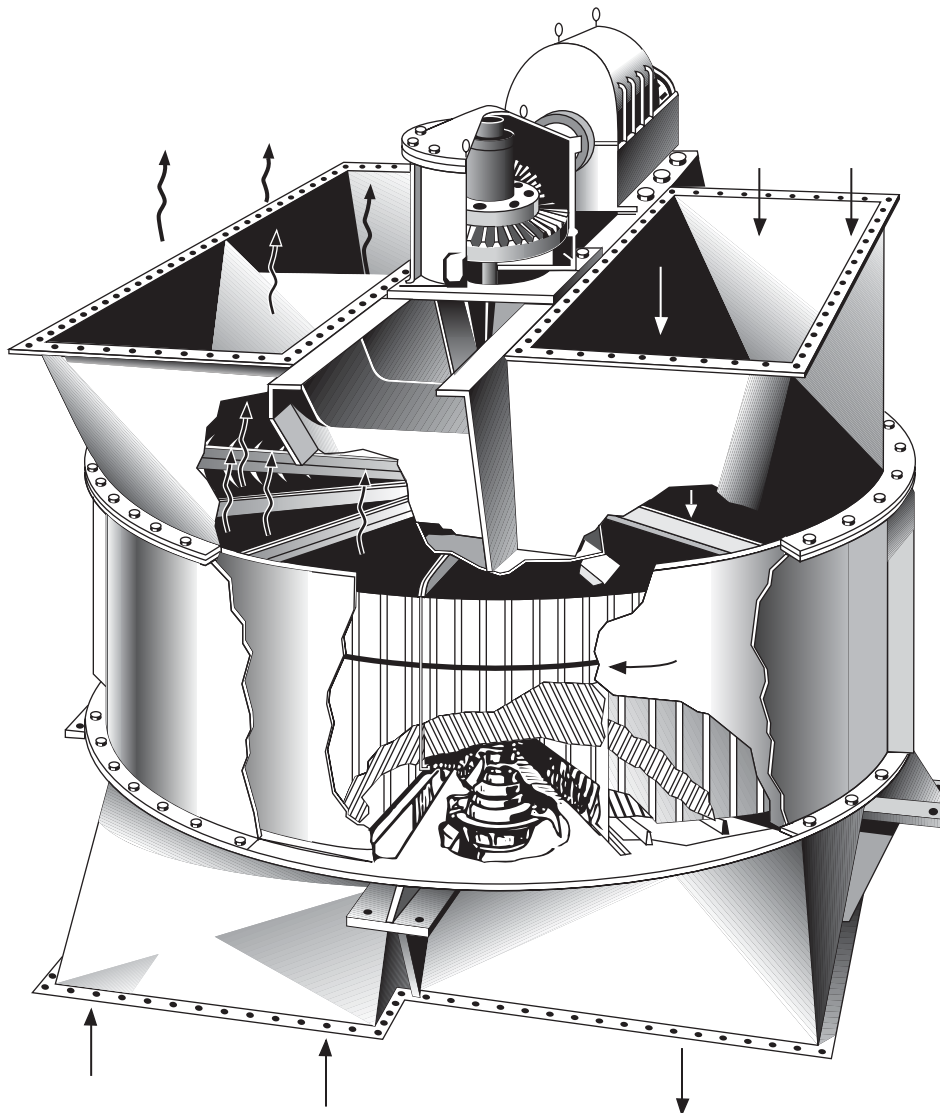
Figure 8—Regenerative Air Preheater

and diameter maps (including the difficult to inspect heater convective tubes), on-stream infrared tube temperature measurements, destructive testing to identify specific types of deterioration or to determine actual remaining creep life, to name a few.

Components of a typical tube reliability program for individual heaters and boilers include:

a. List of active and potential deterioration mechanisms.

b. Inspection techniques to identify whether the potential deterioration mechanisms are active.

c. Review of historical heater and boiler operations and maintenance repairs records to identify active or previously active deterioration mechanisms.

d. Assessment of previous operations and repairs impact on tube remaining life.

e. Defined tasks or procedures, if practical, to minimize the likelihood of potential damaging mechanisms.

f. Rate of deterioration of tubes for active deterioration mechanisms.

g. Method or technique to assess the impact of process changes or heater and boiler operations on rate of deterioration.

h. Assessment of remaining tube life for each mechanism considering previous operations and repairs, current condition and the rate of deterioration.

i. Defined operating boundaries in which the tube life and rate of deterioration projections remain valid.

j. On-stream monitoring tasks to ensure operating conditions remain within the boundaries and procedure to address or assess the impact on tube life of out-of-bounds operations.

k. Inspection plan and monitoring/assessment of other hardware and equipment that impact the deterioration of the tubes like burners, hangers and supports, and thermocouples.

5.2 SAFETY

A leak or failure in a heater can be a minor or a significant incident depending on the temperature, pressure, process fluid, location of the heater, response of operators and other controls. The process fluid is often flammable so a fire results. The potential for personnel injury and environmental impact certainly exists. Boilers, depending on their pressure, have the potential to cause injury due to the significant stored energy. Significant injuries and incidents have occurred from boiler failures. An inspection and reliability program for heaters and boilers is an important component to maintaining safe and environmentally responsible operations.

5.3 PURPOSE OF INSPECTION

The purpose of inspection in a reliability program is to gather data on the tubes and equipment so that it can be analyzed and a reasonable assessment made of the equipment's mechanical integrity for continued service. Repairs can be made if analyses of the data indicate that life is shorter than the planned run length. In addition, repairs or replacements can be predicted for the future by analyses of appropriate data accumulated at regular internal equipment inspections and during routine on-stream monitoring of actual service conditions. Planned repairs and/or replacements allow all necessary drawings, lists of materials, and work schedules to be prepared in the most effective manner. Necessary materials can be estimated and replacement parts either wholly or partly fabricated at the most convenient times prior to shutdown. If work schedules are properly prepared and reviewed, each craft will know exactly what has to be done and the sequence so that overall quality is improved.

5.4 INSPECTION OF FIRED BOILERS

The requirements governing inspection of boilers can differ widely from one location to another since they are often regulated by jurisdictions. Under some jurisdictions, inspections must be made by state, municipal, or insurance company inspectors. Other jurisdictions may allow inspections by qualified owner/user inspectors. In either case, the inspector is usually commissioned by the regulatory authority and must submit reports of the inspection to the official responsible for enforcement of the boiler law. If the boiler is insured, inspection by the insurance company inspector also serves to satisfy his company that the boiler is in an insurable condition.

Normally, governmental and insurance company inspectors concern themselves only with the pressure parts of the boiler, the safety valves, level indicators, pressure gauges, and feedwater and steam piping between the boiler and the main stop valves, superheaters, and economizers. The plant inspector should also be concerned with related nonpressure parts, including the furnace, burners, flue-gas ducts, stacks, and steam-drum internals since these can affect equipment reliabil-

ity and performance. When inspection by an outside agency is necessary, joint inspections by the outside inspector and the plant inspector can reduce the length of boiler outages and result in shared learnings. The outside inspector is primarily interested in seeing that minimum legal safety requirements are met. The plant inspector should be interested not only in safety but also in conditions that affects reliability and efficiency. The outside inspector has an opportunity to examine many boilers that operate under widely varying conditions and often can offer valuable advice on the safe operation of boilers.

5.5 INSPECTOR QUALIFICATIONS

Inspection of heaters should be performed by someone trained and experienced with heater operation, heater deterioration mechanisms and the appropriate inspection techniques to identify or monitor them. The inspector should have experience with or have access to an individual(s) with understanding of burners, tubes, tube hangers and supports, refractories, and overall heater operation. Examiners performing specific NDE procedures should 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 necessary to satisfy owner or user requirements. Examples of other certifications include American Society for Non-Destructive Testing SNT-TC-1A or American Welding Society Welding Inspection certification.

Certification of boiler inspectors may be governed by jurisdictions. Some jurisdictions may require the inspector to have a National Board of Boiler and Pressure Vessel Inspectors certification.

6 Deterioration Mechanisms

6.1 DETERIORATION OF HEATER TUBES

Heater tubes can experience deterioration both internally and externally. Typical mechanisms are described in the following subsections. Table 2 presents a summary of likely mechanisms for various refinery units.

6.1.1 Internal Tube Corrosion

Internal corrosion is predominantly influenced by the chemical composition of the process fluid, process and metal temperatures, fluid velocity and tube metallurgy. Some critical species include sulfur compounds and organic acids (naphthenic acid). The level of these species in the fluid influences the type and rate of corrosion on the internal surface of the heater tubes. Sulfur compounds in particular promote sulfidic corrosion, which can manifest itself as localized and general wall thinning. Similarly, corrosion from organic acid can appear localized in turbulent regions or general thinning in areas. The corrosion rate can be aggravated by other fluid components like chlorides, the type of sulfur compounds, and

Table 2—Deterioration Mechanisms Common to Specific Services

Unit	Tube Materials	Deterioration Mechanism	Comments
Crude Unit Atmospheric Section	5Cr-^{1}/2Mo 9Cr-1Mo Type 316 Type 317	Creep, external oxidation	Caused by abnormal operation, low flow, or flame impingement.
		Sulfidic corrosion Naphthenic acid corrosion	Caused by alloy content, inadequate to resist attack by the level of sulfur compounds and naphthenic acid.
Crude Unit Vacuum Section	5Cr-^{1}/2 Mo 9Cr-1Mo Type 316 Type 317	Creep, external oxidation	Caused by abnormal operation, low flow, or flame impingement.
		Sulfidic corrosion Naphthenic acid corrosion	Caused by alloy content, inadequate to resist attack by the level of sulfur compounds and naphthenic acids.
Delayed Cokers	5Cr-^{1}/2 Mo 9Cr-1 Mo Type 347	Carburization	Common problem in this service; can be detected by chemical spot tests.
		Creep, external oxidation	Excessive metal temperatures from internal coke formation, high duty, low flow, or flame impingement.
		Sulfidic corrosion	Caused by alloy content inadequate to resist attack by the level of sulfur compounds.
		Polythionic acid stress Corrosion cracking (Type 347)	Caused by polythionic acid corrosion of sensitized stainless steel.
Catalytic Hydrodesulfurizer	5Cr-^{1}/1Mo 9Cr-1Mo Type 321/347 SS	Creep, external oxidation	Caused by abnormal operation, low flow, or flame impingement.
		Polythionic acid stress Corrosion cracking	Caused by polythionic acid corrosion of sensitized stainless steel.
		Hydrogen/hydrogen sulfide Corrosion	Caused by alloy content inadequate to resist attack by the level of hydrogen/hydrogen sulfide.
Catalytic Reformer	1-^{1}/4Cr-^{1}/2Mo 2-^{1}/4Cr-1Mo 5Cr-^{1}/2Mo 9Cr-1Mo	Creep, external oxidation	Caused by abnormal operation, low flow, or flame impingement.
		Hydrogen attack	Caused by operation of tube materials above API RP 941 Nelson Curves.
		Metal dusting	Caused by high carbon activity and high-temperature operation. Occurs under specific conditions.
		Spheroidization	Probable in 1-^{1}/4Cr-^{1}/2Mo after long term service.
Catalytic Cracking Waste Heat Boiler	Carbon Steel 1-^{1}/4Cr-^{1}/2Mo 2-^{1}/4Cr-1Mo	Internal corrosion	Caused by inadequate or improper water quality.
		Creep, external oxidation	Caused by abnormal operation, low flow or flame impingement.
		External dew point corrosion	Caused by tubes metal temperatures operating below the flue gas dewpoint.
		Erosion	Caused by entrained catalyst in the flue gas.
Utilities—Boilers	Carbon Steel 1-^{1}/4Cr-^{1}/2Mo 2-^{1}/4Cr-1Mo	Internal corrosion	Caused by inadequate or improper water quality.
		Creep External oxidation	Caused by abnormal operation, low flow or flame impingement.

the presence of hydrogen. Sulfur compounds, in the presence of hydrogen, usually increase the corrosivity of the process.

Fluid and metal temperatures influence the corrosion rate. The highest tube metal temperature occurs at the fire side front face of the tube where the heat flux is greatest. The corrosion rate profile often follows the heat flux profile. Figure 9 shows an example of increased corrosion on the fire side of a tube. Differences in the corrosion rate along the length or around a cross section of a tube are often the result of temperature differences between locations. An example of temperature influence is the increase in corrosion rate with a rise in temperature to 750°F (399°C) for processes with sulfur com-

pounds. Above 750°F (399°C) the corrosion rate decreases due to stable sulfide scale that inhibits further corrosion. Figure 10 is a convection tube that failed from internal corrosion attributed to high-temperature sulfidic attack.

High-velocity fluids, fluids containing particulate, or tubes with two-phase flow can increase the corrosion rate by stripping away protective scale and exposing fresh metal to continue the corrosion process. Corrosion from organic acids and sulfur compounds are significantly influenced by fluid velocity. Particular attention should be given to high turbulent regions.

Tube failures resulting from corrosion are generally due to local stress rupture in which the wall thickness becomes too thin and is overstressed at the metal operating temperature. These failures can appear as small leaks through pits or as "fishmouth" ruptures if the thinning is general or if it is longitudinal grooving.

6.1.2 External Tube Corrosion

External corrosion of the tube depends on the heater atmosphere and temperatures. Generally, the external surface of the tube will corrode from oxidation. The heater atmosphere contains excess oxygen necessary for combustion of the fuel at the burners. Oxidation rates for a metal increase with increased temperature. Refer to API Std 530 for additional information on oxidation. Oxidation may either be a localized condition or extend over the entire length of the tube inside the heater. Excessive oxidation and scaling is usually the result of operating the tubes above recommended levels. This could be the result of overfiring the heater or internal fouling of the tubes, which increase the tube wall temperature. Combustion deposits may have the appearance of oxide scale, but they can be distinguished by checking them with a magnet. Oxide scales are magnetic, whereas combustion deposits are not.

Other types of corrosion attack are possible. Heaters operating with insufficient oxygen or fuel-rich can cause corrosion from the resulting reducing environment. Depending on the type and quality of the fuel, corrosion could occur from sulfidation or carburization. Acid attack can result from the combustion of heater fuels depending upon the sulfur content of the fuel. When the gas or fuel oil has a high sulfur content, one of the combustion products formed and deposited on the outside surfaces of the tubes is a sulfate. This sulfate is harmless during operational periods, but when the deposit is allowed to cool it becomes highly hygroscopic and absorbs moisture from the air, hydrolyzing to produce sulfuric acid, which corrodes the underlying metal. Figure 11 shows a tube exhibiting external corrosion from this type of attack.

When the fuel has a high vanadium content, metal at temperatures above a critical point in the range from 1200°F (649°C) to 1400°F (760°C) is subject to very rapid attack from low-melting vanadium based compounds. The vanadium compounds deposit on the hot metal surface, melt and act as a fluxing agent to remove the protective oxide scale on
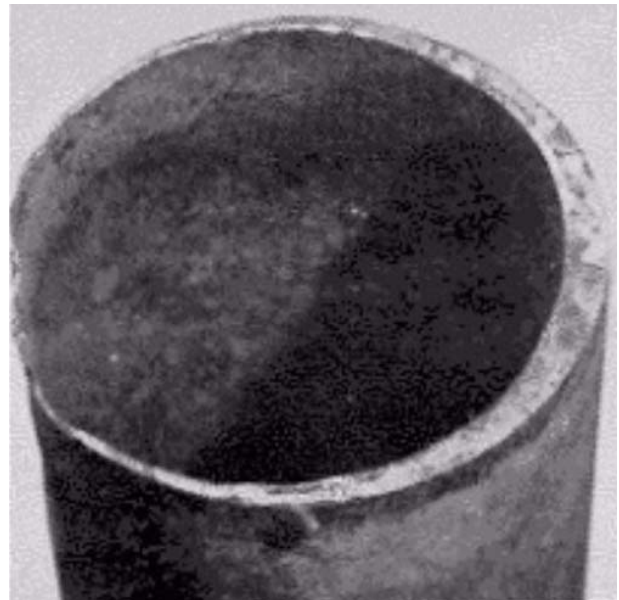
Figure 9—Fireside Face of Tube Severely Corroded
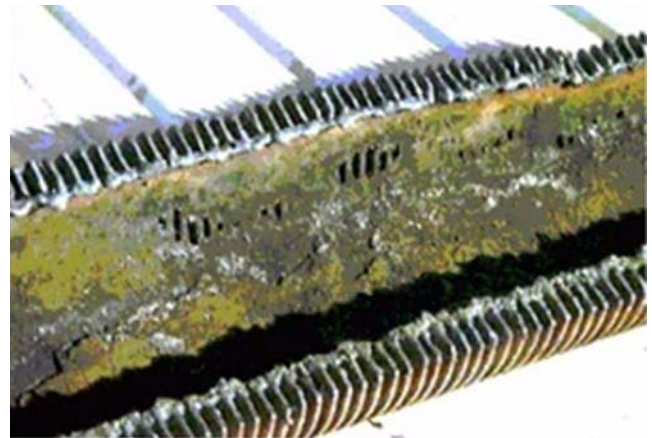
Figure 10—Convective Tube Failure from Internal, High-temperature Sulfidic Corrosion

the tubes The cycle repeats itself as oxide and deposit builds back up on the tube.

Convection sections where flue gas dew point temperatures occur during operations suffer metal loss because of acid material from the products of combustion. Metal loss on the exterior of convection tubes may be difficult to evaluate because of inaccessibility.

6.1.3 Creep and Stress Rupture

Creep and stress rupture are high-temperature mechanisms also dependent on the stress level and type of material. When the metal temperature is above the creep range and the metal is exposed to high enough stress, a straining of the metal occurs which can cause rupture after a long operating period. The strain rate of the metal increases with an increase in

Figure 11—General Metal Loss and Pitting of Tubes After Exposure to Moisture and Corrosive Deposits During Idle Periods

either temperature or stress. High-temperature overload is a rapid strain rate associated with short exposures to an extreme condition of very high temperature, or stress. With stress rupture, the metal is overstressed for the coincident temperature. Stress is usually associated with tube "hoop stress" due to the operating pressure; however, stress can also be longitudinal stress from inadequate tube supports or inappropriate design/construction, which causes a localized high stress. Creep and stress rupture are described in API IRE Chapter II.

The metal temperature plays a major role in the type and severity of the deterioration of the heater tubes. The metal temperature of individual tubes or along the length of any specific radiant tube of a given heater can vary considerably. The principal causes of abnormal variation in metal temperature are internal fouling of the tubes which insulates the tube wall from the process and improper or poor firing conditions in the heater. Some potential signs of creep in tubes are:

a. *Sagging.* Excessive sagging is usually because of a decrease in the structural strength of the tube caused by overheating. It may also be caused by improper spacing of hangers, uneven metal temperatures, or failure of one or more tube supports or hangers. Figure 12 shows some roof tubes exhibiting excessive sagging due to the failure of tube hangers.

b. *Bowing.* Excessive bowing is generally caused by uneven metal temperatures, which may be due to flame impingement or coke accumulation inside the tube. Heating on one side of the tube causes greater thermal expansion on the hotter side and bowing toward the heat source. Bowing may also be caused by binding of the tube in the tube sheets or improper suspension of the tube so that longitudinal expansion is restricted or by the use of improper tube lengths when individual tube replacements are made.

c. *Bulging.* Bulging is generally an indication of overheating. Continuing under the same temperature and stress conditions will eventually lead to creep and stress rupture. The amount of bulging varies with the specific metal and the type of damage, creep or overstress. If the bulge is attributed to overstress (short-term overheating), and the temperature and stress have been returned to normal, typically the life of the tube has not been reduced. Creep life will be reduced, if the bulge is the result of creep damage (long-term overheating). Bulging is considered more serious than sagging or bowing.

6.1.4 Metallurgical Changes

Steels subjected to high temperatures and stress for long periods can undergo metallurgical change. This change results in various conditions, including carburization, decarburization, spheroidization and grain growth. All of these conditions lead to a general reduction in mechanical strength or a change in ductility, which may eventually result in failure of the material. Some materials, including 5Cr-$^1\!/_2$Mo, may be susceptible to precipitation hardening when concentrations of residual elements such as phosphorus, tin and antimony are above certain threshold levels and exposed to heater operating temperatures for a sufficient time period. The result may be temper embrittlement with a loss of elongation and notch ductility as these elements precipitate to the grain boundaries after about a year at temperatures from 572°F (300°C) to 1112°F (600°C). Accordingly, the tube materials have ductile-to-brittle transition temperatures as high as 300°F (149°C) and brittle cracking has been experienced. See API IRE Chapter II for a detailed description of these forms of deterioration.

Type 410 stainless steel can be susceptible to alpha-prime embrittlement or "885°F embrittlement", depending on the trace elements present in the composition. Alpha-prime significantly reduces the toughness of the metal when at temperatures below 200°F (93°C). Brittle fracture can result from impact loads during downtime so extra caution during handling is prudent. At operating temperatures, the material has acceptable toughness.

6.1.5 Erosion

The velocity of flow through a heating coil may cause severe erosion in heater tubes and fittings if the velocity is critical or if direct impingement occurs. Often, the metal loss is aggravated by the corrosive nature of the process. Erosion in heater tubes is usually the result of velocity. Erosion in heater fittings usually results from a combination of impingement and velocity. If the charge rate on a heater is materially increased, the increased velocity may cause metal loss from erosion and corrosion.
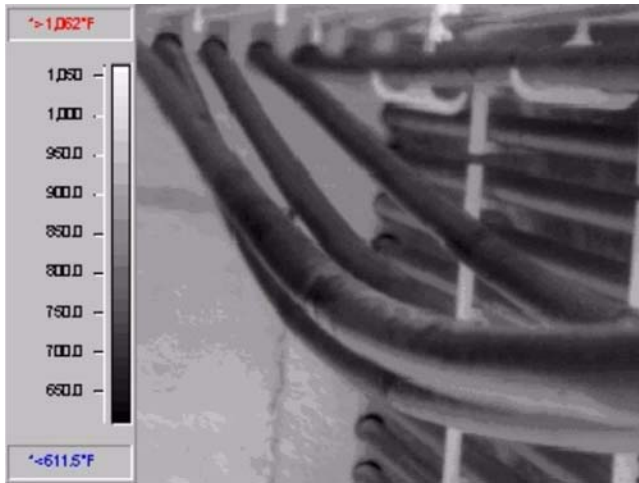
Figure 12—Roof Tubes Sagged as a Result of Failed Tube Hangers

6.1.6 Thermal Fatigue

Metal that operates under cyclic temperature conditions, especially over a wide range, may develop cracks from thermal fatigue. Cracks start at the surface of the material where the stresses are normally higher, progressing slowly at first and then more rapidly with each cycle of temperature change. Thermal fatigue is often found at locations where metals that have different coefficients of expansion are joined by welding. Other common locations for thermal fatigue are in convective tubes where the tube fins can promote cyclic temperature swings, tubes with two-phase flow, and bracing/weld attachments which do not allow for thermal expansion.

6.1.7 Thermal Shock

Thermal shock is caused by a sudden marked change in temperature either from hot to cold or from cold to hot. The stresses resulting from the sudden unequal expansion or contraction of the different parts may cause distortion only or distortion plus cracking. Thick metals are more susceptible to cracking than are thin ones. The most likely time of temperature shock is during unit start-ups. Heating or cooling rates should be controlled to avoid thermal shock.

6.1.8 Liquid Metal Cracking/Embrittlement

Liquid metal cracking is a form of environmental cracking where molten metal penetrates the grain boundaries of the steel. Series 300 austenitic stainless steel tubes are particularly susceptible to this mechanism from molten aluminum, zinc and cadmium. Fireboxes provide adequate temperatures for these metals to be molten since they have relatively low melting points. Contact of stainless steel surfaces with a low melting point metal should be avoided during maintenance outages in particular; including incidental contact such as using marking pens containing zinc and galvanized or aluminum scaffolding poles rubbing against tubes.

6.1.9 Polythionic Acid Stress Corrosion Cracking

Heaters used in hydrodesulfurization, hydroforming, hydrocracking, and similar processes often have austenitic stainless steel tubes and usually process reactor feed or recycled gas containing hydrogen sulfide and sulfur compounds. The austenitic stainless steel tubes in these services can be susceptible to polythionic acid stress corrosion cracking. Polythionic acids form from sulfide scales exposed to oxygen and water in the stainless steel that are sensitized which can occur in most stainless-steel tube materials after relatively short exposures to temperatures in excess of 800°F (427°C) during manufacturing, fabrication or in service. Generally, the risk of cracking increases during downtime when water and air are present. Cracking can be rapid as the acid corrodes along the grain boundaries of the stainless steel.

Cracking can initiate from either the inside or outside of the tube. Cracking from the process side is more common because the process often contains sulfur compounds resulting in sulfide scales. However, cracking can occur from the tube OD if the firebox operates fuel rich and there is sufficient sulfur in the fuel.

Preventive measures include using materials less susceptible to sensitization, preventing acid from forming, and neutralizing the acids. Specific details are as follows.

a. Stabilized grades of stainless steel (e.g., Type 321 or Type 347) are more resistant to sensitization but even these materials can become sensitized after a longer exposure to slightly higher temperatures. A thermal stabilization heat treatment of a stabilized grade of stainless has been shown to significantly improve resistance to sensitization and thereby minimize the potential for cracking.

b. Preventing oxygen and moisture exposure will not allow the polythionic acid to form. This can be accomplished by purging with an inert gas, like nitrogen, and keeping the tubes pressurized with it. When blinding is required, a positive flow of inert gas should be maintained while the flanges are open and a blind is being installed. If desired, a small amount of ammonia can be added to the inert gas as a neutralizing agent. Maintaining a positive flow of inert gas excludes air and moisture.

c. A wash with a soda ash solution can effectively neutralize acids and maintain a basic pH. Soda-ash wash tubes crossovers, headers, or other parts of the heater which must be opened. The usual solution is 2 wt. % soda ash (Na_2CO_3) with a suitable wetting agent. The solution should be circulated so that all gas pockets are moved and all surfaces are wetted. Sodium nitrate at 0.5 wt. % may also be added to the solution to inhibit chloride cracking. The solution may then be drained and reused in piping or another heater. The 2-percent solution contains enough soda ash to leave a film, but a

weaker solution may not. The film is alkaline and can neutralize any reaction of iron sulfide, air, and water. It is important to remember that the film, the residue from the soda-ash solutions, must not be washed off during downtime. Most units are put back on stream with the film remaining. If the film must be removed, flushing during start-up followed by inert gas may be acceptable.

d. Preventing moisture exposure by maintaining tube temperatures above the dew point will also prevent acid from forming. This is typically applied to external tube surfaces which are not neutralized. Depending on the dew point temperature, this may be accomplished either by keeping pilots burning during down times or keeping a burner at minimum fire when access is not needed and safety procedures allow. Tube temperatures should be monitored to (Part 2) ensure they are above the target dew point temperature.

These preventive measures are described in detail in NACE RP 0170.

6.1.10   Metal Dusting

Metal dusting is a catastrophic form of carburization that can result in rapid metal wastage in both ferritic and austenitic alloys. This damage mechanism typically has the appearance of localized pitting, or grooving, along the inner walls of pipe and tubes.

Environments with high carbon activity (greater than 1) and low oxygen partial pressures can be prone to this type of damage if temperatures become high enough for carbon diffusion to occur in the base metal. Depending on the type of alloy, this temperature may be as low as 800°F (427°C) and as high as 1400°F (760°C). In iron-based alloys, this mechanism initiates with the saturation of the alloy matrix with carbon, usually in a very localized manner, followed by the formation of metastable Fe_3C, or cementite. The cementite will decompose, as the carbon activity increases and approaches unity, to form iron particles and powdery carbon. With nickel-based alloys, there is no intermediate formation of a metastable carbide. Instead, carbon will diffuse into the matrix material and then decomposes into graphite and metal particles.

Common process streams where metal dusting has been know to occur include; methanol production, where the production of a synthetic hydrogen gas results in ideal conditions for this to occur; hydroforming units, where the 9% Cr material used in many of the fired heaters have been found with this type of damage and waste heat boilers and where high metal temperatures and high activity of carbon lead to initiation of this damage.

Protection of an alloy against metal dusting requires the presence of an adherent, protective, self-healing oxidation layer on the surface of the material. In general, nickel-based alloys perform much better in a metal dusting environment than do iron based alloys. Alloy 800H is one of the most sus-

ceptible austenitic alloys to this mechanism, with a fast initiation rate and high wastage rates. Similarly, alloys with 20% – 40% nickel are also strongly attacked.

6.1.11   Mechanical Deterioration

Mechanical deterioration may materially reduce the service life of heater tubes and fittings. The two most common causes of this are leakage in the tube rolls—the rolled joints between tubes and fittings—and damage during mechanical cleaning. Leakage in the tube rolls may result from faulty roll procedures or workmanship when the tubes were originally installed, or may be caused from thermal upsets during operation. Similarly, damage to a tube during mechanical cleaning may be caused by faulty procedures or workmanship. One of the most common causes is allowing the cleaner to operate in one position for so long that it cuts the tube metal. Machined surfaces of plug-type header fittings can be damaged by contact with cleaning tools. Cleaning by steam-air decoking can cause serious oxidation and other deterioration of tubes unless temperatures are carefully controlled.

Undue force used to close fittings may result in the development of cracks in the fitting body or at the base of fitting ears and may cause excessive wear or distortion of the plugs of U-bend seats, fitting ears, or holding sections and members-dogs or caps and screws. The use of excess force commonly occurs because of improper cleaning of ground surfaces or mismating of plugs to return bends. Training and close supervision of personnel with regard to the proper care, use, and amount of tightening permissible are essential to prevent this damage. Casting or forging defects may also result in cracks in the fitting body or at the base of fitting ears. One common practice to aid in removing plugs and to reduce the chance of damaging the casting is to heat the fittings. Overheating with a torch may cause the fitting to crack. The depth and seriousness of cracks formed by overheating with a torch should be investigated.

Thermal expansion that has not been accommodated can cause deterioration. Tube materials expand when heated. If the expansion can not be accommodated, it can create stresses that are high enough to cause serious weakening and deformation of the tube or fitting.

For instance, tube failures have resulted from refractory repair work, which did not allow the tubes to expand, and created high enough local stresses to result in creep rupture.

6.1.12   Deterioration Specific to Reformer Heaters

6.1.12.1   Tubes and Pigtails

Reformer heater tubes and pigtails are susceptible to creep and stress rupture due to high thermal and mechanical stresses and high operating temperatures. Failures generally occur due to stress rupture at the hottest, most highly stressed portion of the tube. The hottest areas are normally near the

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bottom or outlet of the tube, since the temperature of the gas inside the tubes rises during reaction by about 500°F (260°C), from about 900°F (482°C) to about 1400°F (760°C). If flame from burners or from combustion products deflected off walls and impinges upon the tube, stress rupture can occur in the hottest parts of the tube.

Reformer heater tubes can fail by creep rupture that is different from most other heater tubes. The tubes have a thick wall with a large thermal gradient across it such that there are significant thermal stresses in the region between the ID and midwall. These thermal stresses are high enough to promote creep initiating where the combination of stress and temperatures are above a threshold and propagating to the inner diameter. Finally, the cracks propagate to the outer diameter resulting in failure.

Minimizing mechanical stresses from thermal growth are critical to pigtail and tube reliability. Reformer heaters have an elaborate support and hanger system designed to allow the tubes to grow in service and to reduce the stress on the pigtails and headers. If the support system is not functioning as designed, it can produce high stresses on the pigtails and tubes to the extent of promoting creep rupture. Without adequate support, tubes can bow in service, further increasing stresses. Bowed tubes have higher stress levels at their bends than do straight tubes. Bending stresses are induced on pigtails from tube bowing, tube movement, sagging of the pigtail under its own weight, and thermal expansion of a pigtail loop. The pigtails are susceptible to thermal fatigue, if the movement is cyclic because of swings in operation or numerous start-ups and shutdowns.

Some cast tube materials may embrittle after exposure to high temperatures. Weld materials that embrittle during post-weld cooling have high residual stresses. Weld material with a carbon-silicon ratio that does not match that of the base metal fissures easily during welding. Any microfissures not detected during fabrication can propagate during subsequent heating, thermal cycles, or continual high stresses from bowing or localized heating. Welding flux must be removed from tube welds. Grit blasting is recommended for flux removal. Flux of lime with fluorides is corrosive if the combustion gases are reducing (because of very little excess air) and sulfur is present.

6.1.12.2 Outlet Headers

The cast alloy headers, like those fabricated from HK material, have a history of cracking near junctions because of embrittlement due to carbide precipitation and sigma formation. Other areas of concern include inlets, outlets, laterals, tees and elbows. These headers are horizontal and do not float freely. The embrittlement that occurs does not allow any restraint of the thermal growth and results in high stresses with resultant cracking. Because of the embrittlement, welding repairs are difficult unless the surfaces are annealed or

buttered with a ductile weld material before welding. Proprietary cast materials have been developed to avoid embrittlement and their use in outlet headers has been satisfactory.

Wrought alloy headers, like Alloy 800H, operating at temperatures near 1400°F (760°C) have also had a good service history. They maintain ductility and can yield, by creep or stress relaxation, to reduce localized stresses. As in any high-temperature design, however, stresses must be kept low, particularly at supports and at openings in the headers.

Headers fabricated from carbon steel or low Cr-Mo require internal refractory to keep metal temperatures low enough to have an adequate design stress and to resist high-temperature hydrogen attack. Because the base metal is not resistant to hydrogen at high temperatures, the refractory must be sound to preserve its insulating properties. Refractory used in hydrogen and carbon monoxide service should have low iron and silicon content to avoid the possibility of hydrogen or carbon monoxide reacting with components of the refractory and the degradation of the refractory's essential properties. Start-up and shutdown procedures must minimize wetting of the refractory, partly to avoid destroying the insulating refractory and partly to avoid carbonic acid corrosion of the steel.

6.2 DETERIORATION OF BOILER TUBES

Similar to heater tubes, boiler tubes can also experience deterioration from internal and external mechanisms. The following subsections describe common deterioration mechanism. Table 2 also summarizes these common mechanisms in boiler plants.

6.2.1 Internal Corrosion

Corrosion of tubes and the drums is largely dependent on the water and water chemistry used within the boiler. Some of the more common types of waterside corrosion include caustic corrosion, dilute acid corrosion, oxygen pitting or localized corrosion, and stress corrosion cracking. A significant factor in the degree of waterside corrosion is the amount of corrosion product deposited. Deposits restrict the heat transfer and lead to local overheating, which can cause concentration of contaminants and corrosives. Depending on which contaminants are present in the feedwater during a period of chemical unbalance, different deposition locations, rates, and effects will be experienced.

Caustic corrosion, or caustic gouging, can occur from deposition of feedwater-corrosion products in which sodium hydroxide can concentrate to high pH levels. At high pH levels, the steel's protective oxide layer is soluble and rapid corrosion can occur. Deposits normally occur where flow is disrupted and in areas of high heat input. When the deposit thickness is great enough to locally concentrate caustic, severe corrosion resulting in irregular thinning or gouging of the tube wall can occur. Figure 13 illustrates this form of localized corrosion.

Figure 13—Localized Tube Wall Loss Caused
by Caustic Gouging

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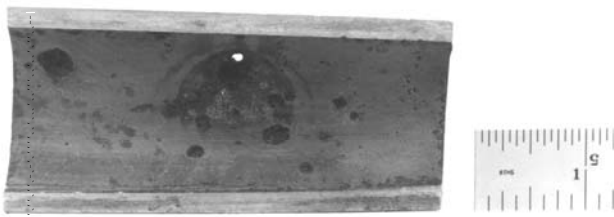
Figure 14—Boiler Tube Showing Penetration of the
Tube Wall by a Localized Oxygen Pit

Hydrogen damage may occur if the boiler is operated with low-pH water. This may be caused by the ingress of acidic chemicals from the water treatment facility, a leak in a saline-cooling water condenser, contamination from chemical cleaning, or other factors that may lower the boiler feedwater pH to less than seven. Close control over boiler water chemistry and monitoring practices are important factors in preventing hydrogen damage.

Boiler tube failures caused by pitting or localized corrosion often result from oxygen attack on the internal side of the boiler tube. Pitting corrosion of economizer tubing normally results from inadequate oxygen control of the boiler feedwater. For full protection against oxygen pitting during shutdown, the boiler should be kept full of water treated with an oxygen scavenger and blanked or capped with nitrogen. Figure 14 illustrates a boiler tube with a through-wall oxygen pit.

While stress corrosion cracking is usually associated with boilers in which austenitic tubes are used for superheater and reheater tubing, failures have occurred in ferritic tubes where a desuperheater or attemperator spraying station introduced high levels of caustic concentration. Stress corrosion cracking

of B-7 studs may also occur in areas where a leaking gasketed joint may allow caustic concentration.

6.2.2 External Corrosion

Fuel constituents and metal temperatures are important factors in the promotion of fireside corrosion. Fireside corrosion can be classified as either low-temperature attack or high-temperature oil-ash corrosion. Corrosion may occur on the flue-gas side of economizer and air preheater tubes. The severity of this corrosion depends on the amount of sulfur oxides or acid in the fuel burned and on the temperature of the flue gas and of the media being heated. When sulfur oxides are present in the flue gases, corrosion tends to be severe if the gases cool down to the dew-point temperature. The gas temperature in economizers and preheaters should be kept above about 325°F (163°C) to prevent condensation of corrosive liquid. Actual dew point can be calculated from the flue gas composition and should be performed for fuels with high sulfur levels. This may be best effected by designing the tubing and the water flow in the tubing so that the gas temperatures are controlled as noted in the preceding text.

External corrosion of boiler parts may be expected when boilers are out of service for long periods of time. The sulfurous acid formed from the reaction of condensed moisture with the sulfur in ash deposits can cause rapid corrosion of boiler parts. Also, if a unit remains idle for an appreciable length of time, a warm humid atmosphere tends to corrode boiler parts and supports, unless adequate mothballing procedures are followed.

6.2.3 Creep and Stress Rupture

Overheating is one of the most serious causes of deterioration of boilers. Overheating of the boiler tubes and other pressure parts may result in oxidation, accelerated corrosion, or failure due to stress rupture. Although overheating can occur during normal boiler operations, most often it results from abnormal conditions, including loss of coolant flow or excessive boiler gas temperatures. These abnormal conditions may be caused by inherently faulty circulation or obstructed circulation resulting from water tubes partly or wholly plugged by sludge or dislodged scale particles. Overfiring or uneven firing of boiler burners may cause flame impingement, short-term overheating, and subsequent tube failure. The results may be oxidation of the metal, deformation of the pressure parts, and rupture of the parts, allowing steam and water to escape. Figures 15 and 16 show boiler tubes that have failed because of overheating.

Boiler tubes may be damaged by poor circulation. Under certain conditions of load and circulation, a tube can become steam-bound long enough to overheat locally and fail. If circulation is periodically reestablished, the hot portion of the tube is quenched by relatively cool water. This often causes thermal fatigue cracks, which may eventually result in tube

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failure. This condition can also result in caustic or chelate corrosion. Steam binding may be caused by the insulating effect of slag deposits on the outside of the lower part of the tube. This demonstrates the importance of avoiding, as much as possible, nonuniform slagging of waterwalls. Steam superheaters can become overheated and severely damaged during start-up if cold boilers are fired at an excessive rate before a sufficient flow of steam is established to keep the superheaters cool. They can also become overheated if the steam vented from the superheater outlet is not sufficient to provide steam flow through the superheater during warm-up or low-load operations. The overheating results in warped tubes and oxidation of the tube metal, leading to early tube failure.

The faulty operation of steam-separating devices may result in deposition of boiler water solids in the superheater tubes, with subsequent damage to the tubes from overheating.

6.2.4 Mechanical Deterioration

Mechanical deterioration of boiler parts can result from a number of causes:

a. Fatigue from repeated expansion and contraction and corrosion-fatigue from the combined action of fatigue and corrosion.

b. Abnormal stresses created by rapid changes in temperature and pressure, especially in the case of thick-walled drums.

c. Improper use of cleaning tools.

d. Improper use of tube rollers.

e. Settlement of foundations.

f. Excessive external loading from connected piping, wind, earthquake, and similar sources.

g. Breakage and wear of mechanical parts.

h. Firebox explosion.

i. Vibration due to improper design or support failure.

j. Improper gaskets that allow steam leaks to score the seating surface.

k. Non-weather-tight casing that allows external tube corrosion during extended shutdowns.

If metal is cyclically stressed in operation repeatedly, it can eventually fatigue and may crack under a stress far below its normal breaking load, as discussed in API IRE Chapter II. The metal in boiler parts may experience expansion and contraction because of temperature changes involved in taking a boiler out of service, and putting it back into service. Also, expansion and contraction can be caused by the normal temperature fluctuations during operation. Tubes may also become fatigued as a result of alternate wetting by steam and water, which causes fluctuating conditions. If corrosion acts concurrent with fatigue, the fatigue resistance of the metal is reduced because of the corrosive medium, and corrosion-fatigue cracks will result. When very rapid temperature changes occur in metal parts (especially thick metal parts), they may be overstressed by the expansion or contraction of

Figure 15—Short-term Boiler Tube Failure Caused by Waterside Deposits, Subsequent Overheating, and Final Bulging of the Tube Wall

Figure 16—Longer-term Boiler Tube Failure Caused by Poor Circulation and Subsequent Overheating, Oxidation, and Final Failure by Stress Rupture

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the portions of the metal that have changed in temperature against the portions of the metal that have not changed in temperature. A similar situation exists when a cold glass tumbler is only partly filled with hot liquid and shatters.

Improperly emploed tube cleaners—allowed to operate too long in one position, for example—may cause damage by cutting grooves inside the tube. Incorrect or excessive cleaning operations especially utilizing acid based products can lead to excessive removal of protective oxide films in boiler tubes and may lead to accelerated corrosion upon re-commissioning. Improper use of tube-rolling tools by underrolling or overrolling may cause tube-roll leaks or damage to the tube ends or tube seats.

Breakage and wear of mechanical parts are probably the most common forms of deterioration of the various parts and auxiliaries of boilers. This is especially true for burners and equipment that handle solid fuel and ash. The associated services are very severe, involving high temperatures, almost continuous operation, and extremely abrasive operating conditions when solid fuels are used.

Figure 17—Dew Point Corrosion from Flue Gas
Corrosion on Radiant Section Header Box

6.3 DETERIORATION MECHANISMS OF OTHER COMPONENTS

6.3.1 General

Nonpressure parts, including refractory linings of heaters, burners, supporting structures, and casings, may also be damaged from overheating. Usually, such overheating is caused by improper operating conditions or is a result of deterioration of other protective parts. For example, if the refractory lining of a heater is permitted to deteriorate from normal wear, erosion, spalling, or mechanical damage, it will no longer protect the outer heater casing and structural supports adequately, and such parts may in turn begin to deteriorate rapidly.

6.3.2 Tube Hangers and Supports

Hangers and supports are made from heat resistant alloys chosen for their high-temperature strength, creep properties, and resistance to corrosion. Most of this hardware is originally made from castings although wrought materials tend to be installed for replacements due to good availability of plate and bars. The form of the material, cast vs. wrought, and the grade of material influence the deterioration mechanisms.

Tube hangers and supports deteriorate for several reasons including stress/creep rupture, mechanical damage, corrosion and poor quality castings. Similar to previous discussions about stress and creep rupture of tubes, hangers and supports fail from an excessive combination of stress and temperature. Components made from a casting generally have better stress rupture/creep properties than the wrought equivalent. Therefore, extra attention should be given to those wrought components. Especially vulnerable are those fabricated for an unplanned replacement of a cast component. Corrosion of the supports and rods can reduce the cross-section enough to elevate the stress level to promote failure. Corrosion can occur from high-temperature oxidation, fuel ash, and acid attack (during turndown). Oxidation can be avoided by proper alloy

selection. Fuel ash and acid turndown attack from sulfur in deposits can be severe depending on the fuel quality.

Mechanical damage from vibration in service or mechanical impact during maintenance work can crack the components. Castings are particularly susceptible to mechanical impact damage since they tend to have poor resistance to impact loads. In addition, some alloys can change metallurgically from long-term exposure at elevated temperatures to become brittle at room temperature.

Poor casting quality can be the root cause for premature failures. Casting defects like voids and cracks, can initiate failure from other mechanisms like stress rupture or mechanical damage. These cast components do not usually receive significant inspection after casting. Some purchasers have found it necessary to require supplemental radiographic inspection to assure themselves of acceptable components.

6.3.3 Casing and Structural Steel

Corrosive agents are produced in the combustion of fuels that contain sulfur and vanadium.

Deterioration from sulfur will occur on cold steelwork when it has been exposed to the heater gases as a result of deterioration of the refractory or insulating linings or if a heater is operated under a positive pressure. It is imperative that the outer casing of heaters be maintained in a tight condition. When flue gases are permitted to permeate to the atmosphere at various locations, they deposit sulfurous acid on the casing and metal parts that are below the dew point. Such deposits are acidic, accelerating corrosion of the casing and the refractory supports. Figure 17 illustrates dew point corrosion of a header box. Most fired heaters are designed to operate at negative pressure. Operations at positive pressure results in flue gas leakage and shell corrosion.

The rate of deterioration caused by climatic conditions primarily depends on whether the atmosphere is dry, humid, or salty and on the industrial fumes that may be present. Deterioration resulting from a humid atmosphere may not be due to geographic location but may be the result of the location of the heater within the refinery. Location near cooling ponds or towers when the prevailing winds are toward the heater may cause deterioration.

The types of deterioration resulting from climatic conditions are rusting of exposed or unpainted steelwork, general deterioration of painted surfaces, and erosion and further deterioration of the external housing of a heater. If the external housing is allowed to deteriorate, rain or other moisture will enter the openings and deteriorate the internal refractory, insulation, and steelwork, especially when the heater is out of service for any reason (see API IRE Chapter II).

6.3.4 Firebox and Ductwork Liners

Firing conditions and heater temperature are the main causes of deterioration of the materials that form the internal

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lining of the heater. The severity of the deterioration will vary with the heater temperature, which in turn is determined by the process operating conditions.

The purpose of the internal materials, including refractory or insulating linings, is to provide heat protection to the structural steel framing, roof structures, and tube sheets, and to improve the thermal efficiency of the heater. At high temperatures, refractory will deteriorate after long-term exposure by spalling, failure of the binding material, melting, and loss of structural strength. When the insulating value of refractory or insulating material is reduced, the supporting steel is subjected to high temperatures and may deteriorate rapidly as a result of oxidation, scaling, and possible metallurgical changes.

Fluxing may occur when fuel ash and refractory are in contact at a moderately high temperature, producing a slag that may be fluid. Metal oxides, including those of vanadium, molybdenum, and sodium, are fluxing agents. At least three deteriorating actions of this slag formation can be recognized:

a. *Melting.* The flux melts at a lower temperature, thereby causing the refractory to become liquid and flow, which reduces the refractory thickness.
b. *Penetration.* The flux can penetrate into the sound refractory, thereby compromising its properties.
c. *Chemical action.* The flux can react with the refractory and chemically degrade it much like metal thickness being reduced by corrosion.

The general effects of this slagging are to decrease the thickness and reduce the insulating effect of the refractory, and thereby allowing a high metal temperature on the supporting steel parts.

6.3.5 Structures

Foundation settlement may be a serious cause of deterioration in boilers because of the severe stress that may be set up in the complicated interconnection of parts, in the external piping, and especially in the refractory linings and baffling. Excessive loads on the boiler by the connection of large pipe lines may cause damage to the boiler foundation and pressure parts.

Settlement of foundations may also result from heat transmission from the firebox and subsequent drying of the soil.

In zones with seismic activity, earthquakes may cause severe damage. The damage will be somewhat similar to that caused by foundation settlement and may be particularly severe to refractory linings. Vibrations from high and moderate winds, earthquakes, burner operating instability, and high flue-gas flow across tube banks can damage various parts of boilers as follows:

a. Stacks may be so damaged that they overturn.
b. Air and flue-gas ductwork may be damaged, resulting in cracks at corners or connections.
c. Expansion joints may crack.

d. Guy lines may loosen or break.
e. Piping and tubing may be overstressed and fail.
f. Anchor bolts of stacks may be overstressed and fail.

7 Frequency and Timing of Inspections

7.1 GENERAL

The first inspection of a heater or boiler is necessary to confirm the anticipated rate of deterioration and to identify any unanticipated deterioration. Typically, a comparison is made with the initial inspection at the time of construction and with design records that detail considerations of corrosion, erosion, and other factors. The first inspection also helps to maintain the safety and efficiency of continued operation and forecast maintenance and replacements, based on the indicated deterioration rate. In the same way, all subsequent inspections are compared with the preceding inspection of the same specific purpose. The determination of the physical condition and the rates and causes of deterioration in the various parts makes it possible to schedule repairs or replacements prior to compromising mechanical integrity and resulting failure. Many of the parts that make up a boiler or fired heater depend on some other part, and when deterioration and serious weakening occur in one part, some other part may become unprotected or overstressed. This can shorten service life.

7.2 BOILER INSPECTION FREQUENCY

The interval between boiler inspections is typically set by the jurisdiction in most U.S. states and some provinces of Canada. In jurisdictions or countries that have no such laws, the inspection interval may be set by the insurance carrier insuring the boiler. Otherwise, external and internal inspections should be scheduled periodically considering the age of equipment, conditions of operation, type of equipment, kind of fuels, method of water treatment, previous inspection result, etc.

7.3 HEATER INSPECTION FREQUENCY

Heater reliability often depends on periodic internal inspections and routine, on-stream monitoring/inspection. Typically, heaters are an integral section of a process unit such that internal inspection can only be accommodated during unit outages. However, the length of time between internal inspections should consider the historic and predicted deterioration rates for components (including the impact of any process change), the historic inspection findings, the results of on-stream monitoring/inspection, previous maintenance activities and their quality.

Similar information can be inputted into a risk assessment, which considers the probability of failure and the consequence of failure. The inspection strategy and interval could be modified by a risk assessment. Additional information on risk-based inspection can be found in API RP 580.

Routine, on-stream monitoring/inspection is a necessary component for improved reliability. Some common on-stream inspections include:

a. Visual inspection of the firebox and in particular burner flame patterns by operations personnel on a routine basis.
b. Installation and monitoring of tubeskin thermocouples for tube metal temperatures.
c. Infrared inspection of tubes for "hot spots" on a periodic basis.
d. "Tell-tale" holes.

API Std 560 provides additional details to support inspection efforts at various sections.

8 Safety Precautions, Preparatory Work, and Cleaning

8.1 SAFETY

Safety precautions must be taken before any heater, boiler, flue duct, or stack is entered. In general, these precautions include but may not be limited to isolating energy sources, lock-out-tag-out, atmospheric gas checks and reduction of confined space temperatures before entering. Dust and acid-containing material on internal surfaces are to be expected. The problem they present may be complicated if fuel-oil additives that leave toxic residues have been used. Protective equipment must be made available and used until it has been determined that safe conditions exist. When vanadium dust is present, protective apparatus and clothing must be used when internal inspections are performed. Consult all applicable common site-specific, OSHA and other federal, local, and state safety rules and regulations.

8.2 GENERAL PREPARATORY WORK

Before the inspection, the tools needed for inspection should be checked for availability, proper working condition, and accuracy. This includes tools and equipment that are needed for personnel safety. Safety signs should be provided where needed before work is started. The following tools are needed to inspect fired heaters and stacks:

a. Portable lights, including a flashlight.
b. Thin-bladed knife or scraper.
c. Broad chisel or scraper.
d. Pointed scraper.
e. Inspector's hammer.
f. Inside calipers.
g. Outside calipers.
h. Direct-reading calipers or special shapes.
i. Mechanical tube caliper or micrometer for measuring the inside diameter of tubes.
j. Pocketknife.
k. Steel rule.
l. Special D calipers.

m. Pit depth cage.
n. Paint or crayon.
o. Notebook.
p. Magnifying glass.
q. Wire brush.
r. Plumb bob and line.
s. At least one type of special thickness measurement equipment (see next list).
t. Small mirror.
u. Magnet.

The following tools should be readily available in case they are needed:

a. Surveyor's level.
b. Carpenter's or plumber's level.
c. Magnetic-particle inspection equipment.
d. Liquid-penetrant inspection materials.
e. Radiographic inspection equipment.
f. Ultrasonic inspection equipment.
g. Megger ground tester.
h. Grit blasting equipment.
i. Micrometer (0 in. – 1 in.).
j. Electronic strain gauge caliper.
k. Borescope.
l. Fiberscope.

Note: When selecting products which will be used to mark or applied to stainless steel tubes, these products should not contain chlorides to prevent stress corrosion cracking. Additionally, any equipment or paint which can/will contact the stainless steel tube surfaces should not be made or coated with aluminum, zinc, lead, and cadmium to prevent liquid metal embrittlement concerns.

Other related equipment that may be provided for inspection includes planking, scaffold material, a bosun's chair, and portable ladders. If external scaffolding is required, it may be possible to erect it before the unit is shut down.

Before the inspection is started, all persons working around a fired heater or boiler, flue duct, or stack should be informed that people will be working on the inside. A safety guard ("hole watch") should be stationed at the inspection door of the equipment being inspected. This person can serve as a guard and can also record data from the inspection findings.

Personnel working inside this equipment should be informed when any work is going to be done on the outside so that any unexpected noise will not cause needless alarm. Vibration of the tubes and the setting should be minimized while internal inspection work is being performed to prevent injuries due to the dislodging of loose refractory.

8.3 PRECAUTIONS TO AVOID POLYTHIONIC ACID STRESS CORROSION CRACKING IN STAINLESS STEEL TUBES

Polythionic acid stress corrosion cracking (PASCC) in stainless steel is a downtime phenomenon. For heaters with

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stainless steel tubes, an evaluation should be made to determine their susceptibility to internal and external PASCC. If deemed necessary, specific steps should be taken to prevent cracking during downtime. These procedures are detailed in 6.1.9 and in NACE RP 0170. When using a soda ash wash solution to externally protect tubes, care should be taken to protect any ceramic fiber insulation from becoming wetted as the fiber can sag under the weight of the absorbed liquid.

8.4 CLEANING

8.4.1 External Cleaning

Tubes may be externally cleaned by various methods. The specific method is usually determined by the accessibility of the tubes and the purpose for which they are to be cleaned. Readily accessible tubes may be cleaned by wire brushing or grit blasting. Grit blasting is preferred if defects are suspected and a close inspection is required, since all deposits can be removed and the bare metal exposed. Refractory should be protected from grit blasting.

All radiant surfaces should be cleaned. Cleaning only a portion of the radiant surfaces may promote overheating of the cleaned surfaces. Scaled or fouled surfaces will obstruct heat transfer and cause the clean surfaces to absorb more heat.

Usually, it is physically impossible to clean the economizer or convection tubes by wire brushing or grit blasting because of tube arrangement. Other methods, such as the use of a steam lance or a stream from a water hose or high-pressure water equipment, may be used. In such instances, cleaning is performed primarily to remove external deposits and improve the heat transfer. Before resorting to steam or water cleaning of the tubes, careful consideration should be given to possible damage to the refractory insulation and brickwork, particularly in a service where a fuel with a high sulfur content is used. In addition, for stainless steel tubes consider using a soda ash solution as detailed in 6.1.9 and maintaining the chloride content of the water at less than 50 ppm. These will minimize potential stress corrosion cracking of the tubes from cleaning operations.

8.4.2 Internal Cleaning—Heaters

Heater tubes may require periodic cleaning to remove internal fouling and coking deposits. These deposits can be detrimental to heater performance and reliability. Tubes and fittings usually require cleaning when deposits cause an increase in coil pressure drop, an increase in firing rate to maintain the desired coil outlet temperature, a decrease in coil outlet temperature, or tube hot spots.

Internal cleaning of heater tubes may be accomplished by several methods such as gas oil circulation, chemical cleaning, steam-air decoking, thermal spalling, mechanical pigging, hydroblasting and abrasive grit. These methods are typically performed off-line, although some heater arrangements can allow on-line thermal or steam spalling. The effec-

tiveness of each method to remove deposits varies with the deposit type. For instance, circulating gas oil prior to steaming and water wash can be an effective cleaner for soft deposits dissolved by gas oil. However, it will not be effective in removing heavy coke deposits. Therefore, when selecting a cleaning method the nature of the deposit, in addition to safety, potential risk of damage, allotted time, and cost should be considered. In addition to potential damage from the particular technique, cleaning can cause leaks in the tube rolls or header plugs of removable headers from thermal forces or the removal of coke. Chemical cleaning consists of circulating an inhibited acid or other proprietary chemical cleaners through the coil until all deposits have been softened and removed. Water washing to flush all deposits from the coil usually follows this method. When the tubes are made of austenitic stainless steel, the chloride content of the water used for flushing should be maintained at less than 50 ppm. Consider using a soda ash solution as detailed in 6.1.9 for cleaning stainless steel tubes. Care must be used in chemical cleaning to avoid corrosion damage to the tubes.

High-pressure water jet blasting is another option for cleaning tubing with plug-type fittings. Abrasive blasting (shot blasting or sand jet blasting) with metal shot or an abrasive medium is also a cleaning option for welded coils.

Steam-air decoking consists of the use of steam, air, and heat to burn the coke out of the tube. Only trained, experienced personnel should use this cleaning method, because improper procedures or control could result in overheating the tubes and supports causing serious, costly damage to the heater. Steam-air decoking will not always remove the coke from a heater fitting. If this is the case, it may be necessary to use mechanical cutters on the U-bends and remove them for cleaning. This is an expensive and destructive method of cleaning.

Thermal spalling is a technique that uses alternating heating and cooling to spall coke off the tube wall. Steam is often used as the process medium to control heating and cooling. Care should be exercised with this technique for the coke particles removed from the wall have caused localized erosion damage of return bends.

Abrasive pigs can be used to clean tubes mechanically. The technique involves propelling a pig equipped with metal appendices through the tubes with water. The pig is sent back and forth through the tubes and deposits are removed much like using a wire brush to clean a surface. This technique often involves some modifications to heater piping to create a location to launch and receive the pigs. The potential advantages of abrasive pigs are that there is limited probability of damaging the tubes as with other techniques like steam-air decoke and acid cleaning.

Various types of tube knockers and cutters are available for the mechanical cleaning of tubes. Selection of the type of cleaning head is a matter of preference. An air motor usually drives the cutting head. In cold weather, however, steam is often used for motive power to warm the tube and reduce the

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effect of shock on the tube. Mechanical cleaning cannot be used to clean the U-bends of sectional fittings. When mechanical cleaners are used, care must be exercised to avoid damage to the tubes or fittings.

8.4.3   Internal Cleaning—Boilers

Steam-drum internals should be inspected before washing to determine any problems, including poor circulation, poor water quality, and low steam purity.

The inside of shells, drums, and tubes should then be washed down thoroughly to remove mud, loose scale, or similar deposits before they dry and become more difficult to remove. The washing operation should be carried out from above if possible, to carry the material downward to the blow-off or handholes. A hose with sufficient water pressure or hand tools should be used to remove soft scale and sludge. The blow-off line should be disconnected prior to the washing procedure to keep mud and scale out of the blowdown drum. The tubes of horizontal-return-tube boilers should be washed from below and above. It is especially important to ensure that all tubes and headers are clear of sludge after the wash is completed. Water should be passed down each individual tube and observed to exit from below. Each header should be opened sufficiently to give clear view so that it can be ascertained that all sludge has been removed. Precautions should be taken to ensure that the water does not come into contact with the brickwork of the combustion chamber. If contact cannot be avoided, the brickwork should be dried out carefully when the boiler is fired up.

The use of an inhibited acid solution on the inside of the boiler is a common method of cleaning the interior surfaces. Prior to cleaning, samples of sludge and deposits should be analyzed to ensure the cleaning solution can adequately remove the material. During the cleaning operation, corrosion probes/coupons are often used to monitor the corrosivity of the circulating solution. After acid cleaning, the interior of the boiler must be neutralized, washed down, and refilled with water. If a nitrogen purge is used after acid cleaning, drums should be checked for oxygen content before entry. Acid cleaning should not be used on superheaters or other equipment, which contains pockets that cannot be thoroughly flushed out. Precautions must be taken to make sure that all sludge is removed after an acid wash.

It is normal practice to fill pendent-type superheaters with condensate or demineralized water and to keep the superheater full of this water while the remainder of the boiler is acid cleaned. During chemical cleaning, all phases of the operation should be closely supervised by experienced, responsible individuals. During chemical cleaning, all electric power and other ignition sources in the near boiler must be turned off to prevent explosion of the hydrogen and other hazardous gases that are normally given off during the cleaning.

Another common method of cleaning uses chelates. The chelates are added to the boiler water, and the boiler is fired to create circulation and thereby facilitate cleaning of the internal surfaces. Insufficient removal of chelates after cleaning is a common cause of boiler tube cracking and subsequent failure.

See the *ASME Boiler and Pressure Vessel Code*, Sections VI and VII, for more information on the care and cleaning of boilers.

9   Outage Inspection Programs

9.1   GENERAL

Maintenance outages provide an opportunity to gain access to the tubes and other internals to assess their present condition and allow for data to be obtained to predict their future reliability. Inspections that can be performed during outages include:

a. Visual examination.
b. Wall thickness measurements.
c. Tube diameter or tube circumference measurements.
d. Tube sagging or bowing measurements.
e. Pit depth gauging.
f. Intelligent pigs.
g. Radiography.
h. Hardness measurements.
i. Borescope/video probe.
j. In-situ metallography/replication.
k. Dye penetrant testing.
l. Magnetic particle testing.
m. Tube section removal for creep testing.
n. Tube section removal for metallography.
o. Tube removal for detailed visual examination.
p. Testing of tubeskin thermocouples.

Table 3 summarizes some of the typical deterioration mechanisms, the associated inspection techniques, acceptance criteria and considerations to prevent recurrence. In preparation for maintenance outages, on-stream inspections should be performed in advance to facilitate defining the appropriate outage worklist, see 11.4.

9.2   VISUAL INSPECTION OF HEATER COILS

The entire heating coil should be given a thorough visual inspection. Visual inspection is a fundamental technique to help identify the effects of deterioration, actual defects, and an indication of potential defects or weaknesses in the tubes, crossovers, fittings, and connections, including blowdown, steam, pressure gauge, vents, and thermowell connections. Conditions found by visual examination are typically followed by a more detailed inspection to assess the degree of deterioration. It provides means to focus inspection efforts.

Table 3—Recommended Inspection and Acceptance Criteria for Deterioration Mechanisms

Deterioration Mechanism	Manifestation	Inspection Technique	Typcial Acceptance Criteria	Prevention Methods
Creep/Stress Rupture	Bulge in tube	Strapping Gauging Circumference Shadows from flashlight	Maximum 1% – 5% growth.	Reduce operating metal temperature and/or operating stresses.
Creep	Bulge in tube	In-situ metallography	No defined criteria. Assess significance and severity of creep voids/cracks.	Reduce operating metal temperature and/or operating stresses.
Creep (or Simple Yielding)	Tube sagging	Measure amount of sag (e.g., with straight edges)	Maximum of 5 tube diameters.	Review metal operating temperatures, tube support system.
Metallurgical Transformation of Ferritic Materials	High hardness	Hardness testing— telebrinnel, Microdur	Maximum 220 BHN for Carbon steel and 280 BHN for Cr-Mo.	Prevent temperature excursions, review burner operation/control and process flow indicators.
Polythionic Acid Stress Corrosion Cracking of Austenitic Stainless steels	Branched cracks	Dye penetrant testing Ultrasonic shearwave Eddy current	No defined criteria. Can consider fitness-for-service analysis.	Use stainless steel not susceptible to PASCC. Use preventive measures like soda ash washing. Refer to NACE RP 0170.
Thinning—External Oxidation	General metal loss	Ultrasonic thickness gauging	Predicted to be above minimum required thickness at next outage.	Reduce tube metal temperatures; upgrade tube material with high oxidation resistance.
Thinning—Erosion	Localized metal loss particularly at bends	Ultrasonic thickness scanning Profile radiography	Predicted to be above minimum required thickness at next outage.	Review flow rates, review process fluid composition, consider material upgrade.
Thinning— Sulfidic Corrosion	General and localized metal loss	Ultrasonic thickness gauging Profile radiography	Predicted to be above minimum required thickness at next outage.	Review operating conditions such as concentration of sulfur compounds in process, metal temperatures. Consider material upgrade.
Thinning—H_2/H_2S	General metal loss	Ultrasonic thickness gauging	Predicted to be above minimum required thickness at next outage.	Review operating conditions such as metal temperature and H_2S concentration. Consider material upgrade.
Thinning— Naphthenic acid	Localized metal loss	Ultrasonic thickness Scanning Profile radiography	Predicted to be above minimum required thickness at next outage.	Review organic acid species and concentration. Consider material upgrade.
Metal Dusting/ Carburization	Localized pitting/ grooving	Ultrasonic thickness scanning Profile radiography	Predicted to be above minimum required thickness at next outage.	Review operating temperature and process conditions. Consider material upgrade.

Tubes should be inspected externally for the following conditions:

a. Sagging or bowing.
b. Bulging.
c. Oxidation or scaling.
d. Cracking or splitting.
e. External corrosion.
f. External deposits.
g. External pitting.
h. Leaking rolls.

Fittings should be inspected externally for the following conditions:

a. Damage or distortion.
b. Corrosion.

Figures 18 and 19 show examples of the bulging that may occur in tubes, Figure 20 shows an example of scaled tubes, Figure 21 shows an example of an oxidized tube, and Figure 22 shows an example of a split tube. Figure 23 shows examples of the external tube corrosion that may occur during a short shutdown period on a heater that has been fired with a fuel of high sulfur content.

Because of the arrangement of the tubes and refractory walls, visual inspection of the external surfaces of the tube is usually restricted to the fireside of the radiant tubes. Special attention should be given to the following locations:

a. Welds.
b. In vertical heaters, the area from the firebox floor to approximately 20 ft (6 m) above the firebox floor.

Figure 18—Bulged Tube

Figure 19—Bulged and Split Tube

Note: Reproduced with permission of The McGraw-Hill Companies. *The NALCO Guide to Boiler Failure Analysis*, R. Port, 1991.

Figure 20—Scaled Tube
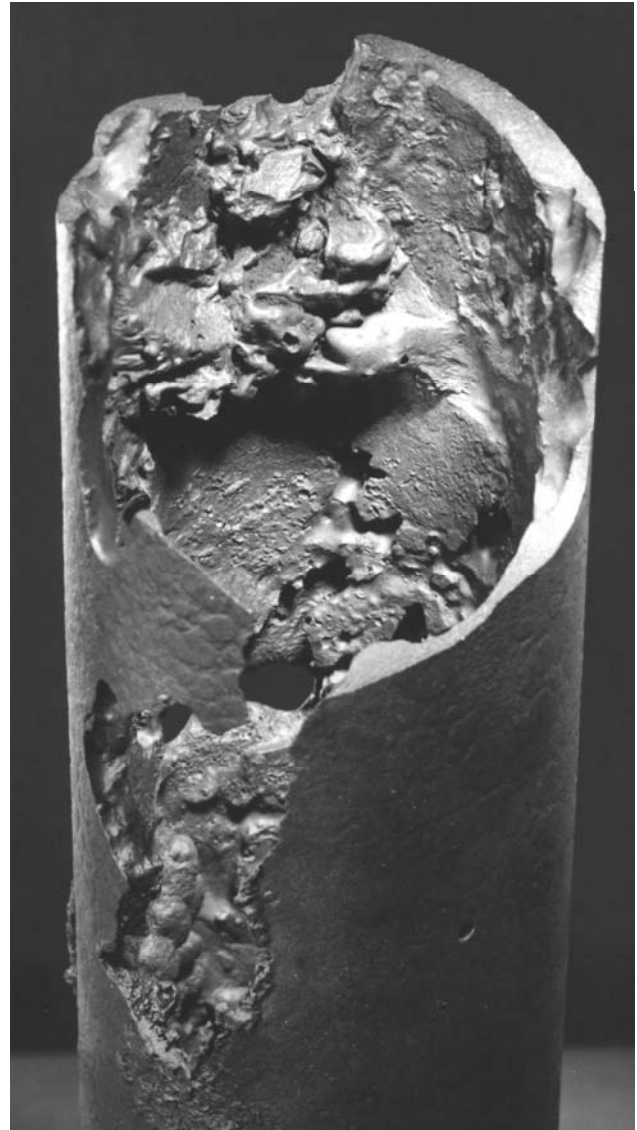
Figure 21—Oxidized Tube

c. Entry and exit points through the tube sheets of inlet and outlet tubes.

d. Tube supports, hangers and guides (inspect for deformation and cracking).

All tubes rolled into fittings should be examined for leakage in the rolled joint. Leaks in tube rolls and around plugs can often be found by observing the location of coke or oily deposits around headers when the heater is removed from service. An examination should also be made when the coil is under test pressure. The inspection should be visual and should in some cases be supplemented by feeling the tube at the rear face of the fitting for indications of leakage.

Visual inspection can sometimes be facilitated by holding a small mirror between the tube sheet and the fitting to obtain a view of the juncture between the tube and the fitting. Roll

Figure 22—Split Tube

Figure 23—External Corrosion

leaks will often not become detectable until a coil has been under pressure for 10 – 15 min. Leakage in the tube rolls can be either a nuisance or a serious problem, depending on the process and the operating conditions of the heater. Where there is no formation of coke, the leak may be stopped by rerolling the tube. Roll leakage is serious, however, in the case of a heater that is subject to coking and that operates at high pressure-temperature conditions or in poisonous or highly explosive vapor service, including phenol or hydrogen service. Oil leaking between the fitting and the outside surface of the tube can result in the formation of coke. This coke formation continues with service, and the force of the coke buildup can be sufficient to cause partial collapse of the tube end and to allow the tube to slip in the fitting. Under these conditions, leakage cannot be corrected by rerolling because the serration in the fitting's tube seat is full of coke, and the mechanical strength of the rolled joint is not improved by the rerolling operation. Figure 24 shows an example of a fitting and a tube that have leaked in the roll.

In the case of rolled-on fittings, the internal surface should be inspected visually for signs of deterioration and to ascertain the fittings' general physical condition. With sectional, streamlined fittings, the housing section (the part the tube is rolled in) should be examined for undercutting, the width and condition of the U-bend seats, and excessive erosion and thinning of the housing in the annular space (the section of the housing between the end of the tube and the inside edge of the U-bend seat). The inside surfaces of the U-bend should be examined for thinning and to ascertain their general condition. With solid fittings, the body section should be examined for undercutting, the width and condition of the plug seat, and erosion and thinning of the barrel section of the body (the cylindrical section with the plug seat at one end and the tube seat at the other end) and the cross port (the connecting section between the two barrel sections).

Figure 25 is a sectional view of a streamlined fitting. It shows the severe corrosion-erosion that can occur in the annular space and at the inside edge of the U-bend seat. The seating face on U-bends and plugs should be examined for corrosion, and the width of the seat should be checked against the width of the seat in the housing or body sections. If there is not a tight fit between the U-bends and the housing for the entire width of the seating surface or if the width of the seating surface is longer on one member, member erosion will be severe. This same condition should be checked on solid fittings at the closure area between the fitting body and the plug. Fittings should be examined to determine the fit and depth of seating between the U-bend or plug and the main body of the fitting. If the fitting seat has become enlarged through service, the U-bend or plug can protrude so deeply into the fitting that it is not possible to head up and get a tight joint when the fitting is under pressure. In the case of a sectional fitting, the end of the U-bend will contact the end of the tube or the tube stop, depending on the type of tube seat used. In the case of a solid fitting, the ears on the plug will contact the outside face of the fitting. Figure 26 shows an example of the type of corrosion experienced in U-bends.

In some cases, a rolled-in tube may also be welded to the fitting. There are two basic reasons for welding a tube to the fitting: (a) to stop leakage by means of a seal weld and (b) to

Figure 24—Fitting and Tube that Have Leaked in the Roll

improve the efficiency of the rolled joint by means of a strength weld. The use of a strength weld warrants careful consideration and justification. The types of defects that are commonly found are cracking, slag, and porosity in the weld. Any welding between the tube and the fitting, regardless of its basic purpose, should be examined carefully. Review by a materials or welding engineer is recommended before any welding to the tubes.

The exterior surfaces of the fitting body and the holding members should be inspected visually. The types of deterioration commonly found on the external surface of fittings are cracking, distortion, and mechanical wear. Cracking is usually confined to the fitting body or, in the case of welded fittings, to the welded joint. Locations in the fitting body that should be examined for cracking include the area around the plug or U-bend seat, the juncture of an ear or horseshoe holding section and the main body, and the ear or horseshoe section itself. If conditions warrant, a visual inspection of cracks can be supplemented by a range of applicable surface, near surface or volumetric NDT techniques.

Visual inspection of the ears, the holding members, and the dogs and caps of the holding members is performed primarily to detect distortion and wear, to determine whether there is a proper fit or contact, and to ascertain whether the strength of the fitting has been affected. Figure 27 shows an example of poor fit between the holding section and the cap on a solid fitting. The threaded portion of the holding screw and the dog or cap should be examined for excessive wear. Distortion that is not apparent to the eye may prevent proper assembly. The plug or U-bend seat in the fitting should be examined for

enlargement, deviations from roundness, change in the width of the seat, and damage to the seating surfaces. The tightness of this joint depends on these four conditions.

For welded fittings, visual inspection is limited to the external surfaces and to the weld attaching the fitting to the tube. The accessible external surfaces of the fitting should be examined closely for any indications of defects, particularly cracks in welds. The inspection of welds should cover a band of 1 in. – 2 in. (2.5 cm – 5 cm) on each side of the weld. Cracks may develop and remain entirely within the weld, or they may start in the weld and run out into the tube or fitting. The inspection of the heat-affected zone and adjacent parent metal is important. It is of paramount importance in the case of alloy welding. The visual inspection of a weld may be supplemented by a range of applicable surface, near surface or volumetric NDT techniques.

Cross-over sections of tubing used to connect sections of coil may be located outside of the firebox or enclosure but should not be overlooked during inspection of the heater. Movement of the several parts of the coil and changes in temperature can cause stress and fatigue. The surfaces of the tubing, especially bend section surfaces, should be examined for cracks.

9.3 WALL THICKNESS MEASUREMENTS

The determination of the wall thickness of the tubes and fittings in a heater is an essential part of inspection. Thinning deterioration mechanisms can be identified and monitored through wall thickness measurements. The two basic

approaches used to determine the wall thickness of piping and tubes are the following:

a. *Nondestructive methods.* These include the following:

1. Measurement by means of ultrasonic, laser or electromagnetic instruments.

2. Measurement of inside and outside diameter.

3. Measurement by means of radiation-type instruments or radiography.

b. *Destructive methods.* One destructive method is removal of a tube or tube section deep in convection banks and inaccessible for direct measurement of the tube wall. However, with the availability of internal intelligent pigs to measure wall thickness, the need for destructive examination is lessened.

Thickness monitoring locations (TMLs) should be selected to provide a means to determine the deterioration extent and to determine the deterioration rate. This usually involves, as a minimum, placing TMLs on all tube passes throughout the firebox. Particular attention should be made to tubes where phase changes occur and where the highest tube metal temperatures are expected. In addition, TMLs should be located on return bends to assess their deterioration. Note that the required thickness for a fitting may be different than that for the tube. For example, the inside radius of a short-radius return bend will have a higher required thickness. Typically, the number of tube thickness points is determined by criteria like a minimum of three points per tube or readings every 5 ft – 6 ft (1.5 m – 1.8 m). Often clean, corrosion-free services require less measurements, while high-corrosion services require more measurement points. Although spot thickness readings can identify general thinning, obtaining thickness in a circumferential band will better identify any localized conditions like corrosion grooving. Thickness measurements should be documented and monitored where bulging, sagging and bowing is observed.

Thickness measurements should be recorded and compared to historical readings in the same locations. These wall thicknesses provide a record of the amount of thickness lost, the rate of loss, the remaining corrosion allowance, the adequacy of the remaining thickness for the operating conditions, and the expected rate of loss during the next operating period.

Measuring and recording the thickness of tubes and fittings when they are newly installed is considered important. If this is not done, the first inspection period may not accurately reflect actual corrosion rates. If the installed thickness of the tubes is not available at the time of the first inspection, corrosion loss is usually determined on the assumption that the wall thickness' of the new tubes were exactly as specified on the purchase order. This is not always true, and hence an error in the calculation of corrosion rate may result.

The ultrasonic method for obtaining tube-wall thickness is the most commonly used method. For most corrosion inspections, straight-beam ultrasonic techniques are used. The sound is introduced perpendicular to the entrance surface and
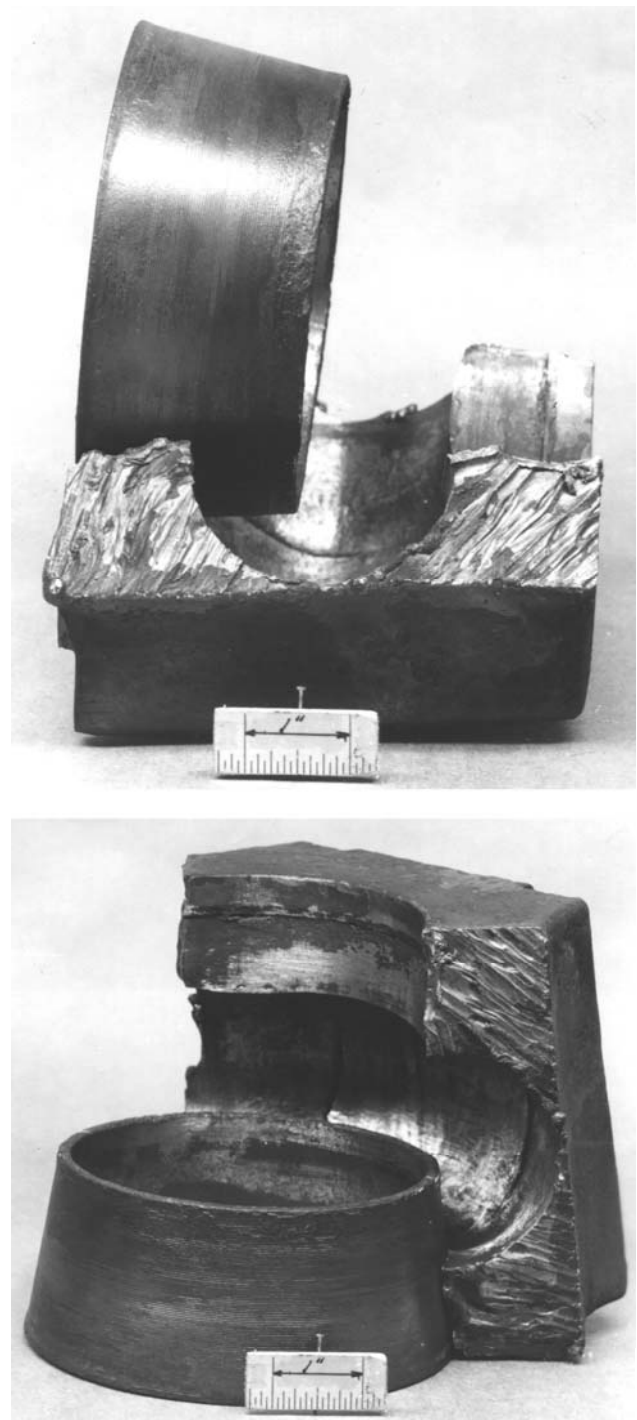
Figure 25—Corrosion/Erosion of the Annular Space in a Streamlined Fitting

reflects from the back surface, which is usually more or less parallel to the entrance surface. Proper cleaning of the external oxidation, or compensating for the thickness of the oxide layer is essential to properly assess metal loss rates. In many cases, cleaning the oxide will be the only viable way to make ultrasonic thickness measurements on the tube.

Figure 26—Corrosion of U-bends
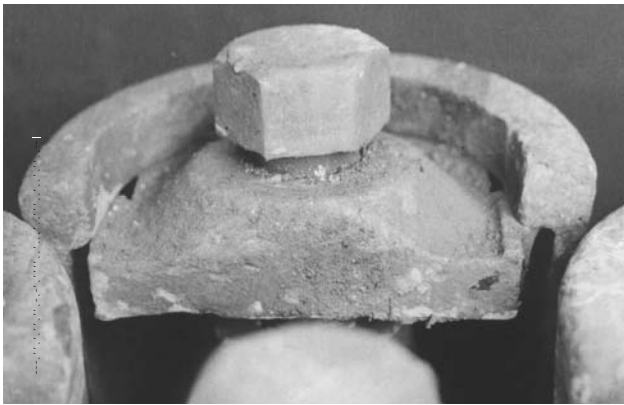
Figure 27—Spreading and Poor Fit of a Horseshoe Holding Section
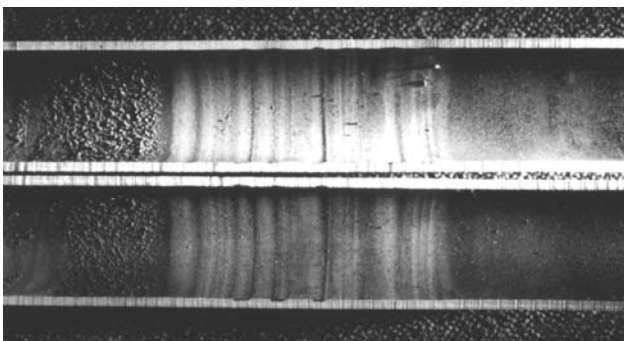
Figure 28—Tube Damage Caused by Mechanical Cleaning Equipment

Other methods to determine thinning of tubes that are less accurate than spot ultrasonic or radiographic inspection include local area scanning with electromagnetic acoustic transducer devices (EMAT) and global-tube length inspection using guided ultrasonic wave devices. In the first of these methods, the transducer compares a sample area of known thickness with the same material properties as the tube being examined and then either a hand-held or an automated crawler head is used to scan the tube areas from the OD. If a thin area is detected, follow-up inspection using spot ultrasonic or radiographic inspection is done. In the second method known as guided wave, an acoustic wave is introduced into the pipe that travels either axially or longitudinally along the tube. Defective areas as well as welds send back signals to a receiver that are analyzed to determine if flaws exist and at what length along the tube based on time and velocity, then follow-up inspection using spot ultrasonic or radiographic methods is done to confirm whether or not flaws truly exist at the identified locations. Although guided wave does not give thickness measurements of flaws detected, it is valuable in evaluating lengths of tubes where spot examination for localized corrosion would be prohibitive based on the amount of measurements that would be required.

At plugged headers where access to the tube ID is available, many types of calipers are available for measuring the inside diameters of heater tubes, including the simple 36-in. (91.4 cm) mechanical scissors and the 2-point pistol type, the cone or piston type, and the 4-12-point electric type. A caliper equipped to measure several diameters around the circumference of a tube is more likely than others to find the actual maximum inside diameter. It is general practice to caliper the inside diameter of a tube at two locations: in the roll and in back of the roll. Since an increase in internal diameter may not be uniform throughout the length of the tube because of erosion, erratic corrosion, bulging, or mechanical damage while cleaning, it is advisable to take several measurements to determine the worst section of each tube. On heaters where the pattern of corrosion is uniform and well established and mechanical damage is known not to exist, measurements for approximately 36 in. (91.4 cm) into the tube may suffice. The roll section of a tube in service should be calipered to locate the maximum inside diameter at any point between the back edge of the tube flare, or the end of the tube if there is no tube flare, and the rear face of the fitting or edge of shoulder left in the tube by the rolling tool.

There are also laser-based profilometry systems, which can provide high accuracy measurement along considerable lengths of the tubes. These devices offer high accuracy but require clean and dry conditions to provide consistent results. These systems are described in 9.6. Thinning at the ends of rolled-in tubes is usually caused by erosion or turbulence that results from change in the flow direction. This type of thinning may also result from frequent rerolling of tubes to stop leakage. Figure 28 shows an example of a tube damaged by a

Figure 29—Eccentric Corrosion of a Tube

cleaning head. In some cases, the outside diameter of the tube may be increased and will have the same general appearance as a tube with a slight bulge. Figure 29 shows an example of eccentric corrosion of a tube. The loss of wall thickness is not uniform around the circumference. In this type of deterioration, the most thinning usually occurs on the fireside of the tube. This type of corrosion is generally accelerated on the fireside because of the high metal temperature there. Eccentric corrosion may also be caused by external scaling. It is often difficult to determine whether tubes have become eccentric as a result of service, because the condition is not readily detectable by visual inspection of the tube ends. An indication of eccentric corrosion can sometimes be found by measuring several diameters at one location. A reliable means of detection is to measure thickness with ultrasonic laser or radiation-type instruments, but these tools can only be used on accessible tubes, usually the radiant tubes. Although this type of corrosion is more common on radiant tubes, it has occurred on convection tubes, usually on those adjacent to the refractory.

Each of the methods to determine wall thickness—measuring the inside and outside diameters of tubes, measuring by means of ultrasonic, laser or electromagnetic instruments, and measuring by means of radiation-type instruments or radiography—can be used to check the thickness of heater tubes.

Electromagnetic techniques cover a broad range of applications including eddy currents, remote field eddy currents and magnetic flux leakage. Each has its own benefits and limitations. Remote field eddy current is commonly used on ferromagnetic tubes. It has benefits in that it can measure wall thickness to within 5% of the nominal wall and will provide indications of other defect mechanisms such as cracking. Most of these techniques are applied using an electromagnetic sensor device that is drawn through the ID of the tube

which may require cutting the tube U-bends at the ends to gain access.

9.4 TUBE DIAMETER/CIRCUMFERENCE/SAG/ BOW MEASUREMENTS

Tubes sustaining creep/stress rupture damage will exhibit diametral growth or sagging. Shining a flashlight along the tube length can be a quick way to identify major bulges, sags and bows. Frequently, the diametral growth will be localized to a small section of the tube and appear as a bulge. The bulge may be limited to the hot face of the tube and, therefore, will not be a uniform circumferential growth. Diametral growth occurs from the operating hoop stresses. Localized bulging can result from internal coke deposits causing the wall temperature to become excessive. Another potential cause is flame impingement, which could elevate temperatures. It is not uncommon to find evidence of both since the elevated temperatures can promote coking in some hydrocarbon services. The amount of bulging provides an indication of the extent of damage up to the point of failure.

Tube sagging is another indication of creep damage or short-term overload except in this case, the stresses are longitudinal and usually result from inadequate support or excessive temperature. Excessive sagging is often caused by short-term overheating because of runaway decoking or loss of flow. In such cases, the tubes should be hardness checked to insure adequate strength remains, and the thickness should be measured. If sagging is caused by long-term creep, a criteria such as 1% – 5% elongation should be used depending on the material.

Tube diameter or circumferential measurements provide an indication of the amount of damage. These measurements can be compared to original measurements to determine the amount of bulging and is often presented as a percentage growth/bulge. Measurements of the circumference can be made with a narrow tape measure often referred to as "strapping". Other techniques include tube gauges calibrated to specified diameters to determine growth or are set to specific percentage growth and used as "pass-fail" gauges. Tube gauges can be fabricated from thin SS plate (0.10 in. – 0.125 in. [0.25 cm – 0.32 cm]). The cutout dimension is the sum of tube OD, mill out of round tolerance per ASTM-530 (approximately 0.0625 in. [0.16 cm]), and creep/stress rupture growth. Typical gauges are made for 2%, 5%, and 10% creep growth. These measurement techniques may not be precise if the tube is heavily scaled. In these instances, the growth may appear more severe if the scale is not removed. One could increase the tolerance of the tube gauge to account for some scale thickness.

The circumference and diameter can also be accurately determined using crawler devices equipped with transducers. The transducers can be either ultrasonic or eddy current lift-off type. These types of crawlers are commonly used when inspecting reformer tubes.

Tube sags are estimated as the distance offset from straight. In reality, the tube is flexible and will have some natural amount of sag and so the measurement will not be precise. Sag measurements can be used similar to diameter measurements to estimate the extent of creep. A significant amount of sag can be tolerated before rupture is a concern and so this condition is not considered serious unless it prevents cleaning or causes headers to jam and wedge against other headers or against the sides of the header compartment. In convection sections, sagging of the tubes in upper rows to a point between those in lower rows can prevent the free passage of flue gas around the tubes. This condition, called nesting, will cause overheating of adjacent tubes and draft loss. If this condition is found, the offending tubes should be replaced.

9.5 PIT DEPTH MEASUREMENTS

General pitting of the external tube surface should be evaluated with a pit depth gauge to assess the depth and to estimate a pitting rate. The gauge should be used in conjunction with an ultrasonic thickness gauge to more accurately determine remaining wall thickness. Scale on the tubes will mask pits and so it is prudent to remove scale in selected areas to find the deterioration.

9.6 INTELLIGENT PIGS/IN-LINE DEVICES

Recent technological advances have produced "intelligent pigs" that can perform multiple inspection functions from inside of the tube. The instruments use laser profilometry to measure tube inside diameters. Simultaneously, ultrasonic transducers measure the tube wall thickness. The instruments are outfitted with multiple ultrasonic transducers, which permit a high density sampling. These inspection tools are useful in addressing creep and corrosion deterioration.

The intelligent pigs are self-contained units and are capable of navigating the tight radius U-bends. This is a significant advantage for inspection of convective section tubes that can not be accessed. Generally, convective tubes only receive a rudimentary visual inspection and their condition is estimated from inspections performed on other components of the heater like the convective tube U-bends and radiant tubes. The pigs are propelled through the tubes using water and allow a thorough, complete inspection of a tube pass. The pig also contains a positioner so the location of deterioration can be identified. Users are cautioned to understand the capability of the intelligent pig to accurately measure the wall thickness and tube inside diameter of U-bends and other fittings. The complex geometry of these locations can make inspection difficult.

Other technological advances for in-line devices have produced various other pig or crawler technologies. One method

is an internal ultrasonic pig that uses an internal rotary inspection system. The pig is designed to maneuver around bends being pushed along by motive water force. The device has a spinning ultrasonic immersion transducer (such as a transducer aimed at an angled-spinning tungsten mirror used for reflection or a specially designed membrane that allows transmission and protects an angled spinning centrally located transducer head). This method is accurate if there is no debris or scale on the tube ID and can very accurately determine the extent of ID and OD corrosion.

Various crawlers have been designed to navigate the ID of a tube along the length and around bends. These crawlers have been equipped with spot ultrasonic devices, spot pit-depth gages, and digital video cameras.

9.7 RADIOGRAPHIC EXAMINATION

Radiographic examination is often employed to measure tube wall thickness and identify the presence and thickness of internal coke deposits. Radiography can show a variation in thickness of a minimum of 2% of total thickness. Thickness is determined by directing the rays tangentially to the tube wall and recording the radiation on a film behind the tube. By comparing with some geometric standard projected on the film, the wall thickness can be determined. Performing radiography at various angles to the tube will allow wall thickness measurements in other planes. Additionally, localized thin areas can often be identified by radiography that could be missed by other techniques, like spot ultrasonic readings. For example, radiography is often employed to identify wall loss on return bends in erosive service.

9.8 BORESCOPE/VIDEOPROBE

The internal visual inspection of heater tubes is limited to heaters with fittings of the removable U-bend or plug type. On tubes up to about 30 ft (9 m) in length, it is possible to view the entire interior reasonably well if a light is inserted at the end opposite the one at which the tube is being examined and the examination is made from both ends of the tube.

The inside surface of a tube can be examined with optical instruments. Considerable time is required to inspect the full length of tube. Consequently, optical instruments are generally used for the more thorough inspection of questionable areas revealed by visual inspection or to assess internal fouling/deposits Most optical equipment today allows videotaping of the images. The videotape can serve as a record of the internal inspection and allows better comparison of conditions in the future if needed.

The internal visual inspection of tubes can be made to locate and determine the extent of the following types of deterioration commonly experienced in heater tubes:

a. Selective, spot-type, or pit-type corrosion.
b. Thinning of tube ends.
c. Cutting or other cleaning damage.
d. Loosening of the tube roll and flare.
e. Erosion.
f. Fouling/coke deposits

Figure 30 shows examples of the spot- or pit-type corrosion often found in heater tubes. This type of corrosion is one of the most difficult to detect. Visual inspection can be hindered if the internal surfaces of the tubes are not free from coke and any other foreign matter. Mechanical cleaning will not always reveal spot- or pit-type corrosion. If this type of corrosion is apparent or suspected, the inside surfaces of the tube at the tube ends might be cleaned using an acetylene torch to burn coke or gritblasting material out of the pits. Gritblasting would be preferred and least likely to damage the tubes as could happen with an acetylene torch.

9.9 HARDNESS MEASUREMENTS

Hardness testing of ferritic heater tubes can indicate that the tubes experienced a severe overheat or identify some forms of embrittlement or carburization. A severe overheat exceeding the lower critical transformation temperature of the metal can cause a hard microstructure to result if the cooling rate is fast enough. If the cooling rate is slow, softening may actually occur. The hard tubes can be susceptible to brittle fracture if they are mishandled or impacted. They can also be susceptible to some forms of stress cracking like sulfide stress cracking during downtime. Refer to API Std 530 for a listing of material transformation temperatures.

Hardness testing of ferritic heater tubes can also be used to qualitatively determine how evenly fired are the tubes. In Cr-Mo tubes, thermal softening will occur at elevated temperatures. Tubes in the firebox which are softest may represent the hottest tubes. Softening can indicate a reduction in tensile strength for a ferritic material.

885°F embrittlement and external carburization may be identified through hardness changes. With each mechanism, there will be a noticeable increase in hardness. However, if the depth of carburization is not significant, the field test instruments may not identify a change and measure the base metal hardness below the hardened layer.

Hardness measurements can be made using available sonic and impact field testing instruments. Caution should be taken when obtaining hardness measurements to assure adequate surface preparation. Surface roughness and oxide scale can dramatically affect the hardness value.

In general, tubes with hardness outside the normal range (either excessive hardness or excessive softening) should be evaluated for continued service and appropriate repairs made if necessary. This evaluation may require the review of one knowledge of the service and potential deterioration mechanisms that may result.
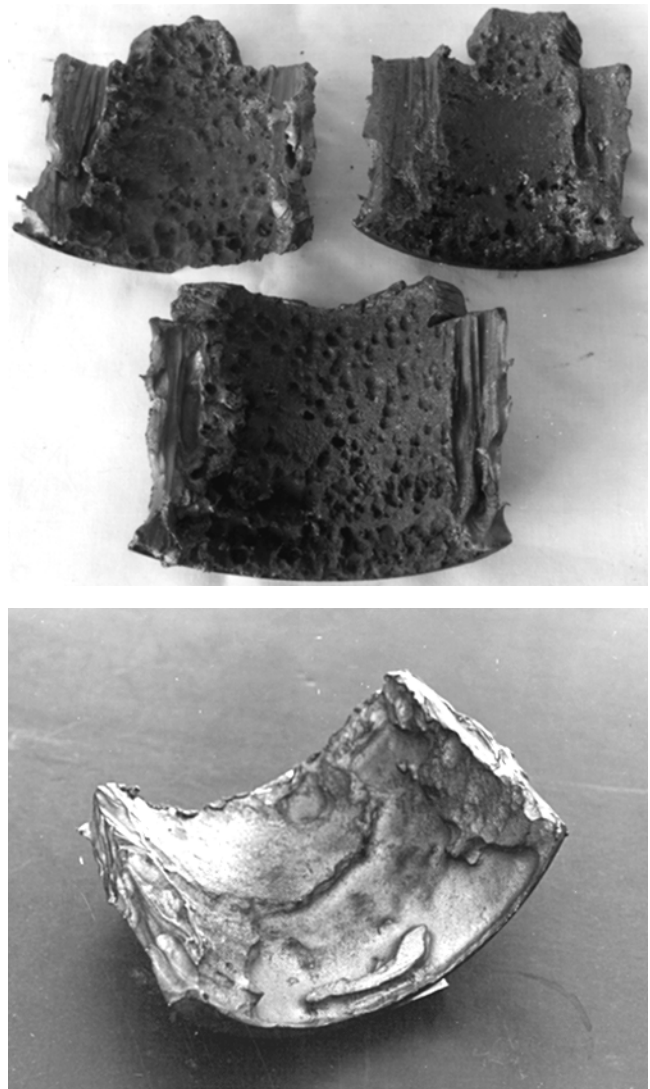
Figure 30—Spot- and Pit-type Corrosion

9.10 DYE PENETRANT AND MAGNETIC PARTICLE TESTING

Dye penetrant and magnetic particle testing often supplement a visual examination for cracking. If cracks are suspected or expected based on experience, one or more of these techniques are employed. Austenitic stainless steel components are often dye penetrant inspected while ferritic metallurgies receive a magnetic particle inspection for cracks. Austenitic stainless steel tube welds are often penetrant tested when external PASCC is a concern. Other common locations where either dye penetrant or magnetic particle testing is used depending on the metallurgy include inspecting attachment welds of tube skin thermocouple, tube hangers, and tube supports. Dye penetrant can be used on ferritic steels as well; however, it is more common to magnetic particle test those components since magnetic particle is quicker.

9.11   IN-SITU METALLOGRAPHY/REPLICATION

As indicated previously, certain types of deterioration experienced in heater tubes result from some change in metallurgical structure. The more common types of deterioration are carburization, decarburization, the initial stages of external stress corrosion cracking, creep, fatigue cracking, and some forms of hydrogen attack.

It is possible to detect most of these types of deterioration in the field by visual inspection, nondestructive testing, in-situ metallography, or replication. Carburization and decarburization can be determined accurately by a chemical or physical test. Most of the testing must be done by specially trained personnel. Damage that results from some metallurgical changes can be determined by a wide range of NDT techniques designed for the characterization of material degradation e.g., ultrasonic, magnetic-particle, and liquid-penetrant testing. In-situ metallography/replication is rarely used alone for evaluation of these deterioration mechanisms. It is best used in combination with other NDE techniques.

9.12   DETAILED EXAMINATION AND DESTRUCTIVE TESTING OF TUBE SAMPLES

When deterioration can not be effectively identified or monitored in service, obtaining tube samples for destructive examination may be appropriate. Metallographic examination can be performed for deterioration mechanisms, such as decarburization, carburization, hydrogen attack, and stress cracking. Physical testing of creep life can be appropriate for severe services and for affirming any calculated remaining life. Oftentimes, calculated remaining tube life include several assumptions of tube operating history that can lead to inaccurate results. The density of scale samples can be measured and may provide information on the tube operating history. Furthermore, physical properties of the tubes can be measured that can assist in damage assessments. Additional information is available through other technical documents.

In many heaters, tubes are not accessible for an internal visual inspection. Some companies make a practice of thoroughly inspecting all tubes that are condemned and removed from a heater, regardless of the reason for the tubes' removal. This inspection is made by cutting a tube into short sections of 2 ft – 3 ft (60 cm – 90 cm) so that the inside surface can be examined. Measurements for metal-wall thicknesses are made at the ends of each section. In some cases, the sections are split longitudinally, thus exposing the entire inside surface for examination. The ends of the tube rolled into the fitting should be removed for examination. They may then be inspected to determine the general condition and effectiveness of the rolled joint.

When external deterioration, including that due to oxidation, scaling, cracking, and external corrosion, is suspected-especially in the case of convection tubes, representative tubes may be removed from the heater and then cleaned and examined thoroughly. The selection of the tubes to be removed may be guided by the tube locations in the heater, the length of time the tubes have been in service, and the general appearance of the tubes in the area. If the tubes chosen for inspection are found to be defective or unfit for further service, other tubes in the same area and of the same or similar age and general appearance should also be inspected.

9.13   TESTING OF TUBESKIN THERMOCOUPLES

During outages, tube skin thermocouples should be tested for accuracy and potential failure. Tube skin thermocouples have a reputation for being inaccurate and failing prematurely. Inspection and testing during outages is an important step to improve reliability. Thermocouple leads are often the root failure by being exposed to flame and radiation, or lifting off the tube surface. Attachment welds should be inspected with dye penetrant for cracks that can cause the thermocouple to read firebox temperature. The sheathing protecting the thermocouple leads should be inspected for any breaches and kinks.

Some thermocouples will have a temperature drift due to long term exposure or temperature cycling. Procedures can be developed to determine if the tube temperature is accurately measured by heating an area adjacent to the tube and monitoring the temperature rise. A calibrated contact pyrometer can measure temperature at that point and be used for comparison to the thermocouple.

9.14   MAGNETIC TEST FOR CARBURIZATION

Austenitic tubes are essentially nonmagnetic. Carburized areas of the tubes become magnetic, and if these areas are large, they can be detected with a magnet. A magnet on a string dropped down a tube will indicate areas that are magnetic but will not indicate the depth of carburization. Some instruments and field services can relate the degree of magnetism to the depth of carburization. Most of the instruments are proprietary, and the field services are limited.

A rule of thumb states that up to 50% carburization can be tolerated on stream before loss of strength materially affects tube life. Although this rule of thumb indicates that a tube with 50% carburization should be replaced, it does not mean that less than 50% carburization will allow the tube to remain in service until the next shutdown. Factors including the rate of carburization, the expected service time until the next shutdown, the amount of excess metal, and changes in pressure and temperature must be taken into account.

9.15   HAMMER TESTING

A hammer test has been an accepted method of exploring the surface of metal objects to locate areas of reduced wall thickness; however, other NDE techniques have made this technique outdated. When a hammer test is made, the variations in metal-wall thickness are indicated by the feel and

rebound of the hammer and by the sound produced. One value of hammer testing is that it is a good way to determine whether the scale on the outside surface of a tube is an oxide due to overheating or a product of fuel combustion. Although combustion deposits may vary in texture depending on the fuel used, the scale that results from oxidation is generally harder, requires a stronger blow to be knocked loose from the tube, and is of a flakier texture than scale from the products of combustion. A magnetic check of the material offers the most conclusive test; oxide scale is magnetic, and scale from the products of combustion is nonmagnetic.

Heater tubes that have been in service may become temper embrittled and have low ductility at ambient temperature. To avoid any possible damage, carbon and alloy steel heater tubes should have a minimum metal temperature of about 60°F (15°C) during hammer tests. In certain cases, the hammer testing of tubes can lead to damage. Austenitic stainless steel tubes may suffer stress corrosion cracking at areas that are cold worked by hammering. Cast tubes and chromium alloy tubes should not be hammer tested when tubes are heavily carburized.

9.16 INSPECTION OF REFORMER TUBES

9.16.1 Ultrasonic Shearwave/TOFD

Creep cracking of cast tubing used in steam/methane-reforming and pyrolysis heaters usually starts near the mid-wall of the heater tube and is normally longitudinal, resulting from hoop and thermal stresses in the tube.

Ultrasonic equipment that implements through transmission (pitch catch) has been used to inspect tubes. With this attenuation method, a grading of percent transmission is made to draw some conclusions about the degree of fissuring, which attenuates transmission of the ultrasound. Since tubes vary in the amount of equiaxed and columnar grains, the calibration standard used should reflect the tubes being inspected. Without an adequate standard, the judgment of percent transmission may be in error. In any case, subsequent inspections with this method may show a high degree of overlap or scatter in damage states when compared with previous inspections.

Ultrasonic time-of-flight diffraction (TOFD) has also been used to compliment through transmission tube inspection. TOFD is a method that detects diffracted waves coming from the tips of flaws and is best used to detect severe flaws, such as fissures in reformer tubes.

Assessment of degradation using these ultrasonic techniques may be accomplished by performing a baseline examination and recording trends over a period of time. A "snapshot" inspection may not adequately assess damage because of the many variables involved.

Evaluations of tubes have indicated that the initiation of internal fissuring will eventually cause the tube to fail. Major fissuring, which is easily detected, indicates that failure may occur in up to 10,000 hours. Since such a wide range of tube life is available for evaluation, a risk analysis should be made. Tubes that are expected to fail in less than 1 year should be replaced. Tubes that may be good for several years may be allowed to remain in service until the next scheduled shutdown, when they can be re-inspected or replaced. Replacement tubes can be ordered and would be on hand when needed. All these evaluations must be based on the assumptions that the original design and casting quality are adequate and that operation, especially with respect to tube metal temperature, is within the design limits.

9.16.2 Radiographic Inspection

Radiographic methods have been used to inspect reforming tubes. However, tight cracks cannot readily be seen unless they are normal to the film. When catalyst is in the tubes, the tight cracks will be harder to find because of the varied film densities and the catalyst edges that are present. It is desirable to remove the catalyst from the tubes, but this is not normally practical or economical when the catalyst is not scheduled for replacement.

Radiographs can show cracks regardless of whether there is catalyst in the tubes. However, radiography may not be as sensitive to initial fissuring and tight cracks as is ultrasonic inspection. If radiographs do show cracks, the cracks can be judged on the basis of how many there are and how wide they appear to be on the radiograph. Normally, dark, wide cracks on a radiograph indicate that the cracks are open to the inside diameter of the tube and that the tube should be replaced.

9.16.3 Eddy Current

Eddy current inspection of stainless steel reformer tubes is employed to identify crack-like defects. The principal behind eddy current inspection is that a defect changes the energy flux induced in the material through a magnetic field. For austenitic stainless steels, the energy field penetrates up to 1-in. deep which is greater than the wall thickness of most tubes. This technique is performed externally so that catalyst does not need to be removed and allows rapid inspection of tubes at travel speeds of up to 1 ft/s (0.3 m/s).

Some operators have found it useful to assess data from a combination of technologies, i.e., diametral, eddy current, and ultrasonic. The advantage of using multiple technologies is a cross-comparison of results, particularly for the case where a damage mechanism may be sensitive to multiple methods.

Most commercial equipment will grade each tube in terms of relative creep damage based on characteristic signals within a particular type of material. In addition, some equipment can also measure wall thickness ultrasonically and tube diameter as it travels along the tube. Diametric changes in tubes can also be determined through laser profiling from the tube ID. These additional measurements combined with eddy current and/or ultrasonic test results can allow an assessment of relative creep damage. Grading of individual tubes com-

bined with subsequent repeat examinations may enhance tube damage trending and ultimate tube replacement planning.

9.16.4 On-stream Repairs

Heaters with external pigtails have been operated to tube rupture. In such cases, pigtail nipping has been used to crimp the inlet and outlet pigtails to cut off the inlet and outlet gases. Designs for pigtail nippers are available but should be checked to ensure that the hydraulic-system pressure is enough to cut off all flow (usually over 5,000 lbf/in.^{2} [34,474 mPa] gauge), that stops are on the anvils to prevent the pigtail from being cut off (the design should be based on wall thickness), and that some locking device is available to keep the crimp closed when the pigtail nipper pressure is released for removal of the hydraulic cylinders.

10 Boiler Outage Inspection

10.1 GENERAL

A preliminary inspection of the inside of all equipment to the extent practicable before the boiler is cleaned is good practice. The location, amount, physical appearance, and analysis of mud, sludge, or scale deposited on the inside of shells and drums will provide information about the effectiveness of the feedwater treatment, blowdown operation, and methods of cleaning needed. The preliminary inspection may also be helpful in determining which parts of shells or drums require the closest inspection. Heavy internal or external scale found either on drums or tubes is an indication to inspect the area closely for metal overheating. Flow marks in fly ash or soot deposited on the baffling can help locate gas leaks in it. Any conditions which indicate that close inspection is required after cleaning should be noted.

After the preliminary internal inspection and general cleanout, the detailed inspection may proceed. Inspection personnel should be familiar with the operation and design of the type boiler for the inspection of components should consider its ability to operate properly for the next run length. To perform an appropriate inspection, access is necessary to all major components. All manhole covers and a sufficient number of handhole plates should be removed for inspection. Representative tubes should be made accessible for much of this length as possible from inside the firebox. Steam drum internals may also need removal to allow access to tubes. Ordinarily, it is not necessary to remove insulation material, masonry, or fixed parts of the boiler, unless defects or deterioration peculiar to certain types of boilers are suspected. Where moisture or vapor shows through the covering, the covering should be removed and a complete investigation made.

In preparation for maintenance outages, on-stream inspections should be performed in advance to facilitate defining the appropriate outage worklist, see 11.4.

10.2 PIPING

A visual inspection should be made for evidence of leakage in pipe and threaded or flanged pipe joints. Water leaks may be detected by the presence of moisture or deposits at the point of leakage and steam leaks by the appearance of the adjacent metal.

Leaks may sometimes be a result of strains caused by deformation or misalignment of the piping system. Deformations may be caused by lack of provision for expansion or by improper supports. If not eliminated, pronounced deformation may place strains of sufficient magnitude to cause failure in small connections. A careful inspection should determine if such defects are present.

When flanged connections are opened, gaskets and gasket seats should be inspected carefully. Gaskets may be damaged by leakage or by improper centering of the gasket when the joint is made up. Gasket seats may be scored by a steam leak at the joint, improper handling, or careless use of tools. Seating surfaces should be inspected for tool marks, other mechanical abuses, and evidence of the type of erosion commonly called steam cutting or wire drawing. Mechanical damage may lead to erosion if not corrected. Either a scored seat must be machined to provide a proper gasket face or the flange must be replaced; otherwise, leaks will recur. Before joints are re-made, ring gaskets should be examined to determine their fitness for reuse. Other types of gaskets should be replaced with new ones.

10.3 DRUMS

All internal surfaces and the connections to all outside attachments, including water-column connections and safety-valve nozzles, should be examined for deformation, corrosion, pitting, grooving, cracking, scale deposits, and sludge accumulation. Special attention should be paid to all seams, whether welded or riveted, and to the areas adjacent to them. If seams are heavily coated, they may have to be grit blasted or wire-brushed before a visual examination is possible. Welded seams and connections should be examined for cracks. Riveted joints should be checked for loose or broken rivets, cracking, or other evidence of distress. Rivets should be hammer-tested for soundness. If there is any evidence of leakage or other distress in lap joints, it should be investigated thoroughly, and if necessary, rivets should be removed or the plate should be slotted to determine whether cracks exist in the seam.

Corrosion along or immediately adjacent to a seam may be more critical than a similar amount of corrosion away from the seams. Such points should receive a close visual examination and ultrasonic wall thickness measurements. Grooving and cracks along longitudinal seams are especially significant, as they are likely to occur when the material is highly stressed. Severe corrosion is likely to occur where the water circulation is poor. Both the internal and external surfaces of

the drum need examination. The top external surface of drums should be cleaned of all deposits, and the surface should be examined for corrosion.

When a more thorough examination for cracks and other defects in plate and weld metal is desired than can be obtained by a visual inspection, a radiographaphic, magnetic-particle, ultrasonic, or dye-penetrant tests may be used as follows:

a. Radiography can identify cracks below, at, or near the metal surface if they are of sufficient size and oriented properly to make a discernable change in the film density.
b. Dry powder magnetic-particle test can determine cracks at or near the surface.
c. Wet fluorescent magnetic-particle test uses a black light for finding discontinuities and is more sensitive to tight cracks than dry powder.
d. Ultrasonic straight beam and shearwave tests can indicate discontinuities in the metal at any depth.
e. Dye-penetrant test is used to locate surface cracks in large or small areas.
f. Electromagnetic inspection techniques may be used for surface and sub-surface crack detection instead of magnetic particle and dye penetrant testing.

Inspection of the steam drum should also include observations of the normal water level. Any bulges or uneven areas that would indicate excessive heat input from leaking fireside baffles should be noted. Evidence of poor circulation may be indicated by waterline gouging along the top half of the top one or two rows of downcomers. This is sometimes accompanied by flash marks on the drum surface at the tube openings. If a sample of the boiler drum is needed for chemical analysis or microscopic examination, a section may be trepanned from the wall. The resulting cavity would need to be evaluated for repair by a suitable method such as welding. Normally, the wall thickness is measured ultrasonically and recorded to establish corrosion rates and remaining life estimates.

Safety-valve nozzles and gauge-glass connections, especially the lower connections, should be examined for accumulations of sludge or debris. A flashlight should be used to visually inspect the nozzle or connection. If the inside cannot be observed directly, a small hand mirror may be used for indirect observation. Special forms of illuminating equipment, mirrors, and magnifying devices are very useful for this type of inspection. When the boiler contains more than one drum, usually only one of the drums will have safety valves on it.

Any manhole davits should be tested for freedom of movement and for excessive deformation. Manhole and handhole cover plates and nozzle seats should be examined for scoring in the manner described in preceding text for pipe flanges. Cover plates should be inspected for cracks.

Drum internals and connections to the drum should be inspected when the drum is inspected. Drum internals, including internal feed header, distribution piping, steam separators, dry pipes, blowdown piping, deflector plates, and baf-

fle plates, should be inspected for tightness, soundness, and structural stability. The vigorous turbulence of the steam and water mixture present in the drum may vibrate such parts loose from their fasteners, attachments, or settings. When these parts are welded in place, it is not uncommon for the welds to crack from vibration. Welds or rivets attaching internals or connections to the drums should be inspected in the same manner as welds or rivets in the drum proper. Steam separators and baffles should be carefully inspected for tightness, corrosion, and deterioration, and associated welds should be checked for cracks. Any bypassing of the steam separator will permit carryover into the superheater, causing salt deposition, resultant overheating, and possible tube failure. Steam separators should be free from deposits that might impair their operation. Some boilers do not have steam separators and depend entirely on dry pipes for water separation.

The holes in dry pipes should be free from any deposits that might restrict flow. Since dry pipe holes are in the top of the pipe near the top of the drum, it may be necessary to inspect the holes indirectly with a hand mirror. Any drain holes in the pipe should also be inspected for freedom from deposits and scale. Not all drums contain dry pipes.

Tube ligaments should be examined for cracks. If tubes are covered by baffle or deflector plates, a few of these plates should be removed to permit a spot check of the condition of the tubes behind them.

The methods described in API RP 572 are applicable to all drums forming any part of a steam boiler.

10.4 WATER HEADERS

Each handhole and handhole plate seat should be examined for erosion, steam cutting, tool marks, and other damage that might permit leakage. If the plate has leaked previously, it should be checked for trueness and possible deformation. Seating surfaces and faces of handholes should be examined for cracks. It may be necessary to use a hand mirror to inspect the handhole seats.

The inside surface of the headers should be inspected for corrosion and erosion. The location and amount of scale buildup should be noted, and the tube ends should be checked for pits, scale, cutting or other damage from tube cleaners, and deposit buildup. If there is considerable scale or deposit buildup, the flow may be restricted to the point that tubes become overheated because of insufficient circulation. Deposits and scale should be removed with a scraper and the depth of coating determined. Lower waterwall headers are particularly susceptible to heavy deposit buildup.

Downcomers and risers should also be inspected for this type of deposit. Thickness readings of headers should be obtained periodically by ultrasonic technique. The headers should be calipered whenever tubes are removed.

External surfaces of headers should be examined either directly or indirectly with mirrors, and particular attention

should be paid to the points where tubes enter the header for indications of leakage from the tube roll. The header surfaces adjacent to tube rolls and handholes should be inspected for cracks. If external inspection of headers reveals pitting, thickness measurements should be made using ultrasonic techniques.

10.5   SUPERHEATER HEADER

Inspections of superheater headers should be conducted in a manner similar to that for waterwall headers. Usually, not all superheater handholes are opened at every boiler shutdown or cleanout unless tubes are to be replaced or other repairs are to be made. However, a few should be removed at every shutdown as a spot check. If the unit cycles frequently, some of the ligaments between tubes should be examined for cracking with either UT or WFMT, depending on access.

Since only dry steam passes through the superheater, there should be few or no deposits present in the headers or tubes. If deposits or scale are present in any degree, immediate steps should be taken to determine why they are present. In addition, the extent of the deposits or scale should be investigated. Superheater tubes with a moderate deposit of scale will rupture readily from effects of overheating. Indications of scale or deposits should lead to an investigation of the steam separators, dry box, operating drum level and fluctuations, blowdown rates, and water quality.

10.6   TUBES

All tubes should be inspected for signs of overheating, corrosion, and erosion. Waterwall tubes and generating tubes nearest the burner are particularly susceptible to overheating and should be closely examined for bulging, blistering, quench cracking, sagging, and bowing. Inspection for blisters and local bulging is easily accomplished by shining a flashlight parallel to the length of the tube so that bulges, blisters, and other deformities cast shadows. Cleaning of a slagged tube may be necessary to find minor blisters. The tube's circumference should be measured at the blister or bulge.

Boiler tubes should be inspected at the steam-drum connection for gouging and caustic corrosion due to steam blanketing. Roof tubes are generally designed for heat pickup on one side only. Therefore, a sagging roof tube due to burned-out hangers is especially susceptible to overheating. These tubes should be straightened, and the hangers should be replaced.

Waterside corrosion, generally caused by faulty water treatment, can usually be detected by ultrasonic thickness measurements of representative tubes. Measurements can also be made from inside the steam drum for a distance of 8 in. – 10 in. (20 cm – 25 cm) into the tubes. The locations measured and thicknesses found should be recorded to establish a tube corrosion rate.

Fireside corrosion is generally caused by moisture that accumulates in fly-ash deposits. Although fireside corrosion may occur anywhere in the tube nest, it usually occurs where the tubes enter the lower drums or headers. Moisture-causing fireside corrosion can come from leaks in tubes, drums, headers, and faulty steam soot-blower shutoff valves. Other sources can come from rain water through stacks and roofs, and from condensation from the atmosphere during downtime. Specific attention should be given to tubes near any openings, like viewports, as air in-leakage can cause increased external corrosion.

Steam tubes should be examined for the type and thickness of internal scale. Ultrasonic techniques exist to nondestructively measure steamside scale thickness from the outside surface. An assessment of tube remaining life can be made from the measured scale thickness of the tube if operating in the creep range as mentioned in 12.3.

When a tube rupture occurs, the tube should be visually inspected. Its appearance may indicate the cause of failure. If the cause is not evident, samples of the tube in the original condition, with deposits and scale intact, should be taken and analyzed chemically and microscopically. The tube sample should be cut at least 1 ft (30 cm) on either side of the failure.

The inside of bent tubes and of straight tubes, as far as it is accessible, should be examined with strong illumination. Straight tubes should be examined by illuminating the end away from the observer.

Internal cleanliness is required to conduct a satisfactory tube inspection. When tube cleanliness is in doubt, a turbine-type cleaner should be used to remove internal deposits. The loosened deposits should be trapped at the discharge ends. The weight of trapped deposit and the internal surface area will indicate the average thickness of the deposit removed.

Fiber optics or borescopes are of limited use on bent tubes but are satisfactory for viewing straight tubes and may also be used to inspect tube internals. Tube ends should be checked for proper projection and flaring. Calipers, micrometers, laser based instruments and ultrasonic instruments can be used to measure tube diameters, dimensions of bulges on tubes, depth of corrosion pits, and tube-wall thickness. These measurements are of great value in determining the effects of corrosion and erosion and in estimating the future lives of the parts measured. Tubes should also be checked for any cutting due to cleaning. Figure 31 is a photograph of the interior surface of a tube that has been damaged by operating a tube cleaner too long in one place.

Erosion of exterior surfaces is caused by the impingement of fly ash or raw fuel solids at excessive velocity or by soot blowers. Fly-ash tube erosion can be arrested by installing shields or by reducing the gas velocity. If erosion is due to soot-blower medium impingement, the soot blowers should be checked for alignment, warpage, and operating wear. Wastage of exterior tube surfaces can be caused by flame
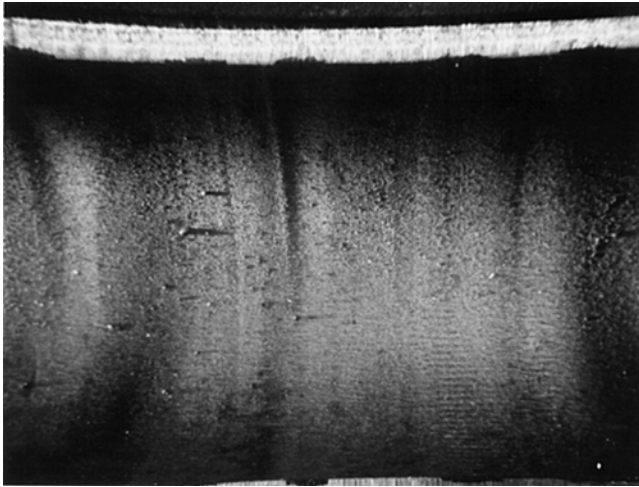
Figure 31—Interior Surface of a Tube Damaged by Operating a Tube Cleaner Too Long in One Place

impingement, which should be corrected by adjustments to the firing equipment.

Some types of waterwalls have tubes widely spaced and the area between the tubes covered by steel fins attached to the tubes. The fins may become overheated and burn or crack. The fins should be inspected for cracks that may extend into the tubes. The tubes should be inspected for signs of leakage that may result from the cracks.

Waterwall tubes should also be checked for alignment. All gas passages should be inspected for slagging or bridging from fly ash or slag buildup. The first gas pass is particularly susceptible to this condition.

Refer to Table 3 for recommended inspection and acceptance criteria for some mechanisms applicable to boiler tubes.

11 On-stream Inspection Programs

11.1 GENERAL

On-stream inspection programs are a vital component to maintaining reliability. Often, inspection efforts focus on the next maintenance outage since it involves significant planning and resources. However, on-stream inspection is the key to monitoring the health of the equipment between major outages and allows proactive response to operations, which would allow premature failure. On-stream inspection programs monitor the operation of the heater and boiler to ensure variables are operating within a satisfactory window selected for the equipment.

11.2 TYPICAL INSPECTION ACTIVITIES

Typical on-stream inspection programs incorporate visual examination of the firebox, external visual examination of casing and components, infrared examination of tubes and heater casing, and monitoring of tubeskin thermocouples.

Tell-tale holes is another practice, although in limited use, for identifying unexpected or accelerated corrosion of tubes on-stream. Other analyzers and instrumentation monitor heater and boiler operation and these are important parts of an over-all reliability program but these are typically monitored for heater and boiler performance.

Tubeskin thermocouples can be an important component in a reliability program, especially for on-stream inspection. Thermocouples measure the temperature of tube walls in-service. They serve a couple purposes. First, the thermocouples can alert to abnormal operation if temperatures dramatically change. Second, they provide a means to calculate and monitor remaining tube creep life. Strategic placement of the thermocouples is necessary so that the entire firebox can be reasonably monitored. Malfunctioning burners or unbalanced firing of burners can create local hot zones in the firebox and lead to premature failures. In addition, tubes that historically operate hot due to their placement in the coil may need a thermocouple, especially if it represents the most severe service of the tubes.

Infrared thermal scanning of tubes helps fill the gaps created with the tubeskin thermocouples. Infrared scanning inspection can determine local tube metal temperatures in the areas not covered by the tube skin thermocouples. Generally, tube ruptures occur in very local areas of overheat. Infrared scanning has proven effective in identifying localized "hot spots" before they cause a failure. A periodic scan of heaters is common practice although some heaters whose tubes are particularly prone to coke buildup may require more frequent scanning. Additionally, infrared scanning provides a means to check the accuracy of tubeskin thermocouples.

Tube skin thermocouples and infrared scanning have some limitations in reading temperatures accurately. The particular type of thermocouple should have a mid-range rating for the expected tube metal temperature for improved accuracy. Thermocouple wires can have the potential to drift with time at temperature and so they require recalibration or periodic replacement. Another significant problem is the attachment of the thermocouple to the tube. If it is poorly attached, the thermocouple can separate from the tube and begin reading firebox temperatures.

Accuracy of infrared scanning can be influenced by the skill of the operator, the angle of incidence, the nature of the combustion products, flame patterns, and scale on the tubes. The infrared operator ideally would be certified in infrared technology and have experience scanning heaters and boilers. The presence of flames can mask the tubes if the operator must scan through the flames. Another significant limitation is scale on the tubes. The temperature of scale on the tubes tends to be hotter than the tube since it may not be tight against the tube. During outages it can be beneficial to remove scale in areas to allow the operator to scan a "scale-free" area and compare to other scaled areas. This could allow better interpretation of results. Grit blasting stainless steel
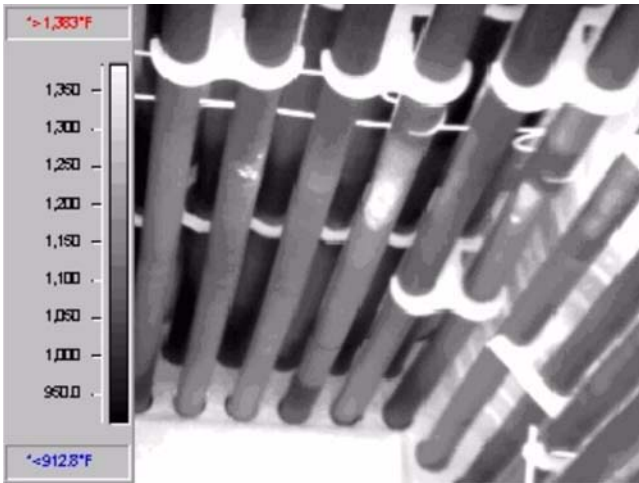
Figure 32A—Infrared Thermography Identifying a Local
Hot Spot on Tubes
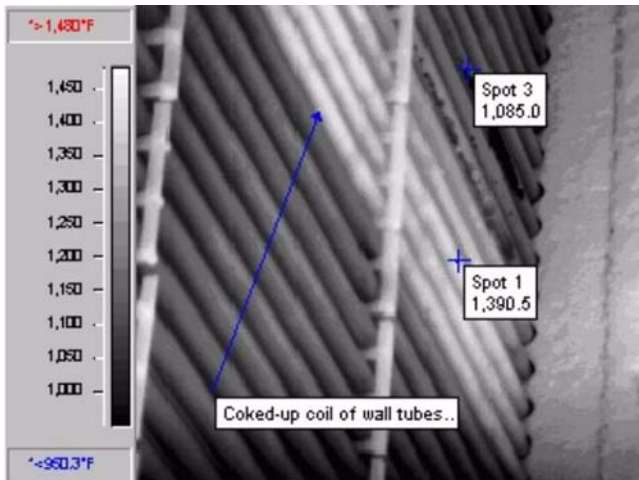
Figure 32B—Infrared Thermography Identifying
a Hot Coil

tubes has also been shown to improve the accuracy of infra-
red by mottling the surface enough to reduce reflectivity
which artificially cause a higher temperature measurement.

External casing can be inspected on-stream both visually
and using infrared. Visual examination can identify areas of
distortion and holes. These can indicate hot areas of lost
refractory and promote continued deterioration. Periodic
infrared scans of the case is more effective than visual exami-
nation in identifying "hot spots", holes, and cracks. Regular
inspection of the firebox is critical for reliability. Inspection
can identify poor flame pattern of improperly firing burners,
fuel rich operation as evidenced by afterburning, and changes
in appearance of tubes, supports, refractory, etc. These
inspections help identify changes early. Any changes or prob-
lems can be addressed or analyzed to prevent further damage
and deterioration from occurring.

Header boxes should be visually examined for evidence of
process leaks. These could indicate a leaking plug header for
those heaters with fittings or a leaking instrument connection
like a a thermowell. If there is evidence of process leakage,
understanding the cause should be investigated.

Figure 32 is an infrared thermograph of an on-stream
inspection that can help identify abnormal operating tube
metal temperatures. In Figure 32A, a section of the tube is
operating at 1400°F (760°C) while in Figure 32B an entire
coil is operating 300°F (149°C) above the adjacent coil. Iden-
tifying these "hot" areas early allows corrective action to
reduce metal temperatures without incident. These conditions
may not be identified by tubeskin thermocouples depending
upon their placement.

The use of tell-tale holes acts as an early detection and
safeguard for accelerated or unpredicted thinning of tubes.
The tell-tale holes minimize the effect of leaks associated
with a heater tube failure. The tell-tale drilling practice is
regarded as a safeguarding measure in loss prevention and
should not be considered a substitute for, or a relaxation of,
good inspection and quality control practices.

a. Tell-tale hole diameters and drilling depths:

    1. Tell-tale hole drill diameters will be $^1/8$ in. (0.32 cm).

    2. Drilling depth tolerance shall be + 0 in. – $^1/64$ in.
    (+ 0 cm – 0.04 cm).

    3. Heater tube drilling depths will be calculated according
    to the retirement thickness in API Std 530.

b. Tell-tale hole locations:

    1. The location of tell-tale holes is based on the corrosion
    type and the heater tubes configuration. Typical drilling
    patterns are located at heat-affected zones, 180-degree
    bends, and areas with potential for accelerated corrosion,
    and random areas on straight run lengths.

    2. Drilling patterns and locations in Figure 33 may be
    used as a guideline in most heaters.

11.3   EXTERNAL TUBE CLEANING

On-stream cleaning of tubes to remove scale may be bene-
ficial to improve the accuracy of infrared scan or to improve
the heat transfer (heater efficiency). Some techniques used
include blasting with walnut hulls, crushed dry ice and water.
Course walnut hulls have proven effective in removing loose
scale; however, the user should recognize that refractory dam-
age can occur where the hulls affect the wall. One benefit of
the hulls is that they burn up in the firebox and most of the ash
leaves the heater through the stack. Another technique is to
water blast the tubes, which removes scale by thermal con-
traction/shock. Consideration needs to be given to the water
type and the spray type so that tube damage won't result. In
this instance as well, refractory damage can result where the
water impacts.

11.4 PRE-SHUTDOWN INSPECTION

On-stream inspection is also important to identify problems which can not be seen while the equipment is out-of-service. A discussion with operations and maintenance personnel is highly recommended to idenfity problem areas. At this time, a review of the operating conditions may also help to indicate problems, such as: O_2 percentage, (inability to maintain target O_2 could indicate leaks or burner problems), draft (unsteady/pulsating draft can damage heater/boiler components), drum levels, pressures and temperatures.

An infrared scan of the casing can allow a hot spot map to be created so that these areas can be investigated during the maintenance outage. Flame locations and appearance can help identify problems with burner tiles, refractory, and floors. Flames emanating from a portion of floor or wall indicate a problem that needs follow-up inspection. Complete an external inspection to determine condition of the structure, such as buckstays, to look for signs of expansion/buckling. Also, inspect external equipment such as blowdown valves, soot blowers, level gauges, external hangers/rods, insulation, etc. for damage that would need to be addressed at the outage.

12 Tube Reliability Assessment

12.1 GENERAL

Tube reliability can only be assessed by understanding the deterioration amount that can be tolerated without compromising the integrity of the tube until the next outage. The assessment is often referred to as the remaining life of the tube. Determining remaining life for all deterioration mechanisms may not be possible, and, therefore, it may be necessary to consult with one knowledgeable in heater design, operation, and deterioration mechanisms. In addition, consulting API RP 579, Appendix F, Section F.7 and Table F-12 on creep modeling, parameters and Omega properties, and other fitness-for-service documents may provide additional guidance on assessing deterioration.

12.2 MINIMUM THICKNESS AND STRESS RUPTURE

Stress rupture is dependent on the stress the metal is exposed to and the temperature of the metal. The common approach to prevent stress rupture failures is to establish a minimum allowable thickness for the tube operating conditions, e.g., pressure, mechanical stresses, and metal temperature.

12.2.1 Tubes

Methods of establishing minimum allowable thickness range from the highly complex to the simple. With the average heater, the operating pressure and temperature are known only for the heater inlet and outlet. The pressure and temperature at intermediate points is typically estimated by calcula-
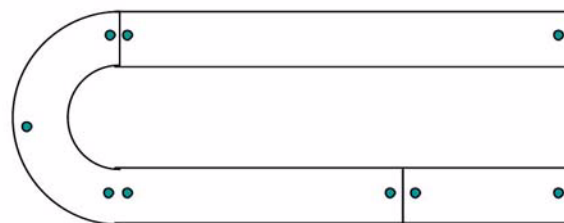
Figure 33—Sample Locations for Tell-tale Holes on Heater Tubes

tions or measured with pressure gauges and thermocouples installed at appropriate locations.

The metal temperature governs the allowable working stress for tube materials. Therefore, for a given tube size and a given operating pressure, the minimum allowable thickness varies with the tube temperature. Tube temperature is an important parameter to know, especially at the highest levels of the normal operating condition.

API Std 530 gives extensive information on the calculation of required wall thickness' of new tubes (carbon steel and alloy tubes) for petroleum refinery heaters. The procedures given are appropriate for designing tubes or checking existing tubes in both corrosive and non-corrosive services.

Many methods, including those involving tube skin thermocouples, infrared cameras, infrared pyrometers, and optical pyrometers, are available to determine the metal temperature of a tube. A simple method is to estimate the metal temperature from the operating fluid temperature and then adjust the temperature estimate based on the location of the tube in the heater—the skin temperatures on a tube closer to the flame or nearer the heater outlet will be hotter than one at the heater inlet.

Under certain conditions, the methods described in the preceding text may result in a thickness that is too small for practical purposes. The minimum allowable thickness must be great enough to give the tube sufficient structural strength to prevent sagging between supports and to withstand upset operating conditions. For this reason, it may be appropriate to add some amount based on experience to the calculated minimum allowable thickness and to use this greater thickness as the limit at which a tube should be replaced. Generally, this would be about 0.125 in. (0.32 cm) in these cases.

12.2.2 Fittings

Similar to establishing the minimum allowable thickness for tubes, the metal temperature of the fittings must be established so that the appropriate allowable design stress of the material can be used. Generally, if the fitting is outside the firebox the fitting temperature is considered to be the same as the temperature of the fluid flowing through it. The metal tem-

perature of a fitting inside the firebox is considered to be the same as that of the corresponding tubes. The allowable working stress value for fittings is determined in the same way as it is for tubes. Minimum allowable thickness can be determined from applying calculations from the appropriate ASME piping codes. Because of stresses that may be set up by closing and holding members and by thermal expansion, the calculated allowable thickness may be too small to be practical. As with tubes, it may be advisable to add some thickness, based on judgment and experience, when setting the minimum thickness at which a heater fitting should be replaced.

When plugs are used in a heater fitting like plug-type or mule-ear fittings or when a sectional L is used in a sectional fitting (see Figure 34), the width of the seating surface in the fitting must be sufficient to prevent leakage. A width large enough to prevent leakage generally provides adequate strength against blowout, but a lesser width should never be used. The proper seating width required to prevent leakage is difficult to calculate and is often determined by experience. When there is no previous experience to be used as a guide, one way to determine these limits is to wait until evidence of slight leakage is found and then set a limit at a point that is a little greater than that at which the slight leakage was evident.

12.2.3   Boiler Components

Because of the great number of variables affecting the limiting thickness and the variety of types, sizes, shapes, operating methods, and constructions of boilers, it is not possible in this recommended practice to present a set of precalculated minimum or retiring thickness. However, it may be quite feasible to prepare one for the boilers in a given refinery. Formulas for the thickness of drums, headers, and tubes are given in the ASME *Boiler and Pressure Vessel Code*, Sections I and IV. ASME B31.1 also provides calculations for wall thickness of power boiler piping. These formulas can be used as guides when repairs and replacements are needed.

12.3   CREEP RUPTURE LIFE

Remaining creep life for tubes in a heater is estimated or measured using various techniques ranging from the approach outlined in API Std 530 Appendix E to destructive creep testing of tube material.

Appendix E, "Estimation of Remaining Tube Life" in API Std 530 is a common approach to assess life of in-service tubes. The calculations are based on the Larson-Miller parameter curves found in the document. API Std 530 provides an average and a minimum Larson-Miller curve for each metallurgy. The most conservative approach is to use the minimum curve since it represents the poorest material properties of those tested. The average curve can also be used,

although the specific heat of material can exhibit properties either above or below this curve.

These life assessments usually require several assumptions about the tubes' thermal and stress history. The history needs to be established to effectively determine the amount of life expended during each operating run under different conditions. One can simplify the analysis by assuming the tubes operated under the severe conditions for their entire life. Once the life fraction has been determined, remaining life can be estimated for specific operating conditions. One can establish an operating window of temperature and pressure for which the tubes can operate where creep rupture would not be expected during the next run length.

More accurate techniques to determine remaining life require destructive creep testing. One technique is the Omega methodology, which uses strain rate data generated in a creep rupture test to determine remaining creep life. The creep rupture test can be performed at temperatures and stresses that closely approximate the actual operating conditions of the tube. This is unique to creep testing, since they require tests at either higher temperature or higher stress to shorten the tests to a reasonable amount of time. The results are then extrapolated back to operating conditions. This extrapolation can lead to inaccuracies in estimates. Only a few samples are necessary for this testing and samples can be prepared from only a small section of tube. The section of tube to be tested should optimally be taken from the location operating under the most severe conditions. Additionally, the samples should be tested in the most highly stressed direction in service. Typically, this will be a sample oriented circumferentially in the hoop stress direction.

The remaining life determinations provide a means to manage tube life of a heater or boiler. The operator of the boiler or heater can understand how the operation affects tube life. For instance, tube life can be monitored throughout the run incorporating all types of operations including most importantly any high-temperature excursions. These remaining life calculations can be used to predict and plan tube replacements.

When inside the heater or boiler, tubes have historically been replaced if they exhibit an increase in tube diameter beyond a specified threshold value. Company practices range from 1% – 5% of the tubes original diameter or circumference for wrought tubes. Creep testing can be used to determine a better relationship between growth and remaining life for particular tube metallurgy in a heater. Some metallurgies exhibit more growth than others do for a similar remaining creep life. Therefore, 5% may be conservative for some metallurgies and not enough for others. Consider consulting with a materials engineer knowledgeable in heater tube metallurgy before establishing threshold criteria.

13 Method of Inspection for Foundations, Settings, and Other Appurtenances

13.1 FOUNDATIONS

All foundations can be expected to settle to some extent. If the settling is evenly distributed and only to a small extent, little or no trouble may be experienced. If the settling is uneven or to a large extent, serious consequences may result. Whether even or uneven, any settlement in a foundation should be studied and, if the need is indicated, checked at frequent intervals by level measurements, which should be continued and plotted until the settlement practically ceases. When settlement is first noted, all pipe connections to the heater should be examined carefully to determine whether they are subject to serious strain and consequent high stress. If conditions warrant corrective measures, they should be taken immediately.

One of the main causes of the deterioration of foundation concrete is high temperature. This causes calcining, which is caused by the concrete's loss of water of hydration and leaves the concrete a weakened mass with very little cohesion. Calcining can easily be detected by chipping at the suspected area with a hammer. If calcining is present, the concrete will fall away as a powder with very little impact from the hammer.

Spalling is another form of concrete deterioration caused by heat or an insufficient thickness of concrete over the reinforcement. The concrete cracks, and moisture can enter and attack the steel reinforcement. The products of corrosion build up and exert sufficient pressure against the concrete covering to cause it to flake or spall, exposing the reinforcement to further attack. Only a visual inspection is necessary to detect this form of deterioration.

13.2 STRUCTURAL SUPPORTS

A visual inspection should be made of all load-carrying structural steel members to see whether deflection is observable. If bending is present in a column, it may be caused by overloading, overheating, or lateral forces applied to the column by the expansion of elements in the heater. These potential causes should be sought, and the cause of the bending should be determined so that proper corrective measures can be taken.

If the bending is due to overloading, either the column should be reinforced by welding or riveting the necessary reinforcement to the column's web to reduce the unit stresses to a permissible value, or the column should be replaced with another one of suitable size. If the bending is caused by overheating, the column should be protected by insulation or a shield. If the bending is caused by expansion of elements in the heater, provisions should be made to accommodate the expansion without stress on the column.
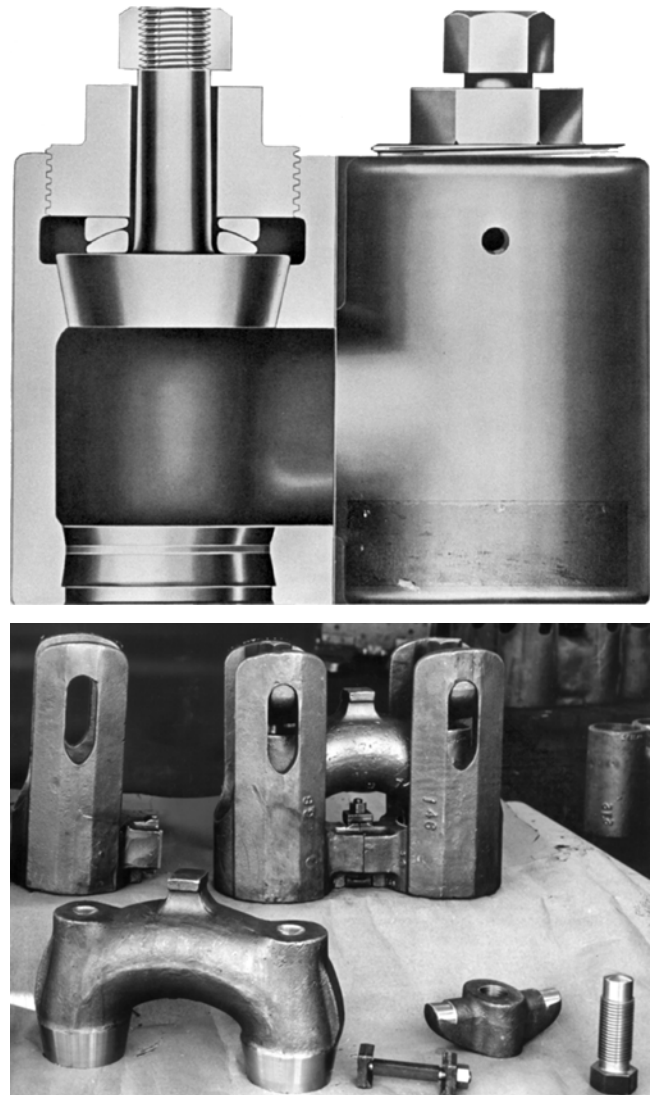
Figure 34—Types of Heater Fittings

Beams and girders will deflect when loads are imposed on them. The deflection should be measured where it is greatest. The amount of deflection should be checked against that calculated for the load on the beam or girder. If the measured deflection is greater than the calculated deflection, overstressing is indicated. If the overstress is serious, the design should be investigated, and corrective measures should be taken.

If corrosion in structural steel members that bear loads directly is so great that the thickness lost is enough to weaken the part, the minimum cross-sectional areas should be measured carefully after the corroded part is cleaned thoroughly to permit the determination of the remaining sound metal. When the measurement has been obtained and the remaining sectional area has been determined, the section modulus should be calculated, and the design should be checked to determine the stress. If the stress is sufficiently higher than the allowable stress, the weaker part should be reinforced or replaced. Useful design information, including information about allowable working stresses, can be found in AISC M015L and M016.

The connections between the columns and the beams and girders should be inspected visually. These connections may be made by riveting, bolting, or welding. For riveted or bolted construction, broken or loose rivets or bolts can be detected by striking the side of the rivet or bolt and by striking the plate. A movement of the rivet or bolt will indicate that it is loose or broken. Inspection of all connections is not warranted, but inspection should be made where corrosion is severe. If the connections are welded, corroded sections should be carefully visually inspected after proper cleaning, and the effect of lost metal thickness should be determined.

13.3   SETTING, EXTERIOR, AND CASING

The exposed parts of the setting should be inspected for signs of deterioration. All metal parts can be adequately inspected with a hammer and visual examination. If the exposed parts are painted, a visual inspection should be made to see whether the coating adheres tightly to all surfaces. Areas exposed by flaking or otherwise damaged should be cleaned and repainted. The casing should be inspected for thinning or perforation due to acidic flue-gas corrosion.

Stairways, walkways, and platforms should be checked to ensure that they have not been materially weakened as a result of corrosion. Heater header boxes should be inspected for warpage and improper functioning. Warpage or improper functioning of doors may allow rain or other moisture to enter. Header box warpage also allows excess air into the heater, spending additional fuel. In some operations, particularly those with heaters that process light hydrocarbons, a sudden change in temperature due to leakage of header boxes can cause enough movement in fitting closures or rolls to loosen them.

Peepholes, access doors, and the like should be inspected visually to see that the fit is satisfactory and minimizes excess air ingress.

Explosion doors, if provided, should be inspected visually for corrosion of the hinges and the door itself and for warpage. Explosion doors should also be visually inspected to see whether there is proper seating contact between the door and the door frame, ensuring a reasonably tight joint. The doors should be manually lifted to check operability. To serve effectively, the doors should open with minimum resistance.

13.4   REFRACTORY LININGS AND INSULATION

Most modern settings consist of structural steel framing with refractory lining or lightweight ceramic or blanket insulation on the walls and roof of the heater. The refractory may be backed up with brick or supported on steel members with heat-resistant hangers. The supporting brickwork and reinforced concrete and the clearance in the expansion joints should be examined for deterioration due to heat, open joints, excessive distortion, or debris. The inspection of refractory should consist of a visual examination for breakage, slagging, crumbling, and open joints. Leakage of the hot heater gases through joints when the edges have crumbled or when the tile or insulating concrete has fallen out exposes the supporting steel to high metal temperatures, rapid oxidation, and corrosion. Leakage of hot heater gases outward instead of air leakage inward may indicate improper draft conditions in the firebox. The supporting steelwork should be inspected thoroughly. Beams, hangers, and supports of any type that have been damaged by heat or show excessive distortion should be replaced. Any accessible insulation used on the exterior should be inspected.

Refractory linings should be inspected for excessive cracks, erosion, fluxing (melting of the refractory), bulging, and fallout. Cracks in the refractory are common and expected. Only the degree of cracking is important. No rules are established indicating what can or cannot be tolerated and so decisions are based on good practice, experience and if available, consultation with one knowledgeable in refractories. If the refractory is determined to be severely cracked, repairs should be made. Metal parts and insulation behind the refractory can become overheated and damaged if these conditions persist.

The presence and extent of refractory erosion or fluxing should be determined. Erosion is caused by flame impingement, high ash velocities, and inferior materials. Erosion may occur around burner throats, heater sidewalls, and heater back walls. In boilers with waterwalls, erosion tends to occur in the refractory material between the tubes, especially on back walls opposite burners. Fluxing is caused by inferior or improper materials, ash containing metal oxides, or flame impingement. Fluxing may occur at almost any point, but

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locations in the direct path of the hot gases would be most susceptible to fluxing.

The depth of erosion or fluxing and the remaining thickness of the refractory should be measured. The depth of local erosion or fluxing may be measured with a straight edge and rule. In areas around burner throats, the extent of erosion or fluxing may be difficult to determine because of the circular or conical shape. Photographs or blueprints of the original installation are helpful references in establishing the extent of erosion in these areas. The thickness of the remaining refractory may be measured by drilling or cutting out a small piece in the suspected area.

Refractory that has fallen out or bulged to the point that it is in danger of falling out should be replaced. The area replaced should be in the form of a square or rectangle. The edges should be cut straight in and not tapered. An area of about 12 in.^{2} (30 cm^2) should be the minimum area cut out and replaced. Bulging and fallout may be due to settlement of the anchor bolts, anchor brackets, or castings or of the heater-setting supports themselves. When bulging or fallout is encountered, the cause should be ascertained so that corrective measures may be taken to prevent a recurrence. Bulging or fallout in waterwalls may be due to failure of the tubes to transfer the severe heat. In rare cases, this may be caused by too large a tube spacing, but it is generally caused by blocked or clogged tubes. When excessive erosion or fluxing occurs in the lower section of a wall, the upper sections may have insufficient support to the point that they can fall out.

Infrared cameras can provide an indication of damaged refractory prior to shutdown. Damaged areas of insulation are observed as higher surface metal temperatures on the casing of the heater.

The condition of refractory linings in the combustion chamber, stacks, flue-gas ducts, observation and access doors, and around burner ports should be inspected. Special attention should be given to the lining sections intended to protect pressure parts and supports from overheating. If any of the refractory in the combustion chamber has fallen out, the supporting steel will be exposed to excessive temperatures that will damage the steel. Linings in stacks and ducts may also have areas where the refractory has fallen out. When this occurs, the outer structure is exposed to temperatures that are greater, in most cases, than the material is capable of withstanding. Outer structures composed of brick will develop cracks; outer structures composed of steel will buckle. Eventually, failures will occur unless corrective measures are taken to replace the refractory. Entrance of air into a boiler, heater or stack, other than through the burners or related openings, may cause inefficient and potentially dangerous boiler operating conditions.

A visual survey of the heater should be made for air leakage into a balanced draft unit and for leakage out of a positive pressure unit. Cracks and loose access and fire doors, peepholes, and joints permit air leakage. An artificial smoke

Figure 35—Yielding and Creep of a
Tube Support Connection

source—titanium tetrachloride, hydrated zinc chloride, or another source of smoke—placed close to the cracks may be useful for the inspection. Use of smoke for the inspection should be done with due consideration of the hazards associated with the materials and the appropriate personnel safety equipment. The material safety data sheet for the type of smoke used should be consulted. Leakage into the heater, when such leaks are adjacent to the structural steel supports, may result in temperature gradients of sufficient intensity to cause failure of the supports. This is particularly likely to occur in areas where combustion is not complete and the concentration of carbon monoxide is high.

13.5 TUBE SUPPORTS

13.5.1 General

Tube sheets and tube supports should be examined to determine their physical condition and fitness for further service. Supports should be examined carefully for cracks, oxidation, corrosion, distortion and sagging. If found to be unsound or weak, they should be reinforced or replaced. Figure 35 shows a support with evidence of creep and yielding. Table 4 is a listing of common tube support material and their suggested maximum use temperature.

13.5.2 Steam/Methane-Reforming Heaters

Tube support methods vary in steam/methane-reforming heaters. Some designs require full support from the top. In these designs the pigtail may be below the tube and unable to take any load from the catalyst-filled tube. Counterweights are often used and may support two or more tubes. The lever or pulley system must work as designed. Interference from tube flange bolts, slipping of supports off tube flanges, and other similar problems have led to pigtail failures.

Table 4—Tube Support Materials Specifications
Maximum Design Temperature

°F	°C	Material	Casting Specification	Plate Specification
800	427	Carbon Steel	A 216 Gr WCB	A 283 Gr C
1200	649	2-$\frac{1}{4}$Cr-1Mo 5Cr-$\frac{1}{2}$Mo	A 217 Gr WC9 A217 Gr C5	A 387 Gr 22, C1.1 A 387 Gr 5, C1.1
1500	816	19Cr-9Ni	A 297 Gr HF	A 240, Type 304H
1600	871	25Cr-12Ni 25Cr-20Ni		A 240, Type 309H A 240, Type 310H
1800	982	25Cr-12Ni 50Cr-50Ni-Cb	A 447 Type II A 560 Gr 50Cr-50Ni-Cb	
2000	1093	25Cr-20Ni	A 297 Gr HK	

Inadequate support also allows tube bending, which puts a bending moment on a pigtail that exits the tube from the side, thus causing localized high stress at the fitting on the tube or the outlet headers.

Outlet headers grow, usually from a center anchor point. Bottom tube supports on short pigtailed tubes must allow movement of the tube bottom to minimize stress on the pigtail. If the tube is designed for bottom movement, the upper tube supports must allow the tube to move at the bottom end. To prevent a pigtail bending moment, the heater lining must not press on the tube. Loose bricks are often used to help close openings. The bricks must move freely if the tube presses on them.

If support springs are used, those that have been stretched should be replaced. A stretched spring cannot support a tube. When the tube is heated up after shutdown, the spring will no longer support it as designed.

13.6 VISUAL INSPECTION OF AUXILIARY EQUIPMENT

13.6.1 General

In addition to any external inspection of auxiliary equipment while the heater is in operation, a close inspection should be made of each piece of equipment while the unit is out of operation. Indications of malfunctions noted during external inspections should be investigated, and any indicated repairs should be made. Since some parts wear out and fail without warning, manufacturers' catalogs and instructions should be reviewed so that all critical operating parts may be investigated.

13.6.2 Dampers

Power-operated or manual dampers are provided on some but not all boilers for superheater, economizer, and boiler outlet-gas control. Damper blades, constructed of thin metal, are susceptible to oxidation and warpage due to overheating and should be inspected for such damage. Supporting brackets, driving rods, pins, and other devices should also be examined. The dampers should be operated and checked for binding closure, and freedom from obstructions should be ensured.

Damper position should be confirmed with both control board and exterior indication devices. Personnel, other than those working on damper operation, should not be permitted in the damper section while the dampers are in operation.

13.6.3 Forced- and Induced-draft Fans

The bearing clearance and the condition of the babbit-bearing surfaces and of the antifriction bearings should be checked, and the shaft diameter should be measured at the bearing surface. The condition of the oil or grease should be checked, and the lubricant should be changed as required.

The general condition of the rotor and rotor blades should be checked, and loose blades should be fixed. Couplings should be examined, and the alignment of all parts should be inspected. If any parts are out of alignment, the cause should be determined and corrective action should be taken. Any dampers should be tested for ease of operation and freedom from obstruction.

Induced-draft fans are subject to erosion and corrosive attacks from ash particles and flue gas. In addition to the inspections discussed in preceding text, inspections of the rotor blades and casings should be made for corrosion, excessive thinning, and holes in the blades and casing. The shaft should be examined for corrosion from dew-point condensation near the casing. Missing or faulty gasket seals around the shaft will allow the entry of cold air and lead to condensation and subsequent corrosion. Rotor blade surfaces should be checked for cracks with magnetic particle testing or penetrant testing focusing on stress riser locations.

13.6.4 Soot Blowers

Soot blowers can be a root cause for deterioration if they are not operating properly. Therefore, soot-blower parts should be inspected for proper alignment, position, and operability. If soot blowers are out of position or misaligned, the blower blast could impinge on tubes which will eventually cause tube failure due to erosion. Soot blowers can also be a source of liquid water that can promote dewpoint corrosion of tubes, casing and the blowers themselves. The shut-off valve to the blowers should be checked to ensure it does not leak
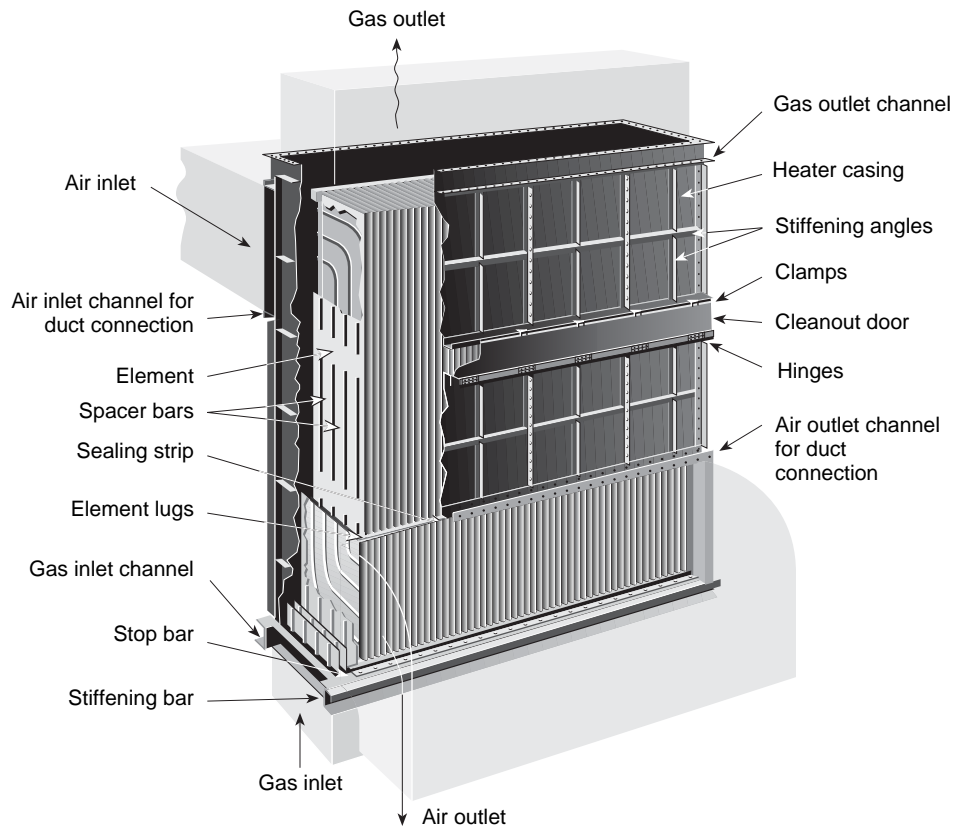
Figure 36—Plate Type Air Preheater

while in service. Condensate can form in the system when the blower is out of service and if it leaks into the firebox can cause dewpoint corrosion.

The blower, supporting hangers, and brackets should be examined visually for soundness and for excessive thinning from oxidation. Soot blowers for the high-temperature part of the boiler are sometimes composed of high-chromium alloys that embrittle in service and so they should be handled/inspected appropriately to avoid fracture. Connection welds of supporting elements should be inspected for cracks. If the welds look cracked, a magnetic-particle inspection should be made. Packing glands and all operating parts of the rotating and retracting types of soot blowers should be examined for good working condition. Because of the potential difficulty of repacking soot blowers in service, repacking should be done during down periods if there is any evidence that repacking might be required.

13.6.5 Air Preheaters

Air preheaters are subject to corrosion due to condensation during extended periods of downtime. Recuperative preheaters, both the tubular type and the plate type (see Figures 7 and 36), are subject to severe corrosion when the element temperature is at or near the dew point. The severe corrosion is particularly prevalent at the flue-gas outlet end. As much as

possible of the recuperative-type preheaters should be inspected for corrosion. Usually, the conditions at the inlet and outlet ends will provide a good indication of what can be expected in the remainder of the preheater. It is not unusual to see extensive plugging of air preheaters when boilers are being fired with heavy oil or coal.

Frequently, air preheater efficiency can be calculated to determine if its surface area is fouled or damaged. A heat balance can be performed around the air preheater to determine if it is leaking from the air-side into the flue gas-side.

Perforated tubes should be replaced or plugged. It is sometimes necessary to remove fairly good tubes or plates to get to the bad ones. Good judgment and consideration for future replacements are important factors in selecting the most economical method for repairing tubes and plates.

Regenerative preheaters (see Figure 8) require a more extensive inspection than do recuperative preheaters. Usually, rotating elements must be removed to clean the preheater. This affords an opportunity for close inspection of all parts. In most classes of regenerative preheaters, the incoming air enters at the same end that the flue gases leave, thus cooling that layer of rotor segments first. Corrosion will generally start at this point because of condensation and proceed toward the other end of the unit. Most preheaters have two sections, and if corrosion at the flue-gas exit ends is not too severe, the
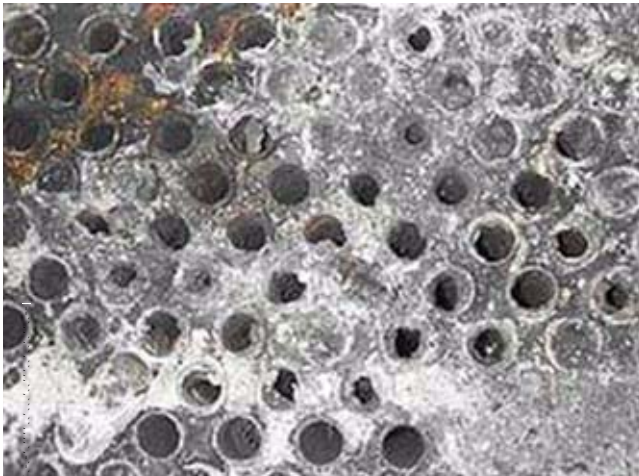
Figure 37—Corrosion Products from Acid Condensation Plug Tubes in Air Preheater

sections can be reversed; otherwise, new sections should be provided. Figure 37 is an example of acidic dew point corrosion of an air preheater.

Rotor seals should be examined for corrosion. They can also be mechanically damaged by falling material, by high-pressure steam or water from soot blowers, or by being stepped on by maintenance personnel.

Soot blowers for regenerative preheaters are quite different from those used in other parts of the boiler. Manufacturers' catalogs and drawings should be examined for points that require close inspection. Soot blowers should be inspected for deposits and leaky valves. Leaky valves and buildup of ash cause corrosion of nozzle tips, and subsequent malfunction of the blowers damages rotor seals and segments. Therefore, steam inlet valves should be inspected for tight shutoff, and drain valves should be inspected for correct operation.

13.6.6   Boiler Blowdown Equipment

Valves should be inspected for tight shutoff. Piping should be checked for corrosion and leakage at all joints. Ultrasonic testing and hammer sounding are good methods of pipe inspection. Elbows and sharp bends are susceptible to erosion and should be examined for indications of thin walls and holes. Coolers should be inspected in the same manner as that described for heat exchangers in API RP 572.

13.6.7   Fuel-handling Equipment and Piping

13.6.7.1   General

Manufacturers' instructions, sketches, and drawings should be consulted before inspecting fuel-handling equipment.

13.6.7.2   Gas

Gas system equipment is not generally subjected to severe corrosion or wear and, therefore, does not require extensive

inspection. This might not be true for boilers firing refinery fuel gas. The seats and packing of control valves, block valves, and bypass valves should be examined, and the valves should be checked for ease of operation and tight shutoff. Burner inspection will depend on the type of burner to be inspected. Usually, operating conditions will indicate the condition of burners. Malfunctioning may be due to fouled or cracked burners or burned burner tips. When the system contains a dry or knockout drum, planning is advisable so that the drum can be removed from service for inspection as required.

13.6.7.3   Fuel-oil Pumps

Fuel-oil pumps should be inspected to ensure that they meet the standards called for when originally purchased (refer to applicable API standards). Fuel-oil heaters should be inspected as indicated in API RP 572. Valves and burners should be inspected as indicated in the preceding text for gas equipment valves and burners. When the fuel contains corrosive products, all items should be examined for evidence of corrosion.

13.6.8   Burners

Burners should be visually inspected to ensure proper operation once per shift. Conditions that need to be corrected include flame impingement on tubes and supports, abnormal flame dimensions and pattern, oil drippage, and smokey combustion. In addition, the burners should provide an even heat distribution. Poor firing from unbalanced burners can cause serious deterioration of the heating elements and setting. Defective burners that can not be repaired in service should be replaced so that they do not lead to premature failure of other components. Obtain the burner drawings from the burner vendor. The drawings will include the installation tolerances, tile diameter and tip drilling information.

Burner plugging problems sometimes can be solved by proper sizing of the fuel drum and demister pad, heat tracing the fuel gas delivery lines, and providing filters or coalescing systems. Regardless, deposits should be analyzed to determine if the source of the plugging can be identified and eliminated.

The following guidelines are general recommendations for maintenance outage inspection. Always consult the guidelines from the burner vendor.

a. The burner tile is an air orifice. It controls the amount of air flow. Since it is extremely desirable to have even air flow to each burner, the tile dimensions are critical. Typical installation tolerance is $\pm$ $1/8$ in. (0.32 cm) on the diameter as shown on the burner drawing. Measure the diameter in three to four locations. Most round tiles are installed as a slight oval shape. This will result in poor fuel-air mixing and a bad flame shape. Burner tiles should not be cracked or spalled. The use of a plywood template helps set the tiles in the proper diameter and concentricity. The burner tile must be centered on the gas tip to obtain uniform fuel air mixing. Typical installation

tolerance is $\pm$ ^{1}/8 in. (0.32 cm). Poor installations result in bad flames as shown in Figure 38.

b. Check the burner drawing for the number of tip drillings and the drill bit size of the port. Use drill bits to check the proper hole size and the proper included angle of the drillings. Do not mix parts from other burners. Be sure to install tips with high-temperature anti-seize compound.

c. The installation tolerance on gas risers is typically $\pm$ ^{1}/8 in. (0.32 cm) on horizontal spacing and $\pm$ ^{1}/8 in. (0.32 cm) on vertical spacing. Bent gas risers can cause these dimensions to be wrong. A common problem is different lengths on the gas risers. Many burners are designed such that the gas jets intersect in the center of the burner. The tips usually have arrows or cutouts to aid in tip orientation. Welding rods can be a valuable check for alignment.

d. Air dampers and registers should be checked for operability. Sticking air registers and dampers are a problem. Sometimes, dry graphite lubricant can improve air register operability. Penetrating oil, grease fittings and the addition of bearings to damper shafts can improve operability.

13.7 STACKS

An external visual inspection should be made of brick, concrete, and steel stacks for conditions that may weaken these structures. Field glasses will be helpful in making inspections of high stacks because they will enable any defects to be observed fairly well from the ground. Brick stacks should be inspected for cracks and for the condition of mortar joints to determine the effect of weathering. Concrete stacks should be inspected for cracks and spalling that may expose the steel reinforcement. Steel stacks should be inspected externally for the condition of painted surfaces, signs of oxidation, and thinning or perforation due to corrosion by acidic flue gases.

In many cases, cracks in brick and concrete stacks are a result of insufficient thickness of the internal insulation or to internal secondary combustion. These potential causes of cracks should be kept in mind when inspecting the interior of stacks.

The linings of all stacks should be inspected for cracks, wear, and structural soundness.

While stacks are in service, an external, infrared thermographic examination can be made that will show hot spots, which indicate failure of the internal liner.

When liquid fuels are burned, soot accumulates in the base of the stack and must be removed occasionally. During the internal inspection, the amount of soot and ash should be noted, and whether they need to be removed should be decided. The inside of steel stacks should be inspected for corrosion or cracking due to condensation of acidic flue gases. Areas at or adjacent to welds are most susceptible to stress corrosion cracking.

Figure 38—Improper Burner Tile Installation Leads to Poor Flame Pattern

Steel stacks in heater and boiler services should be inspected and checked for wall thickness at time intervals that are warranted by experience. In addition to the thickness determination, a thorough hammer inspection should be made of the entire stack, with particular attention paid to the seams, adjacent areas, and areas adjoining any stiffening rings, lugs, nozzles, and the like, which may act as cooling fins to cause condensation of gases and localized corrosion. The minimum allowable thickness at which repairs will be made should be definitely established for such structures. One practice is to establish these thicknesses on the same basis as was used in the original design for the structure (see Figure 39).

Bolts at the base flange and at elevated sections should be checked periodically for loosening and breakage. Elevated flanged connections that are installed for the purposes of field erection should be seal welded internally to prevent the escape of corrosive flue gases, which accelerate bolt failure. In the case of derrick-type flare stacks, the structure itself should be completely inspected. Careful attention should be given to the foundations and anchor bolts. Most derricks are assembled by welding or bolting. Bolts should be checked for looseness and corrosion. If looseness is found, the shank of the bolt should be checked for abrasion from the movement of structural members. The flare-stack roller guides and guide

¼ in. ± plate

⅜ in. ± plate

Lining or insulation where required

⅜ in. ± plate

Metal diaphragm

9⁄16 in. ± plate

Breaching opening

Drain

9⁄16 in. ± plate

12 ft, 0 in. ±

Inside diameter

250 ft, 0 in. ±

15⁄16 in. ± plate

21 ft, 0 in. ±

Inside diameter
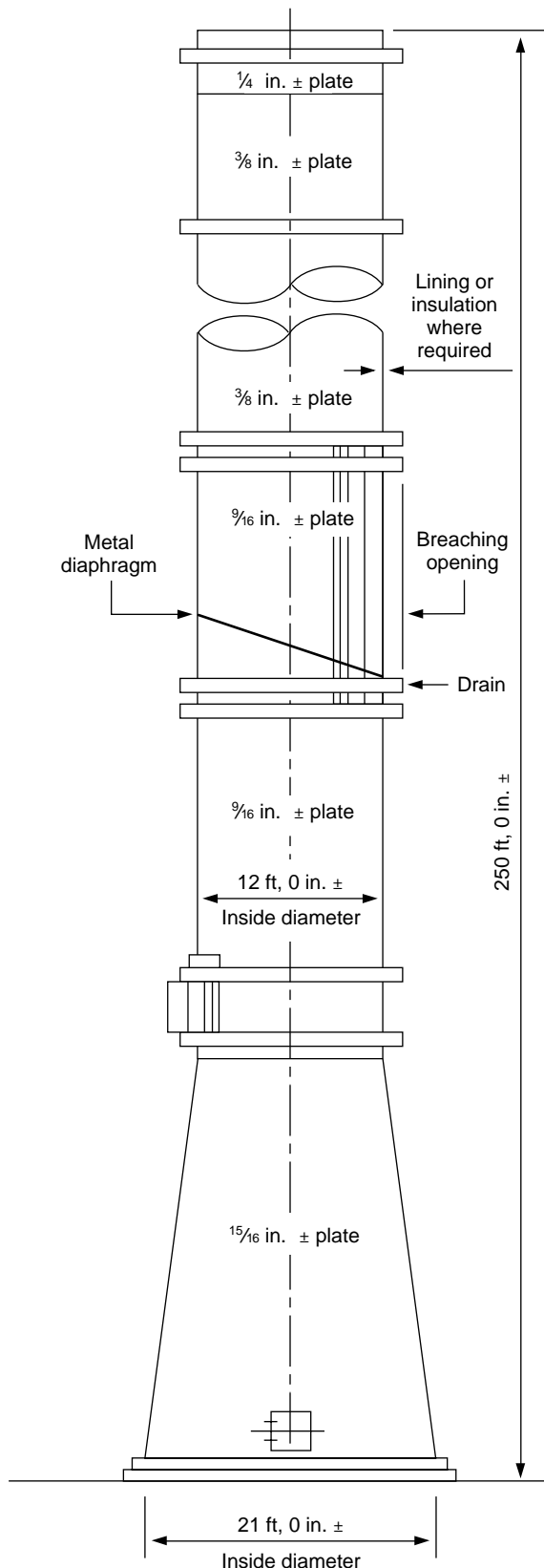
Figure 39—Self-supporting Steel Stack

arms should be checked for alignment and operability and should be realigned or freed if necessary. Ladders, platforms, and all structural members should be checked for atmospheric corrosion to determine whether any section is approaching the minimum allowable thickness.

The guy lines to guyed steel stacks should be inspected visually for corrosion. The wire rope should be inspected for:

a. Reduced diameter due to internal or external corrosion.
b. Corroded or broken wires at end connections, especially at the deadman and the top of the stack, where moisture can be retained.
c. Cracked, bent or worn end connections.
d. Worn/broken outside wires.
e. Kinks, cuts or unstranding.

Electromagnetic inspection techniques based upon flux leakage principles are available for inspecting wire rope as well. These technologies involve a crawler capable of inspecting the length of wire for localized strand defects and general thinning of the wire cross-section. This allows for a quantitative assessment of the wire integrity. The stack painters' trolley and cable should be inspected visually for corrosion or mechanical damage before being used and before being returned to storage. The condition of the connections at the top of the pulley and of the trolley ring and its connections to the stack should be determined carefully.

Lightning rods on stacks and their grounding cables should be inspected visually to see that they are secured and unbroken. The ground rod should be inspected visually to see that it is firmly attached to the cable and that it extends to a ground depth sufficient to provide an electrical resistance of not more than 25 ohms. This should be checked periodically, particularly in dry weather.

The ladders on steel, concrete, and brick stacks should be inspected visually for corrosion and should be tested physically by applying test weights in excess of those that may be imposed by the personnel using them.

The caps on radial brick and concrete stacks sometimes become damaged, causing loose brick to fall or the reinforcing steel to be exposed. Stack caps should be inspected visually so that any necessary repairs can be made, thereby eliminating a hazard from falling bricks and preventing damage to steel reinforcement.

14 Repairs

14.1 HEATERS

Repairs necessary to restore mechanical integrity to pressure retaining components and modifications made to pressure retaining components in heaters should follow the principles of the design and fabrication codes most applicable to the work. The following issues need to be considered when developing repair/modification plans and implementing them.

This is not all-inclusive as other factors may need to be considered for specific situations.

a. Repairs and/or modifications are engineered to meet the requirements of the service including material selection.

b. Weld procedures qualified to ASME Section IX for the material and technique appropriate for the welding that needs to be performed.

c. Welders certified and qualified per ASME Section IX for the procedures to be used.

d. Weld details are defined including any surface preparation, joint preparation, weld joint design, and preheat temperature.

e. NDE techniques to be used and the acceptance criteria. Also, any intermediate inspection hold points need to be defined.

f. Heat treatment requirements for repair welds.

g. Any required pressure testing and the acceptance criteria of the test.

14.2 BOILERS

Repairs and alterations made to boilers should be performed to the applicable codes and jurisdictional requirements appropriate for the locality. As indicated earlier, jurisdictions typically define which type of boilers are legislated and the appropriate repair/alteration requirements. Most often, NB-23 will be the code to which repairs/alterations will be performed to for legislated boilers. Where there aren't any governing codes or jurisdictional requirements, the repairs/alterations should follow the principles of the design and fabrication codes most applicable to the work. Any repairs and alterations need to be considered factors similar to those defined in 14.1 for heaters.

14.3 MATERIALS VERIFICATION

Materials used in repairs should be verified that they meet the materials specified for the repair. This includes, for example, tube materials and welding consumables. Alloy verification is critical to ensure the appropriate material is actually used and installed. Inadvertent substitution with another material can result in premature failure from corrosion, cracking, and stress rupture. Verifying materials often involves testing to show/indicate the proper chemistry. Testing can be accomplished with the use of suitable portable methods, such as chemical spot testing, optical spectrographic analyzers or x-ray fluorescent analyzers. Refer to API RP 578 for additional information on material verification programs.

15 Records and Reports

15.1 GENERAL

Boiler and heater owners and users should maintain permanent and progressive records for their equipment. Permanent records would be maintained throughout the service life of the equipment; progressive records would be regularly updated to include new information pertinent to the operation, inspection and maintenance history of the equipment.

Records should contain at least the following types of information regarding mechanical integrity:

a. Construction and design information. This could include equipment serial number, manufacturers' data sheet, design specification data, design calculations, and construction drawings.

b. Operating and inspection history. Operating conditions, including abnormal operations, that could affect equipment reliability, inspection data reports, analysis of data, and inspection recommendations.

c. Repairs, design and mechanical changes. Repairs should be documented as to the reason for the repair and the specific details of the repair. Similarly, any changes made to the design or mechanical components should be recorded detailing the nature of the changes. Standard report forms are often required to be filled out when any repair or design change is made. In addition, any supporting data and calculations to support the repair or design changes should be included in the record.

The importance of maintaining complete records to mechanical reliability cannot be overemphasized. Inspection records form the basis for determining reliability and establishing a preventive maintenance program. With detailed, complete records, repairs and replacements can be predicted and planned avoiding emergency shutdowns. Planned work saves time and cost by allowing personnel and materials to be scheduled prior to a shutdown. These records also provide a means to identify repetitive problems or issues that could be addressed in preparing company specifications for new equipment.

Inspection reports should be clear and complete. All unusual conditions observed should be reported fully, as what seem to be insignificant details may prove to be of importance in the future. When necessary, sketches, diagrams, and photographs should be incorporated in the report. There should be no unnecessary delay between the inspection and the submission of the report. Sample reports are shown in Appendices B and C.

APPENDIX A—SAMPLE INSPECTION CHECKLISTS FOR HEATERS AND BOILERS
(See following pages for checklists.)

These checklists are examples of the areas and type of information the inspector should focus on during an inspection. They are not intended to be all inclusive since there are a variety of heater and boiler designs which may have particular issues that need to be addressed in an inspection.

Fired Heater Inspection Checklist

Location: Date of Inspection:
Equipment Number: Reason for Inspection:
Inspector(s):   Equipment Description/Service:

A = Acceptable, U = Unacceptable, NA = Not Applicable, NI = Not Inspected

#	Item	A	U	NA	NI	Comments
1	**TUBES—RADIANT**					
a.	External scale					
b.	External corrosion, pitting (describe location, appearance, and depth)					
c.	Bulges/blisters/sagging					
d.	Tube OD measurements					
e.	Externally cleaned					
f.	Internally cleaned					
g.	UT measurements					
h.	Hardness measurements					
i.	Radiographic inspection					
i.	Tube supports and hardware					
j.	Weld condition					
2	**TUBES—CONVECTIVE**					
a.	External scale/debris					
b.	Tube fin condition					
c.	UT measurements (where accessible)					
d.	Tube supports and hardware					
3	**FITTINGS**					
a.	Corrosion (scale, pits, build-up). Describe location, appearance, and depth					
b.	Distortion					
c.	UT measurements					
d.	Condition of tube roll, plug and threads					
e.	Weld condition					
4	**CASING AND INTERNALS**					
a.	Insulation/refractory					
b.	Insulation clips					
c.	Fire brick					
d.	Burner view port					
e.	Convection section					
f.	Thermowells					
g.	Floor hearth plate condition					
h.	Casing condition					
i.	Condition of external coating					
5	**BURNER ASSEMBLY**					
a.	Corrosion (scale, pits, build up). Describe location, appearance, and depth					
b.	Thermocouple condition					
c.	Inlet guide shroud					
d.	Burner tile condition					
e.	Flame appearance					
6	**STACK ASSEMBLY (FLUE GAS)**					
a.	External condition					
b.	Condition of bolts					
c.	Internal Insulation/refractory/coating					
d.	Guy wire supports					
e.	Condition of damper					
f.	Rain cap					
g.	Condition of external coating					
7	**FOUNDATION/SUPPORTS**					
a.	Condition of concrete supports					
b.	Condition of structural steel					
8	**BLOWER**					
a.	Condition of blower motor					
b.	Condition of impeller					

Water Tube Boiler Inspection Checklist

Location: Date of Inspection:

Equipment Number: Reason for Inspection:

Inspector(s):   Equipment Description:

A = Acceptable, U = Unacceptable, NA = Not Applicable, NI = Not Inspected

#	Item	A	U	NA	NI	Comments
1	**TUBES, DRUMS—WATERSIDE**					
a.	Corrosion (scale, pits, build-up)/cracking Describe location, appearance, and depth					
b.	Excessive scale presence. Describe					
c.	Tubes free of blockage, scale					
d.	Weld condition/corrosion					
e.	UT measurements—drums					
f.	Gasket seating surface condition					
g.	Tube borescope inspection					
h.	Internals cracked, corroded, distorted					
2	**TUBES, DRUMS—FIRESIDE**					
a.	External tube corrosion, pitting, erosion (describe location, appearance, and depth)					
b.	External drum corrosion, scale, deposits					
c.	Tube supports and hardware					
d.	UT measurements					
e.	Tube distortion and bulges					
f.	Condition of tube fins, if any					
g.	External sign of roll leaks					
h.	Evidence of erosion from soot blowers					
3	**HEADERS**					
a.	Internal scale and corrosion					
b.	Condition of hand hole plugs					
c.	External corrosion, deposits, scale					
4	**WATER COLUMNS**					
a.	Gage glass condition					
b.	Illuminators, reflectors, mirrors					
c.	Gage cocks and valves operable					
d.	Condition of high and low water alarms					
e.	Connections to drum clean, leak-free					
5	**CASING**					
a.	Condition of insulation/refractory					
b.	Condition of structural steel supports					
c.	Casing distorted, cracked, corroded					
d.	Any obstructions to thermal growth					
e.	Condition of all baffle tile and caulking					
f.	Condition of access and lancing doors					
g.	Condition of external coating					
6	**BURNER ASSEMBLY**					
a.	Corrosion (scale, pits, build-up). Describe location, appearance, and depth					
b.	Thermocouple condition					
c.	Inlet guide shroud					
d.	Burner tile condition					
e.	Flame appearance					
7	**FOUNDATION/SUPPORTS**					
a.	Condition of concrete supports					
b.	Condition of structural steel					

Fire Tube Boilers Inspection Checklist

Location: Date of Inspection:
Equipment Number: Reason for Inspection:
Inspector(s):   Equipment Description:

A = Acceptable, U = Unacceptable, NA = Not Applicable, NI = Not Inspected

#	Item	A	U	NA	NI	Comments
1	**TUBES—WATERSIDE**					
a.	Corrosion (scale, pits, build-up)/cracking Describe location, appearance, and depth					
b.	Excessive scale present (describe)					
c.	UT measurements					
d.	Tube distortion					
e.	Borescope inspection					
2	**TUBES/TUBESHEET—FIRESIDE**					
a.	Corrosion, pitting, erosion (describe location, appearance, and depth)					
b.	Tubes free of blockage, scale, depostis					
c.	Tube borescope inspection					
d.	Evidence of roll leaks					
e.	Tubesheet distortion/cracks					
f.	Refractory spalling, cracking					
g.	Ferrule condition					
3	**SHELL**					
a.	Internal scale and corrosion					
b.	UT Measurements					
c.	External condition					
d.	Condition of external coating					
4	**COMBUSTION CHAMBER**					
a.	Condition of insulation/refractory					
b.	Condition of brickwork					
5	**BURNER ASSEMBLY**					
a.	Corrosion (scale, pits, build-up)					
b.	Distortion from excessive heat					
c.	Flame appearance					
6	**FOUNDATION/SUPPORTS**					
a.	Condition of concrete supports					
b.	Condition of structural steel					

APPENDIX B—SAMPLE HEATER INSPECTION RECORDS

This appendix reproduces samples of the records maintained by a company on the tubes and fittings of its heater. All of these records are used as field records, office records, and completed forms included in the report covering the inspection of the heater.

The *tube layout drawing* shows the actual arrangement of tubes and fittings in the heater. The flow through the heater is also noted. Tubes removed from the heater during the inspection and tubes approaching the minimum allowable thickness for service can be noted by a special color scheme.

The *tube inspection record* shows the history of all tubes in a heater on the date the current inspection is completed and the heater is ready to return to operation.

The *tube inspection record (record of tubes calipered)* is used to record the tube-calipering measurements taken during the current inspection. The figures set in roman type on the top half of each block are the measurements taken during the previous inspection. The figures set in italic type on the bottom half are the measurements taken during the current inspection. The two-digit figures to the right of the inside diameter measurements denote the change in inside diameter from the previous inspection and equal twice the corrosion rate for the interval between the two inspections. Once the

report has been prepared, an extra copy should be made of this record and used as a field work sheet during the next inspection.

The *tube inspection record (instrument caliperings)* is used to record tube thickness measurements taken by radiography or with ultrasonic or radiation-type instruments.

The *tube renewal record* is used to record information on all of the tubes renewed during the interval between the completion of the previous inspection and the completion of the current inspection. It quickly shows the location of the tubes renewed and—of major importance—why the tubes were renewed and how long the tubes had been in service. This record is especially valuable when tube life and what tube material is best suited for the particular service are considered.

The *field work and record sheet (tube rolling data)* is used to record data necessary for the tube rolling operation.

The *record of heater fitting inspection and replacement* is primarily a reference record for heater fittings and shows where the various types of fittings should be checked for thickness. It contains a table for recording the actual outside diameters of a fitting at the various sections. Each point number on a sketch corresponds to a section of a fitting and not to a particular point on the fitting.

TUBE LAYOUT DRAWING (ATMOSPHERIC HEATER—CRUDE OIL PIPE STILL)

RADIANT SECTION TUBES
Tubes 1 and 22: 8 tubes—6 in. outside diameter $\times$ 0.3125 in. wall $\times$ 42 ft, $4^7/8$ in. long
Tubes 2—21: 80 tubes—6 in. outside diameter $\times$ 0.3125 in. wall $\times$ 40 ft, 0 in. long

CONVECTION SECTION TUBES
Tubes 23: 4 tubes—5 in. outside diameter $\times$ 0.3125 in. wall $\times$ 42 ft, $9^1/8$ in. long
Tubes 40: 3 tubes—5 in. outside diameter $\times$ 0.3125 in. wall $\times$ 40 ft, 0 in. long
Tubes 40A: 1 tubes—5 in. outside diameter $\times$ 0.3125 in. wall $\times$ 40 ft, $7^1/2$ in. long
Tubes 24 – 39: 64 tubes—5 in. outside diameter $\times$ 0.3125 in. wall $\times$ 40 ft, $6^7/8$ in. long

SUPERHEATER
18 tubes—
3 in. outside diameter $\times$
0.250 in. wall $\times$
$1^5/8$ in. long

Notes:

1. A copy of this diagram is to be sent in with the tube inspection record after each periodic inspection and test.
2. Color in red all the tubes that are approaching minimum thickness at the time of inspection.
3. A copy of this diagram is to be sent in with the tube renewal record only when the arrangement of the tubes in the heater has been changed.
4. Tubes that are shown in this diagram but are not in the heater or in service are to be crossed out.
5. Tubes that are in the heater but are not shown in the diagram are to be shown in their relative locations and given the same number as adjacent tubes with the suffix "A."
6. The field is to indicate the actual flow when it differs from the flow shown on the diagram.

Figure B-1—Sample Tube Layout Drawing

TUBE INSPECTION RECORD (HISTORY OF ALL TUBES)

PLANT _____ DRAWING _____

UNIT _____ PAGE ____1____ OF ____2____

TUBE LAYOUT _____ DATE _____

Tube No.	Date Installed	Tube	
		Material	Original Outside and Inside Diameter (In.)
Economizer			
1 – 126	2/24/67	1	3.5 x 2.7
Preheater			
1	12/16/70	2	4.5 x 3.5
2	2/29/72	1	4.5 x 3.5
3 – 8	4/17/70	2	4.5 x 3.5
9	9/19/70	2	4.5 x 3.5
23	9/19/70	2	4.5 x 3.5
24 – 82	4/17/70	2	4.5 x 3.5
83	4/17/70	1	3.5 x 2.7
84 – 92	10/26/72	1	3.5 x 2.7
93 – 94	4/24/72	1	3.5 x 2.7
95 – 102	10/26/72	1	3.5 x 2.7
103 – 104	4/17/70	1	3.5 x 2.7
105 – 106	10/26/72	1	3.5 x 2.7
107 – 114	2/24/67	1	3.5 x 2.7
Side wall			
1	7/8/71	1	4.5 x 3.5
2	1/15/72	1	4.5 x 3.5
3	12/17/71	1	4.5 x 3.5
4	7/23/72	2	4.5 x 3.5
5	1/4/72	1	4.5 x 3.5
6	7/31/72	2	4.5 x 3.5
7	1/4/72	1	4.5 x 3.5
8	7/23/72	2	4.5 x 3.5
9	4/24/72	2	4.5 x 3.5
10	7/17/71	1	4.5 x 3.5
11	4/24/72	2	4.5 x 3.5
12	1/10/69	1	4.5 x 3.5
13	4/27/72	2	4.5 x 3.5
14 – 15	1/10/60	1	4.5 x 3.5
16 – 25	4/24/72	2	4.5 x 3.5
26	1/22/72	2	4.5 x 3.5
27	1/29/72	2	4.5 x 3.5
28	1/10/69	1	4.5 x 3.5
29	7/23/72	2	4.5 x 3.5
30	1/15/72	1	4.5 x 3.5
31	7/16/72	2	4.5 x 3.5
32	1/15/82	1	4.5 x 3.5

Figure B-2—Sample Tube Inspection Record (History of all Tubes)

TUBE INSPECTION RECORD (HISTORY OF ALL TUBES)

PLANT _____ DRAWING _____
UNIT _____ PAGE _____2_____ OF _____2_____
TUBE LAYOUT _____ DATE _____

Tube No.	Date Installed	Material	Original Outside and Inside Diameter (In.)
Side wall			
33	4/27/73	2	4.5 x 3.5
34	12/26/72	2	4.5 x 3.5
35	4/5/73	2	4.5 x 3.5

Notes:

Group tubes under headings such as preheater, side wall, vertical, roof, and economizer. Consecutive tubes may be grouped.

Kind of Steel:

1: Plain C	5: 9Cr-1.5Mo	9:
2: 4–6Cr	6: 14Cr	10:
3: 2Cr-0.5Mo	7: 18Cr-8Ni	11:
4: 4–6Cr-0.5Mo	8:	12:

Method for Reporting Welded Tubes:
1-1 for welded C steel.
2-2 for welded 4–6Cr steel.
7-2 for 18Cr-8Ni steel welded to 4–6Cr steel.

Method for Reporting Upset-end Tubes:
The symbol denoting the kind of steel precedes U as follows: 1U, 5U, 7U.

Method for Reporting Tubes with Tube-end Liners:
The symbol denoting the kind of steel precedes L as follows: 2L, 4L.

Figure B-2 (continued)—Sample Tube Inspection Record (History of All Tubes)

TUBE INSPECTION RECORD (TUBES CALIPERED)

PLANT _____   DATE _____
UNIT _____   SHEET NO. _____

Tube No.	Inside Diameter in Roll (In.)				Inside Diameter in Back of Roll (In.)			
	Top or Front		Bottom or Rear		Top or Front		Bottom or Rear	
Economizer								
1	3.69		3.70		3.50		3.51	
	3.72	**0.03**	**3.72**	**0.02**	**3.51**	**0.01**	**3.51**	**0.00**
6	4.02	0.03	4.08	0.02	3.96	0.02	3.95	0.03
	4.06	**0.04**	**4.11**	**0.03**	**4.00**	**0.04**	**4.00**	**0.05**
20	4.10	0.05	4.11	0.04	4.01	0.03	4.00	0.02
	4.14	**0.04**	**4.16**	**0.05**	**4.03**	**0.02**	**4.02**	**0.02**
80	3.98	0.06	4.00	0.05	3.91	0.04	3.98	0.03
	4.05	**0.07**	**4.04**	**0.04**	**3.97**	**0.06**	**3.95**	**0.06**
Vertical								
1	4.48	0.04	4.50	0.03	4.32	0.02	4.36	0.04
	4.54	**0.06**	**4.54**	**0.04**	**4.35**	**0.03**	**4.41**	**0.05**
12	3.79		3.76		3.50		3.50	
	3.81	**0.02**	**3.80**	**0.04**	**3.52**	**0.02**	**3.53**	**0.03**
18	3.98	0.05	4.00	0.04	3.75	0.03	3.70	0.02
	4.06	**0.08**	**4.06**	**0.06**	**3.79**	**0.04**	**3.74**	**0.04**
49	3.87	0.04	3.90	0.05	3.61	0.02	3.59	0.04
	3.92	**0.05**	**3.94**	**0.04**	**3.62**	**0.01**	**3.63**	**0.04**

Note: Figures set in roman type refer to the previous inside diameter and change. Figures set in bold type refer to the current measured inside diameter and change. (When an inspection report is made, a copy of this form is to be saved for use as a field work sheet at the next inspection.)

Figure B-3—Sample Tube Inspection Record (Tubes Calipered)

TUBE INSPECTION RECORD (INSTRUMENT CALIPERINGS)

PLANT_____   SECTION _____

UNIT_____   DATE _____

SHEET NO._____

TUBE NO.	THICKNESS MEASUREMENTS (INCHES)					
	TOP OR FRONT		MIDDLE		BOTTOM OR REAR	

Figure B-4—Sample Tube Inspection Record (Instrument Caliperings)

TUBE RENEWAL RECORD

PLANT _____ TUBE LAYOUT DRAWING _____
BATTERY _____ DATE _____

Economizer											
33	11/4/70	1	4.5 x 3.5	3.70	3.75	4.06	3.98	D	6/15/73	1	4.5 x 3.5
34	11/4/70	1	4.5 x 3.5	3.72	3.78	4.00	4.08	D	6/15/73	1	4.5 x 3.5
Vertical section											
8	3/31/70	2	4.5 x 3.5	3.70	3.72	3.65	3.68	A	6/20/73	2	4.5 x 3.5
9	3/31/70	2	4.5 x 3.5	3.70	3.75	3.62	3.65	B	6/20/73	2	4.5 x 3.5

Notes:

Group tubes under headings such as preheater, side wall, vertical, roof, and economizer. When tubes are renewed, this form is to be filled out and sent in as a monthly report or as a periodic inspection and test report. Calipering reported as inside diameter in roll is to be taken within 5 in. of each end of the tube. All tubes removed for any reason shall be shown and reported. Use two or more sheets of this form as necessary to cover all of the tubes renewed.

Kind of Steel:
1: Plain C	5: 9Cr-1.5Mo	9:
2: 4–6Cr	6: 14Cr	10:
3: 2Cr-0.5Mo	7: 18Cr-8Ni	11:
4: 4–6Cr-0.5Mo	8:	12:

Method for Reporting Welded Tubes:
1-1 for welded C steel.
2-2 for welded 4–6Cr steel.
7-2 for 18Cr-8Ni steel welded to 4–6Cr steel.

Method for Reporting Upset–end Tubes:
The symbol denoting the kind of steel precedes U as follows: 1U, 5U, 7U.

Method for Reporting Tubes with Tube–end Liners:
The symbol denoting the kind of steel precedes L as follows: 2L, 4L.

Cause of Removal:
A : Split tube	D : Thin tube
B : Burned due to split tube	E : Other causes
C : Bulged in operation	F : Burned in operation

Figure B-5—Tube Renewal Record

FIELD WORK AND RECORD SHEET (TUBE ROLLING DATA)

TYPE OF UNIT _____ PLANT _____

UNIT NO. _____ DATE _____

Tube No.	Material	Front or Top Dimensions (In.)						Rear or Bottom Dimensions (In.)					
				Tube End		Inside Diameter of Roll				Tube End		Inside Diameter in Roll	
		Inside Diameter of Tube Hole	Outside Diameter	Inside Diameter				Inside Diameter of Tube Hole	Outside Diameter	Inside Diameter			
				In Roll	In Back of Roll	Required	Actual			In Roll	In Back of Roll	Required	Actual
Sidewall													
8	1	4.54	4.50	3.50	3.50	3.70	3.69	4.53	4.51	3.51	3.51	3.69	3.69
10	3	4.58	4.51	3.51	3.50	3.74	3.74	4.57	4.50	3.50	3.50	3.73	3.75
19	2	4.56	4.48	3.52	3.52	3.76	3.77	4.55	4.48	3.48	3.49	3.71	3.72
26	4U	4.53	4.50	3.34	3.49	3.55	3.56	4.53	4.50	3.35	3.50	3.56	3.55
Preheater													
2	1U	4.53	4.50	3.34	3.49	3.55	3.56	4.54	4.50	3.33	3.50	3.55	3.54
8	3U	4.54	4.51	3.35	3.48	3.56	3.56	4.56	4.49	3.34	3.48	3.60	3.61
9	4U	4.56	4.50	3.32	3.50	3.56	3.57	4.55	4.51	3.33	3.51	3.55	3.56
10	4	4.53	4.48	3.36	3.50	3.62	3.63	4.53	4.49	3.35	3.50	3.57	3.57
85	1-1	3.54	3.50	2.70	2.85	2.88	2.88	3.55	3.49	2.69	2.86	2.89	2.90
87	1U	3.55	3.48	2.56	2.69	2.78	2.79	3.56	3.50	2.54	2.68	2.76	2.77
88	2-2	3.56	3.51	2.69	2.75	2.88	2.89	3.54	3.50	2.70	2.79	2.88	2.89
90	4-2	3.54	3.50	2.70	2.84	2.88	2.87	3.54	3.51	2.71	2.80	2.88	2.87

Figure B-6—Field Work and Record Sheet (Tube Rolling Data)

As close to centerline as possible

A. Cast steel junction box

B. Streamlined return bend with U section bend

C. Cast steel terminal fitting—1 hole

D. Cast steel junction box

E. Cast steel corner fitting

F. Cast steel terminal fitting—2 holes

G. Cast steel return header—2 holes

H. Forged box Ls

J. Cast steel return header—3 or 4 holes

K. Steel return bend

L. Cast steel junction box

M. Cast steel terminal fitting

N. Streamlined return bend with U section bend

Figure B-7—Sample Record of Heater Fitting Inspection and Replacement

Notes:

1. The numbers shown on these sketches representing the sections of a fitting, not individual points.
2. The fitting number shall correspond to the tube number.
3. The symbols used to denote fitting material shall be the same as those used for tubes.
4. The average actual outside diameter at various sections of all sizes and types of fittings on the heater shall be recorded in the table at the right.

Fitting Size	Point Number and Outside Diameter									
	PT	OD	PT	OD	PT	OD	PT	OD	PT	OD

APPENDIX C—SAMPLE SEMIANNUAL STACK INSPECTION RECORD

The condition of a number of stacks can be tabulated on a form such as the sample contained in this appendix.

Note: For photos shown as figure x.x, these come from *The Nalco Guide to Boiler Failure Analysis*, authored by Harvey M. Herro and Robert D. Port. Published by McGraw-Hill, Inc. in 1991.

SAMPLE SEMIANNUAL STACK INSPECTION REPORT

PLANT _____ REPORT BY _____
CHECKED BY _____ APPROVED BY _____
                                                     DATE _____

Complete description of all defects and repairs since last inspection: _____ Inspected for condition and found OK except as noted below. _____

Stack No.	Location and Description	Foundation	Shaft	Lining	Guys and Connection	Lightning, Rods, Points, Conductors, and Grounds	Ladders	Vertical Alignment	Remarks and Recommendations
30	Boiler No. 8, BH No. 2, 6 x 50 ft SS	Blower housing	OK	None	None	None	None	OK	General condition good
31	Boiler No. 2, BH No. 2, 6 x 50 ft SS	Blower housing	OK	None	None	None	None	OK	General condition good
32	Boiler No. 3, BH No. 2, 6 x 50 ft SS	Blower housing	OK	None	None	None	None	OK	General condition good
33	Boiler No. 9, BH No. 2, 6 x 50 ft SS	Blower housing	OK	None	None	None	None	OK	General condition good
34	Boiler No. 10, BH No. 2, 6 x 50 ft SS	Blower housing	OK	None	None	None	None	OK	General condition good
35	FCCU, 11 x 120 ft RBS	Concrete to rock	OK	Firebrick OK	None	5 Points 2 Grounds OK	Outside ladder irons	OK	General condition good
36	FCCU, 4 $1/2$ x 108 ft SS	Platform	OK	None	None	None	None	$2^{1}/_{2}$ in. south, 10 in. west	General condition good
37	FCCU gas flare stack, 1 ft, 8 in. OD x 250 ft high x $^{9}/_{32}$ in.	Concrete to rock	OK	None	OK	None	None	3 ft east, 20 in. south	Recently reconditioned— condition good: frozen concrete crumbling south side on pedestal
38	Badger pipe stills	Concrete	OK	OK	None	OK	None	OK	General condition good

Note: Stack numbers do not appear on any stack. Abbreviations are as follows: BH = blower housing; BS = brick stack; CS = concrete stack; SS = steel stack; RBS = radial brick stack; RTS = radial tile stack; FCCU = fluid catalytic cracking stack.

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	CX53005	Std 530, *Calculation of Heater Tube Thickness in Petroleum Refineries* ISO 13704, *Petroleum and Natural Gas Industries: Calculation of Heater Tube Thickness in Petroleum Refineries*		$ 150.00	
	C53401	Publ 534, *Heat Recovery Steam Generators*		$ 71.00	
	C53501	Publ 535, *Burners for Fired Heaters in General Refinery Services*		$ 71.00	
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