



REFINERY INSPECTION AREAS OF VULNERABILITY

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AREAS OF VULNERABILITY

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– Special Inspection Considerations –

I. SPECIAL INSPECTION CONSIDERATIONS

These Special Inspection Considerations, somewhat related to process equipment type, have been gathered from industry and are presented with the intent that they will be useful in training and in the development of more efficient process equipment inspection programs.

GENERAL

- G-1 Regular thickness inspection procedures for corrosion monitoring should include statistical sampling principles based on the half-life of the remaining corrosion allowance to determine inspection frequencies or dates.
- G-2 Consider criticality factors of hydrocarbon systems and equipment to determine the inspection activity level and/or the locations where material improvements are warranted.
- G-3 Hydrocarbon equipment operations above 400°F should receive more concentrated inspection attention because of a greater likelihood of corrosion in addition to autoignition of C₆ through C₁₈. (Especially watch heavy bottoms hydrocarbon lines carrying sulfur compounds above 550°F.)
- G-4 Increase inspection concentration on equipment containing environments having average corrosion rates of 0.020 inches per year or higher. (This represents the highest 3% rate category of refinery corrosion environments.)
- G-5 For environment corrosion monitoring, include worst-case samples of all expected problem locations in addition to all typical configurations. Be sure the sample includes typical top and bottom, vapor and liquid, and interface locations where appropriate.
- G-6 Consider the possibility of unacceptable stress levels in equipment where changed operating conditions have evolved over a period of time or due to revamps. Double check relief equipment capabilities where necessary.
- G-7 Consider special inspection measures where temperature gradients and fatigue are likely. This may result from temperature cycling, process conditions, differential section size constraints, or from materials with differential expansion characteristics.
- G-8 Consider special inspection measures where creep may occur in equipment.
- G-9 Be alert for wrong material installations. The frequency for erroneous material installations may be approximately 5% without special control checking.

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- G-10 Welded areas subject to preferential attack or deterioration should be identified and watched regularly.
- G-11 Periodically check for cracks or separation of bonded materials with differential expansions. Shutdown temperatures cycling and weather quenching (from rain, etc.) may aggravate such joints.
- G-12 Check closely at locations where 600°F to 800°F sulfur corrosion may occur and at points where naphthenic or other organic acids may be present in the process.
- G-13 Watch areas near flange or welded attachments on equipment which may act as cooling fins and may cause changes in protective scale formation and result in local corrosion.
- G-14 Watch stagnant areas closely where water and/or acid, or the build-up of foul matter may concentrate and accelerate corrosion.
- G-15 Check points at which condensation of acid gases and/or water is likely to occur.
- G-16 Watch locations where conditions may result in high-temperature or low-temperature hydrogen attack.
- G-17 Type 410 steels (12% chrome) are subject to embrittlement after long-time service around 700°F or higher. Care should be taken not to hydrostatically test or apply unusual stresses to these materials at ambient temperatures.
- G-18 Watch equipment subject to stress-corrosion-cracking, especially austenitic stainless steel where chlorides may concentrate and water may occur on some occasions.
- G-19 High velocity and turbulent locations in concentrate H₂SO₄ equipment should be identified and monitored periodically.
- G-20 Watch for graphitic corrosion of cast iron materials in water service (oil coolers on compressors, pumps, and blowers often have cast iron components).
- G-21 Watch steam systems for "steam cutting" of gasketed joints, for dissolved oxygen corrosion, for where condensation and CO₂ corrosion may occur, and for potential graphitization above 700°F.
- G-22 Watch for caustic embrittlement around boilers and in caustic environments with steel above 170°F and unstress relieved steel above 120°F. Steam heaters in caustic tanks may embrittle or corrode carbon steel in the vicinity.

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- G-23 Watch alkali lines and equipment subject to caustic embrittlement, especially where steam or electric tracing may make contact and raise temperatures excessively.
- G-24 Consider cathodic protection of tank under bottoms and buried pipe subject to corrosion.
- G-25 Watch all anchor bolts for corrosion, tightness, and possible overstress.
- G-26 Check vent and connection plugs for tightness upon completion of hydrostatic testing of equipment.
- G-27 As a guide in the assessment of corrosion severity, the depth of a plan-view pit observed on a radiograph will be very close to 1/3 of the measured diameter. Be careful to measure a single pit when they intersect.
- G-28 Insulation metal wrapping may trap moisture causing corrosion (pitting) on the external surface of piping.
- G-29 Check that nipples and valves installed for test purposes during construction are removed and replaced with solid plugs. These test connections, if not removed particularly if covered with thermal insulation, can be potential booby traps.

PIPING

- P-1 Consider expanding the inspection sample for piping systems having maximum/average corrosion rate ratios greater than 4/1 because the potential for extremes is great. Extremes result from multiple corrosion mechanisms.
- P-2 Regularly check piping direction-change and turbulent points in lines carrying catalyst, flue gases, or entrained particles such as slurries.
- P-3 Watch locations such as pipe vent nipples and couplings where eddies may cause rapid wastage (often associated with partial liquid/vapor phases or around pump turbulence).
- P-4 Identify and statistically sample every nipple and nozzle on hydrocarbon equipment where vulnerability to deterioration exists.
- P-5 Periodic radiography of pipe nipples and small piping is an excellent way to monitor corrosion by rate as well as observing special problems such as with couplings and threads.

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- P-6 Occasionally, a vent or drain connection may be hidden by insulation or other equipment. Take precautions to identify all small connections for monitoring.
- P-7 Consider rechecking piping adjacent to previous replacements to be sure nothing was overlooked.
- P-8 Periodically check the integrity of old welded joints made when the performance of welding may have been somewhat irregular.
- P-9 Consider replacing "dummy leg" pipe supports (made with pipe) with supports made from structural steel as active corrosion may be working on the live line inside the dummy pipe where it cannot be checked.
- P-10 Brace any lines that are inadequately supported or reinforced, especially small piping and lines subject to significant vibration.
- P-11 Watch for small screwed piping stubs in equipment that is not seal-welded properly as it may result in stress risers at incomplete thread coverage or undercut at the toe of the weld.
- P-12 Drain or heat low points in lines and equipment where water may collect and freeze during cold weather.
- P-13 Watch all sour water piping from water legs of overhead reflux drums, especially where HCL and/or H₂S are present.
- P-14 Watch for corrosion at transition areas of corrosion-resistant alloy piping where it attaches to carbon steel piping.
- P-15 Watch for carbon steel instrument piping (level controllers, etc.) especially where a column is internally corrosion-resistant clad and the piping is carbon steel.
- P-16 Watch dead ends subject to turbulence or where liquid to vapor interface or concentration may occur, also dead legs subject to stagnation and/or water.
- P-17 Check points at which acid carry-over from process operations is likely to occur.
- P-18 Watch piping downstream of water/acid injection points for localized corrosion.
- P-19 Watch turbulent areas such as downstream of control valves for corrosion/erosion.
- P-20 Watch for expansion joint fatigue.

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- P-21 Watch atmospheric crude and vacuum tower overhead piping for HCL and H₂S corrosion.
- P-22 Watch crude unit stabilizer column overhead piping systems for sulfuric acid.
- P-23 Check for catalyst erosion at nozzles and cavities and protrusions where turbulence is created as well as the outside sweeps of bends in catalyst lines and lines carrying abrasive materials.
- P-24 Steel materials such as A-53 pipe may have less than 0.10% silicon and be vulnerable to more rapid high-temperature sulfur corrosion than even their welded fittings, which may have more than 0.10% silicon by spec. Therefore, be sure to include all pipe segments when monitoring such systems where the silicon content of the pipe and/or the fittings is unknown.
- P-25 Check chrome nickel and chrome molybdenum lines in high-temperature service near points of increased -stress such as at bends and anchor points.
- P-26 Watch aluminum lines at points of accidental contact or for insulator breakdown, which can cause contact with other metals and galvanic corrosion.
- P-27 Pipelines running in ground conduits where contact with dirt or water results in external corrosion.

SAFETY RELIEF

- SR-1 Consider rupture disk installation, using prescribed design, under safety relief valves to stop leaking, corrosion damage, and to reduce maintenance.
- SR-2 Mount stop valves under relief valves, horizontally so gravity cannot automatically close a gate separated from a stem. Be sure to padlock or "car-seal" such valves in the open position and establish a system to maintain the integrity of the lock or seal.

HEATERS

- H-1 Watch "low-flow" conditions in heaters where only the outlet temperature is monitored. "Low-flow" can reduce the outlet temperature and, thus, "call for" additional heat, which condition can overheat stagnant tubes.

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- H-2 Consider heater tube replacement when creep exceeds 3% general growth, 5% local expansion, and 8% expansion due to short-term overheating (single occasion, short duration).
- H-3 Watch heater tubes for carburization in heavy oil service. Carburization lowers the corrosion resistance of chrome-moly materials. This condition can be followed using thickness measurements.
- H-4 Watch for dew points and concentrate sulfuric acid corrosion in heater and boiler convection sections, stacks, and supports where the flue gas is below 350°F.
- H-5 Be watchful of sulfur-bearing flue gas penetrating refractory, condensing on a cold wall and corroding the wall or building up deposits which will spell the refractory. Coatings may stop such corrosion, and sealing the wall of any leaking cracks may stop the penetration and deposit build-up.
- H-6 Watch heater tubes that operate with products, temperatures, and flows conducive to coke formation which may cause tubes to coke, burn, bulge, leak, sag, or rupture.
- H-7 Watch for failed heater tube hangers when tubes sag and creep.
- H-8 Periodically check reradiating cone hanger rods and castings in vertical heaters.
- H-9 Ensure that tightness testing of individual fuel gas block valves at burners is carried out prior to start-up. Leaking burner valve have been the cause of numerous fire box explosions during light-off.
- H-10 Check steam snuffing lines at heaters during downtime. These lines are subject to internal corrosion and fouling due to possible leakage of steam through block valves. Unless periodically tested, loose scale may plug lines when activated during a fire situation.

EXCHANGERS

- E-1 Be sure exchanger bundle impingement plates near outlets are well attached to prevent their breaking loose and blocking the outlet.
- E-2 Watch for tube pit corrosion beneath tube deposits and/or coke formations in hot bottoms service.

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- E-3 Watch for shell corrosion pitting beneath accumulations of deposits where corrodents may concentrate. (Chloride corrosion from catalyst treatment may sometimes be found in depropanizer and debutanizer systems of reformers at the "dead" flow ends, between the nozzle and tubesheet or between the nozzle and the bumped head.)
- E-4 Watch for tube-end corrosion/erosion in exchangers in hot bottoms service, especially if entrained catalyst fines are present.
- E-5 Watch for galvanic corrosion at junctions and gasket surfaces of carbon steel channel barrels and baffles, in cooler or condenser service where tubesheets are brass.
- E-6 Watch for oxygen corrosion pitting in steam generators (on the both shell and tubes) where the feed water has not been properly deaerated.
- E-7 Watch for CO₂ corrosion in non-vented reboilers having carbon steel tubes.
- E-8 Consider special titanium exchanger support requirements during design to eliminate characteristic vibration when installed in equipment designed for other materials.

VESSELS

- V-1 Be aware that existing data suggests that about half of the standard steel vessel construction materials have their ductile-to-brittle property transition temperatures above 50°F. This means that special care should be exercised to reduce the likelihood of impact or significant stress being applied to these materials when near these temperatures. The data indicates that a few did not behave ductilely until 120°F was reached.
- V-2 Watch protective liners and clads for mechanical and environmental damage which can eventually allow corrosion to penetrate the pressure envelope.
- V-3 Closely monitor feed streams and steam injection around vacuum towers to avoid water entry as even small quantities of water may cause flashing at operating temperatures and extensive tray upsets
- V-4 Periodically spot check and repair waterproofing of insulation and lagging.
- V-5 Watch skirts and supports hidden by fire protection for corrosion damage. Periodically spot check at the worst expected locations, especially when significant cracking or spalling of the protection occurs.

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- V-6 Watch the bottom sections of crude, vacuum, and cracker sin-crude columns and drums where partial cladding may exist. The adjacent, unprotected carbon steel is quite vulnerable to sulfur corrosion.
- V-7 Watch for corrosion in the flash zone and dew point areas of atmospheric columns where stripping steam is used.
- V-8 Watch the gas oil or lean oil columns in crackers for H₂S corrosion.
- V-9 Watch the gas recovery and deethanizer columns for hydrogen attack, H₂S and cyanide corrosion in crackers.
- V-10 Periodically check coke drums for bulge-cracking due to local differential quench temperatures over a period of time.
- V-11 Periodically check coke drum skirts for low-cycle fatigue cracking due to cycling thermal gradients. Keyhole slots and insulation arranged to permit the skirt to receive heat from the bottom head may reduce the problem.
- V-12 Watch for radial cracking of flame-cut keyhole slots in coke drum skirts.
- V-13 Be alert to areas in hot oil towers that could trap water during steam-out or prevent free drainage. Remember that one cubic foot of water will form 1600 cubic feet of vapor at 212°F and atmospheric pressure. Violent explosions during start-up have occurred due to hot oil contacting trapped water.
- V-14 High thermal gradients due to coke build-up, can occur in such areas as FCCU reactor heads. Be alert to possible fatigue cracking should this condition be encountered.
- V-15 Threaded carbon steel nipples/bull plugs used in corrosive service should be inspected during turnarounds for corrosion located on the threads.

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TANKS

- T-1 Provide proper grading and drainage of groundwater from around equipment and storage tanks.
- T-2 Check tank connecting lines and excavate when they are in contact with the ground too close to the tank, as freezing or differential movement may crack the nozzle.
- T-3 Watch for evidence of underside floor corrosion when tank area drainage is poor.
- T-4 Watch for cone-roof support column settlement, which may create conditions that impose high stresses on the top shell course.
- T-5 Watch for pantograph-type floating roof seal shoe corrosion/erosion due to concentrate wear from worn seal shoes.
- T-6 Watch for failure of insulation weatherproofing which may cause corrosion under the insulation to the roof or shell. Also watch for insulation "wicking" if it is in contact with a water source such as the ground.

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- Specific Problem Events -

II. SPECIFIC PROBLEM EVENTS

This Specific Problem Events listing of events somewhat peculiar to specific types of units has been gathered from industry and is digested here with the intent that it will be useful for training and in efforts to reduce the reoccurrence of similar problems.

EXTREMELY RANDOM PITTING

No. 1 Crude

- Equipment/Location: Furnace to tower piping.
- Problem: Sour crude random corrosion of steel.
- Circumstances: High temperature sulfur with possible naphthenic acid corrosion of steel with maximum rates of 1/16" per year. Very few locations deeply corroded and completely random.
- Guidance: Consider alloy because of the high rates and extreme randomness of the pitting.

RELIEF VALVE CHATTER

No. 2 Crude

- Equipment/Location: Desalter relief valves at crude tower
- Problem: Pressure drop in long line caused chatter.
- Circumstances: Fluctuating pressure chatter loosened bolts and caused flange to open up.
- Guidance: System problem. Double bolting and pilot operated valves may help.

CHEMICAL INJECTION

No. 3 Crude

- Equipment/Location: Chemical injection nozzle into atmosphere tower overhead line.
- Problem: Erosion-corrosion to hole.

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- Circumstances: A chemical injection quill broke off inside the nozzle, just past the nozzle, to overhead line weld. Inhibitors are also scavengers and remove protective scale when too concentrated as at this location. The turbulence created injecting chemicals caused erosion-corrosion. The nozzle thinned to holes adjacent to the HAZ of the weld.
- Guidance: In addition to U.T. inspection of nozzles, R.T. cross section to pick up thin areas near the nozzle to header weld.

OPERATOR ERROR

No. 4 Crude Unit

- Equipment/Location: Reflux drum
- Problem: Four-inch (4") water drain into multiple drain sewers.
- Circumstances: Four-inch (4") valve was opened to drain off water in reflux and was left unattended. Multiple drain system was plugged or frozen closed. Hydrocarbons spilled into unit due to sewer being frozen and flashed. Could not get back to valve to close. Extensive damage from fire.
- Guidance: Operation took place at night. Operator should have kept close eye on drain to make sure drain was not plugged. Never leave operation unattended even for a few seconds when valve is open on in process vessel.

INTERNAL LINE CORROSION

No. 5 Crude Unit

- Equipment/Location: Type 304 18-8 SS 3" line from a Fractionate Tower to a Surge Drum.
- Problem: Severe local internal corrosion was found on the inside of the line opposite "score" marks on the exterior. The line contained Borontrifluoride and Phenol.
- Circumstances: In fabricating the pipe, a pipe cutoff machine was used without proper lubrication. A sharp, single point cutting tool was also used. The exterior surface of the Schedule 40, Type 304 pipe was deeply scored by the sliding steady rest backup at the cutoff location. This introduced stresses in the pipe all the way to the interior surface of the pipe. Subsequently, the Borontrifluoride and Phenol preferentially attacked the locally stressed areas.

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- Guidance: In cutting off pipe (particularly stainless steel) make sure there is cutting oil lubrication at the steady rest and tool cutoff area. Also, make sure that the cutting tool is sharp. Do not use pipe that has evidence of external scoring or other marks that could cause stresses internally and, thus, promote preferential corrosion.

PREFERENTIAL CORROSION/CARBON STEEL

No. 1 Vacuum

- Equipment/Location: Furnace feed line (585°F)
- Problem: Much higher sulfur corrosion rates for only some carbon steels.
- Circumstances: Uncorroded or very low rate carbon steels were found to have more than 0.10% silicon. Heavily corroded steels had less than 0.10% silicon. Also found in crude and cracker units.
- Guidance: - Use A-106, Grade A, or better, steel to improve resistance to high temperature sulfur corrosion (see P-24 note).

TURBULENT CORROSION

No. 2 Vacuum

- Equipment/Location: Heater to tower transfer line.
- Problem: Corrosion restricted to turbulent areas.
- Circumstances: Silicon killed steel line 36" diameter severely corroded at mitered bends and turbulent areas after 12 years.
- Guidance: Inspect from inside. Consider material improvement.

BOUND GUIDE PIN

No. 3 Vacuum

- Equipment/Location: Heater tubing bottom guide pin.
- Problem: Bound pin caused tube to fail.

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- Circumstances: Top-supported tubes have guide pins welded to bottom of return bends. Bowed tube cracked out a 2N section of tube with the pin.
- Guidance: Removed pins and went to non-attached guide system.

TURBINE CUT FAILURE

No. 4 Vacuum

- Equipment/Location: Heater tube.
- Problem: Turbine cut cracked during shutdown.
- Circumstances: 5% chrome tube cracked during turbinning after operation with a severely cut tube.
- Guidance: Check for turbine cutting and repair damage when serious. Consider alternative cleaning methods.

SULFUR CORROSION

No. 5 Vacuum

- Equipment/Location: Bottoms pump pipe plug in casing.
- Problem: Sulfur corrosion failure.
- Circumstances: A carbon steel pipe plug was erroneously used instead of a 5% chrome plug.
- Guidance: Check all alloy materials where substitutions may be dangerous.

THERMAL FATIGUE

No. 1 Coker

- Equipment/Location: Coke drum support skirt weld.
- Problem: Temperature gradient fatigue cracking.
- Circumstances: 1961 skirt-to-head weld on a 20' diameter carbon moly drum cracked circum. for 24' in 1' to 6' lengths. Successfully ground out and re-welded.

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- Guidance: Periodically inspect visually or by dye penetrant.

THERMAL FATIGUE

No. 2 Coker

- Equipment/Location: Coke drum top head skirt.
- Problem: 4'-8" long crack in 410S cladding.
- Circumstances: 20' diameter carbon-moly drum found to have a leak which ran 22'-4" around top skirt. Successfully repaired.
- Guidance: Periodically inspect upper coke drum skirts supporting derrick.

SEVERE CORROSION ON BLIND FLANGES

No. 3 Coker

- Equipment/Location: Coker overhead vent lines.
- Problem: Carbon steel blind flanges in 5Cr-½ Mo piping system corroded at high rates over 10-year period.
- Circumstances: Earlier decision taken by field personnel to keep existing carbon steel blind flanges, even though the rest of the piping components were being upgraded to 5Cr due to higher sulfur feeds, caused much high corrosion rates.
- Guidance: Be alert to blind flange and spectacle blind materials in alloy piping systems.

SUPPORT FATIGUE

No. 1 Cracker

- Equipment/Location: 1941 Regen support beams (vessel dropped 2").
- Problem: Fatigue cracking of support at numerous joints.

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- Circumstances: Many rough, jagged torch-cuts covered by concrete finally fatigued and cracked at 45° in the web at the bottom corner of the joint. Spalled concrete called attention to it. Some cracks were 35" long and vessel settled 2".
- Guidance: Check WW II vintage torch-cut structures for sharp corners. Also supports where concrete is spalling.

ERODED REGEN AIR DISTRIBUTOR

No. 2 Cracker

- Equipment/Location: Regen pipe air distributor (5% chrome but 18-8 pipe grid subject to the same problem).
- Problem: Erosion/overheating with destruction beyond repair.
- Circumstances: Cracking of pipe air distributor permitted catalyst entrance, erosion, and eventual local overheating. Without an awareness of the problem, attempts to operate continued for days making the grid unrepairable and causing weeks of downtime for fabrication.
- Guidance: Consider the potential for aggravating equipment damage when early trouble signs appear. Plate air grids are less susceptible to total destruction.

STANDPIPE OXIDATION

No. 3 Cracker

- Equipment/Location: Regen standpipe weld.
- Problem: General thinning due to oxidation.
- Circumstances: 26-year-old 1-¼-chrome standpipes operated at 1200°F-1250°F partially failed 10' above slide valve. The weld was found to be only 0.25" under the scale.
- Guidance: Watch for oxidation under refractory-lined low chromes at elevated temperatures.

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THERMAL FATIGUE

No. 4 Cracker

- Equipment/Location: Reactor shell at toe of a vertical weld seam.
- Problem: Thermal fatigue of 1943 vessel 35 years old.
- Circumstances: Much of the wear-resistant refractory-covered 54" crack was obviously very old when found by leaking. The stress relieved steel shell operated at 950-975°F for 5 years with riser cracking.
- Guidance: Beware of possible shell cracks and check whenever an opportunity presents itself.

REACTOR ANNEALING

No. 5 Cracker

- Equipment/Location: Upper 2/3 of reactor exposed to high temperature (carbon ½ % moly).
- Problem: Shell annealed and grew 6" in diameter.
- Circumstances: Temperatures above 1650°F were maintained for some time in trying to recover from stripping steam loss with a badly worn slide valve. Shell was found metallurgically okay.
- Guidance: Shut down at any opportunity, rather than exceed equipment design conditions.

INADEQUATE STRESS RELIEF

No. 6 Cracker

- Equipment/Location: 18-8 riser wye transition weld.
- Problem: Stress relief of 25-20 to 1-¼% chrome intermediate weld materials inadequate.
- Circumstances: Intermediate weld materials, used to reduce thermal expansion problems when joining an 18-8 wye to a carbon steel section, developed an 8" crack after only 9 months. Repairs covered 48" of the 53" O.D. riser line.

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- Guidance: Consider sensitivity of materials to stress relief and monitor closely. Also, consider using a “cold joint”.

EXPANSION JOINT OVERPRESSURE

No. 7 Cracker

- Equipment/Location: 24” catalyst line expansion joint.
- Problem: Overpressured with 600 psi steam.
- Circumstances: Regenerator catalyst heat removal line to the steam generator failed when trying to free a catalyst plug with steam pressure.
- Guidance: Be sure procedures do not call for subjecting equipment to conditions exceeding design allowables.

SULFUR CORROSION

No. 8 Cracker

- Equipment/Location: 8" heater bypass line connecting outlet passes.
- Problem: 700°F sulfur corrosion of steel bypass line normally closed.
- Circumstances: Steel outlet passes were over 800°F and indicated nominal corrosion rates. The cooler steel bypass line was, thus, in the 700°F critical sulfur corrosion temperature range at some location. It failed in just 1.5 years.

THERMAL GRADIENT CRACKING

No. 9 Cracker

- Equipment/Location: Reactor head with internal plenum chamber.
- Problem: Internal coke caused thermal stress cracking.
- Circumstances: 20' cracking in C-½% moly head were caused by creep-rupture from plenum coke build-up insulating part of the head. Repaired with great care.
- Guidance: Remove coke where gradients may occur. Changed to external plenum design.

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LOCALIZED CORROSION ON H.E. TUBE INLETS

No. 10 Cracker

- Equipment/Location: CCU interstage cooler.
- Problem: Tube leaks and bundle failure due to under deposit corrosion.
- Circumstances: Ammonium salt deposition occurred in inlet area of bundle due to insufficient scrubbing of gases by polysulfide injection upstream of bundle.
- Guidance: Improve injection system and retube bundle.

CRACKING OF SOUR SEAL OIL PIPING

No. 11 CCU Heat Gas Compressor

- Equipment/Location: Type 304 SS sour seal oil drain piping.
- Problem: Failure was a result of intergranular stress corrosion cracking (polythionic acid) of sensitized 304 SS initiating from the internal surface. 304L SS in the same service did not experience cracking.
- Circumstances: The 1", 304 SS piping had been in service for about 7.5 years. The inside surface was exposed to sour seal oil at a temperature of 100°F and an operating pressure of 80 psig. Chemical analysis of the cracked sample showed it to have a carbon content of 0.059%, typical of 304 SS. An uncracked sample had only a 0.015% carbon content.
- Guidance: Replace all 304 SS piping in sour seal oil drain lines, gas reference lines and buffer gas lines in any sour wet gas lube sets with solution annealed, 304L stainless steel.

SPENT CAT STANDPIPE

No. 12 Cracker

- Equipment/Location: Thirty-six inch (36") diameter ASTM 240 0.750" thick, type 304L stainless steel standpipe of the Catalytic Cracking Unit Converter.
- Problem: Cracks and holes were found during a scheduled turnaround of the unit in the base metal in the standpipe. The holes appeared to have been caused by the failure of the refractory liner allowing catalyst to erode from the outside at existing cracks.

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- Circumstances: The refractory lined interior surface had been exposed to coked up catalyst at a process operating temperature of 35-40 psig and 950°F temperature respectively. The unlined exterior pipe had been exposed to nitrogen, CO₂, O₂, CO, and SO₂ at a process pressure and operating temperature of 30-35 psig and 1350°F respectively. The standpipe had been in service for about seven years. Plate samples were taken from the standpipe for materials investigation. The results of the investigation revealed a carbon content to be 0.028/0.032% wt., which is typical of 304L rather than 0.04/0.10% wt. carbon content for the type 304H material. 304H is generally required for service at high temperatures. A new spent cat standpipe was fabricated of 304H stainless steel and installed.
- Guidance: During fabrication of new installations be aware of chemical analysis of materials supplied by the supplier. Insist that carbon content or other constituents of the material be within specified limits for the intended environment. The use of a nuclear analyzer would be a useful tool for spot checking of stainless steel materials for chemical analysis.

DEAD END CORROSION

No. 1 Gas Plant

- Equipment/Location: Depropanizer reflux 6" horizontal "live" steel pipe extension to support.
- Problem: 30-year line with no general corrosion failed at a local spot on the bottom.
- Circumstances: Apparently a dam of scale or dirt built up at the far end of the dead end, trapping moisture which eventually corroded through even though there was no measurable corrosion anywhere else in the piping system.
- Guidance: Eliminate "live" dead end Pipe supports. Check all other dead ends periodically, especially dead legs and stagnant bottoms.

THREADED CONNECTION

No. 2 Gas Plant

- Equipment/Location: 8x6" screwed/welded steel reducer in stabilizer reflux line.
- Problem: 8" threads were masked by shoulder on threaded flange. The joint broke in the threads.

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- Circumstances: The threads were masked and the ultrasonic readings did not suggest a much lower minimum thickness than was measured. The other end of the reducer was welded so it looked like it was an all-welded flanged reducer.
- Guidance: Eliminate screwed joints in hydrocarbon lines over 2". Use 3 standard deviations below the average as a guide for additional inspection.

B7M BOLTING FAILURES

No. 3 Gas Plant

- Equipment/Location: Splitter column tops condenser.
- Problem: Internal leaking floating head caused by broken bolts from wet hydrogen sulfide cracking.
- Circumstances: Though these bolts had been checked by the inspector prior to installation and found to have the B7M stamp, they had, in fact, not been heat treated to below 235 BHN.
- Guidance:
 1. Obtain B7M bolts only from qualified, reliable sources.
 2. Ensure that each is stamped with the "M".
 3. Hardness check a selected number to ensure proper heat treatment.

FATIGUE CRACKS IN WELD

No. 1 Reformer

- Equipment/Location: Regenerated cat preheater tube welds.
- Problem: Fatigued weld cracks caused by impingement.
- Circumstances: 2-½" O.D., 1-¼% chrome tubes fillet-welded in the tubesheets cracked in the HAZ from feed impingement.
- Guidance: Several tubes were removed to install an impingement baffle.

BIMETALLIC DIFFERENTIAL EXPANSION

No. 2 Reformer

- Equipment/Location: 321 stainless heater tubes with steel studs.

AREAS OF VULNERABILITY

- Specific Problem Events -

- Problem: Tube cracks from differential expansion.
- Circumstances: After 7 years at 700°F, the studs began cracking the stainless tubes.
- Guidance: Metals with differential expansion rates should not be used when studding tubes.

ERRONEOUS MATERIAL

No. 3 Reformer

- Equipment/Location: Reactor feed/effluent exchanger inlet nozzle.
- Problem: Steel used instead of carbon ½ moly.
- Circumstances: After 13 years U.T. readings indicated nozzle thin. Calipered full thickness. Analysis indicated severe H₂ attack, cracks and fissures.
- Guidance: Check all materials where substitutions may be hazardous.

BRITTLE FRACTURE

No. 4 Reformer

- Equipment/Location: Spherical internal refractory reactor shroud-to-head weld.
- Problem: Non-stress relieved repair weld precipitated brittle fracture (no H₂ deterioration).
- Circumstances: Shroud-to-head steel weld made 7 months earlier. Reactor off-stream a week at 75% H₂ pressure, cooled to 40°F ambient and failed brittly sending head 300' into the air. Numerous cracks less than 3mm at the root of the one-sided weld ran into head.
- Guidance: Consider repair weld design, brittle characteristics, and heat treatment. Also, use only 25% maximum of the design pressure below the transition temperature.

THERMAL FATIGUE

No. 5 Reformer

- Equipment /Location: Reactor bottom flange-to-nozzle weld.
- Problem: Circumferential cracking in the weld.

AREAS OF VULNERABILITY

- Specific Problem Events -

- Circumstances: 3/4N thick 1-1/4% chrome nozzle internally insulated except at the weld. The flange acted as a heat sink and the weld operated much hotter.
- Guidance: Installed a heavier walled nozzle and internally insulated over the weld.

THERMAL FATIGUE

No. 6 Reformer

- Equipment/Location: 16" reactor outlet nozzle weld cracks.
- Problem: Stainless repair weld cracks in carbon - 1/2% moly nozzle.
- Circumstances: 22 year-old repair weld began to exhibit thermal fatigue cracking. Deepest crack was 0.25".
- Guidance: Dye penetrant or radiographically check old welds.

THERMAL FATIGUE

No. 7 Reformer

- Equipment/Location: Reactor valve bodies (1-1/4% chrome, 2" thick).
- Problem: Numerous cracks on inside, some to mid-wall.
- Circumstances: Cracking of uninsulated valves largely at bonnet-to-barrel junctions. Probably a threshold thermal fatigue problem. Ground cracks with radius to 1/2" deep. Successfully repaired deeper ones.
- Guidance: Insulating valves should reduce temperature gradients. Check by radiography with source in the center of valve.

WRONG WELDING ROD

No. 8 Reformer

- Equipment/Location: 30" carbon 1/2% moly transfer line.
- Problem: HAZ cracking of circumferential joint.

AREAS OF VULNERABILITY

- Specific Problem Events -

- Circumstances: Construction repair of weld defect probably used wrong electrode.
- Guidance: Use compatible electrodes when repairing welds and stress relieves.

OPERATOR ERROR

No. 9 Reformer

- Equipment/Location: Main Fractionator Tower/Condensate Unit/Reformer, Desulfurizer
- Problem: Draining tower after steam out - hydrocarbons still present in tower.
- Circumstances: No drain line on the bottom of drain valve (3") -condensate allowed to splash against blind flange and onto concrete. Hydrocarbons present in the vessel spilled out and flashed. Fire caused extensive damage.
- Guidance: Drain line to sewer should always be used to contain liquid and direct the flow.

HEATER TUBE FAILURE

No. 10 Reformer

- Equipment/Location: 9% Chrome - 1 Moly "U" tube in the Platformer Heater - tube is first tube on inlet header.
- Problem: Tube coked solid and split at approximately 1 foot from the inlet header (split was 2 feet long) and at approximately 1 foot from the outlet header (split was 8 inches long).
- Circumstances: The coking of the tube resulted because of a stoppage - either a foreign body was left in the tube or liquid accumulated during a down period due to a power failure. The stoppage did not allow normal flow and coking resulted.
- Guidance: Make sure NOTHING is allowed to restrict flow in the tubes. Allow for a slow start up to dry out any liquid in the tubes. Also, thoroughly inspect the tubes visually, prior to closing the heater, to insure no foreign material is in the tubes.

PIPING FAILURE FROM HOT HYDROGEN DAMAGE

No. 1 HDS

- Equipment/Location: Distillate saturation unit piping.

AREAS OF VULNERABILITY

- Specific Problem Events -

- Problem: Insufficient resistance of carbon steel material to hydrogen containing liquid phase stream, caused through wall crack, decarburization and expensive fissuring in HAZ.
- Circumstances: Liquid phase stream at 780 psig and 600°F contained only 8 mol% hydrogen in solution; but vapor phase contained much higher hydrogen content.
- Guidance: Select materials for vapor phase conditions in hydrogen environments, even if liquid flow is normal. In this case, the piping was replaced with 9Cr-1Mo material.

CORROSION FAILURE OF COMPRESSOR PIPING

No. 2 CFH Plant

- Equipment/Location: Carbon steel piping off recycle compressor in CFH Plant.
- Problem: High corrosion rates caused by high-localized flow/turbulence in hydroprocess stream containing large amount of ammonium hydrosulfides.
- Circumstances: Corrosion rates exceeding 500 mpy can occur in very localized areas in piping systems with condensing ammonium hydrosulfide salts.
- Guidance: Reduce turbulence and flow rates in susceptible piping systems; inspect elbows, tees and other flow disturbing junctions closely; upgrade certain piping systems to high alloy materials; insulate certain systems to prevent condensation.

ACID CARRYOVER CORROSION

No. 1 Alkylation

- Equipment/Location: Tower rundown steel piping
- Problem: Internal corrosion failure from H₂SO₄.
- Circumstances: Slight or periodic acid carryover ran along bottom of horizontal line and around inside sweep of elbow looking down. Elbow which leaked had been measured a month earlier on the outside sweep, OK.
- Guidance: Consider the potential for acid carryover and monitor accordingly wherever acid might run being heavier.

BONNET BOLT FAILURE

AREAS OF VULNERABILITY

- Specific Problem Events -

No. 1 Alkylation

- Equipment/Location: Piping/Depropanizer Tower
- Problem: When valve (6" gate) was reconditioned, the incorrect size was used when bolting the bonnet to the body. Valve had been in service for a couple of months. Another valve with incorrect bolting was found in the unit after this incident.
- Circumstances: The bolts failed in service, shearing the threads and the bonnet was blown off from the process pressure of propane/isobutane (350 psi). Wind was favorable and unit was shut down before the leaking hydrocarbons could ignite.
- Guidance: Audit the company or companies that recondition your valves on a regular basis.

EXTERNAL CORROSION OF PIPE ELBOW

No. 3 Alkylation

- Equipment/Location: Isobutane feed.
- Problem: Vertical dummy support leg filled with water over the years causing corrosion of external piping elbow to which it was welded.
- Circumstances: Dummy support leg had a vent hole at the top of the leg instead of the bottom, allowing it to trap water and "slosh" against the elbow.
- Guidance: Survey all other vertical dummy support legs to ensure that the drain hole is placed at the bottom of the pipe.

CORROSION PENETRATION

No. 4 Alkylation Unit

- Equipment/Location: Sulfuric Alky Plant piping.
- Problem: Severe corrosion downstream of caustic neutralization tee caused piping failure.
- Circumstances: Excessive sulfuric acid carryover was not adequately neutralized and caused high corrosion rates due to low pH.
- Guidance: Better operating control; more frequent inspections of piping subject to operating upsets; better caustic mixing and pH monitoring.

AREAS OF VULNERABILITY

- Specific Problem Events -

TUBE CORROSION FAILURE

No. 1 Hydrocracker

- Equipment/Location: Fin-fan product cooler.
- Problem: Corroded tubes and internal header fouling.
- Circumstances: Internal tube corrosion and header erosion and fouling occurred mainly at the outer bays.
- Guidance: Increased water injection through revamped symmetrical piping system.

BIMETALLIC DIFFERENTIAL EXPANSION

No. 2 Hydrocracker

- Equipment/Location: Reactor effluent/feed exchangers.
- Problem: Internal 347 clad channel body failure.
- Circumstances: Temperature excursion resulted in excessive stress on channel baffle plate welded to channel. It could not expand due to uni-construction.
- Guidance: Installed bolted baffle plate to permit expansion Changed 347 to 309 with 5-15% controlled ferrite.

MISPLACED CHECK VALVE

No. 3 Hydrocracker

- Equipment/Location: Misplaced feed pump check valve causing feed drum overpressure.
- Problem: Feed drum overpressure from "shutdown" during start-up with misplaced check valve.
- Circumstances: Pump check valve on the upstream (wrong) side of the start-up bypass choke line permitted reactor pressure to rupture feed drum where relief design did not anticipate the reactor pressure. Manually operated gate valve inoperable due to high differential.

AREAS OF VULNERABILITY

- Specific Problem Events -

- Guidance: Identify and relocate check valves when in the wrong location. Use motor-operated valves where a high differential pressure potential exists.

OVERTORQUING OF HIGH PRESSURE FLANGE BOLTING

No. 4 Hydrocracker Reactor Effluent

- Equipment/Location: Hydrocracker reactor effluent transfer line.
- Problem: Large number of flange leaks.
- Circumstances: Sudden change in effluent temperature caused a thermal shock/movement to the piping. The flange bolting had been torque too close to yield strength of the material and the extra stress incurred during the thermal shock yielded the bolts and caused the flange to leak.
- Guidance: Insure that bolting procedures are followed, especially in high pressure services. Bolts were replaced and tensioned properly.

BRITTLE FRACTURE FAILURE

No. 5 Hydrocracker Charge

- Equipment/Location: 12% chromium alloy flange in hydrocracker charge furnace outlet line.
- Problem: Low ductility of 12% chrome material due to improper heat treatment.
- Circumstances: ANSI 1500# flange was found to be leaking through the hub. The flange hardness averaged 390 HB. Metallurgical examination of the crack revealed that it was a brittle quench crack and was due to an uncontrolled heat treatment cycle. It was later learned that a exothermic "package" was used to perform field post weld heat treatment of many flanges in this unit.
- Guidance: Be aware of where hardenable alloy materials are in the unit and monitor/audit heat treatment execution in the field. Do not use exothermic heat treatment packages on 12 chrome materials.

SEVERE DEADLEG CORROSION

No. 6 NHT Stabilizer

- Equipment/Location: NHT stabilizer column.

AREAS OF VULNERABILITY

- Specific Problem Events -

- Problem: Ammonium chloride salts collected in blinded nozzle on column bottom causing severe localized corrosion down to 0.076" thickness.
- Circumstances: Ammonium chloride salt corrosion is so localized in deadlegs that wall thickness measurements on column wall was not revealing any problem.
- Guidance: Carefully inspect all deadlegs in systems where ammonium salts can collect.

PILOT-OPERATED RELIEF VALVE FAILURE

No. 7 Hydrocracker High Pressure

- Equipment/Location: Hydrocracker high-pressure separator.
- Problem: 18% overpressure occurred on unit due to failure of pilot-operated valve to function properly.
- Circumstances: During a power failure the pilot-operated relief valve on the high pressure separator relieved and the reactor train did not exceed the 10% allowable overpressure in a relieving condition. Once the pressure came down the unit experienced another overpressure condition. The second time the overpressure condition occurred, the relief valve did not relieve. Our vessels experienced an 18% overpressure before we were able to control the situation. Upon sending the valve to the shop, we requested the valve be tested "as is N to determine if kite valve would not open again. The valve would not open on the test stand. The pilot was removed and tested separately from the main valve and functioned properly at the set pressure. The main valve soft seat had approximately one inch of material blown away and the main valve leaked severely. This leak was sufficiently large to prevent the valve from opening as the valve discharges to another vessel and the backflow preventer allows this back pressure to be exerted on top of the valve piston.
- Guidance: Be careful not to allow soft seat material to be inadvertently installed on relief valves in high temperature equipment. Make sure that service shops test the entire valve assembly during servicing, and not just the valve pilots.

STRESS CORROSION CRACKING

No. 1 H₂ Reformer

- Equipment/Location: Heater tubes, HK-40 above pigtail at the top.
- Problem: SCC from condensation.

AREAS OF VULNERABILITY

- Specific Problem Events -

- Circumstances: Temperatures around 350°F and chlorides developed significant cracking above the pigtail inlets.
- Guidance: Pigtails were moved to the top of the inlet cover flange increasing the temperature to 650°F

FABRICATION DEFECTS IN HEAVY WALL FORGINGS

No. 2 H2 Plant

- Equipment/Location: Heavy wall forgings/Hydrogen Plant vessels.
- Problem: Substantial cracking in heavy wall forgings at attachment weld to thin wall vessel plate.
- Circumstances: Large fabrication related defects located near the fusion line/HAZ of the attachment weld to forgings. Defects were due to poor welding practices, improper preheat and/or postweld-heat treatment during fabrication.
- Guidance: Close inspection attention should be focused on these type configurations during fabrication.

LOCALIZED HIGH TEMPERATURE HYDROGEN ATTACK

No. 3 Hydrogen Plant

- Equipment/Location: Methanator Start-up Exchanger.
- Problem: Localized high temperature hydrogen attack on a non-PWHT'd C-½ Mo (A204-Gr. B). Exchanger operating at 240 HPP at 750°F.
- Circumstances: High temperature hydrogen attack evident at a long seam to circ weld and nozzle attachment weld on a C-½ Mo Exchanger operating 200°F below the C-½ Mo Nelson Curve.
- Guidance: Inspect C-½ Mo equipment operating above the carbon steel Nelson Curve.

STRESS CORROSION CRACKING

AREAS OF VULNERABILITY

- Specific Problem Events -

No. 4 H2 Reformer

- Equipment/Location: H.T.S. product/feed exchanger expansion joint.
- Problem: 8" long crack at bottom in less than one week.
- Circumstances: SCC in the single convolution bellow on the shell side of the exchanger.
- Guidance: Material change from 316 stainless to Inconel 600 has been successful for 10 years.

VIBRATION NEAR

No. 1 Ethylene

- Equipment/Location: Exchanger tubes at top of bundle.
- Problem: Vibration failure.
- Circumstances: Numerous tube leaks and enlarged baffle holes across the top of the bundle developed.
- Guidance: Installed wooden wedges at each baffle on the new bundle at the top.

VIBRATION FATIGUE

No. 2 Ethylene

- Equipment/Location: Compressor oil lines.
- Problem: Vibration fatigue cracking.
- Circumstances: Oil line cracked adjacent to socket welded valve.
- Guidance: Installed wing braces at each branch connection.

LOCAL ACID CORROSION

No. 1 Benzene

- Equipment/Location: Depentanizer overhead condenser outlet.

AREAS OF VULNERABILITY

- Specific Problem Events -

- Problem: Internal localized acid corrosion.
- Circumstances: Steel outlet piping leaked due to localized acid concentration.
- Guidance: Installed flanges forming 180° return for inspection. Injecting disodium phosphate.

UNCONTROLLED OXIDIZATION

No. 1 Sulfur Recovery

- Equipment/Location: Converter outlet line.
- Problem: Overheat oxidization burned hole in line.
- Circumstances: Sulfur deposits on outlet piping ignited during regeneration. Heat also warped top steam generating condenser tubesheet pulling tubes out.
- Guidance: Installed additional thermowell in pipe adjacent to vessel. Will monitor oxygen for better burning control.

PIN HOLE LEAK

No. 2 Chem Plant

- Equipment/Location: Dryer regeneration line in Olefins Unit.
- Problem: External corrosion under insulation.
- Circumstances: Operators noticed ice formation and leaking hydrocarbon when regeneration line was not even in service. After stripping insulation, heavy rust scale was observed and a pinhole size leak identified. This line cycles up to 450°F and down below the dewpoint with each regeneration. A leaking MOV compounded the problem when the regeneration line was not in use, adding to the areas where condensation occurred.
- Guidance: The line was replaced and painted with a high heat aluminum Paint before being reinsulated. Consider not insulating the line in the future.

THREADED CONNECTION

No. 3 Chem Plant

AREAS OF VULNERABILITY

- Specific Problem Events -

- Equipment/Location: Threaded monel ½" pressure tap connection on 6" monel piping to Flash Drum Preheater (Polymer/Butene-1 service).
- Problem: Fatigue failure of threaded connection.
- Circumstances: Threaded connections were used on thin wall (Schedule 80) piping. Pressure gauge assemblies were attached and supported by threaded connections. Line experienced vibrations due to diaphragm pump operation.
- Guidance: Minimize the use of threaded connections. Where necessary, use Schedule 160 threaded piping. Minimize weight supported by pressure tap connections. Reinforce pressure tap connections with repad construction. Added additional bracing to reduce line vibration.

CONDENSATE CORROSION

No. 4 Sulfur Recovery

- Equipment/Location: Reactor steam-out connection.
- Problem: H₂S gas condensate in cold line.
- Circumstances: Uninsulated steam-out connection is cold at times and condensation of H₂S and water corroded line.
- Guidance: Insulate such connections.

DEZINCIFICATION

No. 1 Boiler

- Equipment/Location: Steam tracing valve on pressure controller.
- Problem: Frozen controller cut the pressure tripping off the compressor.
- Circumstances: Dezincified ¾" brass valve stem did not lift gate when opened. Frozen controller sensed a high pressure and began relieving 600 psi steam system. Valve stem separate in the packing area and appeared to rise when turned on.
- Guidance: Be sure flow is established when valves are opened.

AREAS OF VULNERABILITY

- Specific Problem Events -

THERMAL QUENCH FATIGUE

No. 2 Boiler

- Equipment/Location: Horizontal radiant roof tubes.
- Problem: Low-cycle fatigue cracking on bottom.
- Circumstances: When starved for make-up, the horizontal tubes near the steam drum would steam and water quench periodically.
- Guidance: Additional exterior downcomer lines were added.

CREEP FAILURE

No. 3 Boiler

- Equipment/Location: 10" superheater steel outlet header weld-ell
- Problem: Creep failure after 4 years.
- Circumstances: Substitution of “extra strong” for a “schedule 80” fitting (which runs the same thickness through 8”) the 0.500” rather than 0.593” wall caused higher stress and a creep failure after 4 years of service.
- Guidance: Double-check locations having a creep potential. Monitor thickness of all installations where creep is a factor.

BOILER DAMAGE

No. 4 Boiler

- Equipment/Location: Boiler/Utilities.
- Problem: A sulfur recovery boiler was severely damaged due to oven temperature conditions.
- Circumstances: To reduce hazards with thermal burns, the exterior of the fire boiler was insulated. This prevented the refractory-lined steel from cooling off. After several months, the shell was found to be heat damaged beyond repair.
- Guidance: External insulation on refractory-lined equipment needs careful evaluation.

AREAS OF VULNERABILITY

- Specific Problem Events -

THERMAL FATIGUE CRACKING

No. 5 Boiler

- Equipment/Location: Boiler steam generator piping.
- Problem: Thermal fatigue cracks caused by boiler cycling in external steam jumpover elbows.
- Circumstances: Automated boiler (unattended) cycles every few days with steam load demand causing wide temperature cycling from ambient to 350°F.
- Guidance: Inspect elbows with radiography periodically.

CAVITATION DAMAGE

No. 6 Boiler

- Equipment/Location: Concentric reducer in demineralized water train aluminum piping.
- Problem: Excessive metal loss resulted in piping leak.
- Circumstances: A large change in fluid vapor pressure downstream of a control valve caused unstable fluid flow and bubble formation resulting in cavitation.
- Guidance: Install different design control valve, which lowers chances for large changes in vapor pressure of a fluid. If possible, use material more resistant to cavitation other than aluminum.

VIBRATION FATIGUE

No. 7 Boiler

- Equipment/Location: 4" weldolet safety valve nozzle on a 14", 600 psi steam header.
- Problem: Corroded SV spring broke and caused SV hammering to fatigue nozzle weld.
- Circumstances: The 14" header had three 4N weldolet nozzles. One ruptured at the toe of the weld in the 14" header. The pitted SV spring failed due to torsional fatigue. The failure blew piping several hundred feet.

AREAS OF VULNERABILITY

- Specific Problem Events -

- Guidance: Coat new SV spring. Change weldolet connections. Use the braced design with gussets and reinforcing pad.

FEEDWATER EROSION

No. 8 Boiler

- Equipment/Location: 6" boiler feedwater line, 250°F and 1250 psi.
- Problem: Excessive metal erosion on 45° and 90° ells.
- Circumstances: The general and local thinning was caused by high velocity water erosion. The ripples and grooving at welds and sharp grooves were found on I.D. surfaces visually.
- Guidance: Piping details should be carefully matched during welding. Use long radius bends and grind weld roots flush where possible.

INADEQUATE VENT

No. 1 Pressure Storage

- Equipment/Location: Spheroid 3" top vent valve.
- Problem: Misplaced decimal during filling rate calculation.
- Circumstances: Filling through a 16" fire water main with a partially opened top 3" valve at a rate 10 times that calculated. The overpressure ruptured the vessel near the equator and its vacuum collapsed.
- Guidance: Leave the top manway off for venting when water filling. Also, double check decimal points on calculations.

BRITTLE FRACTURE OF LPG BULLET

No. 2 LPG Tank

- Equipment/Location: LPG tank farm.
- Problem: A horizontal vessel failed in a brittle manner during hydrotesting after welded alterations.

AREAS OF VULNERABILITY

- Specific Problem Events -

- Circumstances: The A515-70 material with 1-5/16" thickness had low toughness. The specified 300°F preheat was not applied during welding of a new 24" manway. The repad weld geometry caused a sharp stress concentration at the toe of the weld on the plate.
- Guidance: Ensure proper preheat; avoid sharp stress concentrations in low notch toughness materials; follow the guidance of API RP 920 in making repairs and alterations on equipment that may be susceptible to brittle fracture.

NO. 3 SPHERE OVER-PRESSURE

LPG Farm

- Equipment/Location: Sphere/Tank Farm/LPG
- Problem: A sphere in LPG service was over-pressured by a feed pump.
- Circumstances: One of the 8" ball floats used to detect level lodged in the relief valve inlet when the sphere was accidentally overfilled. The over-pressure expanded the sphere 6" to a new diameter of 48". There was no loss of containment.
- Guidance: Have redundant level transmitters. Examine how elements can fail and under the consequences.

CRACKED FLANGE WELDS

No. 1 Piping

- Equipment/Location: New piping.
- Problem: SA105 flanges were actually made of low alloy hardenable steel instead of carbon steel due to mix up in fabrication.
- Circumstances: Flange weld HAZs cracked after welding and in service due to high hardness (225-325 BHN).
- Guidance: Be cautious of unknown flange suppliers and do a certain amount of positive material identification, even on carbon steel components.

HIDDEN GROOVE

No. 1 Atmospheric Storage

AREAS OF VULNERABILITY

- Specific Problem Events -

- Equipment/Location: 60' diameter x 40' high floating roof tank.
- Problem: Vertical groove from defective shoe.
- Circumstances: Vertical rupture of naphtha tank resulted from corrosion of a 1" to 2" wide scratch to 0.10" deep. Scale masked the groove from visual observation.
- Guidance: Periodically, run a continuous horizontal ultrasonic scan around floating roof tanks.

BRITTLE FRACTURE

No. 2 Atmospheric Storage

- Equipment/Location: 100' diameter x 48' high riveted cone roof crude tank.
- Problem: Brittle fracture caused by a poorly designed and installed bottom corner repair.
- Circumstances: On a -3°F night with a 14 MPH wind, a full tank of crude ruptured. A "fabricated crack," due to the lack of penetration in a butt joint of a ½" thick x 5" wide clad running circumferentially around the bottom corner of the tank ran into and up the entire shell, spilling the contents.
- Guidance: Assume brittle conditions when steel impact properties are unknown. Eliminate all notches and cracks. Watch design carefully near the highly stressed bottom corner of tanks.

AREAS OF VULNERABILITY

- Process Industry Equipment Life -

III. PROCESS INDUSTRY EQUIPMENT LIFE

(Prepared for Presentation at NACE T-8 Committee Meeting)

R. P. Buhrow¹

Consideration of Process Industry Equipment Life invites attention to code requirements and then to potential life limiting conditions.

Code Requirements

Aside from specific jurisdictional laws and legitimate regulations, API 510 is the pressure vessel inspection code for the U.S. petroleum and chemical process industry today.

API 510, Section 6.1, "General", says that to insure vessel integrity, the inspection given to pressure vessels should take into consideration both the condition of the vessel and the environment in which it operates. This places the responsibility for integrity directly on the owner-user organization to consider all factors and to monitor any potential problem that might be present.

API 510, Section 6.3, Internal and On-Stream Inspection, says, "The maximum period between internal or on-stream inspections shall not exceed one-half the estimated remaining corrosion-rate life of the vessel or 10 years, whichever is less." This means that whenever there is corrosion greater than 0.001 inches per year, the rate must continue to be monitored. Paragraph 6.3 also says that if other deterioration is detected, the inspection interval must be adjusted as appropriate.

Potential Life Limiting Conditions

Fortunately, most process equipment construction materials do not inherently deteriorate with time. This is the reason arbitrary, specific code inspection intervals are unrealistic when they must apply to the broad array of process equipment for which codes must be written. The principle of letting each specific piece of process equipment determine its own inspection frequency is essential.

This practice of treating each piece of equipment independently, places a serious responsibility on the owner-user organization to identify problems or conditions that have the potential to affect process equipment integrity.

¹ See "Selection of Steel for High-Temperature Service in Petroleum Refinery Applications," Metals Handbook: Properties and Selection of Metals, Vol. 1, 8th Edition, Lyman, T., American Society for Metals, 1961, Pages. 585-603 for more detail than listed here.

AREAS OF VULNERABILITY

- Process Industry Equipment Life -

For convenience it is helpful to consider potential material deterioration factors which are most heavily influenced by:

Environment

1. Corrosion (chemical attack, assess degree of attack), special types:
 - a. Graphitic corrosion (selective corrosion of cast iron ferrite leaving soft graphite matrix).
 - b. Dezincification (selective dissolution of zinc in uninhibited copper alloys).
2. Erosion (action of particles or turbulence destroying a surface).
3. Stress-corrosion-cracking (cracking due to corrosion and stress), special types:
 - a. Austenitic stainless (chlorides or sulfides and water + stress)
 - b. Sulfide cracking ($< 200^{\circ}\text{F}$, hard areas > 200 BHN, H_2S and water)
 - c. Caustic cracking (stressed steel and concentrated caustic $> 120^{\circ}\text{F}$)
 - d. Ammonia attack cracking (stressed steel, concentrated ammonia and the absence of water).
4. Hydrogen attack (atomic hydrogen penetration causing various problems), special types:
 - a. Hydrogen blistering (H_2S , cyanide, arsenic and water)
 - b. Hydrogen deterioration ($> 400^{\circ}\text{F}$ methane microfissuring of grains see Nelson Chart, API-941)
 - c. Hydrogen cracking (cracking of high strength or highly stressed steel in a hydrogen environment)
 - d. Temporary ductility decrease (due to hydrogen environment penetration and prior to time-temperature evacuation)

Temperature

1. Creep rupture (time, temperature, stress related).
2. Graphitization (carbon steel loss of strength $> 700^{\circ}\text{F}$).
3. Decarburization (loss of carbon and strength as carbon is absorbed by environment at elevated temperature).
4. Spheroidization ($\text{C}-\frac{1}{2}\% \text{ Mo}$ $> 900^{\circ}\text{F}$, loss of strength to 50%)
5. 885°F embrittlement of steel (also of higher chromes, e.g. 12% chrome $> 700^{\circ}\text{F}$ causing room temperature brittleness).
6. Sigma formation (chromium-iron compound exhibiting room temperature brittleness in high chrome-nickel alloys $> 16.5\%$ chrome and containing some ferrite, $1100-1700^{\circ}\text{F}$).

AREAS OF VULNERABILITY

- Process Industry Equipment Life -

7. Blue brittleness (steel and ferrous alloys 400°F - 700°F, associated with working and precipitation of carbides).

Stress

Fatigue cracking (low or high cycle due to stress cycle repetition, also thermal fatigue due to repeated cycles of temperature with significant thermal gradients)

Time

Temper embrittlement (impact loss due to ductile/brittle transition temperature increase with time at elevated temperature, related to certain material sensitivities)

CONCLUSION

The above is not an exhaustive listing, but intended to illustrate some types of common problems which may limit process industry equipment life. The list should be expanded depending upon known environmental and material characteristics. However, when such potential problems are adjudged not present, a material may be considered free from time deterioration.

AREAS OF VULNERABILITY

IV. POTENTIAL INCREASED REFINERY CORROSION GUIDELINES

Attached is a list of general guidelines covering materials and conditions that can lead to increased corrosion rates of refinery equipment. The guidelines were developed to provide Engineers and Operations Supervision with basic information for identifying mechanical and process condition changes that may lead to increased corrosion rates of equipment. Appropriate changes to inspection procedures and possible metallurgy upgrades can then be made to avoid potential premature equipment failures due to increased corrosion rates.

V. GUIDELINES FOR REPORTING REFINERY UNIT PROCESS CHANGES WHICH CAN POTENTIALLY INCREASE CORROSION RATES

1. H_2S or sulfur compounds - At 450°F corrosion rates increase significantly with temperature. Presence of naphthenic acids and high velocity further accelerates the corrosion rate.
2. HCN or cyanides - Corrosion and hydrogen blistering increases with increased concentration of nitrogen in the feed.
3. NH_3 or ammonia - Extremely corrosive to copper, brass and aluminum under any condition. Increased concentration causes increased salt formation in the presence of chlorides.
4. Naph or naphthenic acid - Highly corrosive above 450°F to all steels including 304 stainless steel. Increased velocity further accelerates the corrosion rate. Corrosion becomes more severe with TAN greater than 1.0.
5. Polythionic acid - Formed during unit shutdowns in the presence of iron sulfides moisture, and air on sensitized stainless steel. Unless neutralized by maintaining an alkaline film before exposure to air, it will crack stainless steels.
6. HCl , or chlorides - Reduced pH causes increased corrosion. Increased chloride concentrations leads to increase NH_4Cl salt formation in the presence of ammonia. Austenitic stainless steels such as 304 and 316 suffer possible stress-corrosion cracking with chloride concentrations greater than 30 ppm and temperatures above 120°F.
7. H_2 or Hydrogen - Hydrogen attack or embrittlement increases with temperature over 450°F and H_2 partial pressures over 100 psi. Stainless steels do not suffer hydrogen attack, but can embrittle.
8. NH_4Cl or ammonium chloride - At lower temperatures generally under 300°F in the absence of sufficient water this salt will form or precipitate out and cause severe corrosion. Salt formation increases with increased concentrations of ammonia and chlorides.

AREAS OF VULNERABILITY

9. CO₂ or carbon dioxide - In the presence of water forms carbonic acid which is corrosive to most steels.
10. H₂SO₄ or sulfuric acid - Not corrosive to carbon steel at ambient temperatures and concentrations greater than 90%. Becomes highly corrosive when diluted with water. Corrosion increases with temperature and velocity over 1 fps.
11. NaOH or caustic - Becomes corrosive above 115°F at concentrations of 50% NaOH and above 140°F at 25% NaOH concentrations. Will attack or embrittle all steels above 220°F even in very dilute concentrations. Extremely corrosive to aluminum at any temperature and concentration.
12. NH₄HS or ammonium bisulfide - At lower temperatures, very close to ambient, this salt will form or precipitate out and cause significant corrosion. Salt formation increases with increased concentrations of ammonia and sulfides.