Sour Service Piping Systems
Materials and Fabrication

Society of Piping Engineers and Designers
Calgary, Alberta
February 27, 2013

Presentation Outline

- The main topics I will try to deal with are:
  - Sour Service Definition & Damage Mechanisms
  - Material Requirements
    - Material Standards and Specifications
    - Chemical Composition
    - Heat Treatment
    - Mechanical Properties
    - Marking and Certification
  - Fabrication
    - Welding and PWHT
  - Nondestructive Examination
    - NDE Frequency and Acceptance Criteria

Presentation Outline

- A thorough treatment of this subject would take several days but we only have a couple of hours. Therefore:
  - I will deal only with the oil and gas industry.
  - I will deal mainly with:
    - carbon steels (CS);
    - with only a few comments on low alloy steels (LAS); and
    - nothing on corrosion resistant alloys (CRA's).

Sour Service Definition & Damage Mechanisms

First of all, what is Sour Service?

- For the moment, sour service just means a fluid service containing enough hydrogen sulphide (H_2S) to cause material damage.
- But be aware, that “sour service” may be:
  - an inferred condition based on process fluid descriptions such as lean amine or rich amine in a sour gas treatment facility;
  - indentified by other names such as “wet H_2S service”; or
  - specified for reasons other than materials or corrosion engineering, such as provided in the Alberta pipeline regulations for block valve spacing.

How is Sour Service Defined?

- Since material damage and H_2S is involved, one might expect there would be a simple criterion to easily separate sour from non-sour service.
- Well, although that may have been true at one time, it is no longer the case.
- Now one often needs to involve a process engineer in the final sour/non-sour decision.
- Why is it so complicated?

Why Is It So Complicated?

- If you consider NACE MR0175/ISO 15156 Part 2, Clause 6, or NACE MR0103 Clause 1.3, you will see that the behaviour of CS & LAS in H_2S-containing environments is affected by complex interactions of:
  - material factors such as:
    - chemical composition;
    - method of manufacture and product form;
    - heat treatment and cold work;
    - microstructure, microstructure uniformity, internal cleanliness, and grain size; and
    - mechanical properties (tensile strength and hardness including local variations).
  - and.....,

Why Is It So Complicated?

  - process factors such as:
    - H_2S partial pressure or equivalent concentration in the water phase;
    - chloride ion concentration in the water phase;
    - acidity (pH) of the water phase (which is influenced by a number of variables);
    - presence of sulfur and other oxidants;
    - exposure to non-production fluids;
    - exposure temperature;
    - total tensile stress (applied plus residual);
    - exposure time.
- So that is why a process engineer is usually needed in the final sour/non-sour decision.

So how is Sour Service currently defined?

- For materials and corrosion work, one must rely on the requirements of the applicable standard for the work.
  - NACE MR0175 / ISO 15156 for upstream oil and gas process piping within the scope of ASME B31.3
  - NACE MR0103 for downstream refining and upgrading process piping within the scope of ASME B31.3
  - CSA Z662, Section 16, for pipelines and pipeline facility piping within it's scope.
- And of course, you need to deal with the Owners interpretation of what sour service means and how it must be classified, and this can be confusing.

What is the Future?

- For Canadian pipelines and pipeline facilities, sour service definition issues have not gone unrecognized.
- Some significant changes in CSA Z662 should be expected with the next edition of CSA Z662.
- The changes will likely involve reversion to a former definition for multiphase services.

What is the Concern with Piping Systems Containing Sour Fluids?

- They can corrode and crack, leading to failures that are often sudden and unpredictable, with serious consequences.
  - In addition to usual concerns with failure of pressurized fluid, H_2S is a colorless gas that is toxic in small concentrations, and can be lethal in large concentration unless prompt restorative measures are taken.
  - H_2S is heavier than air and, although it has a rotten egg small in small concentrations, in large potentially lethal concentrations your sense of smell is quickly deadened and does not provide effective warning of a dangerous condition.

How Does Corrosion & Cracking Happen?

- There are <u>two main cases</u> to consider:
  - Damage caused by aqueous corrosion, where liquid water is required for the corrosion reaction to proceed.
  - Damage caused by high temperature (hot) corrosion, where liquid water is not required for the corrosion reaction to proceed.

Damage Caused by Aqueous Corrosion

- To visualize the aqueous corrosion case, consider the following concepts:
  - H_2S dissolves in liquid water forming a "weak" acid, where pH depends on several variables, but is generally not less than about 3.0.
  - The acid corrodes the steel surface forming an iron sulphide corrosion product and atomic hydrogen.

$$Fe + H_2S = FeS + 2H$$

Damage Caused by Aqueous Corrosion

- The corrosion reaction action causes weight loss (general) corrosion and pitting corrosion of the steel surface.
- However, a more insidious result of this aqueous corrosion is cracking and blistering.
- It is insidious because visible corrosion is not necessary for cracking or blistering to occur, so the condition is not easily detected (by typical corrosion surveys), and cracks in particular, can lead to sudden and unexpected rupture.

Damage Caused by High Temperature (Hot) Corrosion

- To visualize the hot corrosion case, consider the following.
  - Hot H_2S reacts directly with the steel surface.
  - It begins to be a threat above 250°C. Liquid water is not required.
  - Corrosion rate depends mainly on metal temperature, steel composition, and concentration of H_2S but other factors such as presence of hydrogen (e.g., in a reactor circuit) or other sulphur species (e.g., in the feed), and velocity can be influential.
  - It is often a threat for upgrading or refining units operating at elevated temperature, or some gas processing equipment such as mole sieve dehydrators that use hot sour gas to regenerate the desiccant.

Damage Caused by High Temperature (Hot) Corrosion

- The net result of this hot corrosion is wall loss, and is commonly referred to as High Temperature Sulphidation or just Sulphidation, and of course, the Americans call it Sulfidation.
- The usual way of assessing the threat is based on the work of Couper and Gorman, with a healthy dose of experience.
- For sulphidation, the threat is usually mitigated mainly by adding corrosion allowance to the extent that it is practical, and then by "alloying up" if the wall loss over the design live is determined to be excessive (e.g., over the maximum reasonable corrosion allowance).
- By "alloying up", for sulphidation that would generally involve increasing additions of chromium, moving in progression from CS to Cr-Mo LAS, straight Cr stainless, and Cr-Ni austenitic stainless.

Damage Mechanisms Resulting from Aqueous Corrosion

- For the rest of this presentation I will be concentrating on the effects of aqueous corrosion since this is where most material and fabrication issues are found.
  - General weight loss and pitting corrosion
  - Blistering – Can be surface and internal
  - Sulphide Stress Cracking (SSC)
  - Hydrogen Induced Cracking (HIC)
  - Stress Oriented Hydrogen Induced Cracking (SOHIC)
  - FYI, there are a number of other names used for damage:
    - The term "wet H2S cracking" is used in the refining and upgrading industries to cover a range of cracking situations caused by hydrogen charging – e.g., SSC, HIC, SOHIC.
    - Soft zone cracking, Type I and Type II SSC, Stepwise Cracking, Hard Zone Cracking, have also been used.

Pitting & Weight Loss Corrosion Example

- 80% H_2S / 20% CO_2 acid gas created a low pH in water condensed in the bottom of this line between the 2nd stage compressor discharge and an aerial cooler. Failure occurred after about 4 years service.
- Failure shows the trouble you can get into when process engineering tells you the gas will be kept above the water dew point.

Blistering, SSC, HIC & SOHIC Caused by Aqueous Corrosion

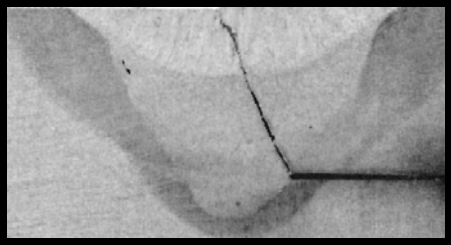
- For these damage mechanisms:
  - Atomic hydrogen (H) generated by the corrosion reaction does not re-combine to form molecular hydrogen (H_2) at the steel surface. So it does not bubble off as hydrogen gas as is typical for most aqueous corrosion reactions.
  - The reason atomic hydrogen does not re-combine to form molecular hydrogen is not clearly understood, so corrosion engineers say things like "H_2S poisons the surface so that molecular hydrogen can't form".
  - So hydrogen atoms, because of their small size, diffuse into the steel. The damage mechanisms are "defined" by how the hydrogen affects the steel, once it gets inside.

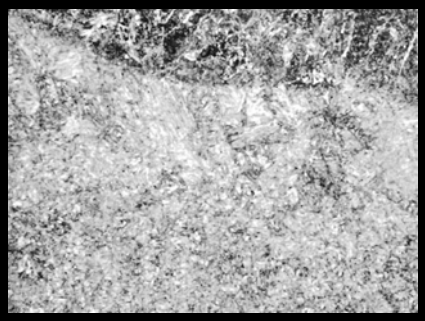
Sulphide Stress Cracking (SSC)

- Once in the steel, hydrogen atoms want to concentrate at locations of high stress such as notches (like weld defects) or hard microstructure (left after hot working, cold working, improper heat treatment, or welding).
- The hydrogen atoms act on the steel causing hydrogen embrittlement, and this form of hydrogen damage in sour service is known as Sulphide Stress Cracking.
- The exact embrittlement mechanism is not fully understood.

Sulphide Stress Cracking (SSC) Example

- Specialty weld joint – not subjected to PWHT, in 35% H_2S service for a matter of hours.
- GMAW root pass. HAZ hardness in root area:
  - 325 to 350 HV_{500}
  - approx. 33 to 35 HRC





Sulphide Stress Cracking

- SSC is cracking of a metal under the combined action of tensile stress & corrosion in the presence of water & H_2S.
- For SSC to occur, one requires:
  - sufficient hydrogen (comes from aqueous corrosion caused by dissolved H_2S in liquid water, but rate of corrosion & hydrogen generation can be influenced by factors other than H_2S alone);
  - sufficient tensile stress (applied and/or residual, which may be magnified by stress concentrating notches);
  - susceptible material (normally assessed by hardness, which is really a proxy for tensile strength or microstructure).
- "Control" of one of these will avoid the problem, but not in a simple way. For example:

Sulphide Stress Cracking

- For the same corrosion environment and stress conditions, a steel with “high” hardness is more susceptible to SSC than a “low” hardness steel.
- For the same hardness and stress conditions, a steel will be more susceptible to failure in a “high” hydrogen charging environment than a “low” hydrogen charging environment.
- For the same hardness and environmental conditions, a steel exposed at a “high” stress level will crack faster than a steel at a “low” stress level.
- The above concepts have lead to risk assessment, and the development of sour service severity levels or criticality. These are well beyond where we can go tonight.

SSC Mitigation

- The most common method of mitigating SSC is by controlling material susceptibility, which for CS and LAS means mainly hardness control. This is the main thrust of the NACE and CSA standards.

Blistering, HIC and SOHIC Aqueous Corrosion

- When atomic hydrogen diffuses through the steel it can get trapped at voids in the steel, where it can combine with other hydrogen atoms to form molecular hydrogen (hydrogen gas, or H_2).
- The resulting hydrogen gas pressure is sufficient to open up blisters and extend cracks from inclusions, as seen by the following slides.

Surface Blisters Roughly a Quarter to a Loonie in Size

Blistering

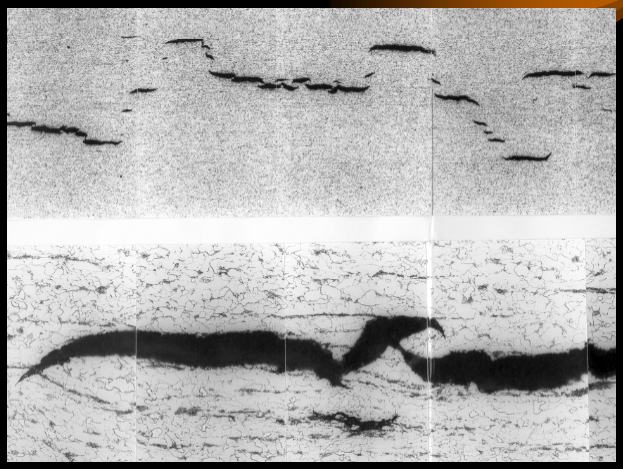
- Blistering is generally associated with plate and products made from plate or skelp (i.e., welded pipe).
- Blisters typically occur at internal voids near the center of the steel or near the surface.
- Large voids near the center of the steel are usually called “laminations”. They can be several square inches to several square feet.
- Small voids anywhere in the steel are usually referred to as inclusions, and the most common inclusions are manganese sulphides. The generally require observation with a low power microscope (e.g., at 50 to 100 times).

Blistering

- In modern steelmaking, the frequency of laminations and inclusions has declined significantly relative to the days before continuous casting, low sulphur steel technology, and inclusion shape control.
- So, although blistering is a problem that has been known for at least 75 years, for new construction it is not a big issue. For tie-ins to old systems it could be an issue.

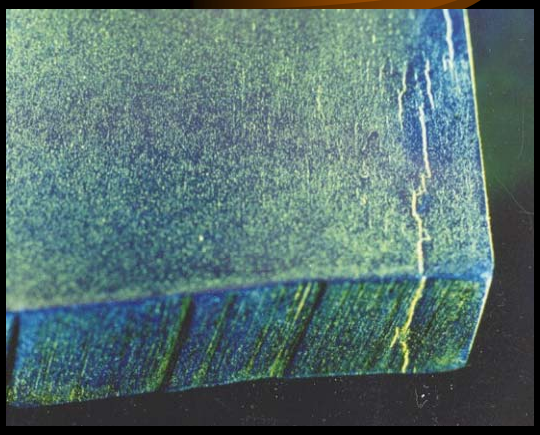
What HIC Looks Like On the Microscope – Grade 359 (X52) Pipe

- Top X50
- Bottom X500



WFMT Indications of HIC in Plate

- HIC has occurred near the center of this plate that was about 75 mm (3”) thick before the sample was removed.



SOHIC – Stress Oriented Hydrogen Induced Cracking – X50

- Same mechanism as HIC, but cracks are oriented (directed) by the presence of an applied or residual stress.
- This SOHIC occurred during SSC testing of a welding procedure joining seamless CS pipe that had been manufactured from steel with inclusion shape control (ISC) by calcium addition.

SOHIC (X500)

- So just because a pipe or component is “seamless” or steel is treated by ISC, doesn’t mean HIC or SOHIC can’t happen.
- It is just less likely than with pipe or components made from plate or skelp.

Testing Standards to Assess Material Resistance to Various Forms of Damage

- NACE TM0177
  - Laboratory Testing of Metals for Resistance to Sulfide Stress Cracking and Stress Corrosion Cracking in H2S Environments
- NACE TM0187
  - Evaluating Elastomeric Materials in Sour Gas Environments
- NACE TM0198
  - Slow Strain Rate Test Method for Screening Corrosion-Resistant Alloys (CRAs) for Stress Corrosion Cracking in Sour Oilfield Service
- NACE TM0103
  - Laboratory Testing Procedures for Evaluation of SOHIC Resistance of Plate Steels Used in Wet H2S Service

Testing Standards to Assess Material Resistance to Various Forms of Damage

- NACE TM0284
  - Evaluation of Pipeline and Pressure Vessel Steels for Resistance to Hydrogen-Induced Cracking
  - This is probably most common NACE sour service test you will see and we will look at it further.
- NACE TM0296
  - Evaluating Elastomeric Materials in Sour Liquid Environments

NACE TM0284 – Assessment of HIC Resistance

- Probably the most common NACE sour service material test you will see, but it is still not widely used for piping. Why?
  - Most plant pipe & components are NPS 16 and smaller and of seamless construction, so they not very susceptible to HIC, and there is no impetus for HIC testing.
  - Larger diameter seam welded pipe & components are susceptible to HIC but they tend to be used in applications where risk of HIC is mitigated by chemistry control alone (e.g., S<=0.010 as mentioned in NACE MR0175 / ISO 15156).
  - In some severe environments, HIC testing is applied for qualification of material, but it is a risk based decision.

NACE TM0284 – Probably the Most Common NACE Sour Service Test

- Full test details are found in standard. It is 23 pages.
- End result of the test is the following crack ratios:
  - CLR – Crack Length Ratio
  - CTR – Crack Thickness Ratio
  - CSR – Crack Sensitivity Ratio
- The ratio's are evaluate against **acceptance criteria that must be provided by the client**.

Material Requirements

ASME B31.3 Process Piping – Standards Used for Sour Service

- NACE MR0175
  - Sulfide Stress Cracking Resistant Metallic Materials for Oilfield Equipment (2002 and prior editions)
  - Metals for Sulfide Stress Cracking and Stress Corrosion Cracking Resistance in Sour Oilfield Environments (2003 edition)
- NACE MR0175 / ISO 15156
  - Petroleum and Natural Gas Industries – Materials for Use in H2S-Containing Environments in Oil and Gas Production
    - Part 1: General Principles for Selection of Cracking-Resistant Materials
    - Part 2: Crack-Resistant Carbon & Low-Alloy Steels, & the Use of Cast Irons
    - Part 3: Cracking-Resistant CRAs & Other Alloys
- NACE MR0103
  - Materials Resistant to Sulphide Stress Cracking in Corrosive Petroleum Refining Environments

Pipeline & Pipeline Facility Piping – Standards with Sour Service Requirements

- CSA Z662
  - Oil and Gas Pipeline Systems
- CSA Z245.1
  - Steel Pipe
- CSA Z245.11
  - Steel Fittings
- CSA Z245.12
  - Steel Flanges
- CSA Z245.15
  - Steel Valves
- The above CSA Standards also reference NACE MR0175 / ISO 15156 for sour service material requirements when they are not fully covered by a CSA standard.

Let's break down the history and rough scope of these documents

- NACE MR0175
  - Is the granddaddy of sour service standards and originated in 1975.
  - Mainly intended for upstream oil and gas production, but was sometimes used in upgrading and refining.
  - Started as a simple document with fairly clear requirements that lasted until 2002.
  - Then, in 2003 the standard took a big change of direction. It started getting complicated.
  - 2003 was the last year it was published, so it is now out of date.
  - However, many MTR's still refer to the 2002 or 2003 editions of this standard.

Let's break down the history and rough scope of these documents

- NACE MR0175 / ISO 15156
  - Is essentially a merger of the thinking behind old NACE MR0175 and the EFC 16.
  - Is a three part document, where:
    - Part 1 was first published in 2001; and
    - Parts 2 and 3 were first published at the end of 2003.
    - Part 1 was not useful by itself. We had to wait until 2003 for the rest of it, so the completed document was commonly called the 2003 edition.
    - Technical Corrigenda were also published (around 2005).
  - 2009 is the current edition, and Technical Corrigenda were provided in 2011.

Let's break down the history and rough scope of these documents

- NACE MR0103
  - A "newish" document that was developed largely from the "old" NACE MR0175 requirements (2002 and prior)
  - Was published for sour process systems in the downstream petroleum business – i.e., upgrading and refining.
  - First year of publication was 2003. The current edition is 2012.
- NACE SP0472 (formerly RP0472)
  - Methods and Controls to Prevent In-Service Environmental Cracking of Carbon Steel Weldments in Corrosive Petroleum Refining Environments

Let's break down the history and rough scope of these documents

- CSA Z662
  - The Canadian standard for construction of cross-country pipelines and pipeline facilities.
  - Section 16 contains most (but not all) sour service requirements
- CSA Z245.x (where x = 1, 11, 12, and 15)
  - A series of Canadian standards for procurement of pipe, fittings, flanges, and valves that can be used within the scope of CSA Z662.
  - Each standard in the series has a sour service section.

Additional Standards and References

- NACE RP0296
  - Guidelines for Detection, Repair, and Mitigation of Cracking of Existing Petroleum Refinery Pressure Vessels in Wet H2S Environments
- NACE Publication 8X194
  - Materials and Fabrication Practices for New Pressure Vessels Used in Wet H2S Refinery Service
- NACE Publication 8X294
  - Review of Published Literature on Wet H2S Cracking of Steels Through 1989

"NACE & CSA" Sour Service Chemical Composition Restrictions – CS & LAS

- Other than normal industry limits within ASTM and CSA standards, there isn't much chemistry control when it comes to sour service materials. Consider:
  - No free machining steels (i.e., steels that contain intentional additions lead, selenium, or sulfur to improve machinability)
    - NACE MR0175 / ISO 15156 Clause A.2.1.2
    - NACE MR0103-2012 Cl. 2.1.2(a)
  - Nickel not exceeding 1.00%
    - NACE MR0175 / ISO 15156 Clause A.2.1.2
    - CSA Z662 Clause 16.6.5 (deposited weld metal)
    - CSA Z245.1 Clause 16.10 (pipe)

Chemical Composition Restrictions – CS & LAS

- For owner or engineering specs, composition controls can be numerous (and confusing).
- Why is this?
  - Changing trends in purchasing – global supply.
  - Changing trends in steelmaking and casting.
  - Changing trends in industry standards.

Changing trends in purchasing – global supply

- It now seems that we buy from anyone with a website and an ISO 9000 quality program.
- And, although many companies have AML's, the level of diligence applied to those wanting on the list, seems to be declining.
- So technical people try to combat this by writing more requirements.

Changing trends in steelmaking & casting

- Until the late 1970's, most steelmakers:
  - used pig iron from a blast furnace as the feed for steelmaking;
  - refined the pig iron in steelmaking furnaces, of which the basic oxygen furnace (BOF) became most popular;
  - cast the steel into individual ingots which, depending on deoxidation, were classified as rimmed, semi-killed, or fully killed; and
  - processed the ingots into plates, pipes, and forgings.

Changing trends in steelmaking & casting

- 1980's were a transition period & now most steelmakers:
  - supplement pig iron from the blast furnace with scrap, and sometimes just use scrap to feed steelmaking furnaces;
  - refine pig iron, pig iron with scrap, or just scrap, in steelmaking furnaces, of which basic oxygen furnaces (BOF) remain popular, but electric furnaces are also popular;
  - cast the steel into long strands using a continuous caster, which requires that most modern steel be fully killed (fully deoxidized); and
  - processed the strands into plates, pipes, and forgings.

Changing trends in steelmaking & casting

- What does it mean now?
  - Use of scrap means more old cars and tin cans so residual element concentrations have increased. Consider:
    - Cu from car wiring and other scrap with electric wiring
    - Cr & Ni from car bumpers and trim
    - Other alloy from drive train and undercarriage parts, and other scrap items
- Increasing residual element concentration means increasing hardenability, which is a bad thing from a sour service point of view.
- However, almost all steel is now fully killed, which is viewed as a good thing for sour service.

Changing trends in industry standards

- Industry standards such as those prepared by ASTM and CSA have had to adapt to steelmaking and casting changes already mentioned.
- It should come as no surprise that committee members who volunteer for standards writing organizations have their own ideas & agendas, and they rarely involve sour service.
- Also, the direction that a standard takes is often driven by the balance between producers and users, and there is limited representation for sour service users.
- So let's look at 30 years of chemistry changes in two ASTM standards
  - A106 for Gr. B pipe;
  - A234 for Gr. WPB fittings.

	A	B	C	D	E	F	G	H	I	J
1	**Standard**	A106			A106			A106		
2	**Year**	1979			2002			2011		
3	**Grade**	B			B			B		
4		***Minimum***	***Maximum***	***Notes***	***Minimum***	***Maximum***	***Notes***	***Minimum***	***Maximum***	***Notes***
5	**C**	-	0.30		-	0.30		-	0.30	
6										
7	**Mn**	0.29	1.06		0.29	1.06	A	0.29	1.06	B
8		-			-	**1.35**		-	**1.65**	
9	**P**	-	0.048		-	0.035		-	0.035	
10	**S**	-	0.058		-	0.035		-	0.035	
11	**Si**	0.10	-		0.10	-		0.10	-	
12										
13	**Cu**	-	-		-	0.40		-	0.40	
14	**Ni**	-	-		-	0.40		-	0.40	
15	**Cr**	-	-		-	0.40		-	0.40	
16	**Mo**	-	-		-	0.15		-	0.15	
17	**V**	-	-		-	0.08		-	0.08	
18	**Nb (Cb)**	-	-		-	-		-	-	
19	**Ti**	-	-		-	-		-	-	
20	**B**	-	-		-	-		-	-	
21	**Cr+Mo**	-	-		-	-		-	-	
22	**Cu+Ni+Cr+Mo**	-	-		-	-		-	-	
23	**Cu+Ni+Cr+Mo+V**	-	-		-	1.00		-	1.00	
24										
25										
26	**Notes:**	A. For each reduction of 0.01 % below the specified carbon maximum, an increase of **0.05 %** manganese above the specified maximum will be permitted, **up to a maximum of 1.35 %.**								
27		B. For each reduction of 0.01 % below the specified carbon maximum, an increase of **0.06 %** manganese above the specified maximum will be permitted, **up to a maximum of 1.65 %.**								
28										
29										

	A	B	C	D	E	F	G	H	I	J
1	Standard		A234			A234			A234	
2	Year		1979			2001			2011	
3	Grade		WPB			WPB			WPB	
4		*Minimum*	*Maximum*	*Notes*	*Minimum*	*Maximum*	*Notes*	*Minimum*	*Maximum*	*Notes*
5	C	-	0.30		-	0.30		-	0.30	
6		-	0.35	C, D	-	0.35	C, D	-	0.35	C, D
7	Mn	0.29	1.06		0.29	1.06		0.29	1.06	
8		-	1.35	A1	-	1.35	A2	-	1.65	B
9	P	-	0.050		-	0.050		-	0.050	
10	S	-	0.058		-	0.058		-	0.058	
11	Si	0.10	-		0.10	-		0.10	-	
12		-	0.35	D	-	0.35	D	-	0.35	D
13	Cu	-	-		-	0.40		-	0.40	
14	Ni	-	-		-	0.40		-	0.40	
15	Cr	-	-		-	0.40		-	0.40	
16	Mo	-	-		-	0.15		-	0.15	
17	V	-	-		-	0.08		-	0.08	
18	Nb (Cb)	-	-		-	0.02		-	-	
19	Ti	-	-		-	-		-	-	
20	B	-	-		-	-		-	-	
21	Cr+Mo	-	-		-	0.32		-	0.32	
22	Cu+Ni+Cr+Mo	-	-		-	1.00		-	1.00	
23										
24										
25	Notes:	A1. For each reduction of 0.01 % below the specified carbon maximum, an increase of 0.05 % manganese above the specified maximum will be permitted, up to a maximum of 1.35 %.								
26		A2. For each reduction of 0.01 % below the specified carbon maximum, an increase of 0.06 % manganese above the specified maximum will be permitted, up to a maximum of 1.35 %.								
27		B. For each reduction of 0.01 % below the specified carbon maximum, an increase of 0.06 % manganese above the specified maximum will be permitted, up to a maximum of 1.65 %.								
28		C. Fittings made from bar or plate may have 0.35 max. carbon.								
29		D. Fittings made from forgings may have 0.35 max carbon and 0.35 max silicon with no								

Owner / Engineer - Select Chemistry for Seamless CS Base Metals

- As an example of chemistry controls for Owner / Engineer specifications, the limits below are from a sour service purchasing specification for seamless carbon steel pipe, wrought fittings, forged fittings and flanges **for welded construction**.

Element	Wt. (Max.)	Element	Wt. (Max.)
Carbon	0.23	Cu+Ni+Cr+Mo	0.60
Manganese	1.35	V+Nb+Ti	0.035
Phosphorus	0.025	Boron	0.0005
Sulphur	0.025	Carbon Equivalent	0.43

Owner / Engineer - Select Chemistry - Rationale

- The main reason for select chemistry is to avoid high hardness after welding, and thereby avoid SSC.
  - Historically, carbon equivalent (CE) was imposed as the main chemistry control, and the CE maximum was traditionally set somewhere between 0.43 and 0.45. This still remains today.
  - Unfortunately however, not everything in metallurgy and welding can be reduced to a single number. This is especially true now that exemption from PWHT has become common.
  - So that is why we currently impose restrictions on several other elements that are in addition to simple CE limits.
  - And, we also include some tramp element (P & S) limits to minimize risk of blistering, HIC and SOHIC.

"NACE" Heat Treatment Requirements

- NACE MR0103-2012 Clauses 2.1.2(c) & 2.1.3; and NACE MR0175 / ISO 15156 Part 2, Clause A.2.1.2 both require one of the following:
  - hot-rolled (carbon steels only);
  - annealed;
  - normalized;
  - normalized and tempered;
  - normalized, austenitized, quenched, and tempered; or
  - austenitized, quenched, and tempered.
- Basically, for NACE, almost any kind of heat treatment is acceptable (as long as hardness is less than 22 HRC)

NACE MR0103 Cold Forming Requirements

- 2.1.7 Cold forming of carbon and alloy steels is allowed.
  - Material shall have met one of the heat treatment conditions listed in Paragraph 2.1.2(c) prior to cold forming. Cold-formed material shall:
    - be thermally stress relieved if permanent outer fiber deformation is > 5%.
    - be stress-relief at a minimum of 593 °C (1,100 °F) (when required).
    - have hardness for P-No. 1 carbon steel of 200 HBW maximum
    - have hardness for other carbon and alloy steel as per standard.

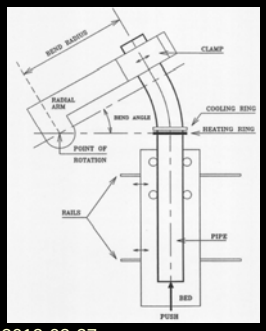
NACE MR0103 Cold Forming Requirements

- 2.1.7.1 “Special Circumstances of Cold Work”
  - Above requirements do not apply to cold work imparted by pressure testing in accordance with the applicable code.
  - Cold-rotary straightened pipe is allowed only when permitted in API specifications.
  - Cold-worked line pipe fittings of ASTM A53 Grade B, ASTM A106 Grade B, API Spec 5L Grade X-42, or lower-strength grades with similar chemical compositions shall contain no more than 15% cold strain, and the hardness in the strained area shall not exceed 190 HBW.

Cold Formed NPS 16 Bend

NACE MR0103 Hot or Induction Bending Requirements

- 2.1.3.2 Bends in P-No. 1 piping formed by heating to above the upper critical temperature (Ac3) are allowed.
  - Material shall have met one of the conditions listed in Paragraph 2.1.2 (c) prior to forming.
  - Hardness in the bend area shall not exceed 225 HBW.



Mechanical Properties

- Both NACE and CSA standards impose limits on mechanical properties for materials and any welds required for manufacturing.
- The limits are generally maximums for:
  - yield strength;
  - tensile strength; and
  - hardness.
- The actual properties and limits are inconsistent between various standards.

Mechanical Properties

- Tensile Strength
  - NACE / ISO has a warning:
    - use of steels with YS above 965 MPa (140 ksi) may crack in <0.3 kPa
  - NACE / ISO Clause A.2.1.4 also has some welding requirements that are tensile strength related

Tubular products with an SMYS not exceeding 360 MPa (52 ksi) and listed in Table A.2 are acceptable in the as-welded condition. For these products, hardness testing of welding procedures may be waived if agreed by the equipment user.

Some tubular products with an SMYS exceeding 360 MPa (52 ksi) (see A.2.2.2) may be acceptable in the as-welded condition if suitable qualified welding procedures are used. The conditions in Table A.1 shall be met.

Mechanical Properties

- Tensile Strength
  - CSA Z662 Clause 16.4.2.2 – limits SMYS for material where no CSA standard exists to:
    - 485 MPa
  - CSA Z245.1 Clause 16.8 – max. tensile strength:
    - 625 MPa for Gr. 386 & lower
    - 650 MPa for grade over 386 but under 483
    - 665 MPa for Gr. 483

CSA Z245.1 – Root-Guided Bend

- CSA Z245.1 also has a ductility test for electric welded pipe for sour service.
- Is a very severe ductility test.
- Performed at lead & trail of each coil.
- Jig dimensions in standard.
- Concept – if two successive tests pass (e.g., lead & trail) then all pipe between tests is “good”.

Tensile Strength Issues

- Just because a standard does not prohibit you from using a high strength material, doesn't mean you should automatically allow the use of it. For example:
  - most of our upstream sour service pipelines are made from pipe, fittings, and flanges with grade not exceeding 359;
  - we have constructed some pipelines with higher grade materials but before doing this, think:
    - obtaining sour service line pipe will probably not be a problem up to grade 483 but how will you handle the fittings and flanges;
    - how will the welding be performed, because now you will probably be looking at low alloy steel electrodes.

"NACE" Material Hardness Limits

- Hardness
  - NACE / ISO Clause A.2.1.2
    - 22 HRC maximum
  - NACE / ISO Clause A.2.1.3
    - 187 HBW maximum for ASTM A105
    - 197 HBW maximum for ASTM A234 Gr. WPB & WCC

Marking and Certification

NACE/ISO - Marking / Certification Part 1, Clause 5, General Principles

- NACE MR0175 / ISO 15156
  - Makes “suppliers” responsible for complying with marking/documentation “requirements”.

It is the equipment or materials supplier's responsibility to comply with the requirements for the marking/documentation of materials in accordance with ANSI/NACE MR0175/ISO 15156-2:2009, Clause 9, or ANSI/NACE MR0175/ISO 15156-3:2009, 7.2, as appropriate.

  - These “requirements” are shown on the next slide, and the only difference is in references to different Annexes.

NACE/ISO - Marking / Certification Part 2 “Requirements”

9 Marking, labelling and documentation

Materials complying with this part of ANSI/NACE MR0175/ISO 15156 shall be made traceable, preferably by marking, before delivery. Suitable labelling or documentation is also acceptable.

For materials qualified and selected for a special application in accordance with Annex B, traceability shall include reference to the environmental conditions of the special application.

The equipment user may request the equipment or materials supplier to provide documentation of the materials used in equipment or components and their environmental service limits as defined in this part of ANSI/NACE MR0175/ISO 15156.

The tables in Annex E provide designations that may be used to identify materials.

NACE/ISO Marking/Certification

- My (liberal) viewpoint on “made traceable”:
  - The heat number or heat code is marked on the item according to the material standard (e.g., A105, A106, A234, A333, A350, A420, A516).
  - The heat number or heat code written on the MTR is what makes certification traceable.
  - The certification must make a direct statement as to compliance, or it must provide the testing information necessary to verify compliance.

NACE/ISO Marking/Certification

- Compliance statements on MTR's vary considerably:
  - From rare outright direct statements such as:
    - "Complies with NACE MR0175/ISO 15156–2009"
  - To outdated NACE MR0175 references such as:
    - "Meets NACE MR0175-2002"
    - "Meets NACE MR0175-2003"
  - To vague statements such as:
    - "Meets NACE" or "NACE"
  - To nothing.

NACE/ISO Marking/Certification

- When the heat identification on product markings and MTR's correlate, and the certification is perfect, there are few issues.
- In the more usual case, where certification is not perfect, you need to assess the test data against the applicable NACE/ISO requirements.

CSA Z662 Cl. 16.4.3 – Sour Service Marking Requirements

- **16.4.3.1** Materials intended for sour service shall comply with the following requirements:
  - (a) materials purchased in accordance with a CSA Z245 Standard shall be marked in accordance with the requirements of the applicable CSA Z245 Standard; or
  - (b) materials purchased in accordance with another materials standard shall be marked in accordance with the requirements of ISO 15156-2 or ANSI/NACE MR0175/ISO 15156-2, or ISO 15156-3 or ANSI/NACE MR0175/ISO 15156-3, whichever is applicable.

CSA Z245.x – Sour Service Marking Requirements

- CSA Z245.1 – Clause 15.2
  - (h) for sour service pipe, the symbol SS;
- CSA Z245.11 – Clause 14.2.1
  - (e) “SS” for sour service, if applicable;
- CSA Z245.12 – Clause 14.2
  - (i) “SS” for sour service, if applicable;
- CSA Z245.15 – Clause 14.1.1 references Table 12
  - Item 11
    - Marking for valves for sour service: “SOUR”, On nameplate

CSA Z662 – Marking Method

- **16.4.3.3** For other than die stamps on rims of flanges, markings for components shall be by one of the following methods:
  - (a) hot marking (with the part being marked above 620 °C);
  - (b) cold marking with low-stress impressions; or
  - (c) external or internal paint marking, labelling, or tagging.

CSA Z245.x – Sour Service Marking & Certification

- By applying identification markings for sour service on the product, manufacturers of CSA Z245.x products are confirming that sour service requirements of the applicable standard are met.
- For pipe, fittings, and flanges, this should not be a problem.
- However, for multi-component products such as valves, it has become an issue.

CSA Z245.15 – Sour Service Valve Marking / Certification Issues

- CSA Z245.15 Clause 13.2 refers to compliance with NACE MR0175/ISO 15156 Parts 2 and 3.
  - Part 3 of that standard has material service restrictions that go well beyond the simple sour material requirements for carbon and low alloy steels. Many CRA's have additional restrictions on maximum temperature, maximum partial pressure of H2S, chloride concentration, and pH.
  - Consequently, the valve manufacturer cannot give a blanket sour service compliance statement without additional knowledge about these additional process conditions.

CSA Z245.x Marking / Certification The CSA Z245.15 Valve Conundrum

  - And, if these process conditions are provided to the manufacturer as a basis for certification, then the purchaser cannot simply change process conditions or move valves where they are needed.
- Hence we have the current standoff where valve manufacturers will generally indicate compliance with NACE MR0175-2002, but are unwilling to give a blanket statement of compliance with NACE MR0175/ISO 15156.
  - unless they have used expensive CRA materials with no restrictions on maximum temperature, maximum partial pressure of H2S, or minimum pH.

Welding & Fabrication

Hardness Control for Welded Joints

- To avoiding SSC in welded carbon steel joints, hardness must be controlled by:
  - postweld heat treatment (PWHT); or
  - temper bead welding.
- The normally accepted hardness limit on cross-sections removed for welding procedure qualification is 248 HV or 250 HV depending on applicable standards, but it is getting more complicated (see next slide).
  - The difference between 248 HV and 250 HV is trivial.

NACE MR0175 / ISO 15156 Part 2 – Weld Hardness Limits

Table A.1 — Maximum acceptable hardness values for carbon steel, carbon-manganese steel and low-alloy steel welds

Hardness test methods	Hardness test locations for welding procedure qualification	Maximum acceptable hardness
Vickers HV 10 or HV 5 or Rockwell HR 15N	Weld root: Base metal, HAZ and weld root metal as shown in Figures 2, 3 or 4	250 HV 70.6 HR 15N
	Base metal and HAZ for weld overlays as shown in Figure 6; see also A.2.1.5 b)	250 HV 70.6 HR 15N
	Weld cap: Base metal, HAZ and weld metal of unexposed weld cap as shown in Figures 2 or 4	275 HV[a] 73.0 HR 15N
Rockwell HRC; see 7.3.3.2	As shown in Figure 5	22 HRC
	Base metal and HAZ for weld overlays as shown in Figure 6; see also A.2.1.5 b)	22 HRC

[a] The maximum shall be 250 HV or 70.6 HR 15N unless
— the equipment user agrees the alternative weld cap hardness limit; and
— the parent material(s) are over 9 mm thick; and
— the weld cap is not exposed directly to the sour environment.

Weld Procedure Qualification Cross–Section Hardness Surveys

- For sour service weld procedure qualifications, a hardness survey of a polished and etched cross-section through the weld has long been a common requirement.
- There is nothing new about this, but what is new, is the level of detail now demanded for the survey, in terms of the hardness test method, indenter load, & location of hardness indentations.

Weld Procedure Qualification Cross–Section Hardness Surveys

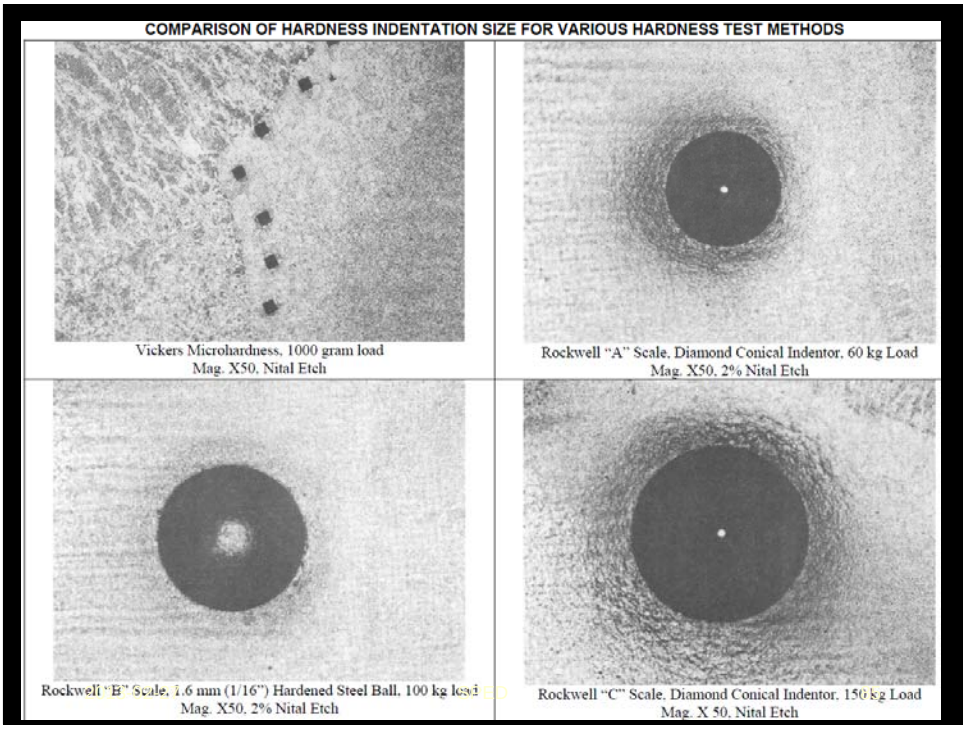
- With respect to hardness test method and load:
  - the standard Vickers method is almost always used now;
  - the required load is often stated as 10 kg but, in the absence of a mandatory requirement, any load between 1 and 10 kg is reasonable;
  - some material standards still require a load in the "microhardness" range (1000 grams or less). The most common examples for us are welding procedure qualifications for CSA Z245.1 Clauses 16.3 & 16.5 for steel pipe, and CSA Z245.15 Clause 13.8 for valves.

16.3

The welding procedure qualification test weld (see Clauses 5.4.6, 13.4(g), 13.5, and 14.1) shall be microhardness tested at the hardest-appearing microstructure; the microhardness at any location therein shall not exceed 248 HV 500 gf.

Weld Procedure Qualification Cross–Section Hardness Surveys

- There is a reason for the detail around hardness test method, indenter load, and indent location. Since the mid-1980's we better understand the relationship between:
  - the size of the indentation;
  - the size of the zones of interest; and
  - the locations of the zones of interest.
- This is illustrated on the following slide, where all indentations were placed near the same weld in the same material.

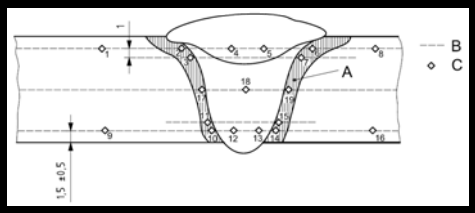


Hardness Surveys of Welding Procedure Qualifications

- So, all of this knowledge has lead to a proliferation of experts wanting to specify exactly how to do a hardness survey.
- The result is a number of sketches included in NACE, API, and CSA standards that are often written as mandatory, but can be conflicting between standards.
- This could give the impression that a contractor might have to do a separate hardness survey to meet every possible nuance of hardness testing variation.

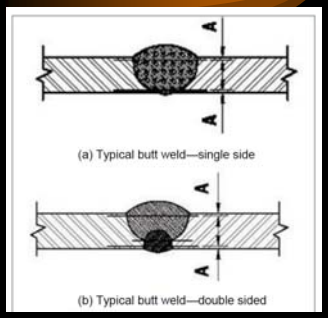
NACE MR0175 / ISO 15156 – Cross-Section Hardness Survey Layout

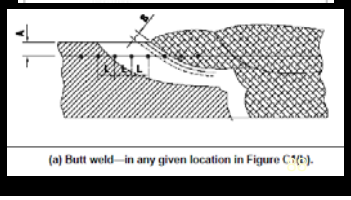
- NACE MR0175 / ISO 15156 layout is different from NACE MR0103 (see next page). Do you see a potential for conflict here, for contractors who would otherwise use the same welding procedure whether the application is an upstream gas plant or oil treating facility, or downstream refinery or upgrader?



NACE MR0103-2012 – Cross-Section Hardness Survey Layouts

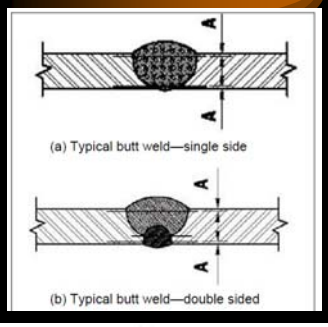
- Sketches to the right are from NACE MR0103-2012 Appendix C (Mandatory), and that would seem to set the requirements.
- BUT, NACE MR0103 refers to NACE SP0472 for P-No. 1 carbon steel, so that document would govern (see next slide).

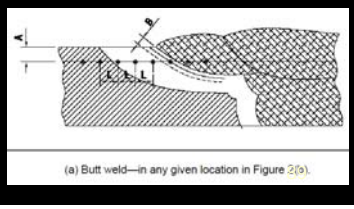



(a) Butt weld—in any given location in Figure C.1(b).

NACE SP0472-2010 – Cross-Section Hardness Survey Layouts

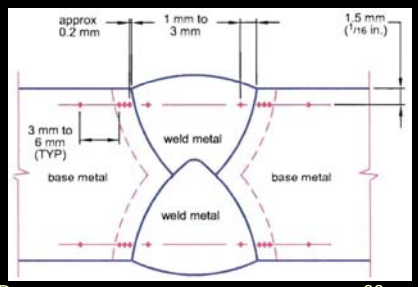
- The sketches appear to be the same as NACE SP0472, but the devil is in the detail, and you actually have to check the dimensions for A, B, and L to be sure.





API RP 582 - Cross–Section Hardness Survey Layout

- API RP 582 is often used as a welding specification for refinery and upgrading plants, where NACE MR0103, & by reference NACE SP0472 would apply.
- Any potential for conflict here?



Cross – Section Hardness Surveys

- So what is a poor contractor to do? One hardness survey for every possible layout? No. I suggest:
  - When hardness testing is required for welding procedure qualification the Contractor shall comply with the following requirements.
    - At least one weld cross-section hardness survey shall be provided for each *PQR directly applicable to the work*.
    - Hardness shall be measured by the Vickers method using an indenter load not exceeding ten (10) kilograms (HV10).
    - Hardness test locations for welds shall satisfy the intent of the governing document (e.g., NACE MR0175 / ISO 15156 Part 2, NACE SP0472, or API RP 582), and shall be placed so that the hardest appearing structures are tested.

Hardness Control by PWHT

- With the usual PWHT applied for carbon steels, finished welds are reheated to a temperature below the transformation range, and hardness is reduced by a tempering heat treatment.
- It is often referred to as “stress relieving”, which occurs in the same temperature range for carbon steels, and this is effectively what most piping codes are trying to achieve with PWHT.

PWHT Temperature / Time Selection

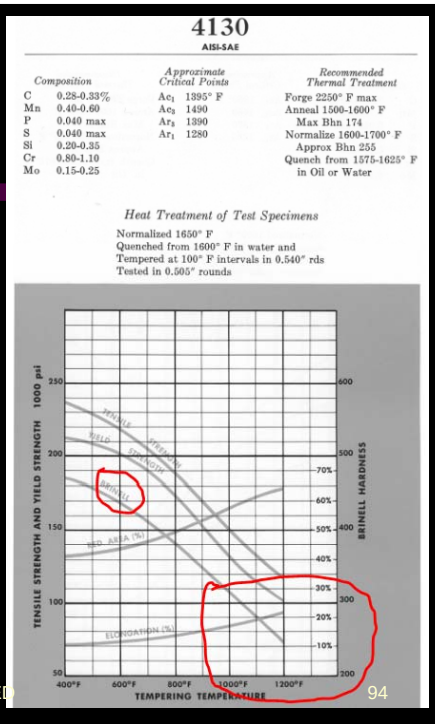
- Characteristics of the base metal and weld metal need to be considered.
- For plain carbon steels, the 595°C (1100°F), 1 hour per inch rule of most codes is adequate.
- Microalloyed steels look like a CS chemically but have a bit of Nb or V added, so they are more resistant to softening, and some owners ask for a minimum of 620°C (1150°F).
- Low alloy steel PWHT temperature (and time) depends on the specific alloy. T/t selection can be estimated using tempering curves.

PWHT Temperature

Why NACE has the fancy words around heat treatment temperature.

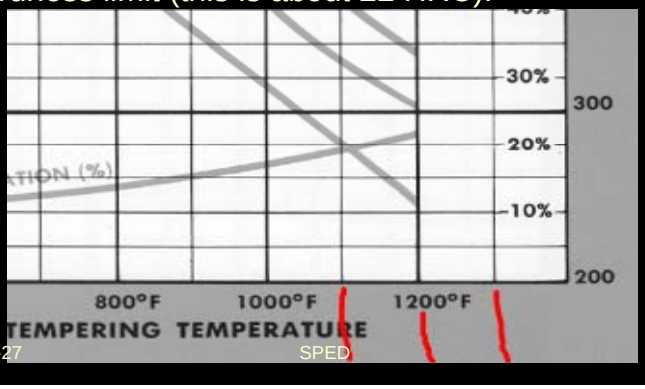
Consider the property curves as a function of tempering temperature on the right.

Now look at the magnified Brinell hardness curve on the next slide.



Why NACE has the fancy words around heat treatment temperature

- At 595°C (1100°F) you get 280 HB. To hard.
- You about 675°C (1250°F) to meet a 237 HB hardness limit (this is about 22 HRC).



Use of PWHT vs "Hardness Qualified" Welding Procedure for Hardness Control

- Historically, weld hardness has been controlled using postweld heat treatment (PWHT).
- It is however, possible to control hardness without PWHT, for very specific situations. This is achieved by careful control of:
  - characteristics of the base metals – carbon steels with chemistry controls, such as mentioned earlier in this presentation; and
  - parameters used for welding – fill / pass sequence, preheat, interpass temperature, heat input, electrode size.

Use of PWHT vs "Hardness Qualified" Welding Procedure for Hardness Control

- Before dealing with piping however, let me first deal briefly with equipment.
  - For manufacture of new equipment, I always recommend PWHT, and I usually ask for a soak temperature of 1175°F, +/-25°F (635°C, +/-15°C) for at least one hour per inch.
  - For maintenance and repair, I also recommend PWHT but it is not always possible, and there are ways to minimizing risk.
  - Equipment however, is are outside our scope tonight.

Use of PWHT vs "Hardness Qualified" Welding Procedure for Hardness Control

- For carbon steel piping in sour service, Owner piping classes often mandate PWHT, whether required by code or not, but there is often an exemption.
  - Don't get caught on services that are sour, but also have other crack inducing agents. One example is amine piping.
  - Warm amine piping should be PWHT since alkaline (amine) SCC is mainly driven by residual stress. See API RP 945.

Use of PWHT vs "Hardness Qualified" Welding Procedure for Hardness Control

- In a typical case, the Owner recognizes that SSC avoidance is primarily a matter of hardness control, and the hardness control method is mainly a matter of cost and convenience:
  - except when PWHT is mandated by the code of construction (e.g., ASME B31.3 P-No. 1 carbon steel process piping over 19.05 mm (3/4") nominal thickness).
- Clearly, if a furnace is available, and the cost of PWHT is not an issue, it is no problem to apply PWHT (provided the welding procedure has been qualified with PWHT, as this is usually an essential variable for welding procedures).

Use of PWHT vs "Hardness Qualified" Welding Procedure for Hardness Control

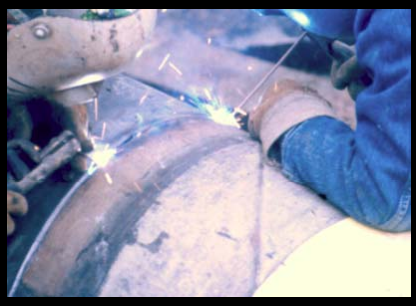
- For the specific case of single-welded joints in sour service piping systems, it is possible to control hardness using heat from arc welding processes. The idea is that, for a single-welded joint welded from the outside, weld deposits of subsequent passes will temper the weld deposits of previous passes.
  - "Single-welded" means joints welded only from the outside of the pipe.
  - Backwelding or other welding on the inside surface is not permitted.

Use of PWHT vs "Hardness Qualified" Welding Procedure for Hardness Control

- There are a lot of rules around qualifying and using "Hardness Qualified" Welding Procedures. A long discussion of requirements and options are provided in NACE SP0472-2010, and review of this material alone would take a whole evening at least.
- So rather than that, let's just look conceptually at what is going on in the next few pictures, and see how the welder can also work as a heat treater.

The Welder as a Heat Treater

- Running the root bead (left) and hot pass (right)



What you see on the inside of the pipe when welder is running the hot pass

- The hot pass is heat treating the root bead.
- Sometimes this is called temper beading, but the root area metal temperatures are hotter than they would be for a conventional tempering or stress relieving operation.

Use of "Hardness Qualified" Welding Procedures is not without risk

- Consider the following excerpt from ASME B31.8, Appendix B. These are good words of wisdom.

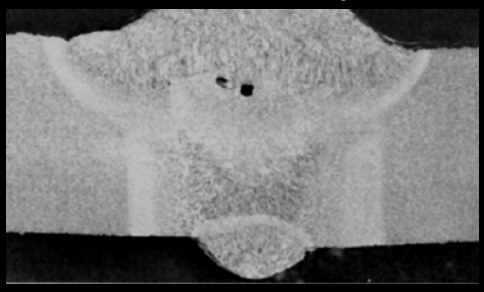
B825 STRESS RELIEVING

B825.1 Carbon Steels

The chemistry of the steel and welding procedure shall be controlled to limit the hardness of the weldment as required by para. B823.2.4. When the effectiveness of such controls is questionable, consideration shall be given to stress relieving welds in sour gas service. In general, temper bead welding, peening procedures, or low-temperature postweld heat treatment does not provide the equivalent protection from service cracking as does a full thermal stress relief.

Just say "no" to Backwelds

- A backweld on the inside of a piping system leaves a hard HAZ (if it is left "as-welded" and not subjected to PWHT). If you put in a backweld and it fails, we can do a cross-section like this, and you will be found out!



Welding – Influence of Microalloy

- This data is from a test weld joining NPS Sch. 80 pipe to an elbow.
- Look at hardness differences.
- What is happening?
  - Consider, the weld thermal cycle was the same for each material.
  - CE and carbon content are virtually identical for each material.
  - However, you can see that the elbow has 0.074% vanadium.

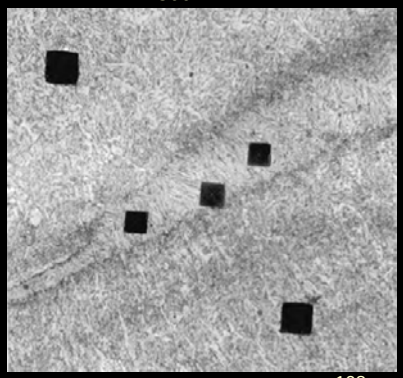
	NPS Sch. 80	
	Pipe	Elbow - LR90
	A333 Gr. 6	A420 Gr. WPL6
C	0.170	0.172
Mn	1.340	1.170
P	0.010	0.021
S	0.004	0.007
Si	0.30	0.35
Al	0.029	0.000
Cu	0.06	0.12
Ni	0.03	0.07
Cr	0.03	0.10
Mo	0.01	0.04
V	0.000	0.074
Nb	0.000	0.003
Ti	0.002	0.000
B	0.0000	0.0000
CE	0.41	0.42
HAZ Hardness at Toe of Cap Pass (HV10)		
Reading	Pipe HAZ	Elbow HAZ
1	207	254
2	200	251
3	200	234
HAZ Hardness at Toe of Root Bead (HV10)		
Reading	Pipe HAZ	Elbow HAZ
1	195	221
2	193	206

Why I Don't Like E8010 and Higher SMAW Electrodes for Sour Service

- SMAW cellulose coated electrodes, E8010 (550 MPa (80 ksi) SMTS) and higher, produce a low alloy steel deposit.
- They are made from mild steel core wire & a extruded coating that contains discrete alloy compounds.
- If you polish the electrode surface a bit with fine emery cloth, and reflect light from the surface, the alloy compounds can be seen with the naked eye, as shiny specks on the coating surface,
- During welding, if the particles don't get completely mixed in the molten weld pool, they can form tiny hard spots, which can crack under hydrogen charging.

Hard Spot at Location of Incomplete Mixing

- Large Indentations: 246 & 238 HV_{300}
- Small Indentations: 457, 406 & 449 HV_{300}

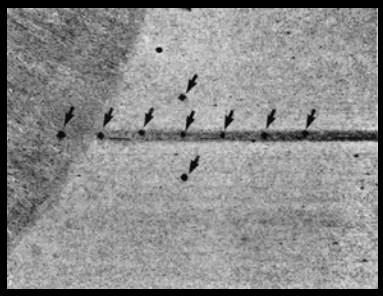


Submerged Arc Welding & Hard Spots

- Incidentally, the same hard spot issue exists for submerged arc welding with active fluxes, which is one of the reasons sour service specifications prohibit their use.

What Happens When Segregation In Pipe Intersects a Weld

- Left X6. Right X50. Detailed hardness survey:
  - 221 & 203 HV_{300} above an below segregation
  - 233 HV300 in weld metal (right)
  - 305, 301, 343, 341, 321, & 296 on segregation



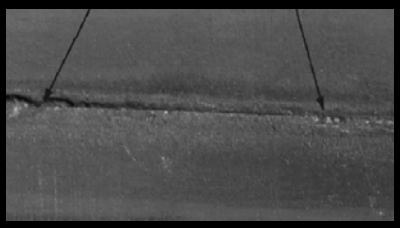
Nondestructive Examination

ASME B31.3 NDE Frequency

- ASME B31.3 Para. 341.4.1(b)(1) indicates a minimum 5% RT/UT for circumferential butt welds in normal fluid service.
- ASME B31.3 doesn't have a sour service category for NDE, and NACE standards do not cover weld NDE. Industry practice however, has been to apply 100% RT/UT, but it is not universally accepted.
- Industry practice does not constitute a requirement of the engineering design (unless you're a lawyer!), so if the Owner or Engineer wants 100% RT/UT, they have to state it.

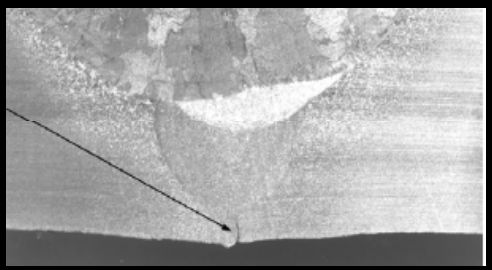
ASME B31.3 NDE Acceptance Criteria

- ASME B31.3 normal fluid service acceptance criteria are specified in Table 341.3.2.
- The main concern with using this table for sour service, is the amount of incomplete penetration permitted.
- What is incomplete penetration and why is it a concern?
- Look at the inside of the pipe.
  - The root bead is not there.
  - It has not penetrated through.
  - Result is a notch on the inside.



Incomplete Penetration

- The notch creates a location for the start of pitting corrosion.
- If corrosion starts there is also hydrogen generation which, in the presence of the notch, increases the opportunity for SCC.



ASME B31.3 NDE Acceptance Criteria
The Way It Currently Is

Table 341.3.2 Acceptance Criteria for Welds and Examination Methods for Evaluating Weld Imper

Criteria (A to M) for Types of Welds and for Service Conditions [Note (1)]										
Normal and Category M Fluid Service			Severe Cyclic Conditions			Category D Fluid Service				
Type of Weld			Type of Weld			Type of Weld				
Girth, Miter Groove & Branch Connection [Note (2)]	Longitudinal Groove [Note (3)]	Fillet [Note (4)]	Girth, Miter Groove & Branch Connection [Note (2)]	Longitudinal Groove [Note (3)]	Fillet [Note (4)]	Girth and Miter Groove	Longitudinal Groove [Note (3)]	Fillet [Note (4)]	Branch Connection [Note (2)]	Weld Imperfection
A	A	A	A	A	A	A	A	A	A	Crack
A	A	A	A	A	A	C	A	N/A	A	Lack of fusion
B	A	N/A	A	A	N/A	C	A	N/A	B	Incomplete penetration

Criterion Value Notes for Table 341.3.2

Criterion Symbol	Measure	Acceptable Value Limits [Note (6)]
A	Extent of imperfection	Zero (no evident imperfection)
B	Depth of incomplete penetration	≤ 1 mm ($\frac{1}{32}$ in.) and ≤ $0.2\overline{T}_w$
	Cumulative length of incomplete penetration	≤ 38 mm (1.5 in.) in any 150 mm (6 in.) weld length

ASME B31.3 NDE Acceptance Criteria
The Way It Used To Be – Note 100% RT

AN AMERICAN NATIONAL STANDARD
CHEMICAL PLANT AND PETROLEUM REFINERY PIPING

ANSI/ASME B31.3–1980 EDITION
TABLE 327.4.1A

Table 327.4.1A
Limitations on Imperfections in Welds

Imperfection	When Required Examination is:	Girth & Miter Joint Butt Welds	Straight or Spiral Longitudinal Butt Welds*	Fillet, Socket, Seal & Reinforcement Attachment Welds	Welded Branch Connections and Fabricated Laps
Cracks or Lack of Fusion	Any	None Permitted	None Permitted	None Permitted	None Permitted
Incomplete Penetration	100% Radiography	None Permitted	None Permitted	NA	None Permitted
	Visual or Random or Spot Radiography	A	None Permitted	NA	A and H
Internal Porosity	100% Radiography	B	B	NA	B and H
	Random or Spot Rad.	C	C	NA	C and H
Slag Inclusions or Elongated Indications	100% Radiography	D	D	NA	D and H
	Random or Spot Rad.	E	E	NA	B and H
Undercutting	Any	Lesser of 1/32 in. or $\overline{T}w/4$	None Permitted	Lesser of 1/32 in. or $\overline{T}w/4$	Lesser of 1/32 in. or $\overline{T}w/4$
Surface Porosity and Exposed Slag Inclusion (3/16 in. nom. wall thickness and less)		None Permitted	None Permitted	None Permitted	None Permitted
Concave Root Surface (Suck-Up)		F	F	NA	F and H
Weld Reinforcement		G	G	G	G and H

NOTES:
NA – Not applicable.
A – The lesser of 1/32 in. or 0.2 $\overline{T}w$ deep. The total length of such imperfections shall not exceed 1.5 in. (38 mm) in any 6 in. (150 mm) of weld length. (See Fig. 327.4.1)

ASME B31.3 Acceptance Criteria for Sour Process Piping Welds

- Most radiographic technicians with oilfield experience know that root bead defects such as incomplete penetration should be avoided for sour service.
- Many reject welds with root bead defects, even if they get scolded for not “calling to the code”.
- If avoiding welds with root defects like incomplete penetration is important to you as a designer, then you need to say it in the engineering design.
- You should not be relying on experience of the technician to keep you out of trouble.

CSA Z662 NDE Requirements for Sour Service Pipelines

- Sour service requirements are contained in CSA Z662 Section 16.
- The NDE requirements seem simply stated under Heading 16.9.3, and would appear to apply to all sour service, but you have to go back to Clauses 16.2.3 and 16.2.4 to get the limitations on scope.

CSA Z662 NDE Requirements for Sour Service

- **16.9.3.2** All butt welds shall be inspected by radiographic or ultrasonic methods, or a combination of such methods, for 100% of their circumferences, in accordance with the provisions of Clause 7.10.4.
- **16.9.3.3** Standards of acceptability for nondestructive inspection - the following limitations shall apply:
  - (a) Indications of incomplete penetration of the root bead shall be unacceptable, regardless of length.
  - (b) Indications of incomplete fusion at the root of the joint shall be unacceptable, regardless of length.

CSA Z662 NDE Requirements for Sour Service

- And now for the limitation on scope...
  - **16.2.3** Additional requirements as specified in Clause 16.9 apply to multiphase pipelines in which the hydrogen sulphide partial pressure (or effective hydrogen sulphide partial pressure) exceeds 70 kPa or 5% of design pressure, whichever is lowest.
  - **16.2.4** Additional requirements as specified in Clauses 16.9 and 16.10 apply to gas pipelines containing hydrogen sulphide meeting the definition in Clause 16.2.1(a).
    - Means gas pipelines where the partial pressure of H_2S is more than 0.3 kPaa.