

Development of the NACE MR-01-75 and NACE TM-01-77 Standards: Part I – Field Observations and Metallurgical Factors

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ABSTRACT

This is Part I of a two-part series intended to narrate the “lost” history leading up to the publication of the first Material Requirement (MR 0175) standard prepared by NACE (now AMPP) and its subsequent auxiliary standards. Part I covers field observations and describe the metallurgical issues that were being investigated in support of NACE T-1B and 1F committees to develop a sour service materials standard. Part II focuses on the rationale behind the use of accelerated laboratory test procedures and their development used for accelerated testing to differentiate metallurgical behavior in sour environments at near atmospheric pressure. The original SSC test methodologies would later be codified as a Test Method in NACE TM 0177 (1977).

A review of the historical events culminating in NACE MR 0175 will provide a technical basis for the Rockwell C 22 (HRC 22) hardness limit for carbon and low alloy steels, information on the 1%Ni restriction, and heat treatment requirements. By recalling the origins of the MR0175 standard, these papers will also provide justification for their continued existence when designing modern, oil and gas wells and flowlines. As the oil and gas industry continues to innovate and mature, it is imperative to maintain knowledge of the origins of the NACE MR 0175 standard and its intended purpose.

Key words: NACE MR 0175, NACE TM 0177, sulfide stress cracking, hydrogen sulfide, Rockwell C 22, HRC 22, SSC, corrosion science and technology, standardization

INTRODUCTION

This is Part I of a two-part series intended to provide background and a rational justification or supporting rationale for requirements leading to the development and publication of NACE⁽¹⁾ MR 0175 and ISO⁽²⁾ 15156. Part I focuses on some of the metallurgical and processing requirements; specifically, Rockwell C 22 scale (HRC) limit, the various acceptable heat treatments and the 1wt% Ni limit for carbon and low alloy steels to minimize the threat of sulfide stress cracking (SSC) in H₂S containing environments. Part II describes the testing and rationale behind the use of accelerated laboratory test procedures and their development to differentiate metallurgical behavior in sour environments¹. This series does not cover all the background and rationale for all the requirements that have become part of NACE MR 0175 and ISO 15156, only the aforementioned.

Phillips Petroleum Company provided the readiest overview of the oil and gas industry in the post-World War II years leading into the 1960s as viewed from a snapshot of tubular good history. As shown in Figure 1, the number of mechanical failures were decreasing from the 1946-1954 timeframe to the 1954-1961 timeframe even though the footage of tubular goods increased. This was attributed to improvements in the metallurgy, production techniques, handling equipment, and inspection equipment. However, in the same timeframe corrosion related failures increased from zero to twenty-five. While most of the corrosion failures were related to weight loss ("ringworm" and general corrosion), several were later identified as sulfide stress cracking (SSC), a newly diagnosed environmentally assisted cracking mechanism identified in the 1950s². The increase in corrosion failures, including SSC, is attributed to development of higher-pressure wells which necessitated higher strength materials. The timeframes shown in Figure 1, 1946 to 1961, reflect the experiences of only one operator at that time.

In these years of oil and gas production, a wide variety of steels were used. Steel compositions used were generally carbon steel grades of oil country tubular goods (OCTG) such as API⁽³⁾ Spec 5A J55 and N80, but also included non-standardized 9%Ni steels. J55 was the "workhorse" steel grade with N80 and 9%Ni being the high strength and very high strength grades respectively being desired more for deeper wells. AISI⁽⁴⁾ 4140 and AISI 4340 were tested and represent steel grades that were in forged products or OCTG along. A few line pipe steels were also tested for SSC.

In oil and gas operations, H₂S cracking issues with steel were originally considered as two separate forms of attack: blistering and brittle cracking. Blistering was noted in low pressure sour storage tanks fabricated from rolled plate steel. Cracking due to hydrogen embrittlement was a problem in sucker rods, valve springs, Bourdon tubes (pressure monitoring), and other applications using high strength steels used in oil and gas production in locations where H₂S containing fluids were produced. Many of these fields had several percent H₂S in the gas/hydrocarbon phase. Operators would perform a hydrogen bake-out of sucker rods and drill pipe by immersing the rod in hot oil or leaving it the hot summer sun to "drive the sulfur out" but was unknowingly driving out absorbed hydrogen absorbed by the steel from sulfide corrosion³. The failure of two 9%Ni production strings at Pincher Creek in Alberta, Canada, one of which lead to a blowout were the first recorded instances of H₂S related cracking of OCTGs even though N80 casing in exploratory wells in this field were also failing⁴. While some of the failures were mitigated by using higher alloyed materials, this approach was not considered cost effective, hence the extensive investigations into the use of low alloy steels.

Refining operations recognized that cracking of steel could be "derisked" by reducing steel hardness in the early 1940's. HRC 20 was the limit based on limited testing and agreed well with experience from exposure to process fluids containing HF⁵. Hardness, which correlate to tensile strength in many martensitic and ferric steels and correlates roughly to the tensile strength in austenitic stainless steels, was recognized as one method of minimizing the effects of blistering and cracking of steel in a sour environment. What an acceptable hardness limit was varied from as high as HRC 35 to as low as HRC 20 for steels in sour service depending on the type of service and operator experience with cracking. Bartz and Rawlins indicated that there was a

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general agreement that steels hardened to HRC 40 and higher were at risk of environmental cracking ³. Maintaining hardness values low while increasing the strength of a steel became challenging. This could be done but involved modifying the alloy composition and/or heat treatments used.

Studies by Fraser and Treseder noted some elemental additions, properties, and processing of J55 and N80 that increased or decreased the overall susceptibility to SSC ⁶. From a physical and processing perspective, four of the major factors to increasing the susceptibility of a steel to SCC were increasing hardness, yield strength, certain heat treatments, and Ni content. Since hardness and tensile strength are generally considered linked properties, these are considered the same for simplification for characterization and are expected to behave similarly provided the yield strength/tensile strength ratio is relatively constant. Other factors were identified, such as Mo and Mn content being related to increased susceptibility but were statistically less significant than the contributors ^{7,8}. Mo has subsequently been identified as a beneficial alloying addition.

Three requirements, hardness, Ni content, and tempering heat treatments to a lesser extent, for select steels were first noted in the committee reports: NACE 1B-163 in 1963 from NACE Canada as well as the draft of NACE Standard RP-100-64T ⁹ and Tentative NACE Specification 50 (Tubulars) and 150 (Valves) ¹⁰. The guidance noted in NACE 1B-163 would be later formalized as a recommended practice in NACE 1F-166 from NACE Canada to eliminate the failures in sour service that had been occurring and to standardize the material specifications for “off-the-shelf” sour service rated equipment ¹¹. Hardness, as Rockwell C scale, was set at HRC 22 maximum and specified tempering at 1150°F (621°C) or more as requirements for valves. Tubulars were to also be tempered at 1150°F (621°C) and the Ni+Cr+Cu residuals were limited to 0.50 wt%. Quench and temper (Q&T) was not a required process for J55 or N80 then; it was not an option until API SPEC 5CT was developed. API SPEC 6A specifically referenced NACE 1F-166 for the HRC 22 requirement in the 5th edition in 1966. These three requirements were later incorporated into the first version of NACE MR 0175 when approved in 1975 after a small crack developed on the wash nipple of an experimental gas injection well killing nine people in Denver City, TX. The addition of the 0.05 psia H₂S for specifying these and other requirements was not added until 1978. While there are select instances where higher hardness values are permitted in various standards for select components, such as Type 2 tubular products in API SPEC 5CT (e.g., L80, T95, C110), these material requirements when applied to a carbon or low alloy steel have successfully mitigated SSC in sour oil and gas production since their inception. Tuttle made these observations in 1970 and again in 1978 ^{12,13}. These observations are still true today as these requirements have worked sufficiently well that no changes (i.e., a failure or key piece of data) have been made since codified in 1975 and under continuous review and modification from both upstream and downstream oil and gas experts ^{14,15}.

Much of the SSC testing performed was on standard grades of tubing and/or casing that were procured to API SPEC 5A ¹⁶, which covered casing, tubing, and drill pipe. The standard grades for casing and tubing covered therein are now covered by API SPEC 5CT ¹⁷. There are two significant changes for these grades per API SPEC 5A to API SPEC 5CT; there was no maximum yield strength in API SPEC 5A and the sulfur and phosphorus limits were higher than they are today. Heat treatment, beyond normalizing post-rolling, was largely optional for all grades listed in API SPEC 5A with the exception of N80. All other heat treatments were non-standard. Maximum yield strengths were added in 1958 and the same values are used in the current version. In summary, the steels melted and tested in 1953 for OCTG are considered lower quality than steels today.

A timeline with a snapshot of the early history leading up to NACE MR0175 and related important/key events is provided in Figure 1. The changes in API requirements for tubular goods from 1953 to 2018 are provided in Table 1 for composition requirements and Table 2 for mechanical properties. P110 in 1960 was the first grade specified to have a Q&T heat treatment.

HARDNESS AS A SUSCEPTIBILITY CONTROL

A few oil companies began testing of steels in sour service to determine what materials were and were not acceptable with respect to SSC performance prior to 1952. Early SSC testing focused on understanding which mechanical properties, if any, could be used to better predict/prevent SSC, besides hardness values borrowed from refinery experience. Two of the other prominent considerations at that time were a maximum yield

strength for a given alloy and an acceptable maximum stress for a given alloy. Materials tested were primarily tubular steels of that time, primarily, 9%Ni, J55, and N80. Less common alloys then, such as 5%Ni, 7%Cr, and 9%Cr were also tested along with modified versions of many of these chemistries. The term “Modified” or “Mod” is used to describe steels with specific additions such as Mo, Al, Cr (to the Ni alloys), and Ni (to the Cr alloys) so that difference in testing by various authors can be more readily compared.

The test specimens, solutions, acceptance criteria, and controls varied among companies and investigators, usually with a goal of documenting in the laboratory the behavior of materials that either passed or failed in field H₂S service. Fraser and Treseder relied on a bent beam test with stress risers as a pass/fail check with statistical methods used to determine trends with the specimens loaded to stresses up to 1 ksi (~7 MPa) above the yield stress¹⁸. This was referred to as the “Shell” test at that time since there was no formalized testing. This test was a little more definitive as specimens were ranked individually with either a 1 for having no cracks (passing) or a 0 for having cracks (fail). Vollmer, along with Bowers, McGuire, and Wiehe, used a bent beam test, but periodically removed the specimens to be cleaned of corrosion product. Many of the specimens in these tests were pre-strained (work hardened) by typically 1 ksi (~7 MPa) and then stressed to between 26% and 122% actual yield strength (AYS), with an average stress of 80% AYS as the effect of loading was being evaluated. This was colloquially known as the “Gulf” test. Bowers et al., did not specifically indicate what the pass and fail criterion was in their tests, so this could only be inferred from data provided by comparing the columns of data; the column containing failure data on the order of a few days was considered to be failing. Specimens of certain materials failed on the order of days did align with the field experience relating to failures of these materials in H₂S containing service environments, while others took over a year and the test was halted^{1,19}. Results of these publications are summarized in Figure 3 and Figure 4 for the steels tested. Heat treatments were also varied in some of this work, but only to a limited extent.

Prange evaluated cracking susceptibility by cathodically charging U-bend specimens stressed to just above yield of similar steels in a 5% H₂SO₄ solution with 20 mg/l arsenic at currently level of 2 A/in² for 105 minutes. The base materials were normalized and air cooled or water quenched⁵. The specimens were bent, then tempered using different temperatures and duration to remove the coldwork from bending, then loaded to varying %AYS. The test environment was loosely based on information gained from operational experience with the failures of steels in HF alkylation units. Results from this work are illustrated in Figure 5, note that no yield strengths were provided.

Information regarding many of the prominent failures prior to 1952 was reviewed by the NACE Technical Committee on Sulfide Stress Corrosion Cracking, Technical Practices Committee 1-G, to start developing an understanding of this new phenomena⁷. The general conclusions were that the failures occurred in steels with greater than 80 ksi (550 MPa) nominal yield stress and not confined to any one alloy type so the results were applicable to both tubular and wellhead materials when exposed to H₂S containing fluids. Mitigation could be provided by using lower yield/tensile strength materials, design the string for lower stresses, use protective coatings, or use corrosion inhibitors. This committee report also prompted the development of a metallurgical solution, particularly in fields where high-strength steels were required and the environmental sour severity could not be easily controlled by chemical methods. While the use of protective coatings or corrosion inhibitors were considered, the use of these practices is often not advised today as a metallurgical/mechanical solution is more robust.

Additional testing using different methods, stresses, and different heats concluded that all steels tested that had greater than HRC 24 all failed, and all steels tested with less than HRC 21 all passed based on field testing^{7,20}. Tests were performed using fluids from Jumping Pound, Pincher Creek, and McKamie-Patterson reservoirs. Both the Shell and Gulf test methods were used and produced similar results, albeit the Shell tests were performed for a shorter duration. A summary of these results is provided in Figure 6 and Figure 7. The corrosion resistant alloys (CRA) from this summary are included only for completeness. The authors at the time were surprised that the majority of the tests in the McKamie-Patterson environment passed as this field had the highest H₂S concentration of those tested. It is now recognized that these tests passed due to the higher wellhead operating temperature, 165°F (74°C) at McKamie-Patterson compared to the 90°F (32°C) at Jumping Pound and Pincher Creek.

Bloom performed testing in 1955 using an early version of tension corrosion specimens ²¹. Specimens from various CRAs and some steels were machined, heat treated, then exposed to a solution containing 0.5% acetic acid saturated with H₂S while having various applied stress levels. These results are presented in Figure 8 and provide some justification that there is no consistent minimum applied stress (%AYS) below which cracking did not occur.

McGlasson and Greathouse performed notched C-ring tests of several alloys in a saturated H₂S solution at ambient temperature and pressure with 5 wt% NaCl added in 1959 ⁸. The C-rings were machined from sections of J55 and N80 tubing, heat treated to provide a range of hardness values, and then stressed in increments from 10% to 100% yield deformation as determined as the point of linearity departure from load-displacement curves on C-rings of the same material. The hardness values obtained were intended to cover a range where failures were known to have occurred, i.e., HRC 24 and higher as well as many lower hardness values to try and determine if a threshold existed. The notch was not meant to be representative of any notch found in tubing, but rather to simulate a wide range of potential notches and radii that could occur in the field making this a useful and realistic testing of material used in field applications. However, McGlasson and Greathouse stated that the use of notched C-rings for testing had little to no practical engineering use other than to test a stressed specimen in an environment, and the “Shell” test was thought to introduce too many unknowns or uncharacterizable residual stresses in addition to surface coldwork from machining. The only advantage to the “Shell” test was that key parameters that affected SSC could be more readily identified. The results from notched C-ring testing of J55 and N80 is provided in Figure 9, where all materials tested at less than HRC 23 pass regardless of the applied stress. No yield strengths were provided for this work.

STEEL COMPOSITION REQUIREMENTS VS. SSC

The initial Ni requirement was listed in Tentative NACE Specification 60 (Tubular Goods) and specified that the residuals, specifically the sum of Ni, Cr, and Cu were to be less than 0.5 wt% was issued as part of NACE 1B-163 in 1963. Mo was restricted to between 0.15% and 0.30%, Mn to 1.90% maximum, and carbon to 0.50% maximum. The Ni limit was increased to 1 wt% sometime after NACE 1F-166 was adopted in 1966, and the other composition requirements were removed.

Ni is an important alloying addition for steels as it increases strength, hardenability, and toughness which is important for heavy wall and low-temperature components, such as forgings. AISI 4340, a 1.5 – 2.0% Ni steel, was a popular alloy for forgings used in oil and gas projects for these reasons and was one of the more commonly tested Ni containing low alloy steels. 9%Ni tubulars were a non-standard grade when used and were more often run into higher-pressure gas and gas/condensate completions where tighter connections required high strength. Since very little of the 9%Ni and N80 tubing run prior to 1950 was tempered, these steels were selected for properties that could be achieved on a large scale as few pipe mills could consistently quench and/or temper sufficiently the quantities of steel used by the oil and gas sector. While Cr could have been substituted for Ni to increase the strength and hardness, Cr additions would require more carefully controlled heat treatment processes as cooling too quickly can result in thermal stresses sufficiently high to cause quench cracking. Additionally, steels with Cr additions were expected to require tempering heat treatments at this time. Therefore, it can be postulated that the desire for 9%Ni tubing was driven by connection design requirements and heat treatment abilities/controls, and not to mitigate against an aggressive production environment. The higher toughness at lower temperatures associated with 9%Ni steels would have been considered an unintentional bonus to operators at that time too as many developments were in locations, particularly in Canada, where ambient temperatures could drop well below 32°F (0°C).

Treseder and Swanson with Shell and Kowaka and Nagata with Sumitomo Metals, now Nippon Steel, performed the largest studies on the effects of various alloying elements on SSC. Shell performed the testing using their bent beam test at 70°F ²², and Kowaka and Nagata used a four-point bent beam stressed to 60% yield at 140°F (40°C) ²³. The test matrix developed by Treseder and Swanson was based on materials currently used by Shell in the 1950s. Kowaka and Nagata more accurately set the compositions based on AISI 4140 and AISI 4340 steels to perform a parametric study for a broader understanding of composition, and heat treatment effects. While Kowaka and Nagata tested alloys with varying C, Mn, Cu, Ni, Cr, Mo, and a group of intentional microalloying additions of V, Ti, and B as carbide formers, Ni had the most significant effect on SSC of all the additions. The effect of tempering was also evaluated by comparing quench and

untempered results to quench and tempered results with tempering temperatures of 1110°F (600°C), 1160°F (625°C), 1200°F (650°C), and 1250°F (675°C). These SSC laboratory tests were performed by both research teams in solutions containing 0.5% acetic acid saturated with H₂S at ambient pressure and temperature. Neither solution contained chlorides.

The results from Treseder and Swanson's testing are reported with respect to their statistical critical stress (Sc) analysis and are shown in Figure 10. Treseder and Swanson used an Sc of 10 as the threshold for acceptance based on a correlation of field experience on J55 (Sc 11 – 17), C75 (Sc 10 – 17), N80 (Sc 5 – 14), and P105/P110 (Sc 3 – 10). Kowaka and Nagata reported their results in time to failure for both yield stress and hardness for a maximum duration of 504 hours (3 weeks), without setting any specific criteria for pass or fail. The yield strength effects are provided in Figure 11 and the hardness effects are provided in Figure 12 from Kowaka and Nagata's testing. Despite differences in test methods, particularly test temperature and the dissolved H₂S concentration in the test solution, there is general agreement between the two data sets; mainly that increasing the Ni content generally of the steel lowers the steel's resistance to SSC.

HEAT TREATMENT VS. SSC

Normalizing (air cooling from the austenitizing temperature) was the standard heat treatment for the majority of the OCTG used in the 1950s due to few steel mills having the ability to routinely and consistently quench and temper tubulars. Additionally, the benefit of normalizing was to eliminate as-cast microstructure or any significant directionality from rolling and promote more uniform properties. Normalizing was also preferred due to cost and schedule as pipe could be rolled and then be subject to air cooling with no requirement to temper after cooling. While normalizing was the standard practice in the 1950s, there was no specific requirement to normalize the full pipe length or normalize any ends if swaged as there are now.

The failure of N80 tubing at Lacq, in Pau, France in December 1951 was resolved by the development of specially alloyed and heat treated N80 pipe²⁴. Lacq was producing primarily methane with 15% H₂S and 6% CO₂ when a series of failures occurred. Based on previous work, Cauchois et al. determined that a spheroidized microstructure would be the best solution and this was achieved by a proprietary Cr-Mo-Al steel with a specific heat treatment that included the upset ends. The heat treatment was developed to produce a "carbon-free ferrite with dispersed fine carbides" using this composition. This process caused steels that were failing SSC tests on the order of hours to become steels that could successfully be tested and run for 3,000 hours (125 days). While the specifics of the heat treatment are not provided, given the proprietary nature along with the intended microstructure, the process was Q&T.

Tension specimens were used by Baldy in 1955 to evaluate SSC susceptibility of N80 tubulars²⁵. The study performed was to develop a better understanding of tempering effects and cold work due to rotary straightening of pipe. These tests involved 1% cold work to simulate rotary straightening of pipes in a 0.5% acetic acid solution with a 50/50 mix of CO₂/H₂S gas at atmospheric conditions, with specimens stressed to various loads. The test matrix and results are provided in Table 3. Note that passing required the specimens to not crack within 1000 hours (~42 days) of exposure. Baldy's works showed the importance of tempering heat treatments after small amounts of cold work were introduced into a pipe. Another observation from this research was the effect of cold work increasing susceptibility to SSC.

Results from Kowaka and Nagata also showed the effects of tempering after quenching as part of the parametric study²³. These results are provided in Figure 13 and show that the tempering of the 0.04% Ni steels causes them to have increased resistance to SSC, with the 0.04Ni-0.60Mo combination having the best response to tempering at all temperatures investigated.

DISCUSSION OF METALLURGICAL FACTORS INFLUENCING SSC

A list of prominent failures reported up to 1972, omitting the heat treatment information, is provided in Table 4²⁶. The majority of the early failures in the tests were predominantly steels containing Ni exceeding 1% (e.g., 9%Ni and AISI 4340 with 1.6 to 2.0 % Ni) and/or had hardness values that exceeded the current HRC 22 requirement in use since 1966 in Canada and 1975 in the United States. The only failures that occurred with material close to HRC 22 were in API C75 grade OCTG. Other than this instance, the use of

HRC 22 cannot be assumed as a guarantee to have prevented these failures but could be considered a sufficiently low hardness to avoid SSC. C75 was a standard sour service grade until 1968 when the HRC 22 was being adopted by various operators. L80 replaced C75 as the de facto sour tubular grade when introduced in 1975. C75 was removed from the list of standard OCTG grades in 1990²⁷. The majority of the failures listed occurred in highly sour gas or gas/condensate systems.

Many of the observed field corrosion-related failures reported were often viewed skeptically as to the mechanism that caused cracking. Several authors would attribute a field failure to SSC, where another would refer to a similar failure as stress corrosion cracking (SCC), and another would refer to another similar failure as hydrogen embrittlement (HE). Ladley summed this well when reviewing corrosion related failures at Continental Oil; some were SSC, some were SCC, and many may have been incorrectly identified². Since the effects of sulfur and phosphorous are better understood today than in the 1950s, many failures may have appeared to be indistinguishable. The higher S and P contents permitted by industry standards then also explain some of the differences in responses between laboratory heats then and field experience, and more importantly between then and current experience, especially when coupled with the increased experience available now as other aspects of well design/control such as brines and muds are more controlled.

Hardness

One property considered to influence SSC is hardness. It is always tested the same way and is a simple and easy test that can even be incorporated for a finished part. Any differences are immediately noted by the units which denote the scale, i.e., HRA for Rockwell A, HRB for Rockwell B, HRC for Rockwell C, and HB for Brinell. While not perfect, conversion can be made between these scales with some accuracy. Yield strengths reported depend highly on the standard method used. API Specification 5A (including 5AC and 5AX revisions) and 5CT, etc. all measure the yield strength at the 0.5% elongation under load (EUL), where API Specification 6A²⁸ uses the 0.2% strain offset per ASTM E8. The difference, while in many cases being small is illustrated in Figure 14, and can cause significant confusion on what is acceptable. Hardness, once the scale is specified, usually does not cause confusion on what is or is not acceptable.

HRC was historically used by pipe mills whereas HB was historically used by mills for bar products and forgings. Rockwell C was also historically considered to be less accurate when measuring hardness of steel that were softer than HRC 20 to 25; in these instances, HRB or sometimes HRA, was considered more accurate for softer steels and other materials²⁹. Thus, some of the early test data, such as that by Prange⁵ or Fraser and Treseder¹⁸, required conversion by ASTM E140N. Additionally, if the value reported was less than 22 regardless of the scale, the higher acceptability requirement of HRC 22 was met. But why HRC22?

Based on the literature reviewed, the use of HRC 22 as a sour serviceability limit was first discussed circa 1955-1956. This is based on Ladley stating that Continental Oil Company had five successful years of experience using HRC 22 as discussed by the Metallurgy Committee at the 1960 South-Central Region meeting of NACE for J55 and N80 tubing in 1961². McGlasson and Whitehouse agreed with the use of HRC 22 to screen J55 and N80 for SSC resistance due to the wide variability in properties tested in 1959 even though their testing indicated HRC 23. N80 should also be provided in the normalized, or more specifically normalized and tempered condition to temper any martensite present in the microstructure⁸. By 1963 Dubrow et.al. stated that field studies performed at Brown-Bassett in West Texas, corroborated laboratory testing indicating HRC 22 should be used for steels exposed to greater than 50 ppm H₂S in the aqueous phase (equivalent to 0.25 psia H₂S in the gas phase), and less than HRC 27 when exposed to less than 2 ppm H₂S in the aqueous phase (0.01 psia H₂S)³⁰.

When comparing a summary of HRC data from the first publications in Figure 3 and Figure 6, a safe maximum hardness can be assessed to be somewhere between HRC 16 and 28. This is further illustrated in Figure 15 comparing the various SSC test results for N80 and the various Ni containing alloys. This approach further refines an acceptable hardness maximum to HRC 23 based on N80. While there were a few of the Ni containing alloys that did pass, there were generally more unacceptable results than acceptable. This finding coupled with the general field experience of 9%Ni alloys in Table 2 leaves some doubt to the general use of Ni containing steels for production and casing tubular goods under sour service conditions.