MINIMIZING THE RISK OF CASING FAILURES IN MULTI-FRAC HORIZONTAL SHALE WELLS BASED ON HISTORICAL LESSONS LEARNED

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INTRODUCTION

Ever since the hydraulic fracturing process was adopted by the oil and gas industry to produce from tight shale formations there have been numerous very expensive failures that occur during these operations.

Many of these failures have been attributed to environmentally assisted cracking (EAC) of high strength API 5CT steel tubulars such as grade P110 casing and couplings.
Understanding the Factors Leading to Failure

When evaluating a well design requiring high cyclic fracking loads, three important parameters must be considered:

1. Stress Level
2. Environment
3. Material susceptibility to cracking due to the environment and/or high cyclic loads
The vast majority of these failures have occurred in standard API connections.

This trend in API connection failures is no coincidence.

Standard API connections are known to have inherently high make-up hoop stresses.
API CONNECTIONS

LTC THREAD PROFILE

BTC THREAD CONFIGURATION

Leak paths blocked by solids in the thread compound.
1. Stress is a Function of turns, which depends on the interference due to wedging the pin into the box, where;

\[ \text{Interference} = (\text{Taper}) (\text{Turns}) (\text{Pitch}) (0.5) \]

\[ l = \frac{TNP}{2} \quad (1) \]

2. Bearing Pressure between the mating threads due to the make-up interference \( P_{\text{m}} \)
Is a function of the material's modulus of elasticity \( E \), interference and ratio of the differences of the various radii squared.

\[ P_{\text{m}} = \frac{EI (b^2 - a^2) (c^2 - b^2)}{2b (b^2) (c^2 - a^2)} \quad (2) \]

3. The hoop stresses induced by the shrink-fit pressure on the outside of the coupling then is;

\[ S_{\text{t,sh}} = \frac{2b^3 P_{\text{m}}}{c^2 - b^2} \quad (3) \]

4. The maximum combined stresses in the coupling OD due to internal pressure \( P_{\text{i}} \) is the sum of Eqs. 3 and 4;

\[ S_{\text{t,i}} = \frac{2a^2 P_{\text{i}}}{c^2 - a^2} \quad (4) \]

Fig. 10—Connection stresses due to connection make-up and internal pressure (hand-tight plane).
## High Stress Connections

<table>
<thead>
<tr>
<th>Internal Pressure</th>
<th>5&quot; 18.00 lb/ft LTC P110</th>
<th>4.5&quot; 13.50 lb/ft LTC P110</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Turns from Hand-Tight</td>
<td>Triaxial Equivalent Stress @ Coupling Face OD</td>
</tr>
<tr>
<td>0</td>
<td>3.0</td>
<td>69,000</td>
</tr>
<tr>
<td>0</td>
<td>4.0</td>
<td>91,000</td>
</tr>
<tr>
<td>0</td>
<td>5.0</td>
<td>114,000</td>
</tr>
<tr>
<td>8000</td>
<td>3.0</td>
<td>94,000</td>
</tr>
<tr>
<td>8000</td>
<td>4.0</td>
<td>116,000</td>
</tr>
<tr>
<td>8000</td>
<td>5.0</td>
<td>139,000</td>
</tr>
</tbody>
</table>

Note: Nominal make-up is 3 turns from hand-tight, maximum is 5 turns.
BTC PIN AND COUPLING

BASIC POWERTIGHT MAKEUP

HANDTIGHT MAKEUP

Triangle stamp (see Note 2)

1.19 mm x 45° approximately

Triangle stamp (see Note 2)
## Coupling Stress at Face with Maximum Standoff and at Extremes of Make-Up

<table>
<thead>
<tr>
<th>Make-Up Position at Maximum Standoff</th>
<th>Internal Pressure</th>
<th>External Pressure</th>
<th>Tension - kips</th>
<th>7&quot; 29.00 lb/ft BTC</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Triaxial Equivalent Stress @ Coupling</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>ID @ Face</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Triaxial Equivalent Stress @ Coupling</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>OD @ Face</td>
</tr>
<tr>
<td>Base of Buttress Triangle</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>115,000</td>
</tr>
<tr>
<td></td>
<td>10120</td>
<td>730</td>
<td>409</td>
<td>153,000</td>
</tr>
<tr>
<td></td>
<td>8770</td>
<td>730</td>
<td>374</td>
<td>148,000</td>
</tr>
<tr>
<td>Apex of Buttress Triangle</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>174,000</td>
</tr>
<tr>
<td></td>
<td>10120</td>
<td>730</td>
<td>409</td>
<td>212,000</td>
</tr>
<tr>
<td></td>
<td>8770</td>
<td>730</td>
<td>374</td>
<td>206,000</td>
</tr>
</tbody>
</table>
Understanding The Environments in Shale Well Completions.

Producing Environments

- H₂S Containing Production Fluids may be present during shut-in periods

Non-Producing Environments

- Poorly treated water based fluids (H₂S generation due to SRB)
- Poorly inhibited acid (HCl)
- Well exposed to acid beyond the acid inhibitor’s life span
- Well exposed to spent acid that contains H₂S and CO₂ from reservoir with no inhibitors

Thermal

- Rapid cool down of the casing string during introduction of frac fluids
Use of Susceptible Materials

SSC Resistance of an API casing Steel²

2) NACE 98 Paper No. 274
Environmental Conditions for which Grades of Casing and Tubing are Acceptable

<table>
<thead>
<tr>
<th>For All Temperatures</th>
<th>For ≥ 65°C (150°F)</th>
<th>For ≥ 80°C (175°F)</th>
<th>For ≥ 107°C (225°F)</th>
</tr>
</thead>
<tbody>
<tr>
<td>ISO 11960(^a) Grades:</td>
<td>ISO 11960(^a) Grades:</td>
<td>ISO 11960(^a) Grades:</td>
<td>ISO 11960(^a) Grade:</td>
</tr>
<tr>
<td>H40 (\geq 65°C)</td>
<td>N80 Type Q (\geq 80°C)</td>
<td>N80 (\geq 107°C)</td>
<td>Q125(^b)</td>
</tr>
<tr>
<td>J55 (\geq 65°C)</td>
<td>C95 (\geq 80°C)</td>
<td>P110 (\geq 107°C)</td>
<td></td>
</tr>
<tr>
<td>K55 (\geq 65°C)</td>
<td>M65 (\geq 65°C)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>L80 Type 1 (\geq 65°C)</td>
<td>C90 Type 1 (\geq 80°C)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>T95 Type 1 (\geq 65°C)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Proprietary grades as described in A.2.2.3.3</td>
<td>Proprietary Q &amp; T grades with 760 MPa (110 ksi) or less maximum yield strength</td>
<td>Proprietary Q &amp; T grades with 965 MPa (140 ksi) or less maximum yield strength</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Casings and tubulars made of Cr-Mo low alloy steels as described in A.2.2.3.2</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Temperatures given are minimum allowable service temperatures with respect to SSC. Low temperature toughness (impact resistance) is not considered, equipment users shall determine requirements separately.

\(\geq\) For the purposes of this provision, API 5CT is equivalent to ISO 11960:2001.

\(^b\) Types 1 and 2 based on Q & T, Cr-Mo chemistry to 1 036 MPa (150 ksi) maximum yield strength. C-Mn steels are not acceptable.

When \(\text{H}_2\text{S}\) is Expected SSC Resistant Steels must be used
Lessons Learned

- Even when H$_2$S is not expected and/or the environment is assumed to be benign, there have been many failures of highly stressed high strength steel couplings and pipe body.

- Producing and non-producing environments during shale well completions can be quite unpredictable.

- However, most of the failures have occurred in steels with a yield strength (YS) of $> 125$ Ksi. (i.e. P110 YS range is 110 – 140 ksi)
Failure Mitigation

**MATERIAL**
- Since non-producing environments during fracking operations on some of these offshore wells can be unpredictable, it has become standard practice by some operators to specify P110 casing material with some restrictions on the maximum allowable yield strength. Depending on the manufacturer, restricted P110 material may have different designations such as restricted yield (RY), or mild sour (MS), just to name a few. The typical maximum allowable yield strength for this RY P110 material is 125 ksi.

**CONNECTIONS**
- Since the highest stresses are always expected to be at the connections, the stress levels can be reduced by using a connection with low make-up stresses. Depending on the economics of the well(s), a standard API connection with high make-up stresses may be substituted by a connection with lower make-up stresses such as a low thread interference connection having a metal seal near the end of pin (i.e. metal to metal seal proprietary connection) and/or any other type of connection having lower stresses upon make up (i.e. modified API connections).

- However, proprietary connections with low make-up stresses are recommended.
Threaded and Coupled (T&C) premium connection

Modified API Connection with pin nose to pin nose torque shoulder
FAILURE ANALYSIS CASE HISTORIES
Failure analysis of modified API connection during the 1\textsuperscript{st} frac stage at 8,050 psi, after initial toe sleeve opening at 7,100 psi and initial toe prep-breakdown with acid injection at 9,200 psi.

Material was Controlled Yield P110.

LOAD CYCLES
1. Toe Prep/Sleeve Break
2. Injection Test
3. Stage 1 Frac Failure Load
As Received Fractured P110 20# 5.5” Modified API Coupling Threaded to a Mill End and Field End Piece of P110 Pipe
### Mechanical Properties and Chemical Analysis of One Half of the Broken Coupling

#### Subsize Round Tensile Test Results

<table>
<thead>
<tr>
<th>SPECIMEN NO.</th>
<th>DIAMETER IN.</th>
<th>TENSILE STRENGTH IN.</th>
<th>% ELONG.</th>
<th>% ROA</th>
</tr>
</thead>
<tbody>
<tr>
<td>977-15</td>
<td></td>
<td>110,000</td>
<td>125,000</td>
<td>12 min.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>246</td>
<td>123,000</td>
<td>22.4</td>
</tr>
<tr>
<td></td>
<td></td>
<td>0.5% EUL - 118,200</td>
<td>0.6% EUL - 122,500</td>
<td>66.5</td>
</tr>
<tr>
<td></td>
<td></td>
<td>0.7% EUL - 123,400</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

#### Longitudinal Charpy Impact Test Results

<table>
<thead>
<tr>
<th>SPECIMEN NO.</th>
<th>TEST TEMP.</th>
<th>NOTCH LOCATION</th>
<th>FT. LBS.</th>
<th>SHEAR</th>
<th>LAT. EXP. (MILS)</th>
</tr>
</thead>
<tbody>
<tr>
<td>977-15</td>
<td>@32 °F</td>
<td>Base Radial Notch</td>
<td>45</td>
<td>99</td>
<td>60</td>
</tr>
<tr>
<td></td>
<td>2</td>
<td></td>
<td>45</td>
<td>99</td>
<td>65</td>
</tr>
<tr>
<td></td>
<td>3</td>
<td></td>
<td>47</td>
<td>99</td>
<td>67</td>
</tr>
</tbody>
</table>

**AS RECEIVED**

**AS MAPPED**

**AS MACHINED**

### Base Chemistry Test Results

<table>
<thead>
<tr>
<th>ELEMENTS</th>
<th>% CONTENT</th>
<th>API 5CT Gr. P110</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carbon</td>
<td>.19</td>
<td>---</td>
</tr>
<tr>
<td>Manganese</td>
<td>1.37</td>
<td>---</td>
</tr>
<tr>
<td>Phosphorus</td>
<td>.008</td>
<td>.030 max.</td>
</tr>
<tr>
<td>Sulfur</td>
<td>.007</td>
<td>.030 max.</td>
</tr>
<tr>
<td>Silicon</td>
<td>.27</td>
<td>---</td>
</tr>
<tr>
<td>Molybdenum</td>
<td>.19</td>
<td>---</td>
</tr>
<tr>
<td>Nickel</td>
<td>.09</td>
<td>---</td>
</tr>
<tr>
<td>Chromium</td>
<td>1.62</td>
<td>---</td>
</tr>
<tr>
<td>Copper</td>
<td>.22</td>
<td>---</td>
</tr>
<tr>
<td>Vanadium</td>
<td>&lt;.01</td>
<td>---</td>
</tr>
<tr>
<td>Aluminum</td>
<td>&lt;.01</td>
<td>---</td>
</tr>
<tr>
<td>Titanium</td>
<td>&lt;.01</td>
<td>---</td>
</tr>
<tr>
<td>Neobium</td>
<td>&lt;.01</td>
<td>---</td>
</tr>
<tr>
<td>Tantalum</td>
<td>&lt;.01</td>
<td>---</td>
</tr>
</tbody>
</table>

**AS TESTED**

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- Broken Coupling Showing Typical Quenched & Tempered Microstructure
VISUAL EXAMINATION

- Visual examination revealed that the failure initiated from the ID of the last engaged thread of the coupling.

- There was no indication of pre-existing defects on the last engaged thread of the failed coupling that may have initiated a crack. However, there was pitting corrosion which was most likely caused by the acid that was used during the fracking operation.
SEM image of pitting corrosion which was probably caused by the acid that was used during the fracking operation.
Macroscopic Features Indicating Fatigue

- Flat Fracture Surface
- Ratchet Marks
- Final Rupture
Fatigue crack propagation flat area is about 67% of the total cross-sectional area of the coupling, the other 33% is final shear tensile overload.

3 Zones

1. Initiation (Ratchet Marks)
2. Propagation (Flat Fracture Surface)
3. Ductile Final Rupture
SEM analysis performed on the mill end fractured coupling revealed that the fracture surface of the failed coupling was severely corroded and that the condition of the fracture surface morphology could not reveal clear indications of the nature of the fracture.
- SEM micrograph showing less severe corrosion attack on the final ductile shear over load zone than in the flat fatigue propagation zone.

- The flat fatigue crack propagation zone was probably exposed more time to the acid in a crevice environment before the final rupture occurred than the final shear fracture surface.
TDAS Modeled triaxial envelope indicates that all three load cases fall within the 1.25 and 1.00 safety factor VME ellipses (i.e. no yielding and/or tensile overload is predicted).
Modified API Connection Make-Up Configuration

- Applied Torque
- Pin Nose in Compression
- Coupling in Tension
The connection was made up close to optimum make-up torque.
- FEA predicted the highest localized tensile and VME stresses to be in the last engaged thread of the coupling which is in agreement with the failure that occurred in this well.

- Based on the FEA contour plot, the peak VME stresses in the last engaged thread are in the range of 170ksi (i.e. Local Yielding Occurs).

- Although highly localized peak stresses don’t result in gross plastic deformation, they may cause the initiation of fatigue cracks if the connection is subjected to cyclic loads and exposed to a highly corrosive environment.
The source of cyclic loading was unclear, since the casing string was only subjected to three known high load pressure cycles that most likely are not enough to cause this type of fatigue failure; however there are two possible sources that come to mind:

1. **Pipe Rotation**, which can cause a connection at a specific location in the well to repeatedly experience bending stresses and exceed the endurance limit of the material, however according to the operator of the well the string was not rotated during completion of the well nor during the failure event.

2. **Flow Induced Vibrations**; high velocity flow through a pipe can produce lateral vibration in pipe in an un-cemented interval (or other interval with no lateral support). Some case histories and studies have been conducted on the effect of flow-induced vibrations. For vibration that produces a lateral motion, the maximum bending stress of a cantilevered system subjected to a distributed load occurs at the laterally supported cantilevered ends.
Vertical un-cemented interval of 5,415 ft.
The connection failure occurred in between a vertical un-cemented interval of 5,415 ft. at a depth of 1,079 ft. The theoretical critical fluid velocity to generate flow-induced vibrations decreases with increasing unsupported length.

The minimum un-supported lengths for this size of casing needed to generate flow induced vibrations at these fluid velocities in well are 443 ft. and 236 ft., respectively. **Indicating a possible flow induced vibration scenario**
The geometry, state of stress and environment in the last engaged thread of the coupling was such that it created a synergistic effect for rapid fatigue crack initiation and propagation.

What About in a Highly Corrosive HCl Environment??
The Connection Failure Was Significantly Accelerated Due to the Geometric SIF Amplification Effect of the crack at The Root of the Last Engaged Thread In the Highly Corrosive Environment

Y Factor Estimated by FEA and Validated Experimentally

\[ Y = \frac{K}{\sigma \sqrt{a}} \]

Simplified Generic Stress Intensity Factor (SIF)

Based on the Results of the Metallurgical Evaluation, Fracture Surface Evaluation, and Stress Analysis, the Modified API Connection Failed Due to Corrosion Fatigue in the un-cemented vertical section of the well.

Even though this type of failure does not occur frequently, this is not an isolated incident. In 2011 a failure occurred in a similar fashion in another API modified connection (see below).
An ERW P110 casing joint has failed on an onshore well during the 23rd frack stage. The well was scheduled to undergo 40 frack stages. Frac fluids containing HCl were being pumped through the casing.
Burst Fracture Surface Containing Mid-wall Brittle Flat Zone with ID and OD Ductile Shear Lips
Weld Cross-Section Away from Burst Showing Weld Fusion Line and Segregation

Burst Weld Cross-Section Showing Weld Fusion Line and Segregation
Tensile Specimen Removed Across the ERW Pipe Showing Mid-wall Zones of Intergranular Fracture Mode
EDS Analysis of Segregation Bands from Specimen Removed Across the ERW
Center-slit Coil From Steel Slabs Containing High Amounts of Centerline Segregation

Excessive centerline segregation may lead to:

- Poor fusion line (FL) fracture toughness
- FL lack of fusion problems/defects
- FL embrittlement due to metallurgical effects
- A detrimental increase in FL hydrogen embrittlement and/or SSC susceptibility.
# Base Metal CVN Impact Toughness

## Comparison Between MTR and Failed Pipe

### Base Metal CVN Impact Test Results @ 32 °F (0 °C) from Failed Pipe

<table>
<thead>
<tr>
<th>Specimen</th>
<th>Impact Energy, ft-lbs (3/4 size)</th>
<th>Impact Energy, ft-lbs (Full Size Converted)</th>
<th>Fracture Appearance (% Shear)</th>
<th>Lateral Expansion</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>21</td>
<td>26</td>
<td>40</td>
<td>12</td>
</tr>
<tr>
<td>2</td>
<td>18</td>
<td>23</td>
<td>40</td>
<td>26</td>
</tr>
<tr>
<td>3</td>
<td>18</td>
<td>23</td>
<td>50</td>
<td>29</td>
</tr>
<tr>
<td>Average</td>
<td>19</td>
<td>24</td>
<td></td>
<td>22</td>
</tr>
</tbody>
</table>

### Base Metal CVN Impact Test Results @ 32 °F (0 °C) MTR Reported Values from Failed Pipe

<table>
<thead>
<tr>
<th>Specimen</th>
<th>Impact Energy, ft-lbs (1/2 size)</th>
<th>Impact Energy, ft-lbs (Full Size Converted)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average</td>
<td>64</td>
<td>116</td>
</tr>
</tbody>
</table>

**API 5CT Requirement** - 15 ft-lbs (Full Size), 12 ft-lbs (3/4 Size)
Weld FL CVN Impact Toughness Comparison Between MTR and Failed Pipe

### Weld FL CVN Impact Test Results @ 32 °F (0 °C) from Failed Pipe

<table>
<thead>
<tr>
<th>Specimen</th>
<th>Impact Energy, ft-lbs (3/4 size)</th>
<th>Impact Energy, ft-lbs (Full Size Converted)</th>
<th>Fracture Appearance (% Shear)</th>
<th>Lateral Expansion</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>8</td>
<td>10</td>
<td>10</td>
<td>27</td>
</tr>
<tr>
<td>2</td>
<td>9</td>
<td>11</td>
<td>10</td>
<td>22</td>
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<tr>
<td>3</td>
<td>9</td>
<td>11</td>
<td>10</td>
<td>27</td>
</tr>
<tr>
<td>Average</td>
<td>9</td>
<td>11</td>
<td></td>
<td>25</td>
</tr>
</tbody>
</table>

### Weld FL CVN Impact Test Results @ 32 °F (0 °C) MTR Reported Values from Failed Pipe

| Specimen | Impact Energy, ft-lbs (1/2 size) | Impact Energy, ft-lbs (Full Size Converted) |
|----------|---------------------------------|---------------------------------|---------------------------------|
| Average  | 43                              | 78                              |

API 5CT Requirement - 15 ft-lbs (Full Size), 12 ft-lbs (3/4 Size)
The manufacturer revealed that this ERW pipe was tempered at a substantially lower temperature than what was reported in the MTR. The Manufacturer stated in the MTR that the pipe was supposed to be tempered above 600 °C (1112 °F). However the manufacturer tempered the pipe at 400 °C (752 °F).

Tempering the casing at the higher MTR reported temperature could have helped avoid the casing from behaving in such a brittle fashion. However, API 5CT does not have a minimum tempering temperature requirement for P110 casing steel material which allows the manufacturer to temper the material at a temperature that can yield low toughness properties.

Metallographic and SEM analysis performed on cross-sections of ERW through-thickness samples revealed that the material contained excessive mid-wall centerline segregation.

Excessive centerline segregation may lead to poor fusion line (FL) toughness, lack of fusion, FL embrittlement due to metallurgical effects and/or a detrimental increase in FL hydrogen embrittlement and/or SSC susceptibility when exposed to producing or non-producing environments.

A combination of factors could have lead to the failure of this pipe however, poor manufacturing practices and QA/QC issues were the main drivers for this failure to occur.
Failure Mitigation Best Practices

• Casing Design Enhancement
• Inventory Sourcing
• Controlled Yield P110 (C110 and/or T95 if necessary)
• Proprietary Connections
• Rig/Drilling Best Practices
• Quality Assurance
Design Enhancement

4-1/2 11.6 P110 LTC

4-1/2 13.5 P110 MTC
Quality Assurance

- Mill selection
- Mill quality plan
- Mill process qualification
- Material specification
- Material test report review
- Mill monitoring (includes threading)
- Post mill inspection (if not done at mill)
- Accessory coordination
- Transportation
- Traceability

Pipe Purchasing Process
Summary on Minimizing the Risk of Casing Failures in Multi-Frac Horizontal Shale Wells

Mitigating risk and potential failures with OCTG’s and threaded connections starts with: Procurement and ends with Final Wellbore Installation:

- **Encouraging Success**
  - Robust casing design
  - Qualified material
  - Proprietary (low stress) connections
  - Stable hole conditions
  - Good primary cement job
  - Smooth curve
  - Solid rig practices (handling, make-up)
  - Fully implemented QA

- **Encouraging Failure**
  - Aggressive (marginal) design
  - Marginal (or worse) material
  - API (high stress) connections
  - Sub-par hole conditions (unstable, DLS)
  - Poor rig practices (handling, make-up)
  - Minimal QA