subsea 7

Material selection for Subsea pipelines (Primary Corrosion Issues)

22 August 2012

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Agenda

- Material Properties
- Pipeline Operating Conditions
- Types of Corrosion assessed
- Material choices for subsea pipelines

Material Selection

What is Material Selection?

Material Selection

Material selection is the process and procedures used in choosing the material that can be produced, formed, heat treated, welded and used successfully for its design life, within time and cost constraints.

Material Properties

- Primarily, the selection of material for Pipeline application is a choice between the following:
- Carbon and Low alloy steel
- Corrosion resistant materials
  - Non-metallic materials – typically plastics
  - Martensitic stainless steels – typically 13% Cr
  - Austenitic stainless steels – typically 316L, 904L & 6Mo austenitic stainless steels
  - Duplex stainless steels – typically 22%Cr and 25%Cr duplex stainless steels
  - Austenitic nickel alloys - typically alloy 825 and 625

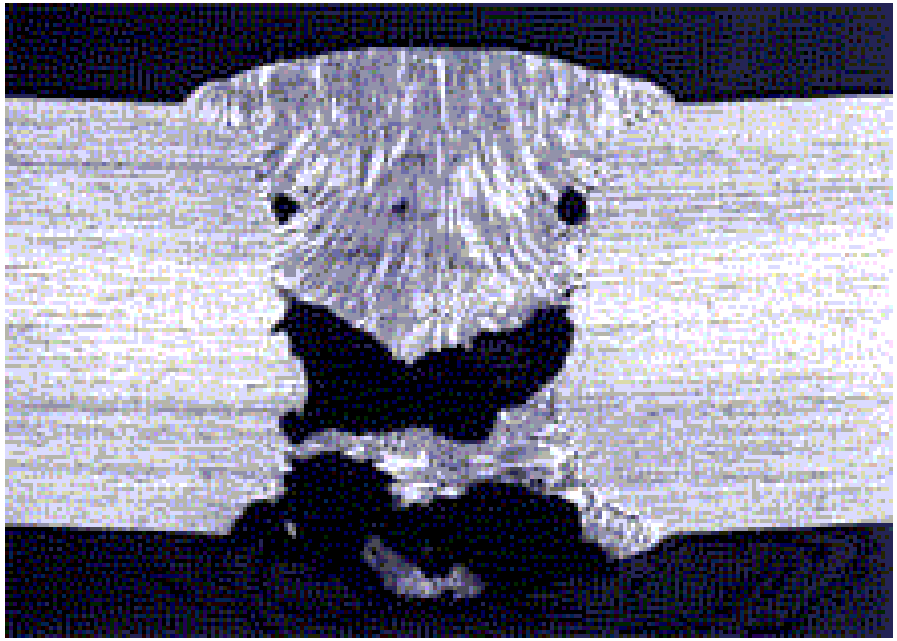
Material Properties

- Guidance is given in the following public domain documents for the selection of carbon steel or CRA materials
  - EEMUA 194 Materials Selection Guidelines
  - Norsok M-001 Materials Selection
  - Materials Selection for Oil and Gas industry (Nickel Institute)
  - NACE Technical Report 1F192
  - NACE MR 0175/ISO 15156-Parts 1-3
  - NACE & EFC reports and conference papers

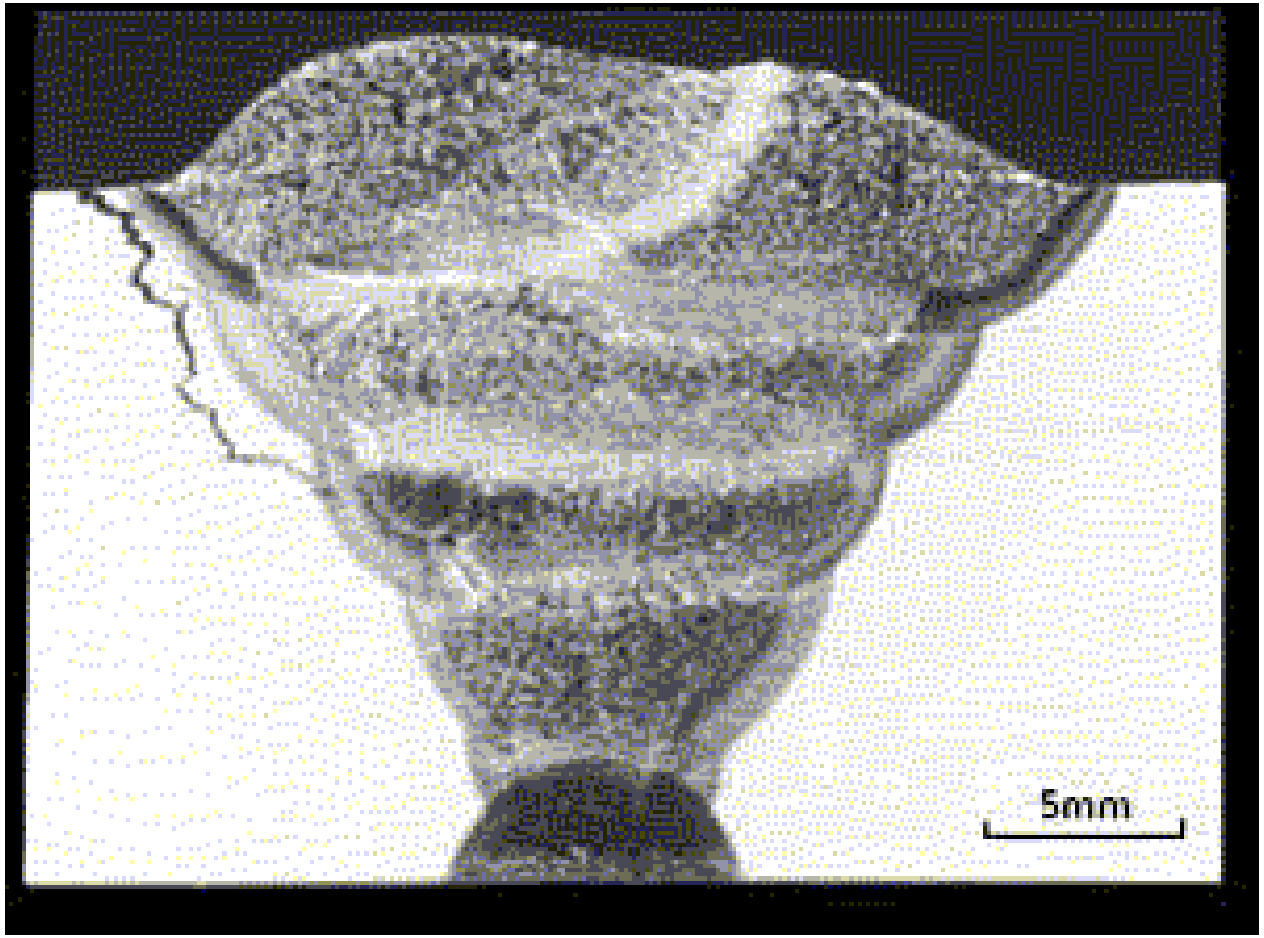
Material Properties

- Mechanical Properties (API 5L, ISO 3183 and DNV-OS-F101
  - Tensile Strength – UTS & YS
  - Fracture Resistance – Charpy & CTOD
  - Ductility - % Elongation, %Area reduction
  - Weldability – CEV & PCM
  - Other Project Specific - Plastic Strains, ?
- Corrosion Resistance – General and Localised
  - Sweet Corrosion
  - Sour Corrosion
  - SSC/SCC
  - Pitting Corrosion

Pitting Corrosion



Sulphide Stress Corrosion Cracking



Pipeline Operating Conditions – Internal Corrosion

- The Pipeline Operating conditions are the principal factors that influences corrosion in pipeline, they include:

a. Pipeline Operating Pressure

b. Pipeline Operating Temperature

c. Composition of internal pipeline content
   - Dissolved Gases in water
     i. Carbon dioxide content (sweet)
     ii. Hydrogen Sulphide Content (sour)
     iii. Oxygen content
   - Chloride content
   - Organic acids, pH.

d. Velocity, flow regime and sand production.

e. Biological activity.

f. Condensing conditions.

Corrosion and Pipeline Material selection

- The following type of corrosion are to be accessed as part of pipeline material selection
  - CO_2 (SWEET) CORROSION
  - OXYGEN CORROSION
  - MICROBIAL INFLUENCED CORROSION (MIC)
  - EROSION CORROSION
  - H_2S (SOUR) CORROSION - HYDROGEN INDUCED FAILURE
- CO_2 corrosion (Sweet)
  i. This is the primary corrosion mechanism in oil and gas pipelines
  ii. Applies to Carbon Steels & Low Alloy Steels
  iii. Its evaluation results in the determination of corrosion allowance to be accounted for over the life of the pipeline.
  iv. Various models exist for evaluating CO2 corrosion

CO_2 PREDICTING MODELS-De Waard Milliams

$$\frac{1}{V_{corr}} = \frac{1}{V_r} + \frac{1}{V_{m(H2CO3)}}$$

$$LogV_r = 6.23 - \frac{1119}{T} + 0.0013t + 0.41Log(fCO_2) - 0.34pH_{act}$$

$$V_{m(H2CO3)} = \frac{2.45 * fCO_2 * U^{0.8}}{d^{0.2}}$$

V_{corr} = the corrosion rate (mm/yr),
T = temperature in degree Kelvin,
t = temperature in degree Celsius,
pH_{act}= the actual system pH,
a = the fugacity coefficient,
pCO_2 = the partial pressure of CO_2 (bar)
U = the fluid flow velocity (m/s),
d = the Hydraulic diameter (m),
$FCO_2 = a * pCO_2$

Other CO_2 PREDICTING MODELS

- Shell – HydroCor
- BP – Cassandra
- TOTAL – Corplus
- Intetech – ECE (Electronic Corrosion Engineer)
- Norsok - M 506
- Honeywell – PREDICT
- IFE – KSC
- OLI - SCORE
- Scandpower - OLGA

Corrosion and Pipeline Material selection

- Oxygen Corrosion
  - Primarily occurs in water injection pipelines
  - Models developed by Oldfield and Salama are primarily used to evaluate this type of corrosion

- MIC
  - Many different types of bacteria both aerobic and anaerobic
  - Anaerobic bacteria generally give greatest problem in oil & gas production
  - Most failures are due to sulphate reducing bacteria (SRB)
  - SRB reduce sulphates to sulphides, producing H_2S which can lead to sulphide stress cracking & reservoir souring
  - Can result in high localised corrosion rates
  - Often introduced via poor injection water quality control

Oxygen Corrosion Models

Oldfield Model

$$CR = \frac{0.0565 \times V \times C_0}{\mathrm{Re}^{0.125} \times \mathrm{Pr}^{0.750}}$$

CR = Corrosion Rate (mm/yr),
V = Flow Velocity, cm/s,
C_0 = Oxygen Concentration, ppb.
Re = Reynolds number
Pr = Prandlt number

Salama Models

$$CR = 0.002 \times c_0 \times C^{0.9} \times \ell^{0.02T}$$

Accounts for zero chlorine

$$CR = 0.004 \times c_0 \times C^{0.9} \times \ell^{0.02T}$$

Accounts for up to 0.5ppm Cl

CR = the corrosion rate in mil (0.001 inch) per year (mpy)
C_0 = the oxygen concentration (ppb),
T = temperature in °C and
C = erosion factor

MIC Corrosion Models

$$CR = C * F^{p}$$

Where C = 2mm/yr

F = $f_1 * f_2 * \ldots\ldots f_n$

P = power law index (0.57)

	Factor when true	Factor when false
pH between 5 and 9.5?	1	0.001
Total Dissolved Solids (TDS) <60 g/l?	1	0.2
If TDS>60 g/l, do SRB grow?	0.2	0.0001
Temperature (T) between 10 and 45 °C?	1	0.2
If T>45 °C, do SRB grow?	1	0.2
Sulfate > 10 mg/l?	1	0.2
Total Carbon (C) from fatty acids >20 mg/l?	1	0.2
Nitrogen (as utilizable N) > 5 mg/l?	1	0.2
C:N ratio <10?	1	0.4
Flow velocity < 1 m/s Flow velocity = 2 m/s Flow velocity = 2.5 m/s Flow velocity = 3 m/s	~1 ~0.6 ~0.1 ~0.01	
Debris on bottom of pipeline	2	1
Pigging frequency never Pigging frequency 13 wks Pigging frequency 4 wks Pigging frequency 1 wk	~1 ~0.3 ~0.001 ~0.0001	
Prolonged oxygen ingress > 50 ppb	5	1
Biocide routinely used?	0.2	1
Operational history: • age pipeline < 0.5 yr • age pipeline > 0.5 yr & downtime =1 wk • age pipeline > 0.5 yr & downtime = 50 wks	 1 ~1 2	

Erosion Corrosion

- Flow regime, Fluid velocity and Sand production rate are key parameters for evaluation erosion corrosion.
- Evaluate critical velocity limit for erosion in a pipeline by making use of the API RP 14E guideline
- If the critical velocity is greater than the liquid flow velocity, erosion is considered to be of no concern to the pipeline otherwise erosion can occur
- If critical velocity is lower than the flow velocity, erosion rate should be estimated using either the Salama or API model, Tulsa Model.

Erosion Corrosion

$$V_e = \frac{C}{\rho_m^{0.5}}$$

V_e = the fluid erosional velocity in m/s,
ρ_m = the mixed fluid density in kg/m^3 and
C = is an empirical constant relating to service and pipe material

$$E = \frac{0.182 * W * V^2 * D}{d^2 * \rho_m}$$ (Salama)

$$E = 5.33 * \frac{MV^2}{d^2}$$ (API)

E = the erosion rate in mm/yr,
W = the sand flow rate in kg/day,
V = the mixture velocity in m/s,
D = the sand size in microns,
d = the pipe internal diameter in mm,
M = the solid production rate in g/s and
ρ_m = the fluid mixture density in kg/m^3

Corrosion and Pipeline Material selection

- Once CO_2, Oxygen, MIC and Erosion corrosion have been taken into account based on the design life, we can estimate the total corrosion of Carbon steel
  - If this is less than typically 6mm to 8mm, carbon steel is considered practical
  - If greater, the pipeline will potentially require corrosion resistant alloys (CRA)
- The choice of CRA material will depend on its ability to survive localised corrosion in given environments notably chlorides and H_2S and the maximum temperature.

Material Corrosion – Sour Service.

- The presence of H_2S with partial pressure approximately 0.3KPa (3mbar) or higher is classes as sour
- Carbon steel or CRA materials can be used following the guidelines of NACE MRO 175/ISO 15156
- NACE MRO 175/ISO 15156
  - Provides a basis for determining if a risk exists
  - Lists materials suitable for sour service under specified conditions
  - Recommends limits on chemistry and hardness (248HV) for avoidance
  - Indicates suitable tests to assess and qualify materials

Material considerations – Carbon steel

- Low cost
- Readily available
- Simple to fabricate
- Significant experience
- Can be controlled to give specific resistance to corrosion e.g. NACE recommendations
- Can be protected by inhibitors
- Can be protected by coatings and CP

Material Considerations – CRA, 13% Cr

- Cheaper CRA with resistance to CO_2 corrosion
- May be cheaper than C-steel with inhibitor
- High strength (X80) therefore lower thickness
- Cannot tolerate higher H_2S
- Sensitive to chloride content- needs high quality coatings
- Susceptible to hydrogen cracking
- Requires post weld heat treatment

Material Considerations – Duplex stainless steel

- Higher resistance to H2S, CO2 and Chlorides
- Expensive (Typically 10 x C-steel)
- Special precautions for fabrication
- Ultrasonic testing of welds complicated
- Failures have occurred due to poor metallurgical control, over protection from CP systems (DNV-RP-112 gives guidance on this)

Material Considerations – Nickel alloys

- High corrosion resistance
- Expensive due to nickel content
  - 825 has 38% minimum Ni
  - 625 has 58% minimum Ni
- Special precautions for fabrication
- Ultrasonic testing of welds complicated
- Can pit in concentrated chlorides- issue for seawater contact during installation and commissioning

Material Consideration – Clad options

- Mechanically Lined Pipes
- Metallurgical clad

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