HPHT & HT Geothermal Wells - Metallurgy Selection & Qualification Process Redefined!

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Preface

Deeper, hotter, and high pressure combined with high H_2S, CO_2 & Cl^- - such environment presents substantial well design and planning challenges. Most important is the risk of loss of integrity as presented by, high energy with multiple threats, to the immediate barrier. Failure consequences are catastrophic hence the driver for a bullet proof well material. Is it easy to select and qualify one? If yes, then why are metallurgy failures a common occurrence in the Oil and Gas and Geothermal Industries?

API TR-1 PER 15K-1, Annex B table B.1 tabulates field failures of production and completion materials from 1975 to present. The list may not be exhaustive but is an indicator of severe consequences of integrity failure as a result of improper material selection and/or qualification.

Context

While negotiating high pressure, high temperature (HPHT) well planning and execution, it can be said that the metallurgy selection and qualification process is perhaps the most challenging and complex of these and has several potential grey areas. The selection and qualification process itself is probably not adequately structured and there is no appropriate industry software available to guide the end users (i.e. operators or well owners). Furthermore, there is only discrete guidance available in the API, ISO, NACE, NORSOK standards or for that matter industry best practices guidelines like 'Guidelines for HPHT wells' by Oil and Gas UK, 'HPHT Well Planning IP 17 vol. 1-3' published by the Energy Institute.

This means it is up to the operators to develop the comprehensive framework requirements to cover this subject for HPHT wells. While Industry majors may have the in-house expertise to develop standards or guidelines, including qualification requirements for Corrosion Resistant Alloys (CRA's) and/or Sour Service Low Alloy Carbon Steel (LACS), this may not be the case with the mid-size to small operators and even large operators may struggle without the right personnel. Furthermore, relying solely on the OCTG supplier could potentially invoke conflict of interest and masking of risks driven by sales.

Although this topic is vast and complex, an attempt is made to provide an overview on HPHT wells metallurgy selection and to mitigate corrosion and cracking risks with a caveat that the devil lies in the details. To add more to the background, during WellPerform's recent assignments of HPHT well planning in the North Sea and South Asia, a number of potential gaps have been revealed with respect to metallurgy strength and material qualification, where the data is either not available or lacks proper attention to detail. Some of these potential grey areas are listed below:

- Anisotropy of cold worked CRA materials, refer to SPE paper 188276-MS where these aspects are highlighted to some detail.
- Stress Strain Curves (SSC) response of high strength tubulars at elevated temperatures which differ relative to ambient temperatures (Sharp-kneed vs rounded-kneed SSC) – Refer to SPE paper 199570-MS.
- Strain hardening i.e. deterioration of material properties under sustained high temperature exposure.
- Brittle behavior and fracture toughness of CRA materials in sour-corrosive environment, both short term and long term.

Based on the above a structured building block approach or a stepwise process to material selection and qualification is proposed. The process diagram below shows a structured approach for assessment of issues that should be evaluated and brought forward for further investigation, risk assessment and mitigation following principle of ALARP.

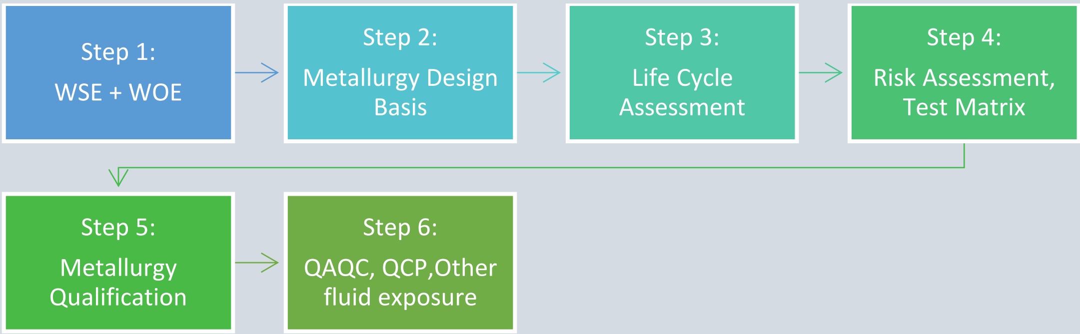

Figure 1: Metallurgy Selection Process

Step 1

Define the well service environment (WSE) and well operating envelope (WOE). This forms the basis of metallurgy selection. One should also assess the variability of key influencing parameters both at the early and late life of the well. This also means that the expected well life and production profile should be defined.

NACE MR0175 and/or ISO 151516 should be referred to chart out key parameters required to define the basis of material selection. In order to have a robust basis the key parameters that define the well service environment, should be established either from the in-situ sampling and measurements from the context well or from offset wells/analogues. Other parameters that could not be sampled downhole should be either software derivative or correlation based.

In addition to well service environment it is also required to define the well operating envelope. What we mean here is the pressure and temperature envelope the well will see during its lifespan both downhole (at reservoir) and at surface. At surface or wellhead, pressures, and temperatures for both shut in and flowing conditions should be known. The below diagram illustrates example of well service environment and well operating envelope parameters.

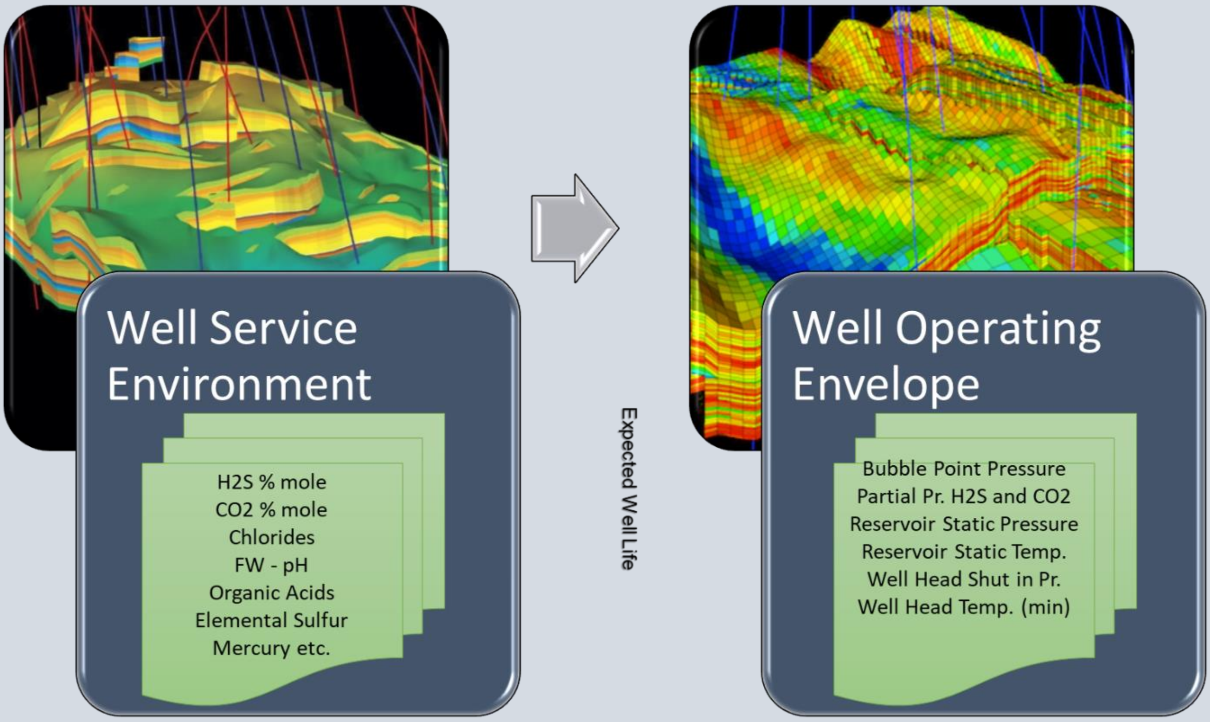

Figure 2: Well Service Environment and Operating Envelope

Step 2

Based on the chosen well architecture, flow-wet and non-flow-wet components should be defined. Efforts should be made to optimize the design and make it fit-for-purpose for the intended service environment. Flow-wet components are continuously exposed to the well fluids and form part of primary barrier like production tubing and liner strings below production packer.

These components are presented with risks of corrosion and cracking due to continuous contact with well fluid. Hence, a comprehensive approach is required for the assessment of all corrosion and cracking risks, mitigation, life cycle cost assessment (Refer to ISO 15663) and a risk-based ALARP approach (Refer to ISO 17776) must be mapped out.

Typically, non-flow wet sections are the production casing and liner above the production packer also classified as secondary barrier. LACS or sour service LACS casing/liner can be deployed as a barrier in this section because of no continuous risk exposure to the downhole environment. Hydrocarbon exposure, if any, could be short term and may have minimum corrosion impact due to packer fluid inhibitors and scavengers. Nevertheless, for secondary barriers, application of a sour exposure cracking risk assessment and mitigation is recommended.

Step 3

The intent should be to perform a life cycle cost analysis (LCCA). Typically, material selection by life cycle cost analysis involves developing a list of materials that are available from manufacturers suppliers that will deliver acceptable performance, from corrosion and cracking resistance perspective, in a given well environment. Further, the material should have a strength envelope that meets with the well design load requirements. The next step includes selection of the most cost-effective alternative based upon estimates of life cycle cost. The life cycle cost estimates include consideration of risks by the project team or the organization.

As the field development progresses and additional well environment data becomes available, it is recommended to revisit and refine the selection criteria based on the new information available. Furthermore, it is imperative to note that no matter how complex the material selection process, a lack of thorough understanding of the well service conditions and corresponding performance of the alloy and qualification gaps can result in failures during the intended service life. Therefore, the following should be applied as a minimum:

- Continue to use conservative approach and
- Follow qualification by fit-for-purpose testing when the anticipated service conditions either approach or exceed the current knowledge base.

Step 4

It is important to map out various risks both for flow-wet and non-flow wet sections when exposed to sour-corrosive environments. It is equally important to define risks types (both corrosion and cracking), the risk basis, and the worst-case scenario occurrence.

Typically, main types of corrosion risk are: Mass loss, Pitting corrosion, Crevice corrosion, Galvanic corrosion, amongst others. The cracking risks are Sulfide Stress Cracking (SSC) and Stress Corrosion Cracking (SCC) meaning that above a threshold combination of material, mechanical stress, and environment severity, a crack may initiate and grow in the pipe wall.

Furthermore, sour-corrosive environments can reduce the material toughness significantly and the risk is crack propagation to fracture of a pre-existing crack.

The below diagram illustrates well conditions with possible worst-case scenario occurrence for the SSC and SCC. Issues like fugacity corrections, supercritical state of CO_2 and H_2S etc. can be dealt with on a case by case basis.

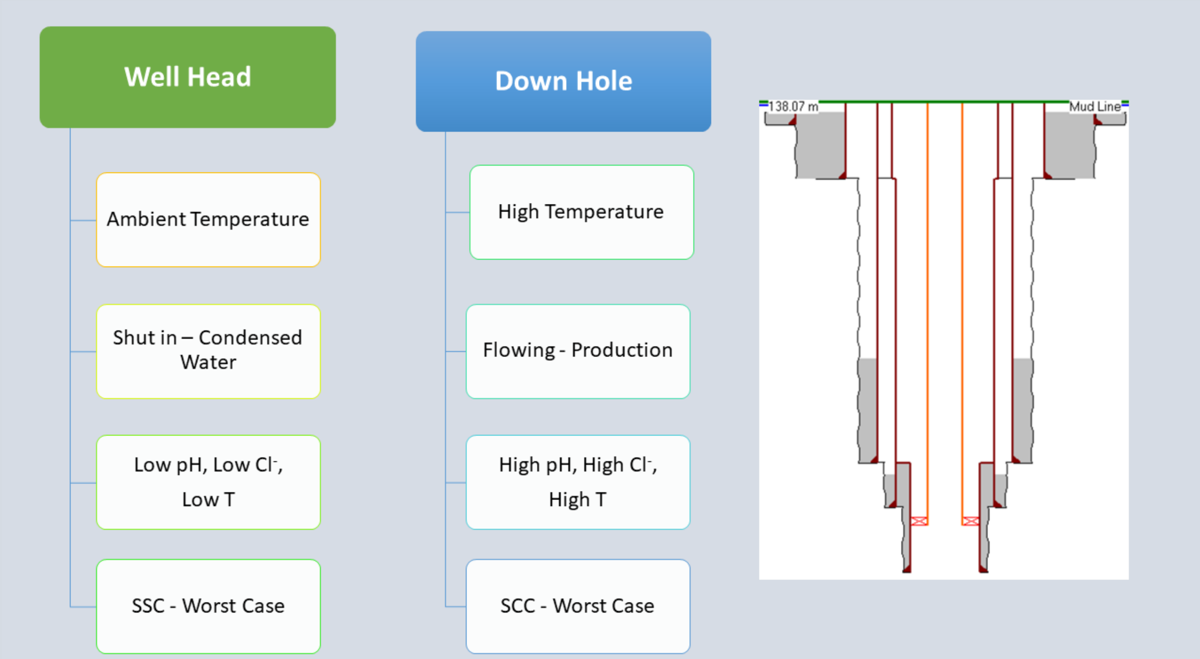

Figure 3: Worst Case illustration of SSC and SCC

Step 5

This step includes understanding of the primary failure mechanism of the selected CRA material. Table B.1 of ISO 15156 part 3, lists potential primary and secondary cracking mechanisms that should be considered for CRA and other alloy groups. This is useful guidance on the potential for corrosion to cause cracking of the CRAs. However, careful review is required as the failure possibilities for sequential exposure or a combined environment failure are possibly not covered.

Thereafter, choose appropriate test method(s), test parameters incl. no. of test specimens, test environment and duration with a clearly defined acceptance criterion. Qualification claims from the supplier including domain maps, details of the testing carried out to arrive at the domain limits, gaps identification i.e. including the way the tests were carried out, requires careful review to ascertain efficacy and context relevancy.

Uniaxial tensile (UT) tests, four-point bend (FPB) tests and C-ring (CR) tests may be performed with the loading arrangements like constant load, sustained load (proof-ring) or constant total strain (constant displacement) loading of smooth test specimens. These test details are covered by NACE TM 0177 and NACE TM 0198.

If the primary failure mechanism is SSC, typically the suitability of OCTG material could perhaps be verified by NACE method A and DCB test i.e. Method D. This would potentially cover the following two failure manifestations: 'crack initiation' and 'crack propagation'. The acceptance criteria for some of the materials is covered in API 5CT. A good discussion should happen for the DCB test acceptance criteria for the group 1 to group 4 CRA materials (Refer to API 5CRA). The DCB test for the CRA's, may be used if cracks are unaffected by the branching and remain in the required plane. NACE-D assesses the propagation of crack from a typically acceptable defect existing on the pipe surface. The test provides a critical stress intensity factor (K_{1SSC}), which represents the resistance of material to crack propagation.

Test specimens should be selected to suit the product being tested and the required direction of the applied stress. A minimum of three specimens should be taken from each component tested. The pH at any point during the test period should not exceed the minimum design basis pH. One should be aware that oxygen contamination of the service environment can influence the cracking resistance of an alloy and should be considered when choosing the test environment.

Three test environments are described in ISO 15156 part 3. If the intent is to replicate well conditions, then type 1 environment is more suitable with partial pressures of H_2S and CO_2 and the test pH equal to the intended service. Upon successful qualification the material can be used for environments equal to or less severe than test environment. As an example, lower partial pressures of H_2S and CO_2, low chlorides, higher pH would categories an environment as less severe.

Step 6

While prequalification of a material for the intended well service environment is an important step for the material selection, it is also recommended to focus on test qualification, QAQC aspects and thereafter quality control plan for the production. The other important aspects to consider are the nature of the annulus, workovers, stimulation fluids that should be considered and to ensure that cracking or unacceptable corrosion are not caused by these fluids. The fluids designed for use as workover-, packer-, and proposed acid stimulation fluids, plus any stable chemical additives, should be pre-qualified by suitable testing.

Conclusions and closing remarks

At WellPerform, we believe the above holistic approach is required to properly address this complex topic of metallurgy selection for HPHT wells. The proposed approach is also valid for geothermal wells, both normal and high temperature albeit often the corrosion and cracking challenges from a geothermal environment are not as severe and complex due to reasons like pressure driven well loads not being as high.

In addition, we also believe that optimized well design to minimize flow-wet sections and thorough understanding of well loads etc., is important to select proper material weight/grade, carry out appropriate risk assessment and to determine fit-for-purpose qualification requirements. This rigorous approach should not be limited to pre-qualification but should be equally carried through and implemented for the OCTG production stage and for accessories qualification.

The above proposed approach was successfully followed by WellPerform on recent HPHT well projects deliveries for operators in Europe and South Asia. The context is complex, and the building blocks help add robustness to the well architecture and extend the well service life while helping to unlock the hydrocarbons for sustained long term production.

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