Predicting pipeline corrosion

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Correlating CO_2 mechanisms with flow regimes can help operators predict corrosion in deepwater pipelines.

With the rapid growth of the deepwater pipeline infrastructure in the Gulf of Mexico, it is important to acknowledge, identify, and develop the critical relationships between corrosion prediction and flow assurance mechanisms. Equally important is the ability to identify locations where maximum corrosion can be expected to occur, and to gain an improved understanding of the process, mitigation, monitoring and corrosion control campaigns over the pipeline's full life cycle.

To accomplish these objectives, case histories have been studied, as well as the correlation of the interaction between CO_2 corrosion mechanisms and flow regimes from numerous management campaigns. Actual relationships are complex, and for practical reasons, it has been determined through research that a new approach utilizing risk-based decision-making procedures applying "what if" corrosion analyses linked to "what if" flow assurance analyses on a risk-based platform is the best way to move forward. Using this methodology, combined with the exchange of pertinent field data,
significant improvements can be made in predicting corrosion in deepwater pipelines. It further provides the basis for more defendable arguments for design justification.

The goal here is to illustrate how comparing base-case corrosion modeling data, such as that generated from available freeware Cassandra and Norsok M506 software, to parallel flow assurance modeling in a targeted manner can generate noteworthy results and unexpected trends in corrosion control. Initially, the work was started as an internal program, but results have progressed to the point it will be used as a company-wide go-by approach for streamlining corrosion and integrity management for deepwater pipelines.

The method makes the assumption that the normally associated disagreement between corrosion modeling and field experience is more likely due to inadequate consideration of c orrosion stimulating flow regime data than corrosion modeling limitations. This moves the onus for predicting corrosion accuracy and reliability away from corrosion modeling to the flow regime modeling side.

Normally, this is heavily dependent on the soundness of the original design, since life cycle rehabilitation, repair, and even basic maintenance issues are costly. This brings into play the Inherently Safe(r) Design (ISD) concept and its importance within the rigorous auspices of the involved risk and consequences. Critical design decisions take into account failure effects on the asset, personnel safety, and the environment, and are maintained as low "as reasonably practical (ALARP condition)." With these drivers in place, there is a strong likelihood of merging and reconciling CAPEX and OPEX so resources and costs are effectively shared for mutual benefit.

If the design basis determines that internal fluids are too corrosive, intervention solutions can be contemplated, including internal coatings or internal corrosion-resistant alloy (CRA) lining or cladding. In this eventuality, costs can appear to be prohibitive, commonly up to and greater than 10 times the equivalent cost of steel. Nevertheless for deepwater assets, introducing CRA liners or cladding can prove to be an acceptable solution, especially for shorter pipelines (<5-10 km length). In such cases, nickel-based alloys can be selected to substantially reduce cost burdens. The benefit of reduced corrosion issues – less enforced inspection, greater confidence in operability, minimized downtime periods – creates a significantly reduced failure risk.

Carbon steel is by far the first choice material to be used with inhibitors, but this has more challenging requirements, such as the need to better understand, accuracy, and reliability of the corrosion performance. The main obstacles often are related to corrosion allowance (CA), which is the designer's tool that provides contingency for corrosion control as a safety margin to cover for corrosion wall thinning during the design life. Usually, this is in the 1-8 mm range, (with 10 mm max). The few extra mil-

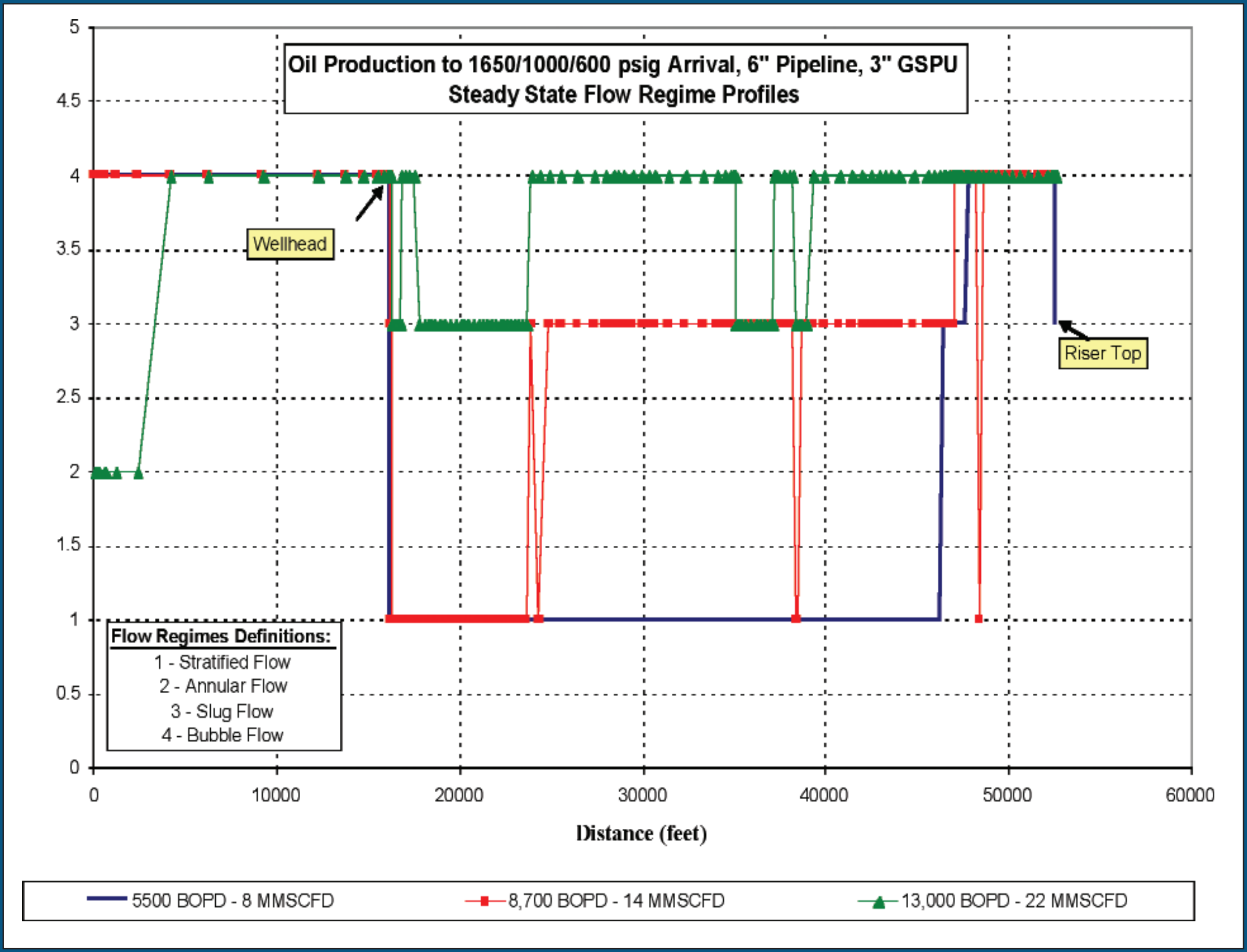

Figure 1. Example oil line relationships between predicted flow regimes and flowline length using the OLGA model.

limeters utilized for this purpose can be significant for long flowlines, especially when corrosion engineers are under pressure from project managers to keep CAPEX costs down.

Technical arguments and history, or experience-based data, is vital to help justify the additional steel thickness. Clearly, this is best accomplished by an improved understanding of uniform corrosion per modeling, erosion, microbial activity (MIC), deadleg corrosion and, flow-assisted corrosion (FAC). In practice, FAC is the least attended to concern largely because it encompasses difficult to address multiple mechanisms, including uniform corrosion, erosion, impingement, high shear, inhibitor persistency, and biofilm formation/slip/retention.

Flow assurance

Flow assurance covers all multiphase transportati5on phenomena. Diligent design methods, knowledge and skills are required to ensure safe continuity of fluids transported from reservoir to topside processing plant. The main areas involve steady state and transient multiphase flow, hydrates, sand, oil, emulsions, wax, scale and corrosion phenomena.

Multiphase fluids transportation cannot be exploited in a safe, controlled approach unless the dynamic flow behavior can be predicted with sufficient reliability. This is crucial to the concept phase feasibility studies, optimal design and safe operations. The interaction between corrosion/scaling, boundary layer theory and flow assurance can be instrumental in determining true production rates. Software tools, such as the OLGA codes, can provide reliable predictive assistance (Figure 1).

Providing an accurate and reliable link between flow assurance modeling and corrosion modeling is one of the main challenges facing the industry today. In present day oil and gas climate, such understandings are emphasized as best integrity management (IM) behavior and flow assurance (production), and both are inextricably linked to revenues. As a result, corrosion engineers can use this natural alliance to ensure that best chemical injection practices are obtained for important corrosion mechanisms such as bottom of line (BOL) and top of line (TOL) (Figure 1).

Challenges

Internal corrosion is the major threat to flowline assets, rather than external corrosion, which is effectively addressed by code compliance to coating and cathodic protection (CP) standards. The statistics vary, but overall it has been determined that internal corrosion causes around 15% of onshore and more than 50% of offshore pipeline failures. With the criticality of deepwater pipelines in the Gulf of Mexico (GOM), it is not surprising that substantial attention is focused on offshore design challenges.

However, there are no commonly accepted "codes of practice" for internal corrosion, so the only recourse has been to utilize the best available corrosion models. In this regard, CO_2 corrosion mechanisms are dominant, and the models have been based on the original work of De-Waard and Milliams, and more recently various joint industry projects held at academic institutions.

In practice, even the "best" models rarely match real time, acceleration, or field results. This can be attributed to the failure in modeling reliability, inappropriate assumptions and inaccurate data inputs, leading most often to conservative, and skewed performance data from secondary parameters, such as biofilming, MIC, crevicing, sanding, and others. One way to address this mismatch is to assume greater safety margin levels by considering worst-case conditions applied to the design life. However, this can lead to a conservative approach with costly reliance on CRAs.

Another important variable impacting life cycle performance is the pipe length, since flow regime development is time dependent and length dependent. This dependency influences corrosion activity through the creation of water drop out (wetted) zones. The result is a loss of inhibitor filming, because the increased surface area impacts the driving forces for slow, fast and spontaneous localized corrosion or passivity. In this regard, inhibition may require multiple dosing and monitoring points, to help quantify true efficacy and reliability of life cycle corrosion management programs.

Other comparative work by NACE is underway regarding Internal Corrosion Direct Assessment (ICDA). Again, steel onshore pipelines are the driving force for this work.

Recommendations for deepwater subsea pipelines remain highly dependent on early predictive design and minimal inspection criteria with emphasis on CA values. Risk-based methods are constantly under review to help quantify critical physical parameters and corrosion mechanisms for specific design and operating conditions. These include high water cut developments, excursionary bursts of MIC/biofilming, transported corrosion products and their re-deposition through turbulent flow phenomena, and transient episodes of sanding. The impact of such upset or nonsteady phenomena can make software-driven data management programs redundant in many cases because the predictive trending can become less reliable. Flow-related mechanisms must therefore be interpreted on a case-by-case basis.

Corrosion allowance development

Determining optimum CA value can be subjective, but case studies have made it possible to develop acceptable and realistic methodology. To allow a defensible CA evaluation, it is best to list the main assumptions to avoid later confusion. The key enabling assumptions are listed below:

- Accept the premise the objective is to differentiate whether to use steel or CRA rather than absolute corrosion rate values.
- Identify dominant corrosive species, field CO_2, with defined or understood water content. It is considered that most competitive "proven" inhibitors can attend to single mechanism corrosion at most concentrations. Problems occur with mixed mechanisms and multi-component chemicals (often called cocktailing).
- Review, verify, prioritize or assume the dominant flow regime, such as single or multiphase flows, stratified, slug, and annular flows projected through the life cycle. This requires reviewing steady state and excursionary or transient flow situations.
- Validate the H_2S souring propensity or lack of it, as this greatly impacts cracking and corrosion behavior. Generally, less influenced by flow regimes unless otherwise advised.
- Corroborate dissolved chloride and oxygen levels, and presence of aggressive organic species such as acetic/formic acids and their derivatives.
- Assume the base corrosion is uniform, but validated by real-time inspection and monitoring, and through analysis of coupons/probes and residues. Expect to witness localized corrosion when unsteady conditions occur.
- Confirm threat and likelihood of biofilm formation assuming growth

pattern will follow laminar or fluid stagnation sites, identify microbial species and MIC over the life cycle.

- Corroborate extent of sand production (steady and episodic), and the impact on materials degradation (applies to steel and CRAs), sand concentration, and particulate sizes.
- Establish extent of pigging, even for CRAs that are subject to scaling, if not indigenous corrosion, and inhibitor application that is viable to creating sustainable inhibitor films and repair such films even at high flow rates under sanding and erosion conditions.
- Corroborate persistency of residual inhibitor filming upon inhibitor dosing loss.

To estimate the most representative corrosion allowance, a baseline CO_2 dominated general corrosion rate can be used. The process works best with more than one model to determine uniform corrosion allowance (CA) and a total, or true CA predictions based on CA plus margins to allow for localized corrosion mechanisms. In the absence of corroborated relationships, these are considered additive, rather than synergistic. For example:

Total CA = Uniform CA + Erosion Allowance + Pitting Allowance + Crevicing Allowance + MIC Allowance + Stagnation Allowance (topographical) + Flow Induced Allowance (fluid shear link). However, multipliers may also be used if synergism effects are considered rate controlling; such decisions would be best done on a case-by-case basis.

Influencing key drivers

The complex array of reactions is competitive, since certain species promote existing CO_2 corrosion while others promote passivation corrosion. These influencers have impact on all corrosion mechanisms, but have a particular stimulus for flow-assisted corrosion mechanisms. These are described below.

Accelerators influencing flow dynamics. Against bare steel, these include the increased flux of transported species such as CO_2, O_2, chlorides (break down passivity), and transported iron oxides.

Passivators influencing flow dynamics. These include surface condition smoothing, residual inhibition, oil wax filming, calcite precipitation, pH buffering bicarbonates, TDS (e.g. Langelier or equivalent).

Flow and temperature impact

Temperature and flow regime are closely linked since CO_2 corrosion is dynamic and sensitive to electro-chemical kinetics and physical imbalances. Generally, steady state (P,T,V) conditions tend to promote protective film compaction, passivation, and low corrosion rates.

Lower temperatures <120°F (~50°C) tend to promote patchy corrosion with softer multi-layered iron carbonate (siderite) scales, providing some barrier protection increasing up to ~140-160°F (60-70°C). Above these temperatures, damaging localized corrosion can be observed as films lose stability and spall off giving rise to galvanic “mesa” attack, even though there is evidence of a downturn in the plateau after ~ 80°C in certain cases.

These trends can be overriden by extreme flow regimes such as slug and annular gas flows. This can prove critical for vertical risers connecting the flowline to the offshore structure or topsides. The geometry can act like a “specification break” where the flow regime shifts due to increased effects of gravity as the flowline transforms from a horizontal to a vertical member (Figure 1). The sag bend at the touch down zone can become a high-risk corrosion component warranting greater corrosion control, typically a thicker section.

The leading edge of slug flows is associated with extreme shear stresses capable of destroying protective inhibitor films. In a similar manner, annular flow regimes can increase surface wall wetting even under lower water cut values, reducing oil phase wetting and undermining inhibitor contact to the wall.

It can be argued that for process steady states (constant P,T, V) steady uniform corrosion can be expected. However, unsteady states, transient states and excursions will promote localized corrosion by initiating pitting/crevice activity followed by growth of the same during future steady conditions. The impact of inhibitors can be crucial in retaining life cycle fitness for purpose.

Here, multiple corrosion and scaling mechanisms need to be addressed under many operating flow regimes: laminar, turbulent, stratified, annular, bubble, and slug. While accelerated non-standard tests can help, the real proof comes during field trials. The best way to quantify and control these parameters is to create risk-based key performance indicators. Significant progress has been made in this area.

Flowline corrosion

While most pipelines or flowlines are horizontal, sections can be subjected to elevation shifts and undulating effects, often to the degree that a major impact on corrosion can be introduced through increased wetting at low lying points. The upward sections also can be sensitive to water drop out as the gravity effects come into play. The challenge is to ascertain the extent of localized corrosion that could occur, and where. This is best addressed by track records, and best judgment supported by cross asset field data that can be realistically performed using the ALARP process. Individual localized corrosion threats can be examined and risk ratings can be used to rank up or down the corrosion allowance assessment. Typically, the ratings high, medium, or low risk (HR, MR, LR) may be assigned to reflect such predictions.

Wettability

Competition between oil and water wetting can be the deciding factor. Oil wetting is inhibitive, whereas water wetting is a root cause of corrosion. The two wetting phenomena have variable resistance to fluid shear, electrochemical, and surface tension properties. The onset of corrosion can be linked to the water cut anywhere in the range ~1-70%. There are no thresholds, but properties such as light/heavy, API gravity, contaminants, and corrosion product stickability are considered rate controlling. This is likely one of the main reasons why laboratory data do not correlate to field data. The former has precise definition while the latter is prone to considerable scatter. Field observations will always govern the decision process. For deepwater assets careful conservatism is vital and easier to justify. It can be argued that:

- For <2% water cut – low risk corrosion
- For 2-10% water cut – medium risk corrosion
- For >10-40 % water cut – high risk corrosion
- For >>40% water cut – very high risk corrosion.

These criteria are significantly impacted by actual flow regimes, though actual water cut is not always an input in corrosion modeling. In all cases, the most susceptible parts will be in the horizontal positions at six o'clock, close to girth welds, and in the vicinity of flow separation geometries such as tees and wyes. Vertical sections also are impacted with gravitational effects coming into play as flow regimes transition to different patterns.

Flow assurance review becomes an important consideration, and active corrosion will affect the surface roughness profile, fluid boundary layer patterns and extent of emulsification with high water fractions being tolerated if the water remains entrained. Examples of flow assurance have illustrated how baseline corrosion rates may be significantly impacted at critical junctures of the flowline routing. As previously indicated, the most difficult prediction is not so much whether localized corrosion will occur, but where.

Physical considerations

For steady state P,T,V conditions, corrosion mechanisms may be properly articulated. However, extreme conditions and fluctuations will have an associated burst of additional energy/velocity, heat flux, and temperature spiking that destroys surface passivating/protective films exposing bare steel to the aggressive CO_2 chemistry and galvanic accelerators, including partial remnants of siderite, magnetite, and sulfides. Resumption of pressures after such an episodic excursion will re-stabilize protective films, but it is important to have an overlap in the increased inhibitor dosage beyond the re-stabilized period.

Flow assisted corrosion

Flow assisted corrosion (FAC) is linked to the flow regime and is related to flow assurance. Since there are many "what if" scenarios, there are a vast number of variables, and it is important to recognize the two extreme boundary conditions, viz maximum flow and zero flow. Controlling such activity minimizes the damage risks. Key observations here include:

- FAC phenomena are often separated from erosion, impingement, and cavitation, and best addressed by the planned suite of in situ corrosion monitoring. This provides predictions and correction by "live"' corrosion data over life cycle.
- Flow regimes are expected to be turbulent, but it is known that dead leg or mini-stagnant zones can exist within the turbulent envelope, leading to accelerated corrosion stimulated by MIC.
- If the threat of localized erosion or significant stagnant pocket corrosion is determined to be high or severe, remedial options such as discrete internal coatings may be introduced as solution options. The impact on CA is medium to high risk.

Pre-corroded surfaces

Pre-corroded surfaces can provide high-risk corrosion initiation sites. The parameter is difficult to quantify, because it influences general and localized corrosion. However, its role in the corrosion process is sufficiently important and must receive attention. Essentially, the bare pre-roughened/pre-corroded steel surfaces will become more active compared to non-corroded surfaces. This may occur under various circumstances, typically:

- Poor storage conditions prior to installation.
- Improper hydrotest exposures (fluid retention).
- Inadequate protection during commissioning (inadequate or zero chemical inhibition).

Also it should be appreciated that pre-corrosion can act as a boundary layer modifier and an accelerator for flow assurance related scales. Scales well anchored in this way will invariably prove to be harder to remove. Pre-corrosion must therefore be treated as a critical variable, and suitable steps taken to minimize if not eliminate it. The impact on CA is low/medium risk depending on preservation levels.

Dead leg corrosion

Dead leg corrosion may be considered a special case or boundary condition of FAC, and is a major threat caused by stagnant fluid corrosion, as well as sludge build up and blockage issues. This is a complex area with multiple degrading corrosion mechanisms at work, often over temporary shut-in periods. There are many accepted actions that can be used once its existence is accepted. These include thicker sections, CRA lining of specific geometries, selective inhibition, etc.

Transported flow-related deposition

Flowline production profiles are subject to change. While the influence on flow regimes can be modeled, the situation is not so clear for the impact of such profiles on corrosion. The main interest here is to maximize productivity. In practice, the multi-phase fluids often influence hydraulic performance, but may or may not be influential regarding impending localized corrosion that is stimulated by well fluid residues such as waxes, hydrates, asphaltenes, and any added chemicals. The following express specific areas of concern:

- Wax and hydrates tend to be of most concern in mixed multiphase flows, and specifically tailored strategies are often developed to manage them.
- Evaluations are performed by flow assurance specialists, using fluid flow modeling techniques applied to hydrates, waxing and slugging phenomena individually. The link between flow assurance and corrosion often is not made in industry because reproducibility is poor.
- Presence of any deposition, whether it be wax, asphaltene hydrates or inorganic calcite scales thermodynamically, can kinetically lead to localized corrosion activity largely by the retention of chloride and or microbe laden waters within randomly patchy scales.

It should be noted that wax, scale or corrosion products can take weeks or months to manifest. However, hydrate formation, mainly in gas flowlines, can form quickly over short periods at points immediately downstream of pipe diameter changes. Additionally, scale and wax treatments are reasonably compatible to corrosion inhibitors. Traditional hydrate inhibitors, including methanol and glycol, can be compatible to corrosion inhibitors when cocktailed. In all cases, it is vital to demonstrate corrosion control is not jeopardized by suitably formulated tests and field trials. Flow-related deposition analysis will require a considerable amount of reliable water chemistry data during the operations phase and an accurate determination of real shear stress values at the wall.

The mixed nature of the deposits will decide that parameter and the corrosion product content could be critical. Using efficient pigging and chemical cocktailing used to address wax/hydrate scaling and corrosion are vital considerations to preserve production. In contrast, asphaltene deposition build up is more complex in its interaction with corrosion mechanisms since the patchy scales can encourage tight crevice corrosion.

It is important to understand that flow-dominated corrosion phenomena require more advanced corrosion monitoring techniques. For deep susceptible horizontal portions of flowlines, actual location of critical localized corrosion is not readily identifiable even with pre-determined high-risk areas. Sighting such corrosion activity is random in nature, depending on the ‘chance’ sites of preferred deposition, metallurgical discontinuities, physically sheltered zones, impingement areas, and biofilm attachment areas.

The best way to use advanced monitoring is through advanced mapping techniques, which provides an outstanding opportunity to evaluate real-time localized corrosion and erosion damage. The units are usually instrumented spool pieces permanently inserted into the flowline, providing an outstanding opportunity for accurate real-time monitoring. However, there appears to be some inconsistency in the results, and some caution is advised.

Integrated subsea systems

Since most new subsea projects in the GOM are in deep water, the limits of current technologies can be tested. To maintain high levels of productivity with this trend, the need for increased subsea system reliability adds new emphasis to the overall design and operational corrosion management philosophy. The emphasis on linking flow assurance and corrosion also impacts the reliability discipline such that assessing malfunction risks are identified to maintain production. To that effect the use of combined inspection data, corrosion monitoring results, and advanced mapping techniques is considered the best way to assure ongoing pipeline integrity management.

GOM operators now conduct involved reliability studies for subsea production systems. These must include all subsea facilities, including moving parts, with an in-depth analysis of all system components. The result of improper design or manufacturing can be a challenge, and the criticality of design, materials selection, and corrosion assessment for deepwater subsea assets means zero or minimal corrosion issues are required during the early years when maximum production revenues are needed to offset high CAPEX. As the life cycle proceeds, corrosion issues tend to be manageable as on-stream data are generated. The OPEX costs are also often minimized and offset by shorter anticipated field life.

Conclusion

Corrosion and its interactions with flow assurance phenomena is a complex discipline. Neither one dominates the other, though the balance of emphasis can change. Corrosion modeling often disagrees with field data. The discrepancy is often blamed on the inadequacy of the models. However, this work has concluded that the differences are better explained by the rationalization of the effects of flow regime on the base and localized corrosion rates. ■

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