Summary
Corrosion is responsible for plant shutdowns, lost production, HSE challenges and high repair costs. But, corrosion challenges can be solved with the right answers, insights and foresight.
The negative effects of corrosion and erosion cost the process-intense industries billions of dollars every year in unscheduled plant shutdowns, inefficient or lost production, high maintenance repair costs or imposed fines.

According to the WCO—The World Corrosion Organization—the estimated cost of corrosion to all the world’s economies is $2.2 trillion USD annually (source; NACE Europe Board—Corrodia, Fall 2010)

When looking at the oil and gas industry specifically, the total annual cost of corrosion in the oil and gas production industry is estimated to be $1.372 billion, broken down into $589 million in surface pipeline and facility costs, $463 million annually in downhole tubing expenses, and another $320 million in capital expenditures related to corrosion. (source; https://www.nace.org/Corrosion-Central/Industries/Oil---Gas-Production)

Imagine if 20% to 25% of corrosion-related costs could be avoided with the right information, insights and foresight. However, most organizations lack the broad expertise to effectively manage corrosion-related problems and there are no sets of standards that cover all eventualities.

Companies that adopt best practices for corrosion prevention and corrosion control benefit from:

- Decrease in downtime risk
- Avoiding environmental, safety and health hazards
- Saving costs due to reduction in unforeseen maintenance costs

Owners, operators, designers and manufacturers each have a role in understanding the end-to-end problem and damage mechanisms to be expected from corrosion.

Raising awareness and improving knowledge & competency is a key performance indicator in many modern asset integrity programs. On-demand access to relevant and trusted information and data helps build the foundational knowledge needed to understand corrosion-related challenges, and the know-how to solve them. Research and published literature are key to understanding the problems and the limitations of corrosion control management, and engineers must be proactive in seeking out the right forms of information and data to save costs, avoid operational hazards and limit downtime.

**General overview**

Corrosion occurs initially on the surface of a metal by means of an unintentional chemical or electrochemical reaction and continues to deteriorate the metal in many different forms; for example, general metal loss, pitting or crevice corrosion, and/or stress corrosion cracking. Some metals oxidize (corrode) more easily than others according to the galvanic series, which is a very important reference to have when making decisions for joining together different materials.

In addition, certain natural and environmental factors are unavoidable. For instance, certain chemical processes require the use of highly acidic feedstocks. Engineers may not be able to cap...
the concentrations of certain corrosive species, rather than need to find answers in design and materials compatibility. Some of the adverse effects include:

- High fluid velocities, which tend to sweep off these normally protective corrosion scales, thus exposing the underlying metal to the corrosive media and the corrosion continues
- Solid particles in the fluids have the same erosional effects on surface corrosion scales
- High concentrations of free hydrogen ions (low pH) speed the release of the electrons to accelerate the corrosion process
- High water temperatures increase virtually all chemical reaction rates

Fabrication & welding knowledge is also critical to ensure the equipment design and manufacture intent is met—quality control is almost never as good as it could be due to the ignorance or misunderstanding of the harmful effects that result when not confirming to approved welding procedures designed to maintain the material corrosion-resistant properties.

Finally, an understanding of the in-service effects over time, particularly changing conditions and management of change during alteration or repair, is paramount.

In processes where corrosion-related problems can result in a significant negative impact on operations, refer to mitigation tactics that can be employed, and an analysis of how a large databank of information is required to properly evaluate these complex problems to ensure the precautions being implemented are effective.

Engineers responsible for process design concepts, including compliance (e.g. codes & standards), therefore, need to reference the correct technical literature and knowledge resource to support the decision-making process. Knowing what the codes & standards are is just a starting point—best practice guidelines, technical reference literature and validated data all play an important role in successfully overcoming corrosion challenges. It is paramount that engineers understand and guard against materials limitations when considering the corrosion control management as part of the project design and/or when considering the in-service inspection & maintenance programs.

The reader is encouraged to have a challenging attitude when it comes to understanding and seeking out solutions to problems associated with corrosion. As engineering problems become increasingly complex and data proliferates at an astonishing rate, relying on a few trusted handbooks and a searchable reference database is no longer enough to truly get ahead of risks—engineers need to harness the power of information and data to their advantage.

This article will cover the oil & gas production workflow from subsea assets all the way to structures & pipelines.
Material selection used for equipment positioned on the seabed must meet more stringent demands to resist the adverse corrosion conditions encountered.

### Subsea assets

Subsea assets typically include all equipment below the water. Production fluids rise from the reservoir under pressure to the topsides facilities via tubing (risers) connected to high pressure valves located on the wellhead. From there the fluids are directed to the separation vessels via flowlines connected to a manifold arrangement.

Material selection used for equipment positioned on the seabed must meet more stringent demands to resist the adverse corrosion conditions encountered not only from the production fluids but also from the aggressive corrosive nature of the seawater. Acid gasses (CO2/H2S), along with chlorides, are ever-present and when dissolved in the associated produced water contribute to causing severe pitting corrosion problems.

Be mindful that when producers and/or water injection well tubing is shut-in (not in-service), produced water will drop-out to settle on the bottom of horizontal tubing (or enter the open-ended tubing), exposing the bottom section of the piping to pitting corrosion from bacteria and/or acid gasses under stagnant conditions. Pipelines and flowlines under low-flow or stagnant conditions are also affected in the same way. A literature search will help identify ways to overcome this problem, including the application of batch dosing inhibitors and biocides, and the use of tools specially designed for cleaning pipelines; an essential requirement prior to the chemicals being used.

In addition, oil and gas wells producing from formations high in sand must deal with erosion problems; flowline choke valves are particularly affected where bulky, forged steel materials can be eroded away in hours. Sand entrained in slower moving fluids simply promote erosion-corrosion. This is a costly mistake when the production tubing is set into a reservoir formation many miles long. Likewise, operators cannot tolerate holes in the risers and topsides choke valves for obvious reasons.

Most subsea equipment is manufactured from carbon steel, which is epoxy coated and wrapped to prevent seawater corrosion. Cathodic protection is almost always applied to protect against coating damage. Intricate equipment like wellhead valves, hydraulic control stations and equipment exposed to high corrosion rates from the production fluids are installed using either corrosion-resistant alloys (CRAs) or carbon steel with a CRA weld overlay to protect the affected surfaces as a means of reducing costs. For oil fields high in CO2, the use of CRAs is unavoidable in many cases.

Once CRAs are considered, the risk of corrosion pitting, crevice corrosion and chloride stress corrosion cracking needs to be evaluated; the National Association of Corrosion Engineers (NACE) specifies certain hardness, pH and chloride level thresholds for CRAs used for oil and gas production equipment. Due to current and movement of the seabed, resistance to corrosion-fatigue is also paramount.

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**Case Study**

The consequences of the Deepwater Horizon incident on April 20, 2010 is a reminder of the risks involved with offshore exploration & production.

In 2012, the drilling rig Discover India’s lower marine riser package became separated from the blowout preventer (BOP) stack. As a result, more than 400 bbl of synthetic-based drilling fluids spilled into the Gulf of Mexico.

An investigation into that incident concluded that hydrogen-induced stress corrosion cracking due to hydrogen embrittlement led to the failure of numerous bolts.

Connectors—typically studs, fasteners and bolts—hold together critical subsea safety equipment, including blowout preventers, which played a part in the Deepwater Horizon incident.

As long ago as 2003 there were indications that the offshore oil and gas industry was experiencing what we have come to call “the bolt problem.” In simplest terms, large bolts and other connectors have been prematurely failing in ways that could lead to catastrophic incidents.
Oil and gas wells producing from formations high in sand must deal with erosion problems; flowline choke valves are particularly affected where bulky, forged steel materials can be eroded away in hours.

The production fluids, essentially crude oil with entrained water and gas, need to be separated since the water and gas are the root cause of all corrosion problems; the exception is low acid gas and low water cuts, but this is very rarely the case, especially since crude oil volumes decline and water cuts increase over time.

To do this, the production fluids (oil, water and gas) are piped from the wellhead manifold to the separator vessels. These vessels are large enough to allow the fluids to slowly move from one end to the other. In doing so, the oil and water separate whilst the gas dissociates and exits through the top gas outlet piping. Even though CRAs might be used, a robust inspection program is required to monitor wall thickness loss, pitting or presence of cracks on the piping circuit up to the KO drum in the gas compression unit. Lengthy settlement time in the Separator allows the produced water to ‘drop out’ of the bottom and get pumped to the water treatment plant. The crude oil is exported either to a pipeline or to storage. The problems associated with oil/water/gas separation are further highlighted in the next section.
Oil, water & gas separation
Managing the corrosion-related risk associated with safely operating high-pressure production equipment is paramount. The information needed to evaluate the risk is extensive and must include all relevant topics. Corrosion-related technical literature, including the effective use of corrosion inhibitors and/or biocide applications, must be available for cross-reference to ensure that by solving one problem you do not knowingly introduce another.

For oil and gas production, not only are the produced water fluids corrosive due to acid gasses, H2S and/or CO2, solids entrained in the fluids settle out into the piping and separator vessels. Solids tend to increase the conductivity of the water and create a large amount of deposits that usually form on the bottom section of pipe or vessel. Under these conditions, crevice corrosion and Sulphur-Reducing-Bacteria (SRB) thrive to cause pitting corrosion since both corrosion inhibitor and biocides applications cannot penetrate the deposits to protect the steel surfaces. Most separator vessels are coated on the inside to prevent these types of deterioration occurring.

Pump recycle lines, used for pump start-up and pressure balance, are shut-in when not in use; this causes stagnant/dead leg conditions and the piping should be monitored or manufactured from CRAs, being mindful of the limitations when used for oil and gas production.

Case Study
A major operator with assets in the Arabian Gulf installed several different ball valves on a system returning high pressure gas back to the separator vessel.

The materials used to connect the valve body and stem were either carbon steel or type 316L stainless steel depending on the pipe specification. The bolts used to connect the valves to the piping system were super duplex.

The split-body valve design was approved and the valves were installed according to the pipe specification.

After five years, one of the valves failed in-service, releasing a stream of 120-bar gas into the environment. Fortunately, there was no ignition, but by any standards this was a major incident and the consequences could have been unthinkable.

The valve body bolts failed due to stress-corrosion-cracking. The combination of hot saline environments encountered in the Arabian Gulf, and intermittent deluge testing, where seawater is used to spray the entire platform equipment, caused salts to build-up over time and concentrate on the bolts. The cost of replacing the bolts to super duplex was measured in millions USD.

Oil pumps are manufactured from carbon steel with CRA trim to resist corrosion from high velocity fluids. Choke valves are also manufactured from carbon steel, but process operators should recognize that erosion of the CRA internal cage/choke devices is difficult to protect against for sand producing wells, hence these valves should be monitored using special sand monitoring devices.
Where CRAs are used, limitations on chlorides and pH may be imposed depending on the material susceptibility to the harmful effects of stress corrosion cracking.

For high strength steels, typically used in high pressure production facilities, precautions must be taken to guard against wet H2S cracking of welded joints. Many vessels are stress-relieved after welding to minimize this problem.

Where CRAs are used, limitations on chlorides and pH may be imposed depending on the material susceptibility to the harmful effects of stress corrosion cracking.

Key words used for any information or data search would therefore include materials strength and limitations on weld hardness when in contact with wet H2S; alternatively, look-up 'post-weld heat treatment,' which may be specified to reduce the susceptibility to cracking of the weld heat-affected-zones. For CRAs the reader should look-up typical restrictions relating to chlorides, pH and temperature, being mindful that certain CRAs perform better than others under certain conditions. The use of graphs, charts and tables (highlighted further in this paper) is most useful to better understand these limitations and to determine the optimum material selection.

After separation, let's look at gas compression.

1: Most highly-tagged corrosion-related keywords in scientific literature published 2012-2016. These keywords help engineers filter down broad searches into relevant results tailored to their needs. Source: SciVal
Gas compression
The gas flashed-off inside the separator is routed to the gas compression module. This process unit compresses the gas into a liquid before drying it by having direct counter-contact with glycol in a purpose-made unit designed to ensure the gas is fully dehydrated before export. The consequences of a leak in the compression module are massive due to the explosive nature and amount of gas escaping due to pressure. The reader is strongly encouraged to research all aspects of the functionality of the process equipment since water draining from these vessels, along with condensate in the medium-pressure part of the process, is likely to be highly corrosive and the use of CRAs is unavoidable.

In all industries, high pressure gas compression facilities utilize high-specification machinery and equipment and as such the knowledge required to safely operate the process is extensive. Sufficient technical literature and other specific materials/corrosion-related information is available to understand the problems that need to be overcome.

Entrained gas entering the separator vessels with the production fluids is flashed-off inside the vessel and routed to the gas compression module. The gas stream is typically corrosive with corrosion rates dependent on the pressure and mol% of acid gas. As the gas is compressed and the pressure and temperature increase so do the corrosion rates.

Wet gas enters the 1st stage knock-out drum in the compression module before entering the compressor. This section is usually fabricated using carbon steel due to corrosion rates corresponding to low pressure and temperature. However, wet H₂S is not only corrosive under dew point conditions so be cautious since the corrosion mechanism could generate atomic hydrogen, a phenomenon that increases the susceptibility of carbon steel to low-temperature, or wet H₂S, hydrogen cracking.

Corrosion rates of carbon steel increase downstream of the 1st and 2nd stage compressor aftercoolers due to increased partial pressure of acid gasses under wet conditions, and increased temperature and the reason CRAs are used with caution since pitting corrosion can occur as shown above.

The gas coolers can be in the form of shell & tube design or from a more compact design. In either case, the material selection is based on hot, corrosive gasses on one side and corrosive seawater used as a coolant on the other. Super-austenitic stainless steel, duplex stainless steel and titanium are all candidate materials for this equipment.

The Pre-Glycol flash drum is usually carbon steel lined with super-austenitic steel or with epoxy or polymeric coatings to protect against acidic conditions.

Case Study
A major O&G operator completed a corrosion study on a new gas compression module as part of an existing field development.

Due to unacceptable corrosion rates of a condensate drain line from the Flash Drum, super-austenitic alloys were specified (SMO-254).

During the fabrication process, the purge gas required to eliminate oxidization of the molten weld metal during welding was inadequate.

The condensate line failed within two-months of being in-service; the release of hydrocarbon was a significant event due to the high pressure and toxicity of the gas.

The failure occurred very rapidly due to internal oxidation of the weld metal when exposed to the corrosive condensate fluids.

A lack of understanding the importance of the welding procedure and the corrosion-resistance properties of the materials being welded was a key causal factor in the failure analysis.

The consequences of a leak in the compression module are massive due to the explosive nature and amount of gas escaping due to pressure.
When researching any literature, be sure to include the functionality of the process equipment involved and how it operates.

The vessel boot could even be clad with Monel. The drains are CRAs as is the condensate take-off piping due to high corrosion rates of carbon steel. The high-pressure gas is then sent to the glycol tower where any remaining water is absorbed in the glycol. The tower and reboiler circuits are constructed of type 316 stainless steel. Downstream of the glycol system, the gas is dry and carbon steel is used for the HP knock-out drum, piping and export piping.

When selecting CRAs, precautions should be taken to guard against stress corrosion cracking, the critical pitting and crevice temperatures should be observed, and the fabrication & welding procedures should be strictly adhered to, especially the purge gas when welding austenitic steels. Wet H2S also causes hydrogen cracking of high-strength steels commonly used for this type of equipment. This is the reason hardness thresholds are specified in wet H2S service.

When researching any literature, be sure to include the functionality of the process equipment involved and how it operates; many vessels are used to drain corrosive water and condensate. Be sure to understand the difference between solid CRA materials and clad CRA materials; the cost difference is enormous. Understand the consequences of failure.

The next phase is water treatment.

Information resources are evolving beyond literature repositories and into true engineering solutions. Knovel, for instance, provides engineering concepts extracted from its corpus to help engineers narrow down results and discover connected content. A search on “corrosion resistance” yields 3,000+ results, but refine that search by “austenitic stainless steel”, which is already suggested for you, and you get 110 results including material properties and interactive data.
Due to the high conductivity of the water, entrained solids and deposits build up, and in the presence of any acid gasses the produced water system is a very corrosive environment.

**Case Study**

Corrosion rates of carbon steel piping on an Arabian Gulf offshore oil production platform were more than 5.0mm/yr for reasons given.

Temporary repairs were made but only lasted so long; replacement of the piping was inevitable and resulted in long periods of downtime since there was no other way of separating the oil/water.

The field produced 85,000bbl/day and when the price of oil was $110/bbl, loss of production was typically in the region $10M/day.

The use of glass-reinforced epoxy (GRE) was not allowed in hydrocarbon service and the critical pitting/crevice temperatures were such that CRAs were initially ruled out.

However, an extensive literature research of materials behaviors in this environment revealed that it was possible to use SMO-254 (austenitic stainless steel) materials at temperatures higher than the critical crevice temperatures published by the manufacturers. The ongoing materials performance was excellent.

**Water treatment**

Without doubt one of the most troublesome modules on any offshore platform is water treatment. Entrained solids, oil-in-water and water-in-oil, along with corrosive produced water, makes this part of the process very problematic and challenging. Not only do you need an understanding of the corrosion-related problems, which are discussed further, but also the environmental impact should the operator inadvertently discharge treated water high in entrained oil to sea.

The water treatment plant receives the produced water from the oil separators. The fluids contain both oil-in-water. For water-in-oil and for some oil-fields, cleaning the water to achieve less than 25-ppm oil threshold so that the water can be responsibly disposed of is troublesome.

Initially, the water is sent to a bulk water separator, where a combination of internal equipment such as veins and mares tails are used to disrupt and agitate the oil to the surface and decant only the water. Emulsifiers and coagulant chemicals are injected to separate oil-in-water and water-in-oil.

Due to the high conductivity of the water, entrained solids and deposits build up, and in the presence of any acid gasses the produced water system is a very corrosive environment.

Despite the high corrosion rates, the equipment is mostly carbon steel with epoxy or polymeric coatings on the internal surfaces of vessels. Fusion-bonded-epoxy coatings are used on pipes where feasible.

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**Temperature (°C)**

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Various materials performance versus critical crevice and pitting temperatures (boundaries or limits).
Engineers are also encouraged to research other best-practice and use cases, which are becoming more and more available via a literature search.

Hydro cyclones are used to further clean up the water prior to disposal. This equipment also must be protected from the corrosive fluids in addition to protection from erosion-corrosion.

Fabrication & welding procedures follow that of the separation process, and given the fact that there is still H2S present in the vessels, could be heat-treated to reduce the weld hardness levels.

Most equipment used in the water-treatment plant will have heavy deposits adhering to the internal surfaces due to the high entrained solids coming from the reservoir fluids. This is the reason inspection programs use corrosion mapping methods to determine wall thickness loss.

For some systems, glass-reinforced-epoxy (GRE) materials have been relatively successful. However, the user is strongly advised to thoroughly research the piping support requirements and best practice for installation since there is a history of failures being reported in many industries due to inadequate support and from water hammer when operating under upset conditions.

Produced water is usually disposed of in a redundant well or a well purposely drilled for this reason. The importance here is to ensure the water chemistry is correct since there is a potential for heavy scaling, which would quickly block the wellhead and tubing.

Engineers are also encouraged to research other best-practice and use cases, which are becoming more and more available via a literature search. For example, the author has personal experience and knowledge of using super-austenitic materials in a produced water outlet stream under conditions far exceeding the CCT/CPT limitations specified by the manufacturer; not that these limits were in any way wrong or misleading. This materials study was conducted under the actual process conditions and, contrary to the precautions mentioned, proved to be satisfactory, resulting in significant reduction in downtime. There are many of these types of use cases and best-practice stories that can be used for comparison and further evaluation by the user.
**Water injection**

Like the produced water treatment plant, the water injection module is another highly corrosive process. Water Injection is used to sweep the oil from the extreme boundaries of the reservoir formation towards the downhole production tubing strategically positioned in the reservoir to gain maximum production and maintain the reservoir pressure.

Corrosion of steel is strongly affected by the amount of oxygen in the water and the temperature of the water. Water velocity also greatly influences the corrosion rates. For offshore production, seawater is used for water injection; the corrosion rates are high even under the best conditions.

The challenge for corrosion control is not so much materials selection, although this plays a part when fluid velocities are high; it is maintaining low oxygen levels to acceptable amounts as explained further.

Seawater is pumped up from the sea via a caisson and treated in a deaerator vessel to reduce oxygen levels to less than 50-ppb. This allows the use of carbon steel materials. Oxygen levels higher than 50-ppb will result in accelerated corrosion of carbon steel, particularly in high flow piping such as booster pump outlets, for example. Therefore, oxygen scavenger chemicals are also used to reduce the oxygen levels and the corresponding corrosion rates. Typical corrosion rates for oxygenated seawater at certain temperatures are shown below.

Upstream of the water injection and booster pumps, reinforced glass-reinforced-epoxy (GRE) piping is used due to the low pressure. These materials need more supports than carbon steel however, and along with the joints are prone to failure should they be subject to water-hammer.

Downstream of the WI pumps, where pressure as high as 120-bar is required, carbon steel materials are used, including the flowlines and injection tubing into the reservoir. The use of super-duplex materials is also considered for very high flowing fluids, particularly for internal pump parts.

**Case Study**

The corrosion rate of carbon steel piping in a water injection system was estimated to be 1.0-1.27mm/yr; the use of oxygen scavengers to reduce the oxygen content to less than 50-ppb along with a corrosion inhibitor would reduce this to 0.127 mm/yr.

The mild steel piping was 10.54mm thick, thus with corrosion rates of 1.27mm/yr in the untreated water, severe problems might be expected within seven to eight years.

By specifying the use of oxygen scavengers and water treatment corrosion inhibitors, the design life was estimated to be more than 50 years.

However, due to high velocity flow the pipe failed within 12 months when placed in-service.

When designing the piping system, the engineers realized that they had to add a “corrosion allowance” to the metal thickness. They failed, however, to understand the adverse corrosion effects of high flow in oxygen-containing seawater systems.

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Also, it is often the case that some production wells are converted to water injectors and visa-versa. When this happens, it is important to follow the management of change so that the materials selection is correct and that chemical applications are adequate. The condition of the tubing should be known for each service before being converted. Engineers often fail to differentiate between the two services when evaluating the integrity condition of production/seawater-injection tubing, commonly assessing the corrosion-rate for one service, which is incorrect since the two services are exposed to different conditions. There are cases where incorrect material selection was based on these simple errors.
Another problem is associated with plankton and algae blooms, which greatly affect water quality at certain times of the year.

Pipelines exporting water to other platforms for injection must be kept clean using cleaning tools, commonly referred to as ‘pigs.’ The pipelines are cleaned frequently to clear any scale or deposit build-up. Batch biocide treatment programs almost always follow the cleaning program. Oxygen scavengers can be injected into the pipelines too if the results from on-line monitoring dictate.

When researching information for materials used for water injection, key areas of research should include information relating to the location; warm gulf seawaters tend to be more corrosive than colder northern regions. The height of the seawater caisson and pump suction off the seabed is also critical to ensure that no deposits from the seabed are being ingested. Another problem is associated with plankton and algae blooms, which greatly affect water quality at certain times of the year.

Be sure to understand the use of CRAs when specifying materials for pump parts and pump outlet piping; super duplex is a good performer but there may be limitations on their use. Titanium used for exchanger tubing is a common choice material, but it too has limitations when it comes to crevice corrosion and fretting, so while it might be the best available (and most costly) it may not be suitable. Check the requirement for chemicals control, namely oxygen scavengers used to lower the oxygen content downstream of the deaerator tower. Corrosion inhibitors are also injected downstream of the fine filters, each flowline and/or export pipeline. Biocides are also essential to control bacteria that breed quickly in seawater systems and it is important that different chemicals are used alternatively so that the bacteria do not become immune to the chemistry.

Finally, thought must be given to the structures and pipelines.

Various corrosion rates of carbon steel at different temperature and oxygen levels
Structures & pipelines

Offshore oil & gas production structures can be fixed platforms, where the jacket is fixed to the seabed, or semi-submersible, where the production facilities are on a floating barge-type platform. Floating, production, storage and off-loading (FPSO) facilities are also common.

In all cases, the structures are manufactured from carbon steel covered with several layers of paint or epoxy coatings. Risers and pipelines are coated and wrapped for added protection. Cathodic protection, usually in the form of sacrificial anodes, guard against holidays (holes in the coating) or damage to the coatings. Carbon steel jackets used for fixed platforms to support the topsides structures are bare carbon steel protected by sacrificial anodes attached to each tubular across the entire structure. Corrosion problems around the splash zone areas are more troublesome due to the wave action.

The steel used for the main structures, such as the jacket, topsides, cranes, heli-pads and flare stacks, are manufactured from high strength steel, hence the fabrication and welding controls are critical.

Pipelines used for export and/or inter-field fluids transfer are usually carbon steel unless corrosion rates due to wet acid gasses and condensate at high pressure are too high. Importance is placed on cleaning programs to keep the internal surfaces clean and free from deposit build-up. This is also a critical parameter for corrosion control using chemical applications, such as inhibitors, oxygen scavengers and biocide treatments.

Critical research criteria would include high strength tubular and structural steels. Coatings and wraps for topsides structures and pipelines are required. The platform jacket (the sub-sea structure fixed to the seabed that supports the topsides structure) requires cathodic protection in the form of sacrificial anodes. Key search words for fabrication and welding of high strength steel structures would provide an enormous amount of useful information.

An inspection of offshore structures literature search would provide a lot of useful information relating to the precautions to be taken to prevent degradation. Enhanced corrosion around the splash-zone of the jackets is common; fatigue cracking of tubular welds can also occur. Fatigue cracking of the production/injection risers is also problematic due to wave action. Inspection of offshore pedestal cranes is another key search phrase; the sudden shock-loading of the crane boom (due to offloading under adverse weather conditions) renders the critical load path to fatigue and/or overloading and cracking of the fillet welds on the crane boom and main structure is common.

Important Notes

Common corrosion-related problems in one industry are prevailing in others, although the solutions are very rarely shared.

Corrosion occurs in many different forms, sometimes simultaneously; when solving for one problem, do not introduce another.

Be thorough in your research. Too often the solutions are incomplete, and problems persist.

Graphs and charts are important, as they provide instant visualization of the problems/solutions.

Failure modes, effects and causes analysis (FMECA) and root cause analysis (RCA) are just two examples of many ways and methods of evaluating a material’s suitability for the intended service.

Material selection must include precautions to be followed during fabrication, welding, installation and commissioning.

Combine key words when researching for solutions to problems; try to avoid the use of single word searches.

Reference to, and the use of the right literature or information provides the user the chance for verification.
Smart inspection sensors... are making inspection programs far more cost-effective and safe.

Conclusion

Every industry has a strong desire to reduce costs. Managers and engineers are constantly on the look-out for new tools and resources to do this; information resources have never been in more demand.

Operating and maintaining aging plants, fitness for purpose, and life-extension are no longer unique challenges, they are common requirements. Engineers are now charged with running and maintaining the assets safely using alternative methods to manage corrosion in all its many forms. Proven and tested inspection and monitoring methods and alternative material selection are out there, and it is the responsibility of these engineers and managers to seek them out.

Materials selection is never a straightforward guard against corrosion. Design principles and acceptance standards are changing as we learn more; the user must keep up-to-date with these changes. Sharing common mistakes and problems across industry needs to improve. Best practices are becoming industry acceptable standards and new technology is driving this. Advances in materials testing have proved new boundaries for materials use.

Smart inspection sensors, e.g. phased array and time-of-flight-diffraction, robotic crawlers, unmanned aerial vehicles (drones) and advanced analytics compiled with deep-learning are making inspection programs far more cost-effective and safe; autonomous inspection and automatic defect recognition is fast becoming a reality.

The engineers’ workplace is changing, and so should the attitude toward harnessing validated information and data. Reference to, and the use of the right literature or information provides the user the chance for verification, a competitive edge, and the chance to reduce costs now and in the future.

Remember, if you don’t find corrosion, it will find you.
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