SPE (Society of Petroleum Engineers) Workstrings International

SUBJECT: RUST GRIP®

Drill string piping AND Intervention Riser Tubulars

Phase 1: Testing began in 2007 to find a coating system for interior and exterior to stop deterioration. Testing with all known and accepted protection coatings on the market.
Phase 2: Began in mid-2011. Tests evaluating a series of newly developed products within the oil and gas industry on actual pipe.
Phase 3: began in August 2014 and eliminating down to 10 coatings and finally down to 4 finalist coatings.
As the testing continued, the last two coatings were being tested, but neither of them met all the requirements needed. At this late stage of testing a new coating called RUST GRIP® was discovered and brought into the testing.
Eight years after the start of the testing processes, RUST GRIP® was tested against the two top final products and outperformed all to be selected as the "System Coating" for drill piping.
Conclusion from RUST GRIP® testing and down hole use:
No notable or inspectable tube body damage due to carrion or pitting
Reduced completion fluid discoloration
Rig did not report any issues with the coating interfering with the slip system or iron rough neck.
Removal of coating by mechanical damage or abrasion does not extend past the area of contact – i.e. no chipping or peeling.
No pipe downgrades to pitting or corrosion.
Pipe was in service of 40 days (64 total days out).
Pipe spent 31 of those days in the completion fluid
Hole temperature of 220F (104C).
Hole depth of 20,000 feet (6060 meters)
Water depth of 1,537 feet (466 meters)
The external coating was still intact, protecting the pipe from excessive corrosion.
Open water trials in 2015: 274 joints over 3 rigs and 240 days in service --- "0" downgrades reported.
Since 2015, the rental company has applied this coating system to over 1,700,000 feet (44,000 joints) of completion and intervention pipe and has experienced zero ("0") corrosion related pipe body downgrades and zero reported field issues.
From report: "The coating system eliminates pipe body downgrades and associated costs for the operator."
21,000 feet of 7 5/8 in. pipe has been in use since 2016. After 29 deployments over four years on four different rigs there has not been a single downgrade due to pitting, OD corrosion, or remaining body wall falling below 95% of nominal.

Superior External Coating for Completion Tubulars

Rust Grip®

SPI COATINGS
PROVEN PERFORMANCE • REAL WORLD SOLUTIONS

Coated 7-5/8" MaXit807 Completion Landing String

Rust Grip® vs. **Uncoated**

Pipe shown above returned from a completion well project

Since 2015, Workstrings has coated over ~~1,000~~ 1,700,000 feet (~~30~~ 44,000 Joints) with zero tube corrosion downgrades

Rust Grip® is the leading external coating solution for minimizing pipe corrosion in completion and open water environments and is exclusively offered by Workstrings International.

Rust Grip® provides a protective film of superior adhesion and flexibility, and is resistant to abrasion, impact, chemical solvents, and acid splash.

The application of Rust Grip® is improving corrosion mitigation efforts when applied to completion and intervention tubulars.

NACE Testing with Proven Internal and External Coatings

WORKSTRINGS® INTERNATIONAL
A SUPERIOR ENERGY SERVICES COMPANY

– SOCIETY OF PETROLEUM ENGINEERS –

Challenge

The oil and gas industry has worked to protect oilfield equipment from the different operational environments to improve longevity of CAPEX and rental equipment for profitability, safety, and environment for both the operator and the service provider. Huge strides have been made over the past 2-3 decades in equipment grades, strengths, connections, and protective coatings.

Plastic and epoxy coatings have been applied to the internal diameter for tubing and drill pipe over this time period as a protection from corrosion. With more than 20 years of global service, TK-34XT™ liquid epoxy coatings have proven to be a very reliable product for drilling, completion, fracking, acid stimulation, and high temperature (in excess of 400 degrees F) applications. It has been the standard for drill pipe, completion pipe, and workstrings for the past 20 years.

External diameter tubular coatings to mitigate corrosion have been more challenging for the industry due to durability during operations, flexibility for inspection, and cost drivers. Over the past 5 years Workstrings International has proven an external coating, Rust Grip™, which has met these challenges for the industry and has saved significant cost, time, and tubular life with no operational issues.

The Tuboscope TK-34XT™ internal coating is normally applied a single time after the pipe manufacturing process. The Rust Grip™ external coating is applied by cleaning and preparing the external surface. The coating is applied with an airless spray system providing a complete and uinform coverage. The external coating is reapplied between deployments.

As the industry explores new areas and further develops existing fields, H_2S has become more prominent in the design parameters. In existing fields where water flooding has created a mild presence of H_2S, this can still pose a challenge for equipment and even for permitting the projects. In exploration areas having increased levels of H_2S or CO_2 has always been very challenging for equipment, safety, as well as regulatory. The common internal coatings such as TK-34XT™ have never been declared as sour service protection especially because it is not always declared "new condition". The external coating is relatively new to the industry and does not have a history in a sour environment.

The major goal when operating in a sour service environment is to **control the environment** so there is no, or minimal, contact of the equipment with wellbore fluids containing H_2S or CO_2. It is often a challenge to control the grade of all equipment in service to the level of protection (or design). High concentrations of H_2S with increased exposure time will cause an issue with any grade of metal. As the internal and external coatings are not a perfect shield for the tubulars, they are a barrier. Especially in a mild sour service environment, Region 1 or Region 2, where higher grade tubulars could be deployed with applied internal and external coatings and the environment controlled. Posed with this challenge, Workstrings took the initiative to have NACE testing done on TK-34XT™ internal coating and Rust Grip™ external coating which are their standard tubular coatings.

Test

The test was conducted per NACE TM0177-2016 Method A tensile test to determine the sulfide stress cracking (SSC) resistance of various steel samples coated and uncoated. The pipe manufacturer's standard vendors for test sample preparation and NACE testing were used for this project. NACE samples were prepared from the weld area of V-150 grade pipe. The weld area seems to be of most concern among operators and the NACE samples would include tool joint, pipe, and HAZ areas. Solution D was chosen which is defined as 7% H_2S and 80% stress level for 720 hours of exposure.

Test Results

Specimen	Type of Coating	Stress Level (ksi)	Test Result	# Hours at Failure
1	Uncoated	96	Failed	123.6
2	Uncoated	96	Passed	N/A
3	Uncoated	96	Failed	328.8
4	RustGrip®	96	Passed	N/A
5	RustGrip®	96	Passed	N/A
6	RustGrip®	96	Passed	N/A
7	TK-34XT™	96	Passed	N/A
8	TK-34XT™	96	Passed	N/A
9	TK-34XT™	96	Passed	N/A

Sulfide Stress Cracking (SSC) Test Results for the Steel and Coating Products (75°F Test Temperature)

Conclusion

This testing is positive for the coatings in that there were 2 uncoated high grade 150ksi samples that failed the testing while all 3 Rust Grip™ samples passed and all 3 TK-34XT™ samples passed. These results show that the coatings create a barrier to the metal. For mild sour service environments, Region 1 and Region 2, the coatings could be beneficial for deploying higher grade tubulars for operations, especially in conditions where higher strength tubulars are required and no sour service options are readily available. This can lower the total cost of ownership for both operator and service provider by using available tubulars with proper coating.

These coatings have proven themselves very successfully as barriers to corrosion in standard environments of salt-based fluids from seawater to heavy completion fluids with no additional chemicals. With the benefit of both the internal and external proven coatings the testing shows benefits as a barrier in a Region 1 and Region 2 sour service environment. With the environments controlled with pH and scavengers, the potential for improved mitigation is increased.

Note: The coating manufacturers are not promoting these coatings as sour service products. There will always be imperfections in the coating process and imperfections due to normal handling and operations.

WORKSTRINGS INTERNATIONAL®

"YOUR FIRST CHOICE IN DOWNHOLE TUBULAR RENTAL

A SUPERIOR ENERGY SERVICES COMPANY

Now Offering an Inexpensive OD Corrosion Mitigation Solution

Superior External Coating for Completion Tubulars

SUPERIOR INSPECTION SERVICES

A SUPERIOR ENERGY SERVICES COMPANY

Workstrings International continues to demonstrate investment in the latest technologies and improved efficiencies for customers with the operational launch of its External Coating Facility in Broussard, Louisiana, USA. The facility, in partnership with **Superior Inspection Services**, is capable of increased capacity and accelerated throughput times, including Range 3. Featuring an enclosed airless sprayer, the facility achieves an optimum application of any desired coating product in a consistent manner.

Rust Grip®, an SPI Coatings product, is exclusively offered by Workstrings International for application and use on Workstrings International tubular and oilfield products only. Rust Grip® is the leading external coating solution for minimizing pipe corrosion in completion and open water environments.

Rust Grip®

SPI COATINGS

Rust Grip® provides a protective film of superior adhesion and flexibility, and is resistant to abrasion, impact, chemical solvents, and acid splash.

When applied to completion tubulars, Rust Grip® is improving corrosion mitigation efforts.

Field proven in Deepwater GoM during 3 back-to-back completions over an 8 month period and also in multiple open water intervention projects with zero downgrades. All pipe tubes returned in excellent condition.

Global Headquarters
1150 Smede Hwy
Broussard, LA 70518 - USA
Phone: +1 337-989-9675
info@workstrings.com

EMEA Corporate
Kirkton Avenue, Dyce
Aberdeen, AB21 0BF - UK
Phone: +44 1224-724900
sales.uk@workstrings.com

Engineering & Marketing
11330 Clay Road, Suite 200
Houston, TX 77041 - USA
Phone: +1 281-999-0047
marketing@workstrings.com

Pipe Specification Mobile App

Download on the App Store

ANDROID APP ON Google play

www.workstringsinternational.com

Workstrings External Coating for Completion Tubulars

Workstrings International Engineering and Operations along with Superior Inspection have developed a solution to drastically improve the corrosion mitigation procedures and minimize pipe corrosion in completion and intervention environments.

Workstrings International and its customers have experienced significant asset loss and cost due to OD corrosion. The most significant loss has been in pipe used in deep water completion environments. Pipe used in open water operations for intervention also have the potential for significant OD corrosion.

- Assets sold to operators due to OD corrosion during the past 8 years:
  - Completion Environments - $17,543,704
  - Open Water Operations - $6,765,967

WSI has gathered data on completion parameters and operations during this 8 year time frame. WSI has done evaluation of completion environments for wells with corrosion issues and without. Corrosion Mitigation Presentations have been developed for rig crews and presented on location at no charge. These presentations are continually revised with new information. New tools have been developed for corrosion mitigation such as the racking mats and pipe wash systems. WSI has brought these solutions to several core customers and many are standard practice now.

History of Corrosion Mitigation Procedures Development

- 2007 - Workstrings and Superior Inspection began working on corrosion solutions with products marketing salt neutralization.
- 2008 - Instrumental in helping develop rig washing systems and corrosion mitigation procedures.
- 2010 - Brought the racking mats to the completion projects.
- 2011 - WSI and SIS began testing external coating options.
- Multiple lab tests conducted on corrosion samples over the 8 yrs.
- 2012 - WSI began field trials with different products. One core customer, assembled a team to work with WSI on this effort.
- 2014 - WSI conducted further screening tests on 10 products.
- 2014 – WSI conducted lab testing in completion fluid and determined that the selected external coatings have little effect on fluid discoloration vs bare metal when exposed to completion fluid.
- 2015 - The top 5 products went into final field trials to evaluate application, dry time, and adhesion.
- 2016 – Our final product, Rust Grip, is being used commercially by several Deepwater Operators and being field trialed by others.

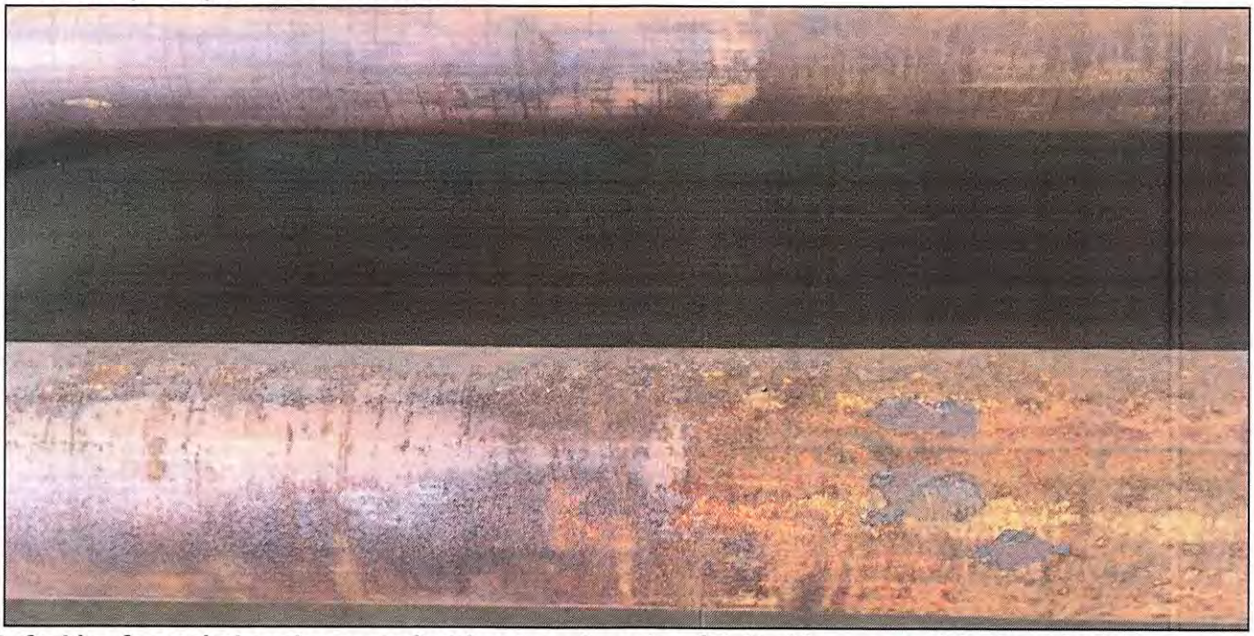
Conclusion: **Pipe corrosion is a complicated puzzle involving many operational parameters and no conclusive ties to fluids, time, air exposure, and rig operations. *All* parameters must be considered for *each* project.**

Due to the complexity of the corrosion problem and the environment, WSI and several operators have concluded that an external coating is the best option.

- Since 2010, WSI has performed experiments and trials on 18 different potential coating solutions.
- Conducted over 10 field trials with several major deepwater operators with varying levels of success.
- Vetted an external coating product and procedure for use in completion operations and open water work that significantly reduces corrosion products on the external surface of the tubulars.
- Built an External Coating Facility for application of coatings.

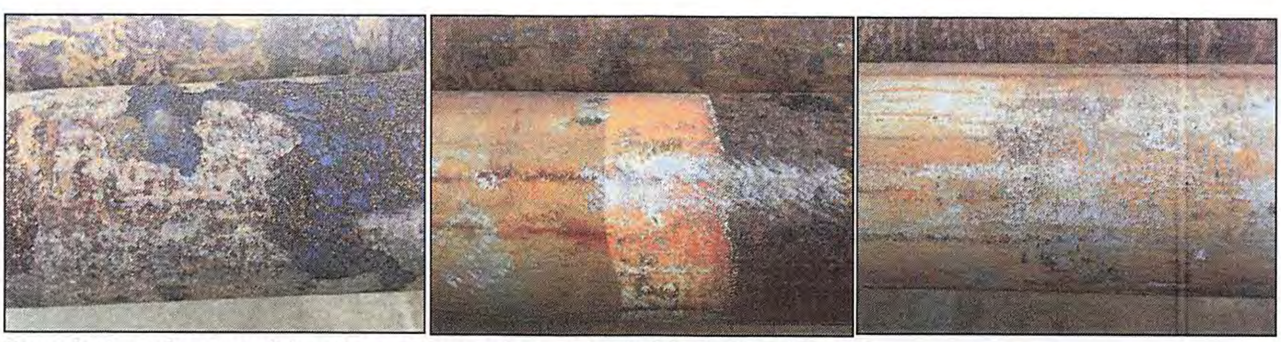
Completion Operation Trials

Operator 2015 Completion Trial 1 – Trialed 3 potential products in the field for approximately **114 days,** exposed to **10.8ppg** to **11.35ppg** CaBr2 for **37** of those days. Joints coated with Product E were the only trial joints visibly recognizable on the return.



Left side of completion pipe coated with external coating /Right side uncoated, before blasting

Operator 2015 Completion Trial 2 – Trialed 2 products in the field for approximately **145 days**, exposed to **14.3ppg** to **14.4ppg** CaBr2/ZnBr for **119 days**. Joints coated with Product E were highly recognizable on the return.



Completion pipe transition from uncoated to coated side, before blasting

Open Water Intervention Trials

Open Water Intervention Riser Projects have similar exposure days to completion landing string.
The first trial in December 2013, started with the use of 6 5/8" GTM69 and 2 3/8" tubing for open water P&A work coated 6 5/8" LS with mill varnish. This trial with the OD coated with mill varnish, experienced 545 jts GTM69 downgrades and 574 jts tubing downgrades within 5 jobs.

- Coated 6 5/8" LS with Product E Results
    - March 2015 - #1 – Coated 6 joints - 55 days in service - 0 downgrades
    - May 2015 - #2 – Coated 64 joints - 31 days in service - 0 downgrades
    - July 2015 - #3 – Coated 74 joints - 24 days in service – 0 downgrades
    - August 2015 - #4 – Coated 44 joints - On-going at the time of this report
    - Sept 2015 - #5 – Coated 86 joints - 19 days in service - 0 downgrades

GTM69, as returned from open water P&A, before blasting

The WSI New External Coating facility is now fully operational, capable of coating up to 150 joints of range 3 pipe per day. It has an OD brush system within facility provides a clean surface, free of debris, prior to coating application. The coating system provides full, uniform, airless delivery of external coating products to any tubular asset.

Completion pipe exiting coating facility

Society of Petroleum Engineers

No Pipe Body Downgrades - Improved Corrosion Mitigation Coating System Provides Significant Operator Savings

Buck Johnson, Chevron North America; Timothy Cappel, Superior Products International II, Inc.; Greg Elliott, Leianne Sanclemente, Greg Moore, Noah Tritz, and James Brock, Workstrings International; Chuck Sewell, Superior Inspection Services

The paper was prepared for presentation at the SPE Subsea Well Intervention Symposium originally scheduled for 11-13 August 2020, but the event was cancelled. The paper is included in the SPE 2020 Symposium Compilation, published 18 January 2021.

Abstract

Objectives/Scope: Tubulars used in completion and intervention riser applications are exposed to both the marine environment and corrosive oilfield chemicals, including salt-based completion brines. Eight years of field history from one company shows a loss of $24.3 million from pipe body downgrades due to corrosion and pitting in these salt-based environments.

Methods, Procedures, Process: This paper documents an extensive development effort spanning over eight years including: research of completion parameters and environments, evaluation of 18 potential external coating/salt neutralization products, multiple lab tests, field trials, as well as testing surface preparation methods, coating application, dry time and adhesion tests. The development of application procedures and construction of an external coating facility are discussed as are rig pipe washing systems and corrosion mitigation procedures.

Results, Observations, Conclusions: The result is an improved corrosion mitigation coating system. A modified epoxy phenolic internal coating combined with a metallic-based, moisture-cure polyurethane encapsulating external coating. Since 2015, over 1,700,000 feet, 44,000 joints, of completion and intervention tubulars utilizing this system have been deployed with zero pipe body downgrades due to corrosion or pitting, and zero operational issues. In addition to reducing replacement cost and loss of capital, this system provides the ability for longer deployment of the pipe on a multiple well program reducing logistics costs.

Rust Grip

Novel/Additive Information: Extensive research, testing, field trials, and successful field deployments have resulted in an improved corrosion mitigation coating system providing significant savings to operators. Pipe body downgrades due to pitting and corrosion have been eliminated. Improved corrosion resistance has allowed multiple-well deployments reducing shipping, inspection, and repair costs. Ultimately this results in longer life of the tubulars reducing total cost of ownership.

Introduction

A completion workstring is used to displace drilling mud to completion fluid, perforate the reservoir zone for production, perform stimulation treatments to the reservoir, apply sand control methods, and install production equipment. It is often a tubular with a rotary shouldered connection containing a metal-to-metal pressure rated seal that is dedicated to the completion operation and is separate from the drill string. A completion landing string is a tubular conduit, also with a metal-to-metal pressure rated seal, typically with a larger OD and ID, used in subsea operations to convey completion hardware, including the production tubing and accessories, from the offshore rig or surface vessel into the well bore. An intervention riser, again with a metal-to-metal pressure rated seal, is a tubular conduit between the offshore surface vessel and a subsea wellhead/tree used to perform intervention procedures typically not requiring a full rig operation.

Early subsea wells did not distinguish between drill strings and completion strings; most used rig provided API drill pipe as the completion string to transport production tubing and completion equipment from the surface vessel to the subsea wellhead. As total well depths continued to approach 30,000 ft, tensile loads and bottom hole pressures increased beyond the capacity of both standard API drill pipe and early rotary-shouldered tubulars with gas-tight, metal-to-metal seals. This led to the development of dedicated, built for purpose, completion and intervention tubulars, which have evolved in design and available sizes since the early 2000s (Chandler et.al 2004) (Corbin, et.al. 2017). The current tubular technology features pipe often with a heavier wall, gas-tight, pressure-rated, large-ID, rotary-shouldered connections compatible with the standard mechanized pipe-handling systems, elevators, iron roughnecks, and slips deployed in the Gulf of Mexico and other global deepwater operations. Normal rig-up and pipe-running procedures are maintained. The robustness of the rotary-shouldered connection ensures that connections can be made up and broken out several times without damage or loss of performance. Due to the specialized nature of these tubulars and the salt-based fluid environment, they are not part of the normal equipment on the rig and are typically provided to the operator by a pipe rental company.

Background

Completion and intervention riser tubulars are exposed to both the marine environment and to corrosive oilfield chemicals, including salt-based completion brines. Eight years of field history from Gulf of Mexico deepwater projects for one pipe rental company showed a loss of $17.5 million from pipe body downgrades due to the corrosion and pitting of completion tubulars and a loss of $6.8 million from pipe body downgrades of intervention risers. See Figure 1. These 30,000 ft. well depth projects magnified the corrosion problem and costs. Typically, operators require that these tubulars have a minimum of 90 to 95 percent of the nominal pipe body wall thickness for offshore use. Corrosion or pitting that removes wall thickness below these limits will result in the tubular being no longer fit for service. Severe pitting can cause the asset to be uninspectable with current tubular inspection equipment and technology due to the roughness of the surface and, therefore, the asset must be removed from service.

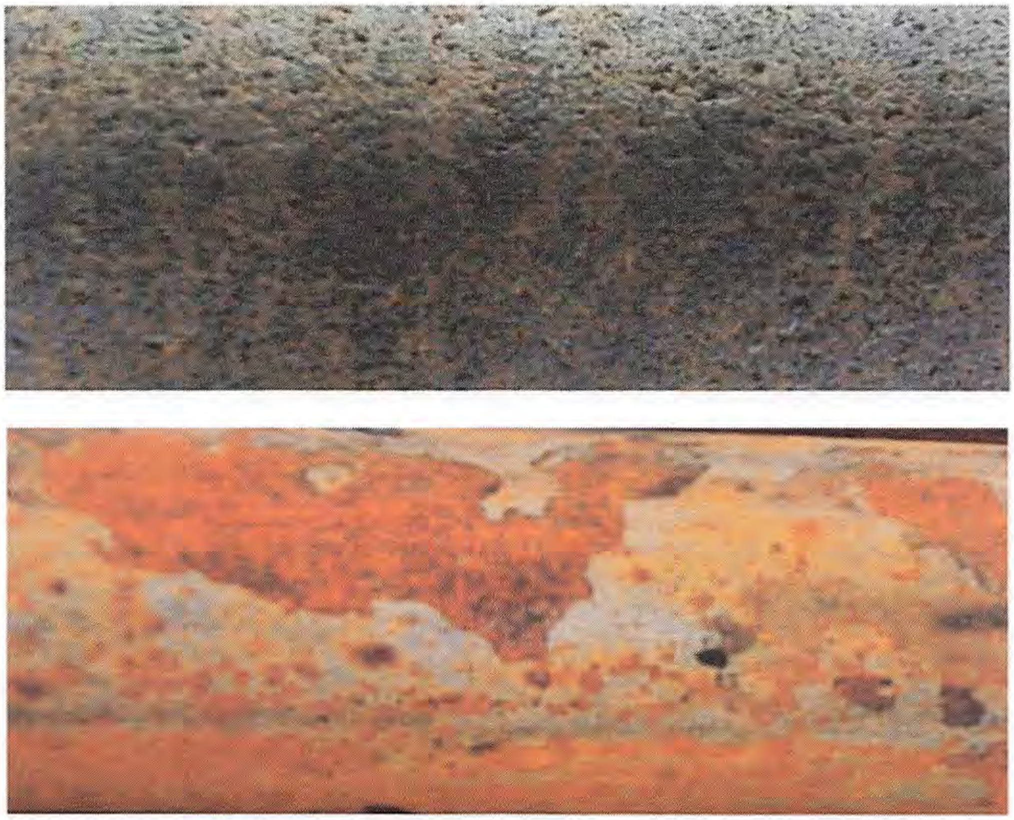


Figure 1—Examples of pipe body corrosion and pitting.

Pipe damage increases operator cost. The operator must pay the pipe rental company replacement value of the pipe that is no longer fit for service. Additionally, the operator must bear the cost of logistics and downtime associated with shipping the tubulars onshore and the replacements offshore. In multi-well projects the costs can compound. The operator must also absorb the non-productive time on breaking down and making up stands. Heavy corrosion on the completion strings can create well problems due to iron contamination of the completion fluid or iron scale in the production equipment.

These specialized tubulars are manufactured to order and lead time can be several months to over a year depending on market conditions. Extended delivery for replacement of downgraded tubulars results in a loss of rental and associated revenue for the pipe rental company. Both operator and pipe rental company incure cost whether loss of asset or loss of time.

Corrosion mitigation practices were initiated in 2007 by using cleaning solutions on the returned rental pipe to neutralize the salt and corrosion products created from the completion salt-based fluids. In parallel, new rig care and handling procedures were introduced and included new equipment that was developed to mitigate corrosion during completion operations. Data was then gathered on completion and operation parameters over the next eight years. Research and testing were conducted on the salt content of the returning pipe and on the efficiency of the cleaning equipment. Data analysis indicated that the initial oilfield chemical used as the rinsing solution was not performing sufficiently to prevent pitting on the tube body.

In 2009, further research began on salt neutralization products and cleaning systems to improve corrosion inibition. New chemical products were introduced for trial in the cleaning system and showed meaninigfull improvement. Rig crews were also trained and instructed to use new procedures and best practices. New recommended best practices included washing the pipe outer diameter with the newly designed wash wand for improved coverage and flowrate every trip out of the hole during completion operations; washing, drying, and applying fresh thread compound to the connections; using a racking mat; and using multiple wiper rubbers. Rig site training was done where possible. See Figure 2.

Figure 2—High-pressure pipe washing wand to rinse salt-based fluids from tubulars with optimum jet design and flowrate, and racking mats to facilitate drainage of completion fluids away from connections in order to mitigate corrosion and pitting.

Additionally, when tubulars which had been exposed to completion fluids were returned from service they were cleaned and treated with the salt neutralizer within 7 days. While these practices were somewhat effective, it placed additional responsibilities on the operator and pipe washing increased non-productive time. A more reliable solution was needed.

Internal Coating

Internal plastic coating has been used for decades to protect oil field tubulars, line pipe, and drill pipe. An epoxy-phenolic, thin-film coating design for drill pipe has been successful in preventing corrosion and pitting under a wide variety of oilfield environments, temperatures, and pH ranges. Additionally, the surface finish of the coating greatly increases the hydraulic efficiency compared to uncoated pipe. These internal coatings have evolved to now provide an improvement in durability three times that of the original drill pipe coating (Pourciau et.al 2002). The increased abrasion resistance provides protection from the passing of wireline and other tools, and the abrasion from flowing solids. Failure of the internal coating system was rare and if there was an incident it typically resulted from application issues and not field conditions. This placed the focus on improving the external coating system.

External Coating

Oil country tubular goods and drill pipe are typically shipped from the mill with a thin coat of environmentally friendly varnish. This provides temporary protection from corrosion under pipe yard storage conditions and has minimal durability. Therefore, pipe yard maintenance includes periodic brush, roll, and spray process where the pipe is brushed to remove the external rust and deteriorated mill varnish, then sprayed with new varnish to renew the pipes appearance and protection. Return pipe cleaning processes are more thorough and include a steel media blast or high-pressure water blast to completely clean and remove rust and previous varnish applications. Tubulars used in completions do not typically use an external mill varnish because it is not a proven protective barrier to the salt-based fluids nor durable enough to remain on the pipe during completion operations. The search began for a coating that would prevent corrosion, be compatible with completion fluids, and have the durability to withstand field conditions.

Evaluation of how corrosion develops and early mitigation practices

The project to qualify or develop an external coating to protect these tubulars was a monumental undertaking. Phase 1 began in January of 2007 with an extensive corrosion test of non-coated pipe samples in various completion fluids followed by another conducted in October of 2009. These testing protocols were developed to understand the corrosion products themselves, the sequence of development of the corrosion, the time involved for the corrosion to form, the depth of the pitting, and the density of the pitting resulting from the corrosion in the deepwater projects using standard completion fluids. This was in conjuction with trialing the initial industry available salt neutralizing chemical (SN1) on return pipe and a major inititive to improve the rig operations' corrosion mitigation processes. See Table 1.

Table 1—Phase1 summary of corrosion process testing and mitigation procedures. SN1 and SN2 are classified as salt neutralizing products.

Date	No. Products	Lab Test / Field Trial	Comments
2007	1	Internal Lab	Initiate salt nuetralizing/corrosion inhibitor product (SN1) into return pipe cleaning process
2007	0	Field Trial	Trialed equipment for rinsing pipe with wash wand on rig; investigating mechanical equipment and procedures for corrosion mitigation
Jan-07	0	External Lab	Extensive testing of pipe samples with various fluid samples at atmospheric temperature and pressure to understand the type and formation of corrosion products
Oct-09	0	External Lab	Extensive high temperature static corrosion testing with different CaCl2 and CaBr2 completion fluids, under different conditions
Nov-09	1	Internal Lab	Research and evaluation of internal waterblasting and sandblasting pipe cleaning process, equipment, and chemicals (SN1) with pipe surface chloride measurements
Nov-09	0	Internal Lab	Investigating thread compounds for corrosion mitgation on connections
Jan-10	0	Field Trial	Introduced the racking mats for improved conditions for the connections in completion operations
Jun-10	2	Internal Lab	Compare current product (SN1) in use for return pipe cleaning process with new corrosion inhibitor/salt neutralizer product (SN2)

Multiple other lab tests were run to evaluate corrosion products on the pipe stemming from rig completion operations. The corrosion product that led to severe damaged pipe was often a rapid forming, tough layer of corrosion that would create dense pitting that could cover the entire pipe OD and require a steel media blast to remove. Parameters surrounding the deepwater completions were gathered. Some completion projects had no corrosion issues and others had the entire completion string damaged due to pitting so severe that the pipe would not inspect and therefore was not usable going forward. Some of this damaged pipe had previously been used over various completion conditions, and some were first deployment tubulars. The pipe grades tended to be the higher strength grades required for the deepwater well operations, but no grade was distinguished as more of an issue with corrosion than another. The fluid ranged from seawater to ZnBr completion fluids. Time exposed to completion fluids or seawater was not a distinguishing parameter either. There were a large number of variables in this project and trying to evaluate the data for common properties and consistency was not a simple task. Several other companies and labs were involved in this effort. It was determined that the variables could not be controlled; the available nuetralizing chemicals did not have the performance required; and the operational corrosion mitigation procedures could not be performed consistently or to a level required to prevent corrosion. Evaluation of external coating products to create a barrier between fluid and pipe then began in 2011 and continued for several years.

Evaluation of industry developed external coating products

Phase 2 of the project began in mid-2011 with tests evaluating a series of newly developed products within the oil and gas industry on actual pipe. The first actual rig trial was conducted using a hand sprayer on a rig location to apply a new salt neutralizing product (SN2) to the pipe OD while tripping out of the hole. This product had showed promising results in the yard, however, the field trial failed with a corrosion product developing rapidly and causing the string to be laid down and replaced. This was probably the result of more oxygen being introduced with the sprayer onto the wet pipe. On site application of a corrosion mitigation product was not attempted again. Concurrently, the first yard trial applied a new external coating product (EC1) with a hand sprayer to actual pipe exposed to the weather and recorded observations and the progression over 8 months. After showing good results, the EC1 product was tested on pipe samples in different completion fluids with positive results. Table 2 shows the timeline of Phase 2 testing and field trials.

Table 2—Phase 2 summary of external coating tests and field trials. SN1-SN2 are a salt neutralizing products. EC1-EC4 are classified as external coating products. Op1-Op4 designate the different operators participating in these trials.

Date	No. Coatings/ Products	Lab Test/ Field Trial	Comments
May-11	1	Field Trial	Op1 trialed corrosion inhibitor/salt neutralizer (SN2) on rig completon operation - Failed
Jul-11	1	Internal Lab	Conducted 8-month testing of new external coating product (EC1) on full joints of pipe in the yard
Dec-11	1	External Lab	Testing of new external coating product (EC1) with various completion fluids on pipe samples
Mar-12	1	Field Trial	Op3 trialed several joints coated with new external coating product (EC1)
May-12	4	External Lab	Op4 did extensive testing of pipe samples with various fluid samples and 4 corrosion mitigation products (EC1, SN1, SN2, CI-Add) to evaluate the corrosion process related to rig processes that created damaged pipe
Aug-12	1	Field Trial	Op4 trialed several joints coated with improved external coating product (EC2)
Oct-12	1	Field Trial	Op1 trialed several joints coated with improved product (EC2)
Nov-12	1	Field Trial	Op1 trialed several joints coated with improved product (EC2)
Mar-13	1	Field Trial	Op3 trialed several joints coated with improved product (EC2)
Apr-13	1	Field Trial	Op1 trialed several joints coated with external coating product (EC3) requiring heat to apply
Nov-13	1	Field Trial	Op3 trialed ~5,000 ft coated with improved product (EC2), exposure to SW and $CaBr_2$/ZnBr completion fluids
Nov-13	3	Field Trial	Op1 trialed several joints coated with 3 external coating products (EC2, EC3, EC4) on a 180 days completion. Some joints were 1/2 coated to observe the affects at equal position in the well
Dec-13	1	Field Trial	Op3 coated the entire string with EC2
Dec-13	0	External Lab	Corrosion evaluation of Z-140 and S-135 completion string

The next step was to trial EC1 in an actual well completion operation. Several joints were coated by a hand sprayer with EC1 and put into the completion string. The results were positive with no excessive pitting on the coated pipe, but some flash rust had developed, and durability was in question. Several operators were willing to trial these external coatings and to provide corrosion samples from actual completion pipe for testing. One operator (Op4) conducted an extensive analysis of the corrosion samples and coated pipe samples in various completion fluid mixtures. The results of the corrosion sample testing consistently showed that the corrosive material consisted predominantly of Fe_3O_4, iron oxide III, magnetite, which agreed with earlier testing. This test result using coated pipe samples with four different products (1 external coating (EC1), 2 salt neutralizing products (SN1 and SN2), 1 corrosion inhibitor fluid additive (CI-Add)) in ZnBr fluid showed that brine and air exposure increased the corrosion rate; fluid additives could contribute to corrosion; some of the salt neutralizing products could be incompatible with the completion brine; and the external coating products had potential to create a barrier for corrosion in the lab. These results were consistent with other testing.

Early Products

Several additional field trials with two modifications of the external coating product EC1 (EC2 and EC4) to improve the durability, and another product requiring heat, EC3, were ran over the next 1-1/2 years with three different operators in deepwater Gulf of Mexico projects on their respective completion operations. Each trial would coat several joints to be placed in the completion string while several parameters were monitored, and pictures provided. EC3 was more durable but the heat required for application was not cost effective. One operator, Op3, coated 5,000 feet of intervention riser with EC2 with positive results and no excessive pitting. The challenge with data from EC1-EC4 trials was to develop a product that would hold up to the rigors of a completion operation consistently, preferably for multiple completion operations, be easy to apply, and be cost effective for the pipe rental company and the operator. To achieve the rugged barrier between pipe and environment required to withstand the deepwater completion and intervention operations, the external coating product search needed to expand to outside the typical oil and gas industry chemicals.

2014

Evaluation of commercially viable external coating products from inside and outside the industry

In August 2014 Phase 3 began by conducting an internal lab comparison of ten external coating corrosion prevention products which included previously trialed products, several new products that came from within the industry, and some from outside the industry. The purpose of this evaluation was to select the best products to recommend for field trial based on the ability to reduce pitting from iron-oxides. The manufacturers' claims of corrosion inhibition of various products were limited in their ability to prevent corrosion over the entirety of actual completion operations. Table 3 documents the series of tests and field trials of Phase 3.

Table 3—Phase 3 summary of external coating test and field trials. EC2-EC12 are classified as external coating products.

Date	No. Coatings	Lab Test/ Field Trial	Comments
Aug-14	10	Internal Lab	Coating Product Comparison Test of previous products, new industry products, and outside the industry products (EC2-EC12)
Dec-14	4	External Lab	External coating completion fluid discoloration test with top 4 external coating products (EC4, EC5, EC6, EC7) from Aug-14 qualification testing
Dec-14	4	Field Trial	Op1 trialed the top 4 external coating products (EC4, EC5, EC6, EC7) from the internal lab Comparison Test with several joints coated with each product, some 1/2 joints and some full joints, completion fluid 12.1-13.9ppg $CaBr_2$
Mar-15	3	Field Trial	Op1 trialed 3 external coating products (EC4, EC7, EC8) from the internal lab Comparison Test with several joints coated with each product, all 1/2 joints, completion fluid 10.8-11.35ppg $CaBr_2$. EC8 was the runner up in the internal test Aug-14 and was added
Apr-15	2	Field Trial	Op4 trialed EC4 and EC8 with more joints coated per each coating than had been used in previous field trials, some 1/2 joints coated, and some full joints coated, completion fluid 14.3-14.4ppf $CaBr_2$/ZnBr
Nov-15	1	Field Trial	Op1 coated an entire 27,000 ft completion string with EC8, completion fluid 11.2ppg $CaBr_2$
Jun-16	1	Field Trial	Op3 trialed EC8 on several joints, completion fluid 13.1-13.5ppg $CaBr_2$

Includes the final selected product, EC8.

10 products Tested Starting 2014

The ten products prepared in the same manner were tested on samples and compared for effectiveness in providing a protective layer on the surface of the pipe capable of inhibiting corrosive pitting. Multiple parameters were monitored. Pipe samples steel media blasted and brushed to bare metal were each coated with a different product by spraying the product on the pipe surface. For each product, the thickness when wet was recorded along with the drying times. The samples were left overnight and then verified for complete curing with each sample subjected to a durability (scrape) test, then the samples were left exposed to the outside environment for a week (70°-95° F with 1.20" of rain), followed by a second scrape test. Properties and observations of each product sample were recorded. At this one-week point, there was visible corrosion on some samples. The samples were then placed in 11.6 ppg $CaBr_2$ completion fluid with typical additives and heated to 190°-200°F for an hour, then removed, and placed outside to be observed for an additional three weeks. The samples had an interim observation after 24 hours of the completion fluid soak; at this point many had discolored further with corrosion. At the end of the 3-week observation time, descriptions and conclusions were documented for each product sample and categorized as "rejected" or "warrants further testing". The selected coating products for further testing were still visibly present on the samples, some signs of rust were present, but the coating was still intact with no signs of scale formation. Four products (EC4, EC5, EC6, EC7) were selected for further trialing in the field. However, the final

Down To 4 Products

chosen product was initially excluded from the first cut due to a longer drying time. This was corrected by the coating manufacturer in the subsequent field trial.

The four selected products then underwent a test in completion fluid to monitor the iron-oxide solids produced after an extended time exposed to completion fluid. All four pipe samples with each a different coating product produced very few solids compared to the uncoated pipe sample with a 75-100% reduction in solids compared to the uncoated sample. This testing was done to have a general understanding of the relative difference of a coated surface to an uncoated surface in completion fluid. The measurements were not as important as the scale of difference. The fluids from the coated samples were clear to slightly tinted where the uncoated sample fluid was visibly red/dark due to the iron oxide products, see Figure 3.

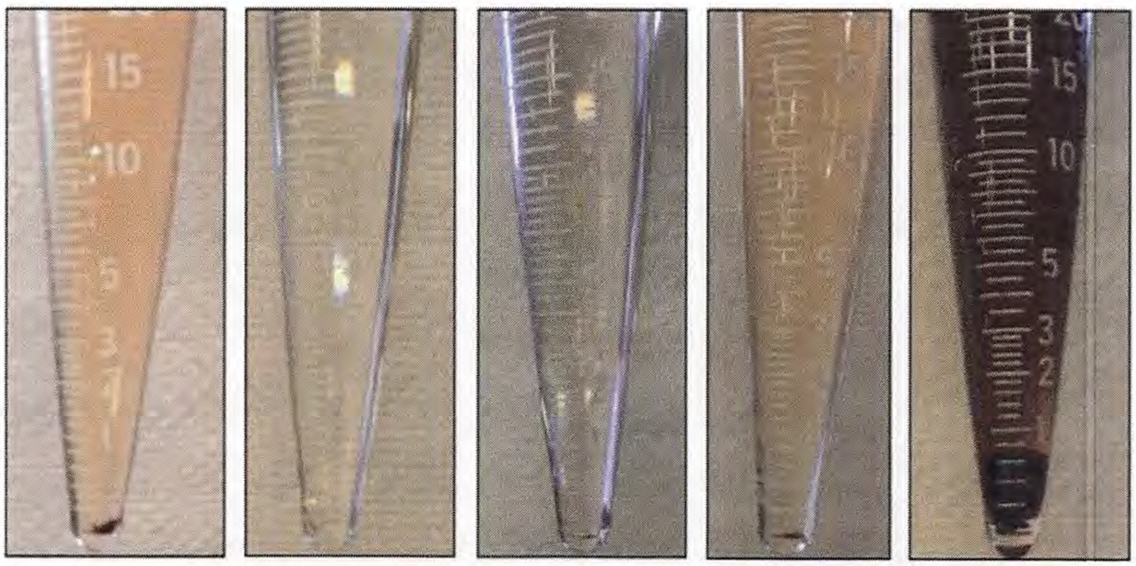


Figure 3—Four coating samples tested on pipe samples immersed in 14.2 ppg CaB_2 fluid for 12 days against uncoated pipe sample on the right.

Down To 2 products

These four selected coating products quickly went for field trial with several joints being coated with each product. Some joints were ½ coated and some fully coated. The completion fluid was 12.1-13.9 ppg $CaBr_2$. The completion operations were approximately 96 days with 57 days exposed to completion fluids. Two of the products, EC5 and EC6, were rejected for application issues and flaking. The remaining two products, EC4 and EC7, had inconclusive results for reducing corrosion and pitting and returned with little or no evidence to the coating still being present or intact.

w/addition of Another product

EC4 and EC7 continued on to the next field trial with the addition of EC8, the next product in line from the qualification comparison test that had been excluded from the previous test due to a slightly longer dry time which now had been improved by the manufacturer. This next completion used 10.8-11.35 ppg $CaBr_2$ with several joints ½ coated with each product. EC4 and EC7, again showed no visible difference between the coated and uncoated sections and the coatings were no longer present or visible. The joints had a layer of rust and scale due to the completion operations and fluid exposure. The pit depth measurements and frequency increased on both the uncoated and coated surfaces. In this trial, all of the joints coated with the third sample, EC8, had visible differences between the coated and uncoated sections. Uncoated sections were covered in scale while the coated sections had no scale and the coating was visibly present. There was no evidence of flaking or chipping. The only coating removal was where there was visible mechanical abrasion. There was evidence to support the coating's ability to reduce pit frequency. The final selected product, EC8, was a metallic-based, moisture-cure polyurethane encapsulating coating. Completion and open water field trials would continue to be conducted on the selected coating system to prove up the ability to create a barrier to the fluids and environment over different well parameters and conditions.

Rust Grip EC 8

Rust Grip (EC8) entered 8 yrs Late but beat out All Other coatings
Process began 2007 - Rust Grip entered Test 2015.

Completion field trial number 1

In November 2015, approximately 27,000 ft. of 5-7/8 in. completion pipe coated with the selected coating system, including external coating EC8, was deployed to the Gulf of Mexico for Operator 1. See Figure 4.

RUST GRIP

Figure 4—Coated pipe prior to shipment to the rig.

A test parameter monitoring sheet was prepared and discussed with the operator to record data. The operator used the coated pipe to drill up the cement in the shoe and then displaced with 11.8ppg $CaBr_2$ with 28 percent ethylene glycol and racked back prior to running the completion. See Figure 5.

According to Test + fluids Team Rust Grip - no contamination, no flaking or peeling - cost savings.

Figure 5—Coated pipe racked back at the rig.

Some of the completion pipe remained on the rig for a total of 86 days. One monitored parameter was the condition of the completion fluid. Iron contamination is often an issue on deepwater completions and requires chemicals and circulation time to correct. According to the project's fluids team, during the completion of this well, there were no issues with iron contamination of the completion fluid. The discoloration of the fluid from the iron had been negligible. This is a cost savings to the operator in chemicals, time, and potential formation damage if there is fluid loss to the reservoir. This was consistent with the data that the coating remains intact thereby creating a barrier.

The coating appeared to withstand the rig environment with no observed flaking or peeling. The coating was removed on some regions of the tool joints mainly where the iron roughneck spinners contacted the pipe body. See Figure 6.

Figure 6—Some damage to coating from spinner, pipe handling, and tongs.

The following conclusions were noted from field trail 1:

1. There was no notable or inspectable tube body damage due to corrosion or pitting, as almost all joints had minimum wall reading above 100 percent remaining body wall.
2. There was some evidence the coating reduced completion fluid discoloration by delaying the rate at which downhole iron-oxide develops, per the project's fluids team. The rig did not report any issues with the coating interfering with the fluid systems.
3. The rig did not report any issues with the coating interfering with the slip system or iron rough neck.
4. The removal of coating by mechanical damage or abrasion does not extend past the area of contact – i.e. no chipping or peeling. This was mostly observed where the iron roughneck spinners contacted the pipe.
5. There were no pipe downgrades to to pitting or corrosion.

2016

Completion field trial number 2

In June 2016, 12 joints of 5-7/8 in. completion pipe were shipped offshore to Operator 3. In August 2016, following the completion, Operator 3 shipped the pipe back in for cleaning and inspection. The operator reported that during the completion of this well the pipe was in service of 40 days (64 total days out). The pipe spent 31 of those days in the completion fluid, characterized as 13.1 – 13.5 ppg $CaBr_2$, with an average down hole temperature of 220°F. The well had a total hole depth of 20,000 ft. and a water depth of 1,537 ft.

A visual inspection of the returned joints was conducted. The external coating was still intact, protecting the pipe from excessive corrosion. The uncoated joints had significant rust and scale build up. See Figures 7 and 8.

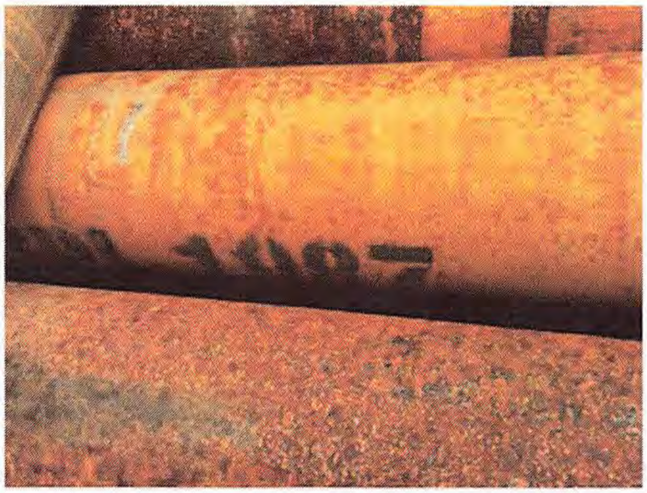


Figure 7—Coated joint (top) and uncoated joint (bottom) post-completion.

Figure 8—Close-up of coated pipe ½ joint (left) and uncoated pipe ½ joint (right).

2015

Open water trials

In 2015, open water intervention projects were becoming more frequent and the first uncoated intervention risers were damaged by extensive pitting that required the operator to purchase the pipe. Several open water fields trials were conducted to evaluate the selected coating system, EC8, under intervention riser application conditions. See Figure 9. These are summarized in Table 4 below.

"0"

Table 4—Summary of open water field trials.

Date	Rig	Number of Joints	Days in Service	Downgrades
March 2015	Rig 1	6	55	0
May 2015	Rig 1	64	31	0
July 2015	Rig 2	74	24	0
August 2015	Rig 3	44	44	0
September 2015	Rig 2	86	86	0

Figure 9—Pipe as returned from open water trial.

External Coating Application Process

The external coating application process for new and used pipe includes steel media blasting of the pipe's exterior to provide proper surface preparation and cleaning. The coating is then applied utilizing an airless sprayer mounted to an automated unit where spray volume, travel, and rotation of tubulars can be adjusted based on OD to insure complete and uniform coverage.

Pipe is cleaned and recoated between deployments. Surface preparation for previously deployed pipe is consistent with that of new and used pipe, using steel media to blast exterior surface and then the external coating is applied through an automated process. Surface touchups can be made manually.

Crucial to the application process is surface preparation, and the ability to automate, ensuring an even coverage by regulating spray volume, travel of the sprayer, and rotation of the tubulars throughout application. The inability to automate can result in coating build up that can affect tubular handling. Or, lack of automation may result in missed coverage, leaving metal exposed. A dedicated coating facility was completed in late 2014 with the capacity to coat 150 joints per day. A quality control process was developed to ensure consistent coating thickness and dry times. See Figure 10 and 11.

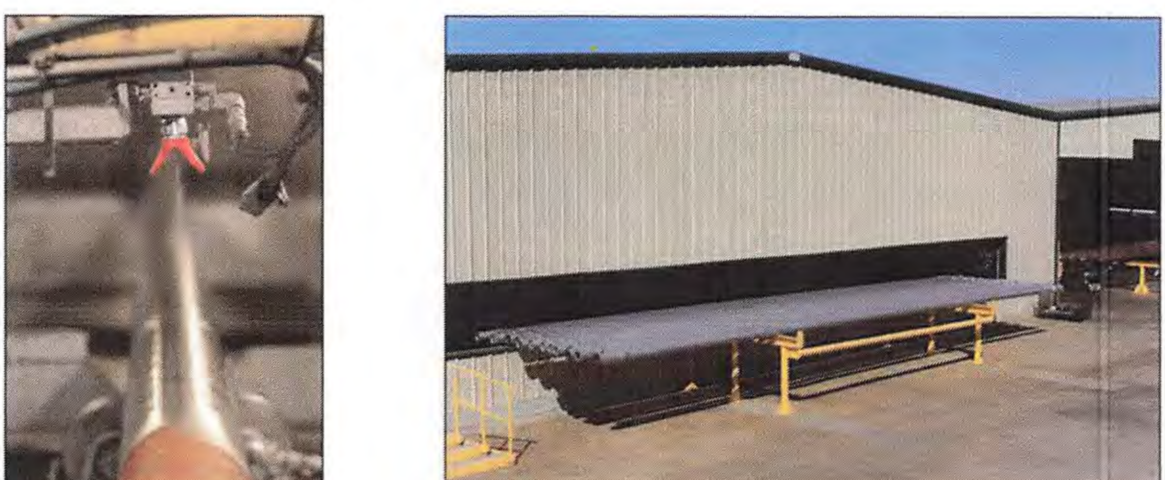


Figure 10—Airless coating application and coating facility.

Figure 11—Pipe ready for deployment.

Final Coating System

The internal plastic coating, modified epoxy phenolic product, provides corrosion resistance in general oilfield environments over a wide pH range, chemical resistance, temperature resistance, flexibility, and resistance to impact, abrasion, and wear from wireline and other downhole tools.

Rust Grip

The external coating is a metallic-based, moisture-cure polyurethane encapsulating coating designed to coat and seal out air, moisture, and chemicals. It provides external pipe protection minimizing corrosion in open water and marine environments. It provides a protective film of superior adhesion and flexibility, and is resistant to salt-based fluids, impact, chemical solvents, and acid splash.

The coating system is applied on the completion and intervention tubular's internal and external surfaces providing protection from exposure to corrosive oilfield chemicals and the marine environment. Chemicals and salt cannot attack the metal. Having both ID and OD coating creates a barrier to fluids and chemicals including some resistance to H_2S/CO_2. These coatings plus other corrosion mitigation practices: using wiper rubbers and racking mats, rinsing the pipe, reapplying thread compound to pin and box connections can eliminate corrosion related damage on tubulars' pipe body and connections.

Deployments

One pipe rental company provides tubulars for completion and open water intervention operations for customers around the world including the Gulf of Mexico since the early 2000's. Battling corrosion has been an obstacle to maintaining the asset quality and life. Providing solid care and handling recommendations to customers has been a challenge as well. This coating system, a modified epoxy phenolic internal plastic coating and a metallic-based, moisture-cure polyurethane encapsulating external coating, has been applied to all of this company's completion and intervention tubulars since 2015.

Since 2015 Coating System

Since the implementation of this coating system in 2015, this pipe rental company has applied this coating system to over 1,700,000 feet (44,000 joints) of completion and intervention pipe and has experienced zero corrosion related pipe body downgrades and zero reported field issues

"0"

Operator Cost Savings

The coating system eliminates pipe body downgrades and the associated costs for the operator. Before this coating systems was available, completion and intervention pipe were often deployed for a single operation then returned to shore for inspection to verify remaining body wall thickness. Eliminating the external corrosion concern has allowed the pipe to remain offshore for multiple operations saving the operator marine transport, freight, inspection costs, and interim repairs. Non-productive time on breaking down and making up stands is also minimized, as well as helping to maintain the integrity of the fluid system and reduce scale that can cause mechanical issues with production equipment.

System savings

Case History

Corrosion Economics

Corrosion related costs to the operator, as it relates to completion tubulars, manifest themselves in a variety of ways, though many are difficult to quantify precisely. One pipe rental company estimates that an operator could spend approximately $370,000 on logistics and inspection while swapping out a completion work string. There is also an estimated cost of $500,000-$1,000,000 per completion if an operator is forced to re-condition their fluids due to iron contamination. Finally, some operators have expressed concern with the potential for scale and rust to compromise the functionality of isolation barrier valves. Failure of these valves can result in losing a well.

Completion Work Strings

Beyond the goal of eliminating corrosion and pitting-related damages, the introduction of externally coated completion tubulars has facilitated a paradigm shift in the way operators manage rental completion tubulars. Prior to the full-scale deployment of external coating, a completion string could not remain with confidence on a rig site for consecutive wells and was often swapped out in the middle of a well or multi-well program due to massive scale build-up and tubular pitting. The introduction and adoption of external coating has allowed completion strings to be used for multiple consecutive completions, eliminating the costs of trucking, marine transport and cranes, and return and outgoing inspection. It also significantly reduces connection repair cost per well. This, in turn, extends the life of the pipe by maintaining the tool joint length requirements for a longer period. Table 5 below reflects completions on a deepwater rig in the Gulf of Mexico from October of 2015 through September of 2017. The wells highlighted in blue reflect completion strings used on consectutive well projects. Typical connection damages on a single completion for a completion string with a metal-to-metal seal can range from 45% to 55%. By deploying external coated assets this operator was able to realize a rate of 15.99% - 24.21% connection damages per well by utilizing the same string over three consecutive completions. The savings realized in connection repairs alone is estimated to exceed $250,000.

Table 5—Reduction of connection percent damage per well as the result of the ability to complete consecutive wells with same OD coated completion workstring.

Consecutive Completions	Date Shipped	Date Received	Connection Repair Costs	Connections Inspected	Recuts	Connection % Damage per Well
1st	10/21/2015		$ 117,353.67	2176		15.99%
2nd			$ 117,353.67			15.99%
3rd*		4/30/2016	$ 117,353.67		1044	15.99%
1	9/12/2016	11/18/2016	$ 208,143.00	1236	611	49.43%
1st	1/13/2017		$ 114,999.33	1392		24.21%
2nd			$ 114,999.33			24.21%
3rd		6/20/2017	$ 114,999.33		1011	24.21%
1	1/20/2017	7/8/2017	$ 217,948.00	1336	629	47.08%

* Completion workstring swapped out mid-well due to concerns of damaged internal coating from coil tubing.

Completion Landing String and Intervention Riser

An inventory of 21,000 feet of 7-5/8 in. pipe has been in use since 2016 as a completion landing string and as an open water intervention riser by one operator in the Gulf of Mexico. This asset has been externally coated prior to shipment on every deployment. After 29 deployments over four years on four different rigs, there has not been a single downgrade due to pitting, OD corrosion, or remaining body wall falling below

95% of nominal. In addition, the 6 5/8 in. pipe used as an intervention riser as discussed in Table 4 had zero joints downgraded.

Conclusions

The internal pipe coating was a proven solution since the early 2000s and continues to be a proven barrier between pipe and fluids/environment. With the investigation of corrsion products, corrosion mitigation chemicals and procedures, and development of a proven external coating product, pipe body downgrades of completion tubulars and intervention risers due to corrosion and pitting are eliminated by using the appropriate external coating system and proper tubular maintenance. This coating system provides a trouble-free solution and significant cost savings to the operator and the pipe rental company through reduction in pipe repairs and damages; loss of capital assets; and rig time due to pipe issues, fluid issues and corrosion issues.

Acknowledgements

The authors wish to thank the management of Chevron North America and Workstrings International, LLC for their support and encouragement in preparing this paper. There have been many contributors to this successful effort over the past 13 years within the Chevron Gulf of Mexico Business Unit, Workstrings Broussard Headquarters, SPI Inc, other major operators, other service companies, current employees, and past employees. The authors wish to thank the time and expertise that so many brought to this project and a successful solution. A special thank you to Joshua Babineaux and Richard Robichaux for their dedication to solving this problem and their team's determination to implement a viable external coating solution and corrosion mitigation practices.

Abbreviations

ft. = feet
in. = inch
ppg = pound per gallon
°F = degree Fahrenheit
pH = acidic/basic scale
$ = US dollars

Metric

foot = meter (M) * 3.048 E-01
inch = meter (M) * 2.54 E-02
lbm/gal (US liquid) = kilogram per meter^3 (kg/m^3) 1.198264 * E+02

References

1. R. Brett Chandler, SPE/IADC, Grant Prideco; J. Rodney Hensley1, ChevronTexaco; Manuel E. Gonzalez, SPE, ChevronTexaco; Andrei Muradov, SPE, Grant Prideco; Michael J. Jellison; SPE/IADC, Grant Prideco; Project-Specific High-Pressure Completion Tubular for ChevronTexaco's Tahiti Project; SPE/IADC 92497 2004 IADC/SPE Drilling Conference
2. Kevin Corbin, SPE, Taylor Begnaud, Chevron, Greg Elliott, SPE, Leianne Sanclemente, SPE, Joshua Babineaux, Jim Brock, SPE, Workstrings International, Guillaume Plessis, SPE, Andrei Muradov, SPE. NOV; An Industry-First 7-5/8 in. Drill Pipe Like Tubular Facilitates Deep Offshore Completions and Interventions by Saving Time and Reducing Cost; SPE-184726-MS 2017 IADC/SPE Drilling Conference

3. R Pourciau, SPE, ChevronTexaco; Case History: Internally Coated Completion Workstring Successes: SPE-77687 2002 SPE Annual Technical Conference and Exhibition