SME Corrosion Technical Report of O&M Activities
for the
GAIL Rajahmundry Sites Visit of the Krishna Godavari (KG) Basin Area
(December 15\textsuperscript{th} – 20\textsuperscript{th}, 2014)
of

GAIL (India) Limited

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1.0 INTRODUCTION

At the initial contact and request by GAIL’s Mr. G. Chakraborty, on November 28th, 2014 the writer was requested to check his availability and timing of a proposed trip for the subject site visit during December 2014. As can be seen from the subject title the trip initiated and terminated between December 15th and 20th, 2014 (Calgary time). Selected from the GAIL competitive bid (No. GAIL/NOIDA/C&P/140810), Empanelment of Expert/Consultant for various O & M activities of GAIL, I was requested to provide technical guidance in response to a number of technical objectives for the KG Basin area which were promulgated by Mr. Sateesh Kumar on December 15th, 2014.

The large focus of the writer’s recent trip was to assess the feasibility of the newly deployed corrosion inhibitor infrastructure (pumps and quills) as well as the chemical formulation (Deltamike Gas Line Corrosion Inhibitor (H2S)) for sour wet gas transmission pipelines receiving upstream gas from various ONGC GCS locations. To that end the writer visited ONGC GCS locations at Mandapeta and Mori as well as the 65 km VSPL - LNG pipeline upstream facilities near the city of Rajahmundry.

This report documents the site visit with expert comments regarding the assigned following tasks:

1. Site visit of KG Basin pipeline terminals for familiarisation and corrosion inhibitor dosing system.
2. Adequacy check of Corrosion inhibitor injection system at KG Basin pipelines
3. Recommendation of corrosion inhibitor dosing in VSPL LPG pipeline (test piece removed from pipeline available)
2.0 CONCLUSIONS

2.1 Recently installed chemical injection facilities (within the past 3 – 4 months at ONGC sites) are inadequate to provide the essential levels of chemical availability required to ensure long-term internal corrosion mitigation of GAIL gas transmission pipelines.

2.2 The “DeltaMike” chemical corrosion inhibitor formulation being advocated by ONGC for use in GAIL pipelines is inadequate for the corrosive parameters being observed by the writer at the select locations visited and also in conjunction with pipeline operating and compositional data provided during and after his site visit.

2.3 The ONGC recommended “DeltaMike” corrosion inhibitor was tested at atmospheric pressure which is not representative of pipeline conditions. Additionally, the reported 85% protection level derived by testing is considered in North America to be poor-to-marginal performance where protection levels of 95+% are expected at minimum.

2.4 GAIL must be prepared to run both continuous and batch corrosion inhibitor treatments to provide acceptable levels of internal wet gas pipeline protection on its piggable pipelines.

2.5 The use of chemical of chemical corrosion inhibitor injection quills are not being properly deployed with respect to orientation of the quills relative to the gas flow within the pipeline.

2.6 Based on limited historical failure data from the various pipelines in the KG Basin, wet gas pipelines with a CO₂ partial pressure in excess of 15 psig (1.06 kg/cm²) are at an elevated risk of severe and aggressive internal corrosion.

2.7 The writer was provided with gas analyses from 28 pipelines from among 61 KG Basin pipelines. Nineteen of these could be assessed for CO₂ partial pressure and it was determined that 7 or 36.8% had partial pressures > 15 psi. Consequently, there are indeed some higher risk pipelines which require more operational scrutiny in terms of corrosion monitoring and corrosion inhibition.

2.8 Microbiologically influenced corrosion (MIC) appears to be implicated in corrosion of wet gas pipelines and is likely the source of souring by H₂S at various locations where corrosion product/scale was collected.
2.9 The VSPL – LNG pipeline failure exhibits pits associated with oxygen, acid attack (most likely derived from carbonic acid and CO₂) and randomly scattered H₂S attack. Notwithstanding, more work is required in a materials lab in India to document the pit morphologies and give guidance on actual corrosion mechanisms.

2.10 The current GAIL handling procedures for damaged pipe spools is likely non-existent and at a minimum is inadequate for evidentiary reasons which are resulting in the loss of valuable corrosion product and mineral scale samples for forensic analysis.

2.11 Indoctrination and training of all field staff regarding internal pipeline corrosion is absent and is a contributory factor associated with previous pipeline integrity problems being or having been encountered by GAIL.


2.13 Corrosion monitoring is inadequate for GAIL wet gas transmission pipelines. Specifically, the use of ER (electric resistance) sensors and corrosion coupons are incapable of delivering reliable and timely data respectively.

2.14 Samples collection and handling is not satisfactory in general from what the writer has observed in his brief trip to the Rajahmundry KG Basin area.

2.15 The above cited conclusions must be properly addressed and dispositioned, otherwise more failures can be expected to continue and become more frequent.
3.0 RECOMMENDATIONS

3.1 Upgrade and improve all chemical injection sites for corrosion inhibitor into GAIL natural gas and LNG pipelines. The current deployment set-up of injection facilities will not provide the high (i.e. 99+ %) inhibitor availability which is essential in mitigating wet gas internal pipeline corrosion.

3.2 The current corrosion inhibitor recommended by ONGC should be substituted with a combination of monthly batch chemical treatments using Nalco Champion EC1122A and continuous injection with Nalco Champion EC1118A at 75 ppm based on total liquids in a given pipeline system.

3.3 Retractable, chemical injection quills should be installed with a counter-current orientation. Injection locations must be located and placed in locations near the source of gas or LNG inflow but yet be free from being struck inadvertently by pigs. A retractable injection quill is preferred to allow removal for inspection, repair and replacement.

3.4 Ensure that chemical corrosion inhibitor injection for gas and LNG pipelines is downstream of GAIL inlet scrubbers receiving gas from ONGC. A review of the layout of the piping being treated at ONGC Mori /GAIL Mori has a scrubber immediately downstream of the corrosion inhibitor injection location (refer to Figure 2 which shows the GAIL receipt location immediately downstream of the ONGC Mori GCS).

3.5 On-line and/or real-time internal corrosion monitoring must be deployed on all higher risk wet gas pipelines to assess the interim use of the recommended alternative corrosion inhibitor formulations to facilitate optimal chemical treatment levels.

3.6 Internal corrosion monitoring should deploy LPR (linear polarization resistance) on pipelines with CO₂ partial pressures between 15 and 30 psi and EN (electrochemical noise) on very high CO₂ partial pressure pipelines above 30 psi CO₂.

3.7 Advanced corrosion inhibitor testing must be conducted as soon as possible given the imminently high corrosion threat from numerous KG Basin pipelines. There are only about a half-dozen reliable labs in the world capable of doing the requisite testing needed for the GAIL pipeline infrastructure.

3.8 The VSPL – LNG pipeline requires testing of solids, a materials failure investigation, MIC testing before a long-term reliable corrosion inhibition strategy can be developed.
3.9 GAIL should consider the feasibility of conducting interim batch chemical treating of the VSPL – LNG 18” X 65 km pipeline with the Nalco Champion EC1122A product. Targeted treatments based on failure history location are required to determine the chemical batch volume or “pill” required as it needs about 200L/km when the chemical is diluted to a maximum of 20% with diesel or hydrocarbon condensate.

3.10 Internal corrosion predictive modeling (ICPM) should be conducted using NACE International Standard Practice SP00208-2008 LP-ICDA and/or the pending MP-ICDA Standard Practice on the VSPL – LNG 18” X 65 km pipeline to determine the root-cause of the pipeline failures thereby definitively identifying the contributing mechanisms and paving the way for an effective mitigative plan.

3.11 It is quite probable the GAIL wet natural gas pipelines are prone to MIC (microbiologically influenced corrosion) and hence the future use of biocides is quite likely. Additional chemical injection facilities for continuous biocide treatment should be at least budgeted for by GAIL and anticipate their deployment by early Q3 – 2015.

3.12 Samples collection and handling within GAIL should be extensively and carefully reassessed. The writer has provided some guidelines in Section 4.4 of this report. It is recommended that GAIL meet with the writer to discuss all protocols for petroleum fluids sampling, water collection, solids collection and analyses of all of these.

3.13 Collection of physical evidence including pipeline samples must follow strict Chain of Custody protocols to minimize loss and contamination of these crucial pieces of evidence. Without these processes the effective mitigation of pipeline failures is compromised.
4.0 DISCUSSION

4.1 Chemical Corrosion Inhibition Application Methodology

4.1.1 Current Status Quo Since Fall 2014

The writer visited the Krishna Godavari (KG) Basin area and two on-site ONGC chemical injection sites at Mandapeta and Mori respectively. Both locations deliver wet gas directly into the GAIL gas pipeline infrastructure. Figure 1 below shows the Mori set-up for corrosion inhibitor injection into the GAIL gas pipeline upstream of the LACT.

![Figure 1 - Corrosion inhibitor injection station at ONGC Mori upstream of LACT into the 12" GAIL pipeline system which flows to Dindi. Injection of chemical is via pneumatic PD pump. Note the absence of a sight glass to measure injection rate. (December 18th, 2014)](image)

As can be seen in the picture above in Figure 1 at **ONGC Mori**, there is no absolute and immediate measure for chemical consumption other than volumetric consumption differences from the blue pail. Specifically, unless the original level of corrosion inhibitor was accurately measured and then, the exact time duration between readings is known, the chemical injection rates are ostensibly uncertain or approximations. Additionally, there is no in-line strainer or filter for the corrosion inhibitor discharge line off the pail and upstream of the pneumatic PD pumps. In-line filtration typically requires a 50 µm filter. The gas is being chemically treated with what is believed to be a water-soluble corrosion inhibitor (i.e. Deltamike). The gas stream contains approximately 116 lbs/MMSCF of water at 40.87 kg/cm² (580 psi) and 37 °C. The wet gas is reported to contain 0.58 mol% CO₂ and reported trace levels of H₂S. Production rates and water
saturation levels were not provided; therefore it is not presently possible to assess the potential water drop-out. Liquid hydrocarbon dropout is not predicted to occur based on a PVT analysis performed by the writer. The very narrow two-phase envelope for liquid retrograde hydrocarbon condensation exists because the overwhelming majority of the gas is methane.

A review of the layout of the piping being treated at ONGC Mori /GAIL Mori has a scrubber immediately downstream of the corrosion inhibitor injection location. Figure 2 below shows the GAIL receipt location immediately downstream of the ONGC Mori GCS. The water dump off the scrubber will result in the water soluble corrosion inhibitor largely being lost and NOT injected into the GAIL pipeline where it is required. As a result the location of the chemical injection site (Figure 1) is ineffective and should be moved to downstream of vertical scrubber at the GAIL Mori.

![Vertical Scrubber at the GAIL Mori Receiving Station](December 18th, 2014)
Figure 3 below is a photograph of the GAIL Mori Gas Receiving Terminal where the corrosion inhibitor should be injected rather than upstream at the ONGC GCS which is located to the left of the wall in the background in Figure 2 above.

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**Figure 3 – GAIL Mori Gas Receiving Station where corrosion inhibitor injection site should be move to from ONGC Mori. (December 18th, 2014)**

On Wednesday, December 17th, 2014 the writer visited the ONGC Mandapeta GCS. The injection of chemical at ONGC Mandapeta does properly utilize an injection sight glass or pump setting gauge to measure the pneumatic pump rate of corrosion inhibitor into the GAIL pipeline. The gas being chemically treated with corrosion inhibitor (i.e. Deltamike), contains approximately 116 lbs/MMSCF of water at 30.19 kg/cm² (428.5 psi) and 38.75 °C. The wet gas is reported to contain 4.59 mol% CO₂ and 3.5 ppm H₂S. The gas production rate is 12,215 SCMH (~ 10.4 MMSCFD). Assuming the gas is at saturation with respect to water, the potential water dropout into the downstream
pipelines owned by GAIL is about 0.5 m³/d. Theoretical chemical consumption rates are very low and are likely being overdosed at present.

4.1.2 Suggested Improvements for GAIL Chemical Treatment Methodologies

Correct chemical injection is predicated upon the “inhibitor availability (IA)” consequently to have a reliability level of 99% on-time; international norms of pipeline integrity management require high reliability, automated back-up or redundant pumps. Given the internal corrosion threat is severe in some KG Basin locations it is highly advisable that GAIL install redundant electric venture pumps similar in configuration as to that depicted in Figure 4 below. Bulk chemical storage tanks are required with at least a 60-day reserve of chemical available at any time. Therefore, a daily chemical rate of 5 L/d translates into a reserve of at least 300 L bulk chemical storage tank. Therefore typical 125 US gallon (475 L) capacity tanks are required but again is dependent upon desired chemical injection rates. Reputable corrosion inhibitor manufacturers will generally supply these tanks as part of their overall service strategy. The writer suggests GAIL pursue this path as it is essential that any potential for cross contamination by unknown chemicals or using older bulk chemical tanks can be detrimental to reliable inhibitor performance.

Figure 4 – Electric driver, Redundant Corrosion Inhibitor Chemical Injection Pumps in a Canadian gas production operation to achieve a 99% delivery of continuous corrosion inhibitor. See the vertical sight glass behind the right pump.
A typical chemical injection set-up is provided in the schematic below in Figure 5 below; of significance in the below drawing is the absence of a redundant pump which is deployed when the corporate mandate for 99+% inhibitor availability is expected.

Figure 5 – Typical Chemical Injection System – source is Kilgore College (Kilgore, Texas); Chemical Injection Methods “Pros and Cons”

4.1.3 Chemical Injection Quills and their Application

Chemical injection of the water soluble corrosion inhibitor (i.e. Deltamike) is part of the current status quo pipeline integrity program at Mandapeta and Mori. The corrosion inhibition injection station as shown in Figure 1 employs injection quills to inject the corrosion inhibitor into the GAIL gas pipeline system.

The availability of corrosion inhibitor for effective corrosion inhibition, using the present system employing injection quills, depends upon a number of factors such as the operating conditions (i.e. Pressure, Temperature and gas flow rate), injection quill orientation, inhibitor density relative to water, pipeline diameter, insertion length required to injection zone, and the injection port size & type.

A comparison of the current corrosion inhibitor injection system with a typical chemical injection system (as shown in Figure 5 above) is as follows:

- Generally a chemical bulk tank, made of material compatible with the chemical handled with an adequate storage capacity (i.e. typical 125 US gallon (475 L) as
identified by the writer above) has to be used along with a spill contaminant reservoir (sized 1.5 - 2 times the size of the storage tank). Thus, the blue pail used in place of a storage tank is largely inadequate.

- A typical chemical injection system requires a chemical filter upstream of the pumps for larger particulate removal and an inlet chemical filter (50 µm) for the corrosion inhibitor discharge line or in accordance to the maximum free passage diameter of the quills employed.

- In the status quo corrosion inhibitor injection system, there is no gauge to set pump discharge rate and measure the pneumatic pump rate of corrosion inhibitor at Mori. There was a sight glass located on the Mandapeta chemical injection station. A general configuration as shown in Figure 5 employs a positive displace pump (with higher discharge capacity than the maximum process pressure). However, as identified by the writer above, GAIL is advised to install redundant electric venture pumps in place of the pneumatic pumps and a pump discharge pulsation dampener be installed, which decreases the pressure spikes in pump discharge.

- Injection of chemicals in gas/liquid pipelines is achieved using a nipple, quill or atomizer with 50 micron inlet filter, check valve, pressure gauge and isolation valve. For gas pipelines, usually an insertable atomizer (pneumatic atomizer or spring activated hydraulic atomizer) is used for injection of most chemicals. Injection quills, as in the case of the present GAIL system, should be used for injection of corrosion inhibitors if the gas velocity exceeds 15 ft/s (i.e. 4.57 m/s). Unless there is a significant gas velocity, the chemical will not be adequately dispersed into the gas stream, when using an injection quill.

- Continuous or batch inhibition is required via injection quills and the systems should include a double block and bleed arrangement or other positive shut-off system to mitigate leakages of chemical injectant (i.e. the corrosion inhibitor) into the gas stream when the system is not flowing or out of service.

The proposed NACE International Standard Practice being developed by Task Group TG 174 Refinery Injection and Process Mix Points requires the injection systems to include the following, at the minimum extent:

1. Upstream process piping equivalent to twice the piping diameter;
2. Main process piping 10 diameters downstream or past the point of two changes in direction (whichever comes first), or the next pump or pressure vessel;
3. Selection of the injection device (e.g. quill);
4. Chemical injectant piping back to the first upstream block valve.
The proposed **NACE International Standard Practice**, *Refinery Injection and Process Mix Points* also provide for the recommended orientations of the injection quills in the pipeline, as shown in Figure 6. Co-Current injection is suggested when wetting is the desired result and counter-current injection is desired when an increased spray zone is desired. Based on the writer’s experience better success will be achieved if the quills (or spray nozzles) are oriented counter-current to the gas flow.

![Figure 6 - Co-current or Counter-current injection quills (I = Injection, R = receiving stream, and M = Mixed stream) are recommended in accordance to the NACE International Standard Practice under development, Refinery Injection and Process Mix Points.](image)

Further while using injection quills, the following are to be considered as best operating practices:

i. Quills should discharge into the center of the receiving stream to enhance dispersion and prevent contact of the undiluted injectant with the pipe wall;

ii. Quills with beveled ends are considered with an angle between 30° and 45° be used and Quills with slotted ends enhances dispersion of the injectant;

iii. When possible, quills should be fully retractable to allow removal for inspection, repair and replacement;

iv. The quill design shall include retraction stops and protective blow out chains.
4.2 Chemical Corrosion Inhibitor Suitability and Alternative Options

4.2.1 Current ONGC “Deltamike” Program Started in Late 2014

The recommended corrosion inhibitor now being deployed into GAIL wet gas operations over the past 4 – 5 months in at least the KG Basin is not suitable for these gas compositions and operations. The primary reasons for this non-capability of this specific “Deltamike Specialty Products” inhibitor are based upon the following issues:

- Hydrocarbon liquids in wet gas pipelines appear to be much less than the 10% by volume with brine. Since the inhibitor is likely a water soluble, hydrocarbon dispersible formulation there will be a certain amount of chemical which does NOT partition into the water phase or is retained in the hydrocarbon liquid media (a blend of 70% crude oil and 30% (by volume) of xylene). Additionally, the type of xylene is not specified as para, ortho or meta or a blend thereof, all of which will affect the partitioning coefficient of the Deltamike inhibitor.

- Testing was not conducted at representative line pressures but rather at atmospheric pressure which changes the corrosivity of the fluid as acid gases tend to flash and buffer the test medium in-situ pH (which was not specified).

- The concentration of CO₂ is not representative of the actual dissolved CO₂ expected in many locations.

- Dynamic test duration is too short at 24 h as this is not representative of overall corrosivity which initially spikes in the first 24 h and then stabilizes as a function of inhibitor concentration.

- The perceived inhibitor efficiency minimum acceptable level of suitability is too low at 80%. The test result in the 24 dynamic wheel tests at 85% is unacceptable. High performance chemical corrosion inhibitors MUST have minimum per-cent protections (i.e. %P) of at least 95%.

- Based on experience, the test dosage rate of 35 ppm (based on water volume) appears to be too low. NACE International recommends the dosage volume in wet gas systems is always based on total liquid volume. Other concentrations are always required to assess the performance of such products to ensure their dynamic range of application and that the inhibitor if over dosed in some cases results in the product being a “corrosion accelerator”.

Figure 7 below shows the chemical product as stored at the ONGC Mori facilities. As can be seen a bulk chemical storage tank is far better and safer to avoid accidental contamination of the product.
4.2.2 Suggested Alternative Interim Chemical Corrosion Inhibitor Treatment Options

It is strongly recommended **GAIL immediately switch their Deltamike, ONGC continuous corrosion inhibitor product on an interim basis**, (i.e. pending the results derived from advanced corrosion inhibitor screening tests) to substitute to a combination of both a **monthly batch** chemical treatment program and a continuous feed program of Nalco Champion using products **EC 1122A and EC 118A respectively**. The EC1122A batch chemical inhibitor should be batched into the GAIL pipelines at an 80:20 blend of inhibitor to diesel (or condensate) to achieve a 0.003” (76 μm) **ACTIVE** film thickness. If the product is diluted above at 4:1 then the total blend thickness target must be 0.0036” (91.4 μm). The EC 1118A is recommended by Nalco Champion to be dosed at a rate of **25 ppm (vol)** based on the liquid volume anticipated to condense or be as free water. GAIL should vary these rates only if on-line monitoring is employed such as LPR (linear polarization resistance) which can yield instantaneous rates for inhibited corrosion rates. Notwithstanding, the writer suggests the inhibitor be initially **dosed at 75 ppm and adjusted if and only if on-line monitoring suggests the rates can be lowered**.

The Nalco and then Nalco Champion recommendations respectively, are predicated upon correspondence sent to GAIL on January 3rd, 2014 for the EC 1122A and September 13th, 2014 for the EC 1122A products. Both proposals were sent to GAIL representative, Mr.
G. VaraPrasad, Senior Manager, (NG, P/L, and O&M). The batch testing was performed in a HP, HT circulating flow loop which was an attempt to mimic or replicate typical wet gas transmission lines for GAIL in the KG Basin whereas, the continuous inhibition testing was done regrettably, at atmospheric pressure (or nearly so) in a so-called “kettle test” which is largely restricted to no more than 3 psi since the “kettles” are glass vessels. The results nonetheless are better than those attained with the ONGC testing for the current Deltamike product with a P% (protection) of 85% P for the Deltamike as opposed to 97.5% P for the EC 1118A. Since the continuous inhibitor testing was done at atmospheric pressure in both “screening” tests, it is imperative that advanced testing be conducted soonest. The writer issued an email reply on December 29th, 2014 to Mr. Debasis Sengupta, in response to questions posed to the writer by GAIL on December 23rd, 2014 regarding testing in Point 6 of that email reply. Given the extreme corrosivity of the wet gas and high CO₂ partial pressure pipelines in-service of being brought back into service, testing should be given the highest priorities by GAIL.

4.2.3 Biocides

Presently, there is no treatment for microbiologically influenced corrosion (MIC) in the subject pipelines as very little evidence other than low concentrations of H₂S has been reported from stain-tube tests conducted in the field by the gas producers such as ONGC. However, solids spot testing conducted by the writer on December 19th, 2014 using concentrated HCl suggests that not only CO₂ is a leading threat but also microbial action and likely sulphate reducing bacteria. Figure 8 following show the dissolution of solids samples collected from GAIL pipe specimens at VSPL and tested at the GAIL Rajahmundry office. There is the rapid effervescence of CO₂ from FeCO₃ (siderite) corrosion product but also the appearance of yellow spots (sulphur deposits?) and the deep, sharp yellow colouration of the solvent after acidification. This suggests the presence of sulphur-bearing products and/or ferric ions (Fe³⁺) arising from ferrous (Fe²⁺) oxidation when exposed to air. The intensity of the yellow colour is quite unusual and may suggest other issues at work which have yet to be defined.

![Figure 8](image-url)  
Figure 8 – Corrosion product being dissolved by HCl. The bubbling is indicative of CO₂ attack and the yellow spots are likely sulphur or sulphur bearing compounds.  
(December 19th, 2014)
GAIL should be prepared to test for bacteria and archaea in accordance with NACE International Standard Practice TM0212-2012 Detection, Testing, and Evaluation of Microbiologically Influenced Corrosion on Internal Surfaces of Pipelines. This testing should be coordinated and conducted as soon as possible as it will have to be a consideration for the proposed corrosion inhibitor testing mentioned previously by the writer. If the bacteria and archaea can be identified then this will help align biocidal treatment testing and applications strategies for GAIL.

4.3 VSPL LNG Pipeline Observations and Path Forward

4.3.1 Internal Corrosion at VSPL

The writer visited the VSPL upstream LNG pipeline facilities near Rajahmundry. This is the start of an 18” X 65 km long pipeline as shown in Figure 9 below. The purpose was to visually inspect failed piping spools which had been recently removed from the 18” pipeline.

![Figure 9](image)

**Figure 9 – VSPL LNG pipeline at upstream pig launcher facilities near Rajahmundry (December 19th, 2014)**

Inspection of a failed piping spool was conducted as effectively as possible despite the spool not being sectioned. The piece revealed two distinctly different types of scale; one that was acid insoluble and the other as very active as that shown in Figure 8 previously. Figures 10 & 11 following, shows the failed pipe spool from the outside indicating the pinhole leak and the ID of the pipe showing pits likely caused by MIC and air contamination possibly. Figure 11 faintly shows a narrow line of very small diameter pits which may be suggestive of air contamination.
Figure 10 – VSPL failed pipe spool indicating the pinhole leak as marked on the OD. (December 19th, 2014)

Figure 11 – The inside corroded LNG pipe spool. The yellow circle identifies a line of very narrow deep pits which may be indicative of oxygen contamination of the LNG. (December 19th, 2014)
Figure 12 is a magnification of the line of narrow deeper pits as circled in Figure 11.

Figure 12 – A magnification of the line of narrow pits on the LNG pipe spool as shown previously in Figure 10. *(December 19\textsuperscript{th}, 2014)*

Interestingly, the scale morphologies are quite different when examined visually. Figure 13 shows a solid flaky scale which is insoluble in concentrated HCl. Figure 14 on the other hand depicts the vigourous reaction of the powdered scale obtained after wire brushing to expose the pipe ID wall surface.

Figure 13 – Insoluble flaky scale removed from the LNG failed spool in concentrated HCl. *(December 19\textsuperscript{th}, 2014)*
As a result of the vastly different reactions to the scale samples derived from the GAIL VSPL LNG pipe spool it suggests the flaky, non-pulverized scale may have an organic thin film that is impervious to the acid but after wire brushing the material and increasing the exposed surface area of the scale the results are seen in Figure 14. Since the writer was only at the site for about an hour there was insufficient time to do a more thorough assessment of the pipe. It is highly recommended that the spool be tested at a reliable metallurgical laboratory in India and that scale samples are assessed as well. Absent this information the writer can only at best speculate what may have led to this failure. Consequently, at this time CO₂ corrosion is implicated, MIC is possible based on the presence of what appears to be sulphur and or sulphur compounds including polysulphides and quite possibly air contamination leading to oxygen corrosion. Suggested labs in India were provided in the previously mentioned email exchanges of December 23rd and 29th respectively under Point No.’s 1, 2 and 3.

4.3.2 Chemical Corrosion Inhibitor Treatment Options for VSPL - LNG

At this juncture, it is too early to identify a longer-term and reliable corrosion inhibitor for this 65 km long pipeline. Corrosion products and a process operations review is recommended before applying corrosion inhibitor. Notwithstanding, it is recommended the pipeline be possibly batch chemically treated with the Nalco Champion EC-1122A batch inhibitor in a similar manner as previously described in this report. This will provide some short-term protection for the pipeline. However, the chemical “pill” batch volume is

Figure 14 – Powdered scale from the failed LNG pipe spool reacting with concentrated HCl. Note the bubbling and yellow deposits forming suggesting CO₂ and MIC involvement in the failure. (December 19th, 2014)
calculated to be approximately 51.6 bbl (8.2 m^3), which is far too large for a typical pig barrel. GAIL must therefore ascertain where there problems have been predominantly located and tailor the chemical batch “pill” size to cover the desired length where the amount of chemical required is about 1.26 bbl/km or about ~200 L/km. The treatment protocol should ultimately be finalized with the local Nalco Champion representative and GAIL Operations personnel. It is also recommended that this pipeline be assessed using NACE International Standard Practice SP0208-2008 Liquid Petroleum Internal Corrosion Direct Assessment (LP-ICDA) or the pending Multiphase ICDA (MP-ICDA) protocols to accurately identify the problem locations, root-cause, mechanisms and a reliable mitigative plan.

4.3.3 Corrosion Mechanisms Being Encountered in the KG Basin

Examination of solids collected from corroded natural gas and LNG pipe specimens both provide telltale indirect evidence into the contributory mechanisms which are degrading pipe. In the very short time which the writer was at site he was able to determine that internal corrosion is being driven by at least three if not 4 or 5 different mechanisms. Chief among them and a common denominator in both the natural gas and the LNG pipelines is CO₂. The writer recommends that any and all pipelines with an operating CO₂ partial pressure >14.99 psi be given priority toward establish a sound chemical treatment and corrosion monitoring protocol going forward. At present there is no guidance on this level of CO₂ apparent in India. Secondly, the removal of water is critical to the long term safety of these pipelines. The common North American maximum allowable water content is 7 lbs H₂O/MMSCF. The writer has read technical data suggesting that many GAIL pipelines have water saturation levels of 115+ lbs H₂O/MMSCF. Clearly, water of condensation is likely to occur as are the associated extreme and aggressive corrosive attack to the pipelines. Dehydration is highly recommended where possible.

A review of KG Basin data provided was reviewed for potential aggressiveness based upon CO₂ partial pressure. The graphical results of this review are provided below in Figure 15. Nineteen (19) gas pipeline gas analyses were provided to the writer during his site visit. There are approximately 61 pipelines in the KG Basin. Gas analyses are required from at least 34 pipelines if available. The writer has an additional 8 analyses but the operating pressures were not provided. Based on the 19 lines evaluated, 7 or 36.8% of these pipelines have CO₂ partial pressures > 15 psi. These lines are at an elevated risk of internal corrosion. It is important to realize the KTAA EPS has a CO₂ partial pressure of over 60 psi! Extra attention should be paid to this line by GAIL in terms of inspection, monitoring and fitness for service.
Figure 15 – CO₂ Partial Pressures of select KG Basin Gas Pipelines

4.4 Pipeline Sampling Procedures and Methodologies

It is recommended GAIL should have appropriate **Handling Procedures for Damaged Pipe Spools** includes but is not limited to following key steps:

**Documentation**

- Key work steps should be photographed as appropriate during excavation and extraction of the damaged pipe and other pertinent details regarding the failure. In addition, any physical evidence collected at the scene by GAIL on-site personnel should be labeled and documented in the evidence log. Including, but not limited to:

  - Date and time the photograph was taken
  - Location of damaged pipe spool (i.e., Failure site in GIS data format if available)
  - Person/Organization responsible for specific action
  - Description of failure - Detail of fracture or damaged surface, magnified appropriately to show relevant features
  - Coating in area of failure if available
  - Evidence of internal or external corrosion near fracture or damaged surface
  - Residues or corrosion products near the fracture or damaged surface (e.g., soil)
  - Details of areas indicating outside force damage
  - Any flaws or damaged areas should be indicated
  - Mark all materials to indicate their position/orientation in the pipeline prior to failure and direction of flow
Excavation and Extraction of Damaged Segment

- Damaged steel surfaces can rust quickly when exposed to the atmosphere and moisture. Immediately after excavation or exposure of the failure segment, the damaged/fracture surfaces should be coated with a light, water dispersing oil or lubricating oil.

Pipe Section Sample Preservation

- Physical evidence should be protected from contamination by proper packing and wrapping - Avoid damaging the fracture surfaces during handling to maintain “as-is” condition
- If physical evidence needs to be stored prior to transportation, it is recommended to place them in secure location at job site to prevent contamination during transport and storage
- In some cases, physical evidence may have to be stored with local authorities. It is imperative that strict access and supervision is provided when wanting to sample or inspect these items

Transport of Physical Evidence

A “Chain of Custody” form should be used to track the failed pipe from the ditch (i.e., excavation site) to the testing laboratory (see Figures 16 and 17 below)
### Chain Of Custody Form - Delivery

<table>
<thead>
<tr>
<th>Client Name:</th>
<th>Telephone:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Date:</td>
<td>Fax</td>
</tr>
<tr>
<td>Address:</td>
<td></td>
</tr>
<tr>
<td>Contact:</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Product:</th>
<th>Description</th>
<th>Information</th>
</tr>
</thead>
<tbody>
<tr>
<td>Name:</td>
<td>Date:</td>
<td>Time:</td>
</tr>
<tr>
<td>ProductNo:</td>
<td>Initial:</td>
<td></td>
</tr>
<tr>
<td>Name:</td>
<td>Date:</td>
<td>Time:</td>
</tr>
<tr>
<td>ProductNo:</td>
<td>Initial:</td>
<td></td>
</tr>
<tr>
<td>Name:</td>
<td>Date:</td>
<td>Time:</td>
</tr>
<tr>
<td>ProductNo:</td>
<td>Initial:</td>
<td></td>
</tr>
<tr>
<td>Name:</td>
<td>Date:</td>
<td>Time:</td>
</tr>
<tr>
<td>ProductNo:</td>
<td>Initial:</td>
<td></td>
</tr>
</tbody>
</table>

- Initialing the section above indicates the description, date and time is accurate
- Signing the section below relinquishes the items to __________

<table>
<thead>
<tr>
<th>Prepared By:</th>
<th>Signature:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Relinquished By:</td>
<td>Signature:</td>
</tr>
<tr>
<td>Received By:</td>
<td>Signature:</td>
</tr>
</tbody>
</table>

**Figure 16: Chain of Custody Form - Delivery**
### Chain Of Custody Form - Acceptance

<table>
<thead>
<tr>
<th>Product No.:</th>
<th>Description</th>
<th>Information</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
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<td></td>
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<tr>
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<tr>
<td>Product No.:</td>
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<tr>
<td>Product No.:</td>
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<tr>
<td>Product No.:</td>
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</tr>
<tr>
<td>Product No.:</td>
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<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

- Initial: the section above indicates the description, date and time is accurate.
- Signing the section below, indicates acceptance of the items from ________

Prepared By: __________________ Signature: __________________

Relinquished By: __________________ Signature: __________________

Received By: __________________ Signature: __________________

---

**Figure 17: Chain of Custody Form - Acceptance**