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In-Situ Coating of Steel Pipelines via Pigging

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Foreword, Scope, Rationale	4
Referenced Standards and Other Consensus Documents	4
Section 1 General	5
Section 2 Summary of the In-situ Coating Methodology	5
Section 3 Definitions	6
Section 4 Owner-Provided Information	7
Section 5 Applicator Qualifications.....	8
Section 6 Coating Material	8
Section 7 Surface Preparation of Pipe	10
Section 8 Coating Procedures	12
Section 9 Inspection and Testing	12
Section 10 Summary and Conclusions	13
Other Referenced Documents	16
 Table 1 Coating Properties	 9
Figure 1 Example Decision Tree for Pipeline Chemical Cleaning Process in Preparation for Coating	14
Figure 2 Example Decision Tree for Coating Application	15

Foreword

In-situ pipeline coating was originally pioneered in the 1970s and has been used effectively to protect the internal surface of existing pipelines and extend the life of steel pipelines for many years.

Scope

This report provides the most current technology and industry practices for the internal in-situ cleaning and coating application in an existing steel pipeline. This report presents general practices and preferences in regard to the cleaning, surface preparation, drying, and the application of a coating in a steel pipeline by the pig (scraper) batching method. It is applicable to onshore or offshore steel pipelines in all industries including the oil and gas gathering, distribution, and transmission industries. It is also applicable to welded steel water and brine handling pipelines.

Rationale

In-situ coating is a non-traditional corrosion coating technology for the following reasons: (1) the cleaning process does not involve traditional abrasive blasting, and (2) the process lacks the ability to 100% inspect either the surface preparation or the coating application. Acceptance criteria rely on analytical data, test area inspection, and limited visual inspection. There is a recognized need for this report in order to make the broader industry aware of what is a seldom used but very established technology and to ensure long-term effectiveness of the coating in such applications by including the necessary details. This report is intended for use by pipeline operators, pipeline service providers, government agencies, and any other persons or companies involved in planning, designing, maintaining, or managing pipeline integrity.

Referenced Standards and Other Consensus Documents

Unless specifically dated, the latest edition, revision, or amendment of the documents listed in the table below shall apply.

AMPP/NACE/SSPC, www.ampp.org:	
SSPC-PA 2	Procedure for Determining Conformance to Dry Coating Thickness Requirements
NACE No. 2/SSPC-SP 10	Near-White Metal Blast Cleaning
ASTM International, www.astm.org:	
ASTM D3359	Standard Practice for Adhesion Measurement by Tape Test
ASTM D6677	Standard Practice for Scribe Adhesion
ASTM D5402	Standard Practice for Assessing the Solvent Resistance of Organic Coatings Using Solvent Rubs

AMPP technical reports are intended to convey technical information or state-of-the-art knowledge regarding corrosion. In many cases, they discuss specific applications of corrosion mitigation technology, whether considered successful or not. Statements used to convey this information are factual and are provided to the reader as input and guidance for consideration when applying this technology in the future. However, these statements are not intended to be recommendations for general application of this technology and must not be construed as such.

Section 1: General

Pipelines have been internally coated for many years for many reasons including flow enhancement/hydraulic efficiency, product purity, corrosion protection, etc. The internal coatings applied to pipelines for corrosion protection provide a physical (protective) barrier between the steel and the corrosive commodity being transported and are considered an effective corrosion control measure. Plant-applied internal coatings are commonly applied to individual pipe joints, with welded field joints coated/protected separately by different processes, including sleeves, couplings, mechanical interference connections, and robotically controlled blasting/coating equipment. In-situ pipeline coating, also known as the “pig batch method,” is a procedure used for coating existing pipelines or for new pipelines, post-construction that require a continuous and consistent coating.

This report presents general practices and preferences regarding the cleaning, surface preparation, drying, and the application of a protective coating in a steel pipeline by the pig (scraper) batching method. It is applicable to onshore or offshore steel pipelines in all industries including the oil and gas gathering, distribution, and transmission industries, as well as water handling systems.

Included are methods for mechanical and chemical cleaning, surface preparation, solvent drying, coating selection and application, quality control, applicator qualification, final acceptance criteria, and recommended coated pipeline operation.

The in-situ process for internal cleaning and coating of steel pipelines is a complex procedure that requires a specialized and experienced applicator.¹⁻² Only coating materials formulated for or having physical properties suitable for in-situ application are utilized. The applicator and coating material are selected by the owner based on fitness for purpose.

In-situ pipeline coating selection and procedures are determined by specific criteria relating to the project to be executed. Since no two pipelines are identical (size, length, location, terrain, service), this report provides guidelines to help the applicator develop specific hydraulic and pneumatic procedures and controls based on individual pipeline parameters. To ensure proper cleaning and coating application, all pig batches are run at predetermined, stable velocities. In special cases, abrasive cleaning may be considered, but this is quite limited.

The coating inspector or company representative has access at all times to the work performed, in accordance with the company specifications, and will have the right to inspect such work and all materials furnished by the applicator.

For pipeline cleaning, surface preparation, and coating applications the applicator has to use personnel, equipment, and procedures that have been pre-qualified for the specific coating being used. Pipeline owners/operators are responsible for specifying applicable safety, health, and environmental practices to ensure compliance with all applicable regulations.

Section 2: Summary of the In-situ Coating Methodology

The in-situ process for internally coating pipelines involves cleaning the line with a combination of chemical and mechanical means to remove all residual product, solids, by-products, corrosion products, moisture, and any other species to produce a clean, dry internal steel surface. Once this clean surface has been attained, liquid coatings are applied using a pig train which consists of a slug of coating between two polyurethane pigs. The pig train moves from the pig launcher to the receiver and deposits a coating film, which is dried by flowing dry air. Multiple pig trains are used in consecutive pig runs to build the coating to the specified final dry film thickness (DFT), and dry air is run until the coating has reached its final cure.

An example decision tree-type cleaning process is shown in Figure 1, while the coating process is shown in Figure 2. These figures are for illustrative purposes only and represent a typical operation - they are not intended to be the industry standard since each pipeline will likely require its own specific procedure tailored to the properties and condition of the existing pipeline.

Section 3: Definitions

Applicator: The organization(s) engaged to perform in-situ pipeline internal cleaning and coating of the pipeline as defined in this document.

Batch: The quantity of an individual coating material produced by a coating manufacturer during a continuous production run.

Chemical Cleaning: Chemical treatment of the pipe inner surface with chemicals to achieve a surface preparation as required by the coating manufacturer such as a near-white surface as defined by NACE No. 2/SSPC-SP 10 or better.

Coat: One layer of a coating applied to a surface in a single continuous application to form a uniform film when dry, or, the act of applying a coating.

Coating: Product, in liquid, paste, or powder form, that, when applied to a substrate, forms a layer possessing protective, decorative, and/or other specific properties, or the act of applying this product.

Coating Manufacturer Technical Representative: Technical representative appointed by an owner-approved Coating Manufacturer.

Coating System: The complete number and types of coats applied to a substrate in a predetermined order. (When used in a broader sense, surface preparation, pretreatments, dry film thickness, and manner of application are included).

Company: Asset/Pipeline owner or operator or their delegated representative.

Dry Film Thickness (DFT): The thickness of a dried film, coating, or membrane.

Frac Tank: Large capacity on-site temporary steel or plastic tank for storage and transport of liquids and/or solids in Oil & Gas operations.

HCl: Hydrochloric Acid, a mineral acid used to dissolve corrosion products.

Induction Time: The period of time after mixing a two-part coating necessary to initiate chemical reaction.

Inspector: The authorized agent of the owner.

MEK Wash: A slug of methyl ethyl ketone run through a pipeline to remove any residual solvents from the surface.

Mil: One one-thousandth (0.001) of an inch. 1 mil = 25.4 micrometers.

Owner: The owner company or authorized agency that purchases the in-situ coating service.

Pot Life: The maximum elapsed time during which a coating can be effectively applied after all components of the coating have been thoroughly mixed.

Rust Bloom: Discoloration indicating the first stages of rust formation.

Slug: The quantity of product or coating loaded into a pipeline, normally between two pigs, used during cleaning or coating operations.

Supplier: The manufacturer and/or distributor of the coating material.

Take Down Process: A critical sequence of steps at the end of the cleaning process that must be completed to prepare the pipeline to receive the first layer of coating.

Test Spool: A short, flanged section of pipe in the pipeline that can be removed for visual inspections during both cleaning and coating processes.

Section 4: Owner-Provided Information

The pipeline operating company (Company or the Owner) -delegated Representative provides complete and detailed information to the Coating Applicator regarding the candidate pipeline to assist in the development of an execution plan, procedures, material quantities, manpower, equipment, and pipeline-specific requirements. The information to be provided will include the following:

1. Pipeline layout, with all information about tees, blinds, valves, sampling ports, directional changes and elbows, road crossings, pump stations, “protruding” corrosion mitigation and/or monitoring components such as inhibitor injection nozzles, corrosion monitoring probes, gas or fluid flow probes, and other protruding appurtenances, etc. This not only becomes important for determining the piggability of the line, but also in determining where the inspection drop-out spools might be located.
2. Samples of all liquids, and/or corrosion by-products and gas specifications upon request of the applicator, including any historical data on pipeline service. This will include any additives or chemical treatments for the line, because some chemical treatments (e.g., anodic corrosion inhibitors) can leave residual films of iron scale.
3. Prior pigging history, including types of maintenance pigs utilized, condition of pigs as received, if damage has occurred, type and extent of damage, cases where pig passage time was significantly greater than anticipated, cases where pigs have been stalled/stuck in the line and the measures used to resolve those occurrences. Also, prior history and results from gauge plate pig runs, mechanical or electronic caliper pig runs, and intelligent pig runs should be reviewed.
4. Steel samples of new and/or old corroded pipeline upon request of the applicator if possible. While the composition of the corrosion product may change upon removal (by physical ablation or oxidation), residual films and impurities, including waxes and asphaltenes, may require custom chemical treatments.
5. Identify the wall thickness, size, length and type of steel, etc. (seamless, submerged arc, ERW) and strength of all sections of the line to be coated. This is particularly important if there is a change in wall thickness from one section to the next. Note that it is not possible with current technology to clean/coat pipelines of different nominal diameters with the same pig train.
6. Topographical map or elevation change information, including water depths. This is important for determining compressor size and air volume needed to push the pig train up through elevated sections.
7. Samples of any cleaning pig scale or deposits if available, which would include both organic residuals and inorganic scales from either the pipe wall or from the water chemistry.
8. The intended future service and design life of the pipeline so that eventual coating selection (discussed in Section 6) and criticality of inspection can be quantified. It may be determined that the service demands on the pipeline eliminate the possibility of in-situ coating.
9. Pipeline operating details and service details. Details will include operating pressure and temperature and any known previous services not covered by the other items listed.

Once the information about the pipeline is collected, some additional considerations should be noted before selecting an in-situ coating for the pipeline. Propulsion of pigs and pig trains using compressed gases may be difficult in smaller diameter lines and at lower pressures. Stalling and surging can be anticipated. This may become more severe as the pigs move down the line, as the further down the line the pigs move, ever larger volumes of gas must be added to overcome the inertia of a stalled pig. Also, longer lines, if they cannot be sectionalized, may not be feasible to coat, as the coating train may not reach the downstream receiver prior to the end of the coating pot life. These considerations, along with some other items specific to the pipeline (ambient temperatures, production loss during downtime, integrity management after coating) are factors to consider.

Section 5: Applicator Qualifications

The in-situ process for internal cleaning and coating of steel pipelines is a complex procedure that will have to be adjusted as needed for each individual pipeline since no two pipelines are truly the same. This requires a specialized and experienced applicator, including supervisors and technicians, who have commercial experience to perform the in-situ cleaning and apply the coating system specified. There is no current standard for this technology. Coating application is in accordance with all written requirements from the manufacturer of the coating, with the exception of minimum applied coating thickness.

Before the start of work, the applicator will typically submit the following information and data for review by the owner:

1. General procedures and quality plan, including space requirements at the site and disposal plan for effluent. Procedures cover the elements discussed in Section 6. The procedures are used as guidance rather than as a specification since adjustments to the procedure will likely be necessary as the line is cleaned and eventually coated.
2. Equipment: In-situ pipeline coating requires the use of specialty equipment and materials to be provided by the applicator and/or the owner, typically including the following:
 - i. Sufficient quantity of oil-free or instrument-quality air compressors with air hoses.
 - ii. Suitable chemical (desiccant type) air dryers capable of achieving the required dry air dew point.
 - iii. Positive displacement pumps or other methods to pump chemicals and/or coating into the pig launchers.
 - iv. Mixers of high torque and speed to produce a homogenous coating mix within the allowed time frame.
 - v. Suitably designed pig launchers and receiver assemblies with valves and connections capable of handling all cleaning solvents as well as the coating.
 - vi. Sufficient pigs/scrapers to perform the scope of work.
 - vii. Sufficient chemical and air hoses with acceptable safety documentation, with proper connections to eliminate leakage, and safety cables for personnel protection.
 - viii. Sufficient tools to complete the scope of work.
 - ix. Sufficient storage/holding/mixing tanks (i.e., frac tank).
 - x. Quality control equipment – Acid titration kits, chloride test kits, DFT gauges, viscosity measurement equipment, temperature/humidity measurement tools, and any other necessary devices for the particular cleaning and coating process used.
 - xi. Additional personal protective equipment (PPE) such as goggles/face shields, rubber gloves, and acid-resistant coverings as required.

Section 6: Coating Material

Coating selection is ideally done by the pipeline owner in consultation with the applicator. For the owner, a coating capable of performing and achieving the desired service life in the process conditions is of primary importance. For the applicator, working with a coating that lends itself to in-situ application is the top concern. This combination of chemical hardness and application friendliness greatly limits the coating product options available. Most often, the applicator will provide a list of coatings that they know can be applied by this process, and the owner will select the most suitable for their particular service.

Only liquid coating materials formulated for or having physical properties suitable for in-situ application can be utilized, but this may be dependent upon the specific pipeline of interest. Some of the requirements include high-solids content,

long pot life at the ambient and pipeline temperature during application, air dry/cure at the pipeline/air temperature, viscosity and wettability that enables film build when pig-applied, and capability to adhere to an acid-cleaned steel surface. There may be additional requirements, e.g., low-temperature cure, extended pot life for longer lines or higher working temperatures, etc.

While there are no hard and fast rules for what designates acceptable parameters for all these properties, a rule of thumb may be as follows:

1. Solids content of at least 70% to avoid mud cracking in locations where the coating may pond (e.g., corrosion pits).
2. Pot life (at ambient) of a minimum of 6 hours, to enable adequate pre-mixing, pumping, running the pig train, and collecting excess coating. This pot life may also be needed in case of recoverable equipment malfunctions such as hose splits, compressor shutdowns, pump problems, etc., with redundancies built into the equipment plan.
3. Air cure at pipeline temperature, which may vary down the length of the line. For subsea lines, the temperature at the bottom of the sea is often around 4 °C regardless of season, and it is not possible to heat the pipeline well above this temperature for purposes of curing the coating. Running heated air may cause additional problems of “skinning” the coating, which would result in differential shrinkage and poor final coating film quality.
4. Viscosity and wettability are difficult to define, but the coating has to have properties that allow for film build to several mils without running or sagging, and which cannot be removed by the back bell of the coating pig as the pig train runs through the pipeline.
5. Adhesion to an acid-cleaned surface is more about the very low anchor pattern (0.5 mils [13 micrometers]) that will be achieved by acid cleaning. Most coatings depend on surface roughness and the associated increase in surface area to achieve adequate adhesion. The standard in-situ cleaning process cannot create this type of surface.

The coating material is typically a 2-part mix, though 3-part coatings may be used if required for the service conditions. These coatings are usually mixed in drums just before coating – inline or plural component mixing equipment is difficult to employ due to the large volumes of coating product required.

The coating material supplier furnishes all necessary information to the applicator, including Safety Data Sheets (SDS), Product Data Sheets (PDS), Certificate of Analysis, and any additional information not provided by either of these. This information includes the coating properties listed in Table 1.

Table 1
Coating Properties

PROPERTY	REQUIRED DATA	NOTES
Shelf Life	In accordance with supplier's specification at the recommended storage conditions	(1)
Volume Solids	% solids in final coating film	
Theoretical Coverage rate of 1 mil (25.4 micrometers)	Gallons/mil (liters/micrometer) applied	
Recommended Nominal Coating Thickness (Dry Film Thickness, DFT)	As required for performance	(2)
Overcoat Interval min/max	At pipeline surface temperature	
Mix Ratio by Volume	To be supplied as kits	
Pot Life	Pot life based on pipeline criteria @ 77 °F (25 °C)	
Temperature Application Ranges	For both ambient and steel surface temperatures	
Temperature Limits for Cured Product	Immersion service limits	
Cure Time	Final cure only	
Disposal Method	Per local environmental requirements	
Acceptable Thinners	In accordance with supplier's specification	(3)
1. Only unopened containers of coating are considered for use 2. DFT for in-situ coating is very likely to be less than for the same product when spray-applied 3. Use of thinners is avoided, as this lowers the volume solids		

Section 7: Surface Preparation of Pipe

Before commencing cleaning and surface preparation, the internal surface is evaluated for the presence of heavy corrosion deposits, iron sulfide deposits, hydrocarbons, or other solids that may affect the cleaning process. The applicator develops an initial cleaning procedure based on the known condition of the pipeline which can be modified based on actual cleaning run results and the requirements of the coating to be applied.

This section emphasizes the importance of properly preparing the steel surface before the coating application. An uncontaminated and adequately dry pipe surface is important because the condition of this interface directly affects the coating application, cure, and service performance. Adequate and correct surface preparation is the single most important factor in assuring proper coating adhesion and adequate service life of the thin-film protective coating.

Initial cleaning of a pipeline with a high degree of solids or deposits is generally performed by progressive pigging, starting with low-density foam pigs and progressively increasing in size and aggressiveness based on the amounts of solids being removed. Pigs and pig batches are propelled using compressed air or inert gas. A typical progressive pigging procedure contains the following:

1. Initial pig runs with low-density foam pigs and water batches help flush out suspended solids. Spiral brush pigs, full brush pigs, hard-body brush, and appendage-type pigs can then be used as required.
2. If detergent or chemical cleaning batches are being used in combination with water flushes, the specific batches are mixed as required for concentration and batch size.
3. Sampling of the effluent as it is removed from the pipeline is used to determine the amount of suspended solids being removed to evaluate the progressive cleaning progress. For acid cleaning, the acid depletion is measured. Pre-determined cleanliness standards are used to determine the degree of cleaning required or when the pipeline pigging is complete. Visual inspections, suspended solids percentage (i.e., less than 2%), test spools, or concentration of chemical runs are examples of cleanliness standards.
4. A subsequent degreasing step (or steps) with detergent may be needed to remove any residual hydrocarbons.
5. All operational records are documented and included in the final project report.

Acid cleaning is a method of preparing steel surfaces by chemical reaction. The cleanliness standard is NACE No. 2/SSPC-SP 10 (near-white metal). The inspected surface when viewed without magnification has to be free of all visible oil, grease, dust, dirt, mill scale, rust coating, oxides, corrosion products, and other foreign matter, except for staining. A different surface finish is allowed when the procedure (e.g., use of a surface-tolerant coating) has been pre-qualified by the supplier and approved by the owner.

Inspection of the pipeline is limited to only accessible areas such as the ends of the pipeline and test spool locations representing a small percentage of the pipe bore total surface. Test spools for onshore pipelines are employed whenever possible for inspection and testing purposes, both during cleaning and coating.

During surface preparation inspection, flash rust is expected and can be cleaned by wiping with a cloth and hydrochloric acid solution before or at the time of inspection. In inaccessible areas, it is expected that light non-adherent rust will be present and have to be accounted for when selecting a coating for the given service conditions, knowing that its performance will not be 100% of what it would have been under more controlled surface preparation and application conditions.

Additional inspection techniques may be employed (e.g., tethered cameras or in-line cameras) to increase the available surface area for inspection. Such techniques have to take into account the risk of damage to the inspection device – and thus, the necessity of removing any and all pieces of the device from the pipeline before continuing the process.

Hydrochloric acid (HCl) batches are designed to remove all residual iron oxide and iron sulfide scale, producing a surface finish comparable to, and not less than, a NACE No. 2/SSPC-SP 10 surface cleanliness. Solution batches of inhibited hydrochloric acid in pre-determined concentrations and volumes are injected between suitable batching pigs. The

specific gravity and acid concentration are documented. During the acid runs, the batch will have a sample recovered at the receiver, and acid strength is measured by conventional acid-base titration methodology to determine the extent of acid concentration depletion, which complements any visual inspection at test spools. The sample is also monitored for solid content, as determined by means of an on-site electric or manual centrifuge.

For offshore pipelines or pipelines where an inspection spool is not available, HCl depletion and suspended solids measurement methods have to be used to determine surface cleanliness. Generally, when the acid depletion (as measured by titrated acid strength) falls to low levels, the pipeline is judged to be “clean” of corrosion scale.

Following acid batch runs, water flushes are run with pigs and effluent samples are monitored for solids content. The purposes of the water rinses include flushing loose scale out of the line and buffering the pH. Water and brush flushes continue until the solids level reaches acceptable levels and the HCl depletion percentage meets the criteria, indicating visual inspection at the inspection spool is appropriate. An additional HCl wash may be run at any later stage in the process if excessive rust bloom is discovered at the test spool.

Following surface preparation and inspection, the steel surface is properly prepared for coating application, which is referred to as the “Take Down Process.” This requires a critical sequence of operations that ensures that the steel surface is properly conditioned and ready for coating application.

The inspection of the test spool requires temporary removal of the test spool(s) which allows flash rusting within the pipeline. The first step in the Take Down Process requires the running of a final HCl batch of suitable volume to remove any flash rusting caused by exposure of ambient air to the pipeline in the area of the test spool.

Immediately following the HCl batch, an intermediate surface treatment process is executed on the acid-cleaned surface to provide increased corrosion resistance and enhance the adhesion properties of the coating system. This is accomplished by a solution batch of phosphoric acid run through the pipeline at a pre-determined speed.

Following the phosphoric acid run, a water solution is run to balance the pH to acceptable levels. The substrate to be coated will dictate whether this rinse has to be run separately or can be run in conjunction with the phosphoric acid treatment. Tests may be made to ensure that the final flush has rendered the system at an acceptable pH. A sample of the used flush solution is also tested for chlorides to determine that the chloride content is below 400 ppm. In the event that the sample indicates the chloride content is above 400 ppm, the rinse procedure is repeated until the desired chloride count has been achieved.

Solvent drying consists of a suitable volume of solvent (methanol and/or MEK) run between batching pigs to displace residual water and dry the pipeline. A wiper pig will be run if deemed necessary to remove ponded solvent. The final solvent used is selected to be compatible with the coating material, so that coating slugs running through the residual are minimally affected by the presence of solvent.

Quality control tests performed and documented during the chemical cleaning operation include provisions for the following:

1. pH test of solutions.
2. Specific gravity test for the phosphoric acid.
3. Flush Water Chloride Test
4. Clear vials for visual observation of solids in effluent
5. Dew point measurements of inlet and pipe outlet
6. Pipe surface temperature (critical for determining coating re-coat window and final cure)

Supplemental abrasive blast cleaning may be used as an additional surface preparation aid. Abrasive blasting is an internal cleaning and surface preparation technique that uses abrasive particles and nitrogen combined with a turbulent flow rate at an extremely high velocity to clean the internal of select pipelines. Depending on pipeline condition and required cleaning specification, this process can be used as a standalone cleaning technique or in conjunction with a chemical cleaning program.

There are severe limitations on the length and diameter of pipeline that can be effectively cleaned by abrasive blasting. Blasting is difficult for any pipe under an 8-inch nominal diameter, and the segment of line that can be abrasively blasted is typically less than 4 miles in length. Also, abrasive blasting is not effective in removing hydrocarbon residual, wax, or loose solids. Because of the limitations, abrasive blasting is often used only after the pipeline has been chemically cleaned, and for the purpose of providing some surface profile rather than for scale removal or general surface cleaning.

Section 8: Coating Procedures

This section covers recommended procedures for coating material handling, mixing, application, and curing. Storage, handling, mixing, and, if necessary, thinning of the coating materials is done by the applicator. This is in accordance with the coating manufacturer's recommendations or as directed by the Coating Manufacturer's Technical Representative.

The coating material typically is a two-part material to be mixed in the ratio recommended by the coating manufacturer. The base portion is pre-mixed using suitable motor-driven mixers (propeller or shear blade type) at a revolution rate sufficient to ensure adequate mixing without entrainment of air in the coating mixture. Once the base is thoroughly mixed, the curing agent (activator) is incorporated in the proportions recommended by the manufacturer.

The mixing start, mixing completion, and loading times are recorded for all batches mixed. Coating temperatures and ambient temperature during the mixing period, activation period and after each run of coating, and induction time (if necessary for the coating used) are recorded. The mixed coating is then loaded and run between coating pigs.

After each run, the residual liquid coating volume is measured as recovered from the receiver in order that the theoretical dry film thickness may be calculated, also called the "gallons in – gallons out" method. If possible, this calculation may be compared to a DFT reading at the test spool.

Intermediate curing, as recommended by the coating manufacturer, is elapsed before the next layer of coating can be applied. A compressed dry air purge is maintained to remove solvent vapors that flash off during the intermediate curing.

All air used for drying and coating operations is dehydrated to a dew point temperature that will eliminate any condensation on the internal surface of the pipe. The dew point of the air is verified to be at least 3 °C or 5 °F lower than the pipe temperature. Desiccant dryers of sufficient capacity are used and monitored for an adequate dew point.

Subsequent runs of mixing and coating will then be repeated. Theoretical dry film thickness calculations are made after each coating run. If a test spool is available, an intermediate inspection of the test spool may be made to verify theoretical calculations. When inspections for DFT or theoretical calculations indicate the DFT to be within the desired specification, no further coating runs are required.

For offshore pipelines, or pipelines where a test spool is not available, theoretical DFT calculations alone are used for final DFT acceptance criteria. In these cases, DFT measurement at the end of the pipeline is not to be used for acceptance. The DFT at the ends of the pipelines will not be representative of the coating in the rest of the line due to the reduced speed of the coating pigs at the ends of the pipeline where lower coating thickness reading is expected, or where backflow of excess coating may lead to excessive thickness at the 6 o'clock position.

Forced air blowing and continued ventilation are used to achieve final curing. Complete curing of the coating is directly time/temperature related, as outlined in the manufacturer's specifications.

Where applicable, the test spool is removed to check DFT and coating appearance to verify that the coating is curing. At the time which will be as per the coating manufacturer's recommendation for final cure, an adhesion test may be performed. If the test spool is to be re-installed into the pipeline after the adhesion test, the coating is repaired locally per the coating manufacturer's recommendations.

Section 9: Inspection and Testing

The Inspection Test Plan (ITP) document will govern the test criteria, with both the applicator and owner signing off on applicable test criteria. The applicator has to have suitable inspection equipment at the construction site to perform the tests listed in this section.

The inspection and measurement required in this section are conducted by trained and qualified personnel.

1. Surface Preparation – As a minimum, the pipe bore interior shall be cleaned following NACE No. 2/SSPC-SP 10 standards. When possible (accessible), use NACE or SSPC visual standards for comparison.
2. Dry Film Thickness Measurement – Should there be an accessible test spool to perform DFT measurement, the equipment consists of a magnetic spring-loaded instrument (SSPC-PA 2 Type 1 Gauge) and a set of calibration standards, or an electronic instrument (SSPC-PA 2 Type 2 Gauge) with calibration shims. After calibration of the instrument, one spot measurement is recorded, which is the average of three gauge readings at the 12, 3, 6, and 9 o'clock positions at each opening of the inspection spool and each opening of the pipeline where the inspection spool is located (or at other clock position at company's discretion). The average of the four spot measurements is the average DFT for the pipeline. Additional spot measurements may be taken at other clock positions at the company's discretion. These additional measurements may be used in qualifying the DFT.

Theoretical Dry Film Thickness Calculations: Theoretical DFT measurement is calculated based on the theoretical spread rate of the coating used, the internal surface area of the pipeline, and the total volume of coating applied to the pipeline, as shown in Equation (1).

$$\text{DFT} = \frac{(\text{Volume of coating loaded} - \text{Volume removed}) * (\text{Vol Fraction solids in coating})}{\pi * (\text{Pipe diameter}) * (\text{Pipe length})} \quad (1)$$

Final acceptance by the owner of the theoretical DFT calculations or DFT measurements is made during the final coating thickness inspection. Additional coating can only be applied within the allowable recoat window for the coating. Therefore, final acceptance of the coating as applied is decided at the time of the final inspection.

3. Curing: MEK rub test, if specified, is as per ASTM D5402 at the test spool location.
4. Adhesion Testing: The Adhesion Test is destructive to the coating and may be performed on a representative section of pipe that will be removed from the system or can be repaired. Acceptable methods include ASTM D3359 (tape test) and ASTM D6677 (scribe test).

Holiday testing is not used as acceptance criteria for in-situ pipeline coating application, but only as a spot-check quality control measurement. It is not possible to holiday test an entire pipeline, it is only possible to use holiday testing in accessible areas such as test spool locations. At the test spools, flange welds are typically rough and are often a source of holiday indication on thin-film coatings using wet sponge testing apparatus. Unless careful weld preparation or grinding has occurred, some holiday indications may be expected on particularly rough welds.

For these reasons, it is not recommended to specify that the coated pipeline be "holiday-free" after coating, a typical requirement for tank and vessel linings. This is one of the accepted risks for in-situ coatings and may be a limiting factor when selecting the process for pipeline rehabilitation.

Any holiday inspection that is done occurs only after final curing of the coating, or at least after the recoat window for the coating has been exceeded. Typical in-situ coatings are not suitable for full recoating after this time so additional coatings cannot be applied.

Section 10: Summary and Conclusions

In-situ coating, while long established in the pipeline community, is not well-known or understood by most pipeline integrity engineers. Due to the individual characteristics of each pipeline, the practice is as much an art as it is a science and should only be attempted by applicators with sufficient experience. The owner, when selecting in-situ coating for an application, has to understand the risks and limitations of the process. Nevertheless, properly executed in-situ coating projects can extend the life of a pipeline by many years and represent a useful tool for integrity management.

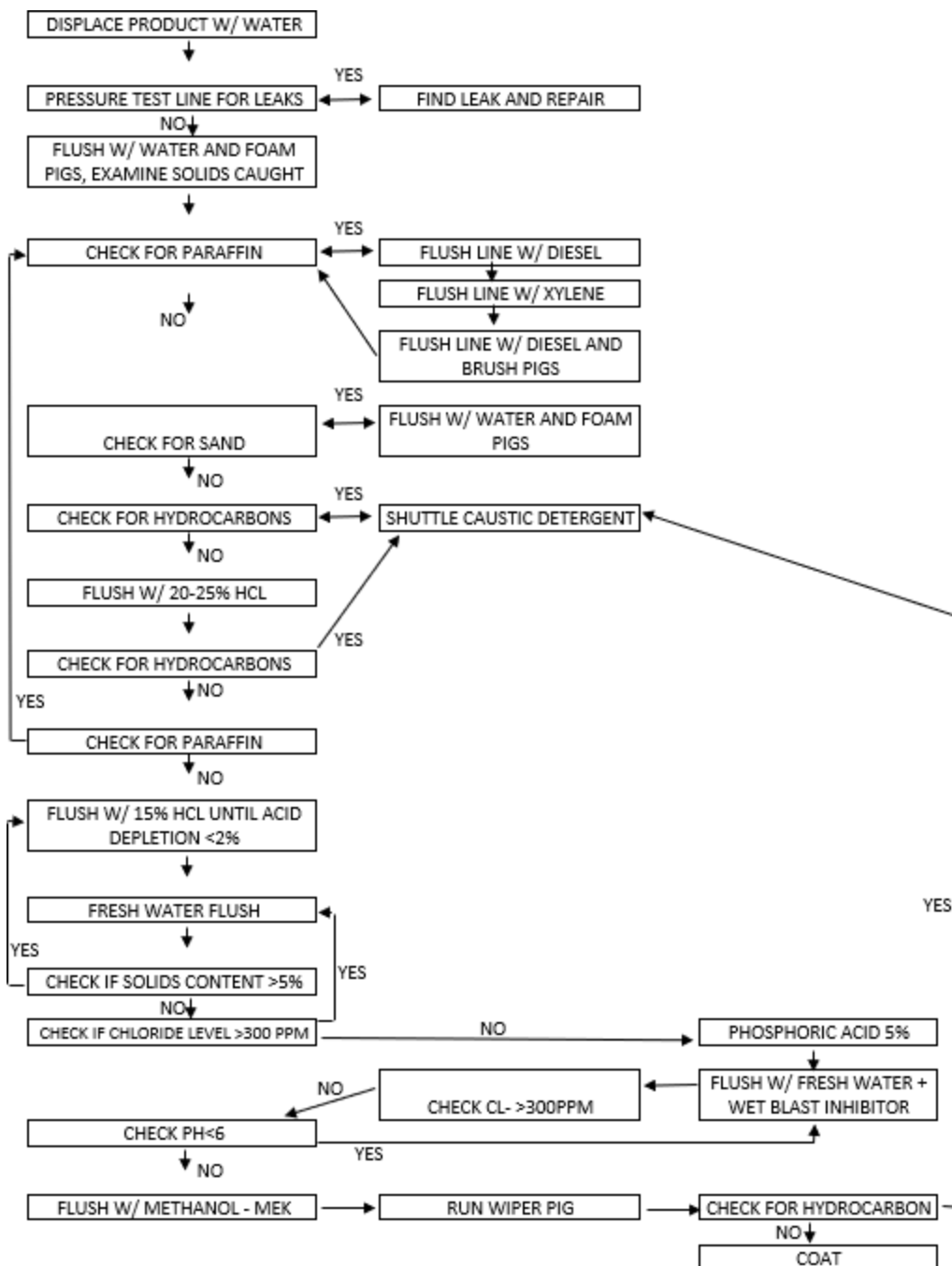


Figure 1: Example Decision Tree for Pipeline Chemical Cleaning Process in Preparation for Coating³

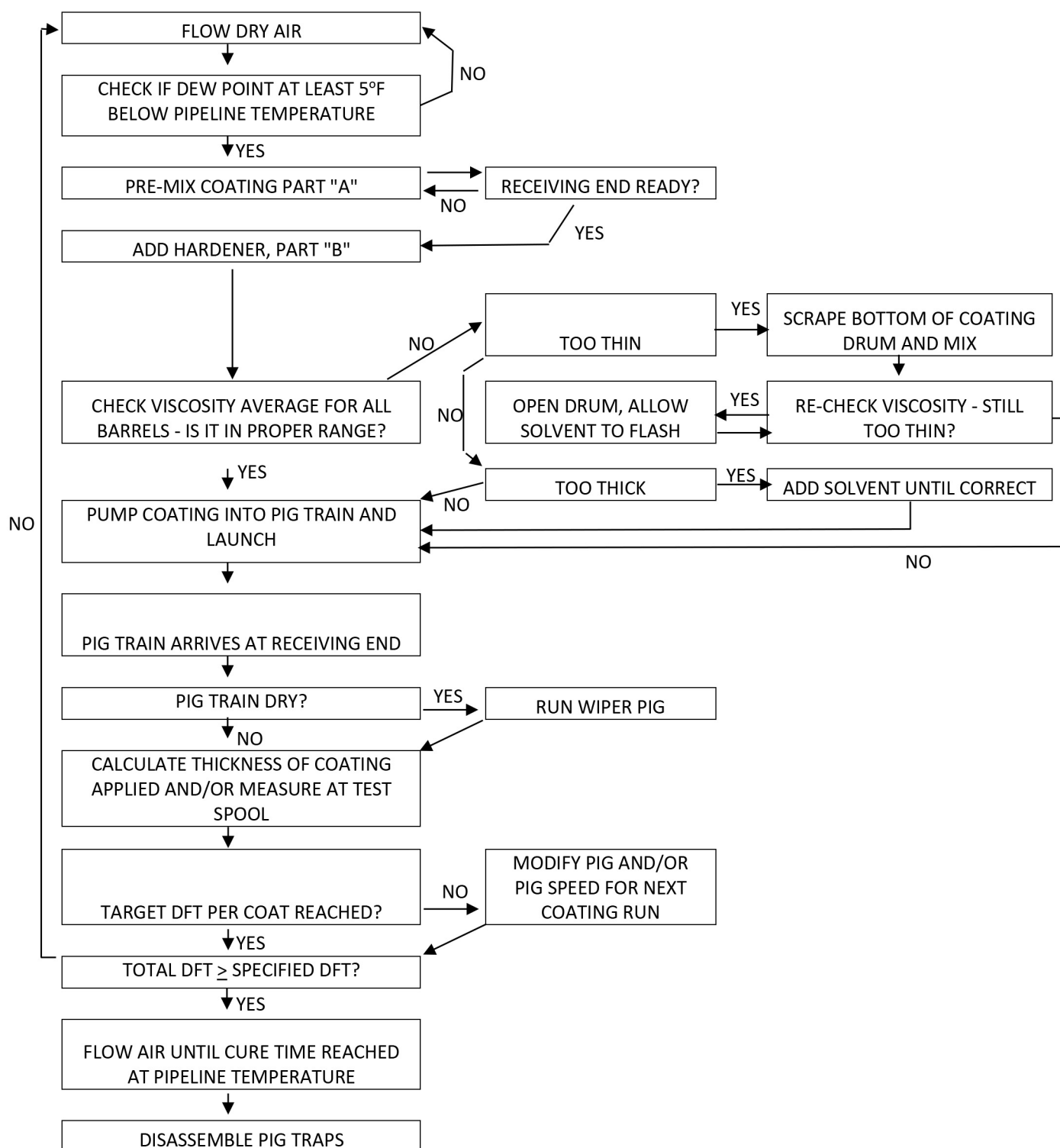


Figure 2: Example Decision Tree for Coating Application³

Other Referenced Documents

1. K. Cato, "A Process for Lining Oilfield Pipelines," CORROSION 2000, paper no. 00178 (Houston, TX: NACE, 2000), pp. 4-5.
2. L. Choate, "Developing and Advancing the State-Of-The-Art Technology of the In-situ Internal Cleaning and Coating of Oil & Gas Pipelines," CORROSION 2001, paper no. 01612 (Houston, TX: NACE, 2001), p. 5.
3. G. Ruschau and D. Moore, "In-Situ Coating for Pipeline Rehabilitation," Proceedings of the NACE Western Canada/Alaska Regional Corrosion Conference, Anchorage, AK, Feb. 1996.