U.S. DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
SPECIAL PERMIT

Special Permit Information:

Docket Number:	PHMSA-2009-0390
Pipeline Operator:	Colonial Pipeline Company
Operator ID#:	2552
Date Requested:	November 17, 2009
Original Issuance Date:	November 25, 2019
Effective Date:	November 25, 2019
Code Section(s):	49 CFR 195.310

Grant of Special Permit:

By this order, subject to the terms and conditions set forth below, the Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS)[1] grants this special permit to Colonial Pipeline Company (Colonial) waiving compliance from 49 Code of Federal Regulations (CFR) 195.310 for certain pipeline segments along the Colonial hazardous liquid pipeline system in the states of Louisiana and Georgia. The Federal pipeline safety regulations in 49 CFR 195.310 require the operator of a hazardous liquid pipeline to retain hydrostatic test pressure recording charts and other related hydrostatic test records for as long as the tested facility is in use.

Purpose and Need:

On the condition that Colonial complies with the terms and conditions set forth below, this special permit would relieve Colonial from the recordkeeping requirements in 49 CFR 195.310 for certain pipeline segments and requires Colonial to perform alternative safety measures in lieu of record retention. This special permit waives compliance from 49 CFR 195.310 for two (2)

[1] Throughout this special permit, the usage of "PHMSA" or "PHMSA OPS" means the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration, Office of Pipeline Safety.

segments of Colonial's Line 01, a 40-inch diameter, hazardous liquid pipeline running from Houston, Texas, to Greensboro, North Carolina.

The Colonial pipeline segments subject to this permit are in Acadia, St. Landry, Point Coupee, and West Feliciana Parishes, Louisiana; and in Fulton, DeKalb, and Gwinnett Counties, Georgia, as further described below.

Special Permit Segments:

This special permit applies to the ***special permit segments*** (***special permit segments 1 and 2***) defined as follows using the Colonial references (see Appendix B: Special Permit Segment Location Maps):

Special permit segment 1 - approximately 64.450 miles of Line 01 from Church Point Station (station number 4976+11) to Baton Rouge Junction (station number 5+32) in Louisiana. The 1.922-mile reduction from the original 66.372 miles is due to locating the records for sections identified below.

- **PHMSA Note:**[2] In addition to the proposal, Colonial located hydrostatic test records for sections within ***special permit segments 1 and 2***. ***Special permit segment 1*** excludes the following segments for which Colonial has the hydrostatic test data.
    - LOC 203: Station 6412+39 to Station 6421+83 (near Bayou Courtableau)
    - LOC 203: Station 6747+53 to Station 6770+85 (Atchafalaya River crossing)
    - LOC 203: Station 7897+36 to Station 7907+27 (Louisiana Highway, Mississippi River Bridge relocation)
    - LOC 203: Station 8209+89 to Station 8268+68 (Mississippi River crossing)

Special permit segment 2 - approximately 10.234 miles of Line 01 from the Chattahoochee River (station number 951+65) to the Georgia Highway 141 (station number 1492+76) in Georgia.

Special permit segments include ***special permit segment 1 and 2***.

PHMSA grants this special permit, subject to the conditions below, based on the findings set

[2] Information noted as "**<u>PHMSA Note</u>**" is supplemental information received from Colonial that gave a better understanding of the status of ***special permit segments 1 and 2*** in regards to meeting this condition.

forth in the *"Special Permit Analysis and Findings"* document, which can be read in its entirety in Docket No. PHMSA-2009-0390 in the Federal Docket Management System (FDMS) located on the internet at www.Regulations.gov.

Conditions:

PHMSA grants this special permit subject to Colonial implementing the following conditions:

1) **Maximum Operating Pressure (MOP) Limitations**:
   a) Colonial must continue to operate ***special permit segment 1*** at or below its existing MOP of 574 pounds per square inch gauge (psig) and must continue to operate ***special permit segment 2*** at or below its existing MOP of 743 psig.
   b) If Colonial hydrostatically pressure tests ***special permit segments 1 or 2*** in accordance with 49 CFR 195.304 for pressure based upon MOP and test duration after this special permit has been granted, Colonial will not be required to implement the below **Conditions 2 through 20** for the ***special permit segment*** that was tested. After implementing these special permit conditions, Colonial has the option at any time to pressure test a ***special permit segment*** and submit pressure test documents to PHMSA for discontinuing the special permit.

2) **Integrity Management Program:** Within six (6) months of the grant of this special permit, Colonial must incorporate ***special permit segments 1 and 2*** into its written integrity management program (IMP) as a hazardous liquid pipeline that could affect a high consequence area (HCA) in accordance with 49 CFR 195.452. Colonial must follow and implement the requirements of 49 CFR 195.452 and these special permit conditions in evaluating the integrity of ***special permit segments 1 and 2.***

3) **Close Interval Surveys:** Within one (1) year of the grant of this special permit, Colonial must perform a close interval survey (CIS) on ***special permit segments 1 and 2.*** A CIS need not be performed if Colonial has performed a CIS on the Line 01 pipeline along the entire length of each ***special permit segment*** less than five (5) years prior to the grant of this special

permit. If factors "beyond Colonial's control"[3] prevent the completion of the CIS within one (1) year, a CIS must be completed as soon as practicable and a letter justifying the delay and providing the anticipated date of completion must be submitted to the Director, PHMSA Southern Region[4], no later than one (1) month prior to the end of year one (1) of this special permit.

All CIS data must be integrated with in-line inspection (ILI) data to evaluate and prioritize corrosion risk associated with locations where CP levels are determined not to be adequate per 49 CFR 195, Subpart H. All CIS deficiencies shall be remediated within three (3) years based on a detailed corrosion threat scoring and risk analysis. See Appendix C: Corrosion Threat Reduction Program for additional details.

Colonial must receive a "no objection" letter from the Director, PHMSA Southern Region prior to executing any process changes associated with Appendix C.

Table 1: Dates of Previously Completed CIS Surveys on Special Permit (SP) Segments

Location Code	Year of Previous CIS	Next Scheduled CIS
202 (SP Segment 1)	2017	2022
203 (SP Segment 1)	2014	2019
204 (SP Segment 1)	2014	2019
502 (SP Segment 2)	2017	2022
202 (SP Segment 1)	2015 (static survey)	2020
203 (SP Segment 1)	2015 (static survey)	2020
204 (SP Segment 1)	2015 (static survey)	2020
502 (SP Segment 2)	2015 (static survey)	2020

4) <u>**Close Interval Survey – Reassessment Interval**</u>: Colonial must perform a CIS and remediate any areas where cathodic protection levels are determined not to be adequate per 49 CFR 195, Subpart H within ***special permit segments 1 and 2*** at least once every five (5) calendar years, not to exceed 68 months. All remediation associated with CIS reassessments must be performed as described in **Condition 3**. CISs within the reassessment

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[3] Examples of "beyond Colonial's control" would be extreme weather conditions, lack of issuance of environmental permits with prompt application by Colonial, or landowner issues that might limit Colonial location access to remediate the condition. Colonial's budget cycle and manpower and contractor schedules are examples of factors that are within Colonial's control and cannot be used for an extension of remediation time interval.

[4] If PHMSA changes the region that is responsible for the Colonial ***special permit segments 1 or 2***, the Director, PHMSA Southern Region, will instruct Colonial on the appropriate PHMSA Regional Director to contact.

interval are not required to be performed in the same year as ILI reassessments.

5) **Coating Condition Evaluation**: Within one (1) year of the grant of this special permit, Colonial must perform a detailed evaluation of the pipeline coating system and remediate areas where coating degradation poses a corrosion threat on the pipeline within ***special permit segments 1 and 2.*** The coating evaluation must utilize ILI data integration and target cathodic shielding due to disbonded coating. However, a coating system evaluation and remediation need not be performed on the ***special permit segments*** if Colonial has performed a coating evaluation and remediation on the ***special permit segments*** less than five (5) years prior to the issuance of this special permit. See Appendix D: Modified Recoat Calculator (MRC) for additional details.

   Colonial must perform coating rehabilitation within one (1) year of discovery where the corrosion rates on matched pits exceed 10 mils per year even where CP is considered adequate per 49 CFR 195, Subpart H.

   If factors "beyond Colonial's control" prevent the completion of the coating evaluation and remediation within the one (1) year from the grant of this special permit, a coating evaluation and remediation must be performed as soon as practicable and a letter justifying the delay and providing the anticipated date of completion must be submitted to the Director, PHMSA Southern Region no later than one (1) month prior to **Condition 5's** completion date; Colonial must receive a "no objection" letter from the Director, PHMSA Southern Region prior to extending the schedule.

   Colonial must report the results of coating evaluation, excavations, and remediation to the Director, PHMSA Southern Region. Colonial must obtain a "no objection" from the Director, PHMSA Southern Region for any changes to the coating evaluation, remediation of damaged coating, process changes associated with Appendix D, and any schedule extensions as defined in **Condition 5.**

   - **PHMSA Note:**
     - Colonial has stated that they have been performing the MRC defined in Appendix D since 2017 on the special permit segments.
     - Colonial will continue the MRC process as required in this **Condition 5.**

6) **Operation and Maintenance Manual – Reassessment Intervals**:

a) Within six (6) months of the grant of this special permit, Colonial must amend its written O&M manual to require ILI inspection and reassessment intervals of the Line 01 pipeline for ***special permit segments 1 and 2*** at a frequency consistent with 49 CFR 195.452, but at least once every five (5) years at reassessment intervals not exceeding 68 months.

b) Colonial must amend applicable sections of its O&M manual(s) to require the CIS inspection and reassessment intervals of ***special permit segments 1 and 2*** at a frequency at least once every five (5) years at reassessment intervals not exceeding 68 months.

- **PHMSA Note:** Colonial has stated they have performed reassessment intervals according to the requirements outlined above since 2002. Table 2 below identifies all the historical ILI inspections.

7) **In-line Inspection Initial Assessment**:

a) Colonial must perform ILI threat assessments along the entire length of ***special permit segments 1 and 2*** using ILI Tools (high resolution magnetic flux leakage (HR-MFL) or ultrasonic wall measurement (USWM); HR-geometry or HR-deformation tools; and ultrasonic crack detection (USCD)) and must remediate discovered conditions in accordance with **Condition 16** of this permit.

b) If ILI assessments have not been run within five (5) years of the grant of this special permit using ILI tools (HR-MFL or USWM; HR-geometry or HR-deformation tools; and USCD), Colonial must complete ILI tool inspections on the ***special permit segments*** within one (1) year of the grant of this special permit.

- **PHMSA Note:** Colonial assessments using ILI technology are listed in Table 2 below.

Table 2: ILI History and Assessment Findings on Special Permit Segments

Segment	Threat	Technology	ILI Date	Immediate	60-Day	180-Day	Other
LA Segment - Church Point – Baton Rouge	Metal Loss Corrosion	USWM[3]	1993 / 2001	**	**	**	150
		MFL[4]	2004 *	0	0	5	5
		MFL\DEF Combo[5]	2009	0	0	13	0
		MFL\DEF Combo	2013	0	0	4	0
		MFL\DEF Combo	2018	0	0	0	0
	Deformation	Deformation (DEF)	1988 / 1995	**	**	**	228
		Deformation	2004 *	0	0	0	0
		MFL\DEF Combo	2009	0	0	0	5
		Deformation	2012	1	0	0	0
		MFL\DEF Combo	2013	0	0	0	0
		MFL\DEF Combo	2018	0	0	0	0
	Crack	USCD	2015	0	0	10	2
	Cyclic Fatigue	DEF and USCD	2013 & 2015	0	0	0	12
GA Segment - Chattahoochee R. – GA Hwy 141	Metal Loss Corrosion	MFL	1993 / 1998	**	**	**	6
		MFL	2003 *	0	0	0	3
		MFL\DEF Combo	2008	0	0	3	0
		MFL\DEF Combo	2012	0	0	0	3
		MFL\DEF Combo	2017	0	0	4	0
	Deformation	Deformation	1988 / 1998	**	**	**	9
		Deformation	2003 *	0	3	2	0
		MFL\DEF Combo	2008	0	1	0	0
		MFL\DEF Combo	2012	0	0	0	6
		MFL\DEF Combo	2017	0	0	0	1
	Crack	USCD	2012	0	0	0	0
		USCD	2017	0	0	0	0
	Cyclic Fatigue	DEF and USCD[6]	2012 / 2017	0	0	0	4

* Indicates IMP Baseline Assessment
** Indicates tool run was prior to regulatory requirements in 49 CFR 195.452 were established.

[3] Ultrasonic Wall Measurement (USWM) ILI tool.

[4] Magnetic flux leakage (MFL) ILI tool.

[5] ILI tool that includes MFL and deformation inspection for pipe corrosion and dents.

[6] Ultrasonic crack detection (USCD) ILI tool.

- **PHMSA Note:** All actionable anomalies have been remediated by Colonial. In addition to the ILI assessments, Colonial has also performed Smartball leak detection inspection and no acoustical anomalies were found in the ***special permit segments***.

8) **In-line Inspection Reassessment Intervals**: Colonial must schedule ILI reassessment dates for the ***special permit segments*** in accordance with 49 CFR 195.452 by adding the required time interval to the previous assessment date, but may not exceed a five (5) year not to exceed 68-months reassessment interval.

   - **PHMSA Note:** As per 49 CFR 195.452, Colonial has completed numerous ILI assessments for these ***special permit segments*** on at least a 5-year frequency, as listed in Table 2 above.

9) **Damage Prevention Best Practices**: Colonial must incorporate the applicable best practices of the Common Ground Alliance (CGA) into its Damage Prevention Program for the ***special permit segments***.

10) **Field Activity Advance Notice to PHMSA:** Colonial must give notice to the Director, PHMSA Southern Region within 14 days of discovery resulting from an ILI to enable PHMSA to observe the excavations relating to **Conditions 16 - Anomaly Evaluation and Repair, and Condition 18 - Casings**, of field activities in the ***special permit segments***. Immediate response conditions do not require advance notice, but the Director, PHMSA Southern Region should be notified by Colonial no later than two (2) business days after the immediate condition is discovered. The Director, PHMSA Southern Region may elect to not require a notification for some activities.

11) **Annual Reports to PHMSA**: Colonial must report the following annually, by not later than March 31 for the previous calendar year, to the Director, PHMSA Southern Region with a copy to the Director, PHMSA Engineering and Research Division; and post the annual report on the special permit docket (PHMSA-2009-0390) at **www.regulations.gov**.

    a) Any new integrity threats identified during the previous year and the results of any ILI or direct assessments performed (including any unremediated regulatory required anomalies over 30% wall loss, cracking found in pipe body, weld seam, or girth welds; and dents with metal loss, cracking or stress riser) during the previous year in the ***special permit segments***.

b) Any reportable incident or any leak normally indicated on the DOT Annual Report, and all repairs on the pipeline that occurred during the previous year in the ***special permit segments***.

c) Any on-going damage prevention initiatives affecting the ***special permit segments*** and a discussion of the success of the initiatives.

d) Any mergers, acquisitions, transfer of assets, or other events affecting the regulatory responsibility of the company operating the pipeline associated with the ***special permit segments***.

12) **<u>Cathodic Protection Test Station – Location</u>**: At least one (1) cathodic protection (CP) pipe-to-soil test station must be located within each HCA with a maximum spacing between test stations of one (1) mile within the ***special permit segment***. In cases where obstructions, environmental conditions, or sensitive areas prevent test station placement, the test station must be placed in the closest practical location. The following locations in ***special permit segment 1*** are currently identified and accepted to have the spacing greater than (1) mile:

Test Station Spacing No.	Begin Station No.	End Station No.	Distance
12	6413+39	6501+84	8845
13	6501+84	6587+30	8546
14	6587+30	6698+81	11151
22	8208+20	8271+72	6352

Colonial must install CP test stations as required within one (1) year of the grant of this special permit. If factors "beyond Colonial's control" prevent the completion of the installation of CP test stations within one (1) year after the grant of this special permit, Colonial must complete installation of CP test stations as soon as practicable and a letter justifying the delay and providing the anticipated date of completion must be submitted to the Director, PHMSA Southern Region no later than one (1) month prior to the required installation date. Any extended installation schedules submitted to PHMSA from Colonial must receive a "no objection" from the Director, PHMSA Southern Region prior to implementation.

13) **Cathodic Protection Test Station - Remediation**: If any annual CP test station reading within the ***special permit segments*** falls below 49 CFR Part 195, Subpart H requirements, remediation must occur within six (6) months of the test station reading and must include a CIS 100 feet upstream and 100 feet downstream of the test station to verify that the cause of the deficiency has been mitigated. If factors "beyond Colonial's control" prevent the completion of remediation including coating repairs within six (6) months, remediation must be completed as soon as practicable and a letter justifying the delay and providing the anticipated date of completion must be submitted to the Director, PHMSA Southern Region no later than one (1) month prior to the end of the six (6) months completion date. Any extended evaluation and remediation schedules submitted to PHMSA from Colonial must receive a "no objection" from the Director, PHMSA Southern Region prior to implementation.

14) **Interference Currents Control:** Colonial must address induced alternating current (AC) from parallel electric transmission lines and other sources that may affect the pipeline in the ***special permit segments***. Within one (1) year of the grant of this special permit, Colonial shall prepare and implement an induced AC and direct current (DC) mitigation program and perform all remediation, including any required grounding systems, necessary to protect the pipeline from corrosion caused by stray currents.

    a) At least once every five (5) calendar years not exceeding 68 months, Colonial must perform an engineering analysis on the effectiveness of the AC and DC mitigation measures and must evaluate any AC interference where the time-weighted current density (∑(VAC/No. of Readings collected/24 hours)) is between 20 and 100 Amps per meter squared. In evaluating such interference, Colonial shall integrate AC interference data with the most recent ILI results to determine remediation measures. If Colonial does not remediate AC interference where the time-weighted current density is between 20 and 100 Amps per meter squared, Colonial shall provide an engineering justification for not remediating such interference to the Director, PHMSA Southern Region, who may accept or reject the justification and require remediation.

    b) Colonial must take interference readings (continuous 24-hour recordings) during the calendar quarter of the known or anticipated highest voltage reading. If there are any significant increases or changes to the amount of electricity/current flowing in any co-located high voltage alternating current (HVAC) power lines, such as from additional generation, a voltage up rating, additional lines, or new or enlarged substations, Colonial must perform an AC mitigation survey along the entire co-located pipeline ***special permit segments*** right of way (ROW) within six (6) months of any such change.

c) Within six (6) months of the engineering analysis, Colonial must remediate any AC interference where the time-weighted current density is greater than 100 Amps per meter squared. Remediation means the implementation of performance measures including, but not limited to, additional grounding along the pipeline to reduce interference currents. Any DC interference discovered during periodic monitoring or interference testing that results in CP levels that do not meet the requirements of 49 CFR Part 195, Subpart H, must be remediated within six (6) months of discovery.

d) If factors "beyond Colonial's control" prevent the completion of remediation within six (6) months of the interference evaluation and remediation, remediation must be completed as soon as practicable and a letter justifying the delay and providing the anticipated date of completion must be submitted to the Director, PHMSA Southern Region no later than one (1) month prior to the end of the six (6) months completion date. Any extended evaluation and remediation schedules submitted to PHMSA from Colonial must receive a "no objection" from the Director, PHMSA Southern Region.

- **PHMSA Note:** Colonial has stated they monitor AC potentials and perform AC current density calculations as a part of their Annual Test Point Survey Program. Colonial has completed this evaluation for both ***special permit segments*** in 2019. Colonial has indicated this condition has been initially met and the reassessments will continue based on the special permit requirements. Colonial has also performed an additional engineering analysis in ***special permit segment 2*** where AC mitigation systems currently exist.

15) **Field Coating**: Colonial currently has the coating data for the pipe in ***special permit segments 1 and 2***. If Colonial identifies through subsequent inspections that a different coating exists or is known to shield CP for girth weld joints then Colonial must:

a) Analyze ILI logs in the areas of girth welds for potential corrosion indications.

b) For any ILI corrosion indications above 30% wall loss at girth welds where the coating type is unknown, the girth weld joints must be exposed and evaluated each time the ILI is run or until the unknown girth weld coating is replaced.

c) If any stress corrosion cracking (SCC[5]) activity is found on girth welds or pipe of "any coating type" in the ***special permit segment***, the pipe and girth welds in the ***special permit segment*** must be remediated within six (6) months of finding the SCC.

d) If factors "beyond Colonial's control" prevent completion of the coating shielding evaluation and remediation within six (6) months of permit receipt, remediation must be completed as soon as practicable and a letter justifying the delay and providing the anticipated date of completion must be submitted to the Director, PHMSA Southern Region no later than one (1) month prior to the end of the six (6) months completion date. Any extended evaluation and remediation schedules submitted to PHMSA from Colonial must receive a "no objection" from the Director, PHMSA Southern Region prior to implementation.

- **PHMSA Note:** Colonial has stated they have completed this evaluation and that there are no known indications of shielding as a result of coating failures on the ***special permit segments***.

16) **Anomaly Evaluation and Repair**:

a) **General**: Colonial must account for ILI tool tolerance and corrosion growth rates in scheduled response times and repairs, and must document and justify the values used.

i) Colonial must demonstrate ILI tool tolerance accuracy for each ILI tool run by usage of calibration excavations and unity plots that demonstrate ILI tool accuracy to meet the tool accuracy specification provided by the vendor (typical for depth within +10%

[5] "SCC" activity shall be defined as over both a 10 percent wall thickness depth and 2-inches in length.

accuracy for 80% of the time).[6, 7]

ii) Colonial must incorporate ILI tool accuracy by ensuring that each ILI tool service provider determines the tolerance of each tool and includes that tolerance in determining the size of each anomaly feature reported to Colonial. Colonial must compare previous indications to current indications that are significantly different. If a trend is identified where the tool has been consistently overcalling or under-calling, the remaining ILI features must be re-graded accordingly.

iii) Discovery date must be within 180 days of an ILI tool run for each type ILI tool (HR-MFL, HR-geometry/caliper/deformation, and ultrasonic crack detection tools).

b) <u>Dents</u>: Colonial must repair dents on Line 01 in ***special permit segments 1 and 2*** in accordance with 49 CFR 195.452(h)(4) repair criteria.

i) ***Special permit segments 1 and 2*** must have a high-resolution deformation ILI tool inspection as part of the initial ILI.

ii) Dent repairs must be performed in accordance with Appendix E: Deformation (includes deformation with secondary features, multiple, and buckles).

iii) A detailed engineering critical analysis incorporating current stress concentration, dent geometry, and cycle accumulation must be performed on all remaining

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[6] ILI tool calibration excavations may include previously excavated anomalies or recent anomaly excavations with known dimensions that were field measured for length, depth, and width, externally re-coated, CP maintained, and documented for ILI calibrations prior to the ILI tool run. ILI tool calibrations must use ILI tool run results and anomaly calibrations from either the ***special permit inspection area*** or from the complete ILI tool run segment, <u>if the continuous ILI segment is longer</u> than the ***special permit inspection area***. A minimum of four (4) calibration excavations must be used for unity plots.

[7] Other known and documented pipeline features that are appropriate for the type of ILI tool used may be used as calibration excavations for ILI tool calibration with technical documentation of their validity. To use other known and documented pipeline features as calibration excavations for ILI tool calibration Colonial must complete both of the following: **(1)** submit a plan for using known and documented pipeline features as calibration excavations to, and receive a "No Objection" from, the Director, PHMSA Engineering and Research and the Director, PHMSA Southern Region prior to performing the ILI tool calibration using pipeline features. The plan must include at least the following information: reason that known and documented pipeline features will be used in place of anomalies on the pipelines; the pipeline features that will be used for the ILI tool calibration, and the technical justification for using the pipeline features for ILI tool calibration. **(2)** submit a report to the Director, PHMSA Engineering and Research and the Director, PHMSA Southern Region with the results of the use of pipeline features for the ILI tool calibration that includes technical documentation establishing the validity of using the pipeline features for the ILI tool calibration.

unremediated dents over 2% pipe diameter.

- **PHMSA Note**: Colonial has performed its Dent Risk Ranking Prioritization Matrix (DRRPM) on all dents in the ***special permit segments***.

iv) All excavated dents over 1% pipe diameter must be remediated.

c) **Response Time for ILI Results**: Colonial must investigate, excavate, evaluate, and repair all anomalies located on Line 01 within each ***special permit segment*** based on ILI data results in accordance with 49 CFR 195.452(h)(4). However, Colonial must incorporate the design factors and wall loss criteria set out below into its anomaly repair criteria, including anomalies located in HCAs. Colonial must evaluate ILI data by using either the ASME Standard B31G, "*Manual for Determining the Remaining Strength of Corroded Pipelines,*" the modified B31G (0.85dL), or R-STRENG for calculating the predicted failure pressure ratio (FPR) to determine anomaly responses.

i) ***Special permit segments***:

- **Immediate response**: Any anomaly within ***special permit segments 1 and 2*** operating up to 72% specified minimum yield strength (SMYS) (0.72 design factor) that meets either: (1) an FPR less than 1.16; (2) an anomaly depth greater than 80% wall thickness loss; or (3) a crack anomaly depth greater than 50% wall thickness.

- **60-day response**: Follow 49 CFR 195.452(h)(4)(ii) for anomaly response within ***special permit segments 1 or 2*** operating up to 72% SMYS (0.72 design factor), except designate a FPR less than 1.25 for anomaly repairs;

- **180-day response**: Any anomaly within ***special permit segments 1 or 2*** with pipe operating up to 72% SMYS (0.72 design factor) that meets either: (1) an FPR less than 1.39; or (2) an anomaly depth (corrosion or cracking) greater than 40% wall thickness loss.

- **Monitored response**: Any anomaly within ***special permit segments 1 or 2*** with pipe operating up to 72% SMYS (0.72 design factor) that meets both: (1) an FPR equal to or greater than 1.39; (2) an anomaly depth equal to or less than 40% wall thickness loss or crack depth. The schedule for the response must take tool tolerance and corrosion growth rates into account.

- **PHMSA Note:** Colonial compares all anomalies to established maximum operating pressure (EMOP) at the corresponding locations. Additionally, all anomaly's safe operating pressure (SOP) are compared to the nominal segment internal design pressure (IDP) and are addressed as per 49 CFR 195.452. Colonial's method of calculating SOP includes the application of tool tolerance.

  - <u>**Crack Anomalies**</u>: Cracking anomalies found during excavations, assessments, pressure tests, and ILI tool[8] runs over both a 10 percent wall thickness depth and 2-inches in length must have procedures[9] developed for assessment and evaluation. These anomalies must be evaluated as either a body crack, seam crack or girth weld crack in accordance with Appendix A and **Condition 16** requirements:

    - Colonial must perform direct examination of known locations of cracks or crack-like defects using phased array, automated ultrasonic testing (AUT), or equivalent technology that has been validated to detect tight cracks.

    - Any anomalies found in pipe in the ***special permit segments*** with cracking, that is classified over both a 10 percent wall thickness depth and 2-inches in length, must be modeled for failure stress and crack growth analysis.

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[8] Internal inspection tool or tools capable of detecting corrosion, deformation and mechanical damage (including dents, gouges and grooves), material cracking and crack-like defects (including stress corrosion cracking, selective seam corrosion, environmentally assisted cracking, and girth weld cracks), hard spots, and any other threats to which the covered segment is susceptible. A person qualified by knowledge, training, and experience must analyze the data obtained from an assessment performed under paragraph (b) of this section to determine if a condition could adversely affect the safe operation of the pipeline. In addition, an operator must explicitly consider uncertainties in reported results (including, but not limited to, tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying tool performance) in identifying and characterizing anomalies.

[9] Pipe, seam and girth weld crack evaluation procedures must be submitted to the Director, PHMSA Southern Region for "no objection" prior to Colonial use for the special permit.

- If cracking anomalies are found, they must be assessed using one of the following methods[10]:
  - In-the-ditch examination methods[11]
  - Pressure test with spike test,
  - Pressure reduction,
  - Engineering critical assessment (ECA)[12], or
  - Replace with new pipe.

Colonial must receive a "no objection" letter from the Director, PHMSA Southern Region prior to executing any process changes associated with Appendix E or the response time identified above.

17) **<u>Girth Welds</u>**: Colonial must provide records to PHMSA to demonstrate the girth welds on ***special permit segments 1 and 2*** were non-destructively tested (NDT) at the time of construction in accordance with:

a) The Federal pipeline safety regulations at the time the pipelines were constructed. If not, show that at least 10% of the girth welds in each ***special permit segment*** were non-destructively tested (NDT) after construction but prior to the application for this special permit provided at least two (2) girth welds in each ***special permit segment*** were excavated and NDT inspected.

b) If Colonial cannot provide girth weld records to PHMSA to demonstrate either of the above in **Condition 17(a)**, Colonial must accomplish either (i); or (ii) and (iii) of the following:

i) Certify to PHMSA in writing that there have been no in-service leaks or breaks in the

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[10] Procedures for assessing and evaluating crack type anomalies including pressure tests, in-the-ditch assessment methods, ILI and ECA must be submitted to the Director, PHMSA Southern Region and Colonial must receive a "no objection" prior to using the procedure.

[11] In-the-ditch examination tools and procedures for crack assessments (length and depth) must have performance and evaluation standards, including pipe or weld surface cleanliness standards for the inspection, confirmed by subject matter experts qualified by knowledge, training, and experience in direct examination inspection for accuracy for the type of defects and pipe material being evaluated. The procedures must account for inaccuracies in evaluations and fracture mechanics models for failure pressure determinations.

[12] ECA for crack safe pressure evaluations are in Appendix A.

girth welds on ***special permit segments 1 and 2*** for the entire life of the pipelines, or

ii) Evaluate the terrain along ***special permit segments 1 and 2*** for threats to girth weld integrity from soil types, soil settlement, soil movement, terrain, or heavy loads across the pipeline; and

iii) Excavate, visually inspect and nondestructively test at least two (2) girth welds in each ***special permit segment*** in accordance with the American Petroleum Institute Standard 1104, *"Welding of Pipelines and Related Facilities"* (API 1104) as follows:

A. Use the edition of API 1104 current at the time the pipelines were constructed; or

B. Use the edition of API 1104 recognized in the Federal pipeline safety regulations at the time the pipelines were constructed; or

C. Use the edition of API 1104 currently recognized in 49 CFR 195.3.

c) If any girth weld in any of the ***special permit segments*** is found unacceptable in accordance with API 1104, Colonial must repair the girth weld immediately and then prepare an inspection and remediation plan for all remaining girth welds in ***special permit segments 1 or 2*** based upon the repair findings and the threat to the ***special permit segments***. Colonial must submit the inspection and remediation plan for these remaining girth welds to the Director, PHMSA Southern Region and remediate girth welds in ***special permit segment 1 or 2*** in accordance with the inspection and remediation plan within 60 days of finding girth welds that do not meet this **Condition 17 (c)**.

d) Additionally, all oxyacetylene girth welds, mechanical couplings and wrinkle bends in ***special permit segment 1 or 2*** must be removed.

e) Colonial must complete the girth weld testing, and the girth weld inspection and remediation plan, within one (1) year after the grant of this special permit. If factors "beyond Colonial's control" prevent the completion of these tasks within one (1) year, the tasks must be completed as soon as practicable and a letter justifying the delay and providing the anticipated date of completion must be submitted to the Director, PHMSA Southern Region no later than one (1) year after the grant of this special permit. Colonial must receive a "no objection" letter from PHMSA prior to implementing any schedule completion modifications.

- **PHMSA Note:** Colonial has provided the records to demonstrate that at least 10% of the girth welds in ***special permit segment 1 and 2*** were non-destructively tested (NDT).

18) **Casings**: Colonial must identify all shorted casings (metallic or electrolytic) within ***special permit segments 1 and 2*** no later than six (6) months after the grant of this special permit and classify any shorted casings as either having a "metallic short" (the carrier pipe and the casing are in metallic contact) or an "electrolytic short" (the casing is filled with an electrolyte) using a commonly accepted method such as the Panhandle Eastern, Pearson, DCVG, ACVG or AC Attenuation. A casing survey and shorted casing assessment need not be performed if Colonial has performed a casing survey and shorted casing assessment on the Line 01 pipeline along the entire length of ***special permit segments 1 and 2*** less than one (1) year prior to the grant of this special permit.

   a) **Metallic Shorts**: Colonial must evaluate any metallic short on a casing in ***special permit segments 1 and 2.*** If a shorted casing is identified, Colonial must attempt to remediate. If the short cannot be remediated, Colonial must submit a Remedial Plan for "no objection" to the Director, PHMSA Southern Region within 90 days of an unsuccessful short clearing attempt and receive a "no objection" from the Director, PHMSA Southern Region prior to implementation.

   b) **Electrolytic Shorts**: Colonial must evaluate any electrolytic short[13] on a casing in ***special permit segments 1 and 2*** by performing a detailed review of the ILI data of the cased pipe identifying any corrosion growth on the carrier pipe. Where corrosion growth exceeds 10 mils per year, the shorted casing must be remediated within 6 months from the time the shorted casing was identified. Remediation may include removing the electrolyte from the annular space of the casing, filling the casing with a dielectric filler/corrosion inhibitor or installing CP or modifying an existing CP system in the vicinity of the cased pipe.

- **PHMSA Note:**
    - Pipelines electrolytically shorted to a carrier pipeline typically allow for CP

[13] NACE SP0200-2008 Steel-cased Pipeline Practices defines the terms "metallic short" and "electrolytic contact."

current flow to the carrier pipeline.

- Corrosion growth is monitored through the ILI program.

c) **<u>All Shorted Casings</u>**: Colonial must install external corrosion control test leads on both the carrier pipe and the casing in accordance with 49 CFR 195.575 to facilitate the future monitoring for shorted conditions. A metallic vent pipe directly welded to the casing may be used as a test point to monitor in lieu of test wires.

d) **<u>Evaluation Schedule</u>**: If factors "beyond Colonial's control" prevent the completion of the shorted casing evaluation and appropriate remediation within six (6) months of the short identification, then the evaluation and appropriate remediation must be completed as soon as practicable and a letter justifying the delay and providing the anticipated date of completion must be submitted to the Director, PHMSA Southern Region no later than one (1) month prior to the end of the six (6) months completion date. Any extended evaluation and remediation schedules submitted to PHMSA from Colonial must receive a "no objection" from the Director, PHMSA Southern Region prior to implementation.

- **PHMSA Note:** Colonial monitors casings and evaluates shorted casings as a part of their Annual Test Point Survey Program and monitors corrosion activity on all cased pipelines within the ***special permit segments*** as a part of their ILI Assessment within the Integrity Management Program. Colonial has stated that it has completed this evaluation for both ***special permit segments*** in 2019.

19) **<u>Pipe Seam Evaluations</u>**: Colonial must identify any pipe in ***special permit segments 1 and 2*** that may be susceptible to pipe seam issues because of the vintage of the pipe, the manufacturing process of the pipe, or other issues. If the pipe in ***special permit segments 1 and 2*** has a seam other than double submerged arc-welded (DSAW), Colonial must report it to the Director, PHMSA Southern Region. PHMSA may require Colonial to prepare a pipe seam threat evaluation.

- **PHMSA Note:** Colonial's pipe in the ***special permit segments*** is DSAW and therefore a pipe seam evaluation is not necessary unless non-DSAW weld seams are found.

20) ***<u>Special Permit Segment</u>*** **<u>Specific Conditions</u>**: Colonial must comply with the following requirements.

a) **<u>Depth of Cover</u>**: Colonial must monitor the ***special permit segments*** 1 and 2 ROW for exposures, erosion, washouts, and loss of cover through its aerial patrol, annual mowing, corrosion surveys, and other patrols (Colonial Procedures for Right-of-Way Procedure for Exposed Piping, NOP-ROW-001, Revision 10, dated 02/23/2019; Corrosion Prevention Procedure, CPP-FP-CIS-01, Revision 6, 08/13/2019).

   i) ***Special permit segments*** with less than 30-inches of cover in non-consolidated rock must be mitigated through evaluations using Colonial's Process for Depth of Cover Evaluation for Shallow Pipe (located in IM Plan, not dated).

   ii) Colonial's Abnormal Operating Procedure for ROW Surface Inspection (AOP-ROW-001, Revision 5, 02/23/2019) requirements must be implemented in response to a suspected leak or following a natural disaster.

   iii) Colonial must determine the risk of the exposure and implement the appropriate mitigation measures for exposed pipe using Colonial Procedures for Right-of-Way Procedure for Exposed Piping (NOP-ROW-001) and Engineering Standard for Exposed Pipe Assessment & Repair (ES-03-102, Issue No. 5, dated 02/26/2019). Any depth of cover remediation must be completed within one (1) year of the discovery.

   iv) Should Colonial change the requirements in its procedures referenced in **Condition 20(a)** and those changes impact the implementation and remediation of soil cover, Colonial must submit the procedure changes to the Director, PHMSA Southern Region for a "no objection" letter prior to implementation.

- **PHMSA Note:**
  - Colonial stated they have performed depth of cover surveys on ***special permit segment 1*** (Louisiana segments) in 2005 and 2006. Colonial stated that "any remedial actions required were mitigated at that time and no further actions have been identified."
  - Colonial stated they use ILI, ground patrol data, above ground markers (AGM) survey data along with INS packages, Close Interval Survey procedure CPP-FP-CIS-01, mowing contractor, and satellite data to evaluate exposed and shallow cover.
  - Colonial also stated they perform depth of cover measurements as a standard

practice as part of field excavations.

b) **Line-of-Sight Markers**: Colonial must install and maintain line-of-sight markers on the pipeline in the ***special permit segments*** except in agricultural areas or large water crossings such as lakes or swamps where line-of-sight signage may not be practical. Colonial, at a minimum, must identify and replace any missing or damaged line-of-sight markers during pipeline patrols. If pipeline patrolling in accordance with 49 CFR 195.412 cannot consistently identify areas with missing or damaged line-of-sight markers, then Colonial must on a calendar year basis, not to exceed fifteen (15) months, conduct ground patrols in the ***special permit segments***.

- **PHMSA Note:** Colonial meets the line-of-sight pipeline markers Condition through the assessment and repair/replacement of markers annually by mowing crews who are operator qualified for the task.

c) **Data Integration**: Colonial must maintain data integration of special permit condition findings and remediation in ***special permit segments 1 and 2.*** Data integration must include the following information: Pipe diameter, wall thickness, grade, and seam type; pipe coating including girth weld coating; MOP; HCAs (including boundaries on aerial photography); hydrostatic test pressure including any known test failures; casings; any in-service ruptures or leaks; ILI survey results including HR-MFL, HR- Deformation, USCD, or USWM ILI tools; CIS – all; depth of cover surveys; rectifier readings; test point survey readings; AC/DC interference surveys; pipe coating surveys; pipe coating and anomaly evaluations from pipe excavations; SCC excavations and findings; and pipe exposures from encroachments.

   i) Data integration documentation and drawings to meet **Condition 20(c)** must be completed and available for review in Colonial's geographic internal web mapping system containing all items listed above.

   ii) Data integration must be updated on a continuing basis and with at least an annual review of integrity issues to be remediated.

   - **PHMSA Note:** Colonial has stated that publicly available satellite imagery sources such as Google Earth are accessible with an average refresh time of 1 to 3 years.

Colonial has high-resolution photography from 2012 incorporated in alignment sheets and collected video overflight in 2017.

d) **Root Cause Analysis for Failure or Leak**: Colonial must notify the Director, PHMSA Southern Region within five (5) days, if a leak or rupture occurs on mainline pipe in either of the ***special permit segments*** and must initiate a root cause analysis.[15] A 'root cause analysis' must be performed to determine the cause of the failure and must be sent to the Director, PHMSA Southern Region within 120 days or as soon as practical (if Colonial is not able to accomplish the analysis within 120 days, Colonial will notify the Director, PHMSA Southern Region within 10-days prior to expiration of the 120 days) of the accident. PHMSA will review the 'root cause analysis' report to determine if revocation, suspension, or modification of the special permit is warranted based upon accident findings.

e) **Pipe Properties Records**: Colonial must mechanically and hydrostatically test pipe in ***special permit segments 1 and 2*** that does not meet **Condition 21(b)** as follows:

i) Test a minimum number of pipe lengths/joints, or at least two (2) pipe lengths/joints when percentage is less than two (2) pipe lengths/joints, in accordance with 49 CFR 195.106.[16]

ii) ***Special permit segments 1 and 2*** pipe must meet the requirements of 49 CFR 195.106.

iii) ***Special permit segments 1 and 2*** pipe must be tested for mechanical and chemical properties (properties) as required in 49 CFR 195.106.

iv) The requirements in **Condition 20(e)** must be completed within one (1) year of the grant of this special permit and must meet pipe properties requirements for the pipe design factor in accordance with 49 CFR 195.106.

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[15] This condition does not alter any accident reporting time lines as required in 49 CFR 195.50, 195.52, 195.54, and 195.55.

[16] If mill test reports (MTRs) are missing on a segment of pipe, this special permit will allow non-destructive (NDE) test methods and alternative spacing of test locations with submittal of the NDE procedure by Colonial to PHMSA and receive a "no objection" from the Director, PHMSA Southern Region.

- **PHMSA Note:** Colonial has provided the mill test reports (MTRs) to demonstrate pipe property records of both the ***special permit segments***.

f) <u>**Pipeline System Flow Reversals**</u>:

i) If a pipeline long term flow reversal (exceeding 90 days) is planned for ***special permit segments 1 or 2***, Colonial must document the flow reversal operational, integrity, and safety processes for the ***special permit segment*** as follows: all technical, operational, integrity management, and safety procedures implemented; including any pressure tests, pressure control changes (pressure relief or monitor size or location changes), ILI inspections, direct examinations and repairs, emergency responder and public notifications prior to the change in natural gas flow direction and any leaks, failures, incidents, or remediation conducted; and confirmation of the lowest failure pressure (ratio to MOP), most severe dent, and largest wall loss anomalies remaining.

ii) Colonial must use and document measures implemented to meet PHMSA Advisory Bulletin (ADB-2014-04), "Guidance for Pipeline Flow Reversals, Product Changes and Conversion of Service" issued on September 18, 2014 (79 FR 56121, Docket PHMSA-2014-0040).

iii) Colonial must submit the documents in **Condition 20 (f)(i) and (ii)** above to the Director, PHMSA Southern Region; Director, PHMSA Standards and Rulemaking Division; and Director, PHMSA Engineering and Research Division within 180-days prior to any planned pipeline system long term flow reversals for a ***special permit segment***.

iv) Based upon PHMSA's review of Colonial's flow reversal process for the ***special permit segment***, Colonial may be given a "no objection" to the pipeline flow reversal by PHMSA or may be required by PHMSA to re-apply for a new special permit.

g) <u>**Remote Closure and Monitoring of Mainline Valves**</u>: Colonial must be able to detect a pipeline rupture within ten (10) minutes of initiation and initiate closing ***special permit segments 1 and 2*** isolation valves within 30 minutes of a rupture or other high-volume leakage failure (event) as follows:

i) A mainline valve on either side of a ***special permit segment*** must be equipped for remote closure and have motorized operators on the valves for ***special permit segment*** isolation. The following installation and conversion actions will meet the condition;

   A. Colonial must convert a manual valve to an emergency flow restrictive device (EFRD) at the Krotz Springs, Louisiana Station. This valve change will create a 33-mile valve spacing for the Louisiana ***special permit segment 1***. The 66-mile Louisiana ***special permit segment 1*** will have an EFRD on both boundaries and the middle. Additionally, three (3) check valves are located within the ***special permit segment 1*** at Mile Posts 19, 34, and 62.[17]

   B. Colonial must install a new remotely operable EFRD valve at Smyrna, Georgia Station. This valve change will create a 36-mile valve spacing from Colonial's Smyrna Station to Dacula Station. This spacing includes the 10 mile Georgia ***special permit segment 2***. Smyrna Station is located about eight (8) miles upstream of the beginning of ***special permit segment 2*** (Chattahoochee River) and Dacula Station is located about 18 miles downstream of the end of the ***special permit segment 2*** (Highway 141).[18]

ii) If personnel response time (including the time for assembly of operational personnel, drive time under severe traffic conditions at normal speeds, and time to start closure of the valve(s)) to all isolation mainline valves, in-flow tap valves, and crossover valves on either side of ***special permit segments 1 and 2*** exceeds the 30 minute duration from the time the event is identified in the control room; Colonial must provide remote control through a SCADA system, other leak detection system, or an alternative method of control.

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[17] The Krotz Springs, Louisiana EFRD will potentially save a maximum drain-down of 145 barrels from a seven (7) mile distance upstream of the valve and the valve itself. If a spill occurred on the downstream side of the valve, the Krotz Springs EFRD would potentially save a maximum of 1,000 barrels of hazardous liquid, when the release is between the Krotz Springs EFRD and the Mississippi River valve, the distance is 27 miles.

[18] The Smyrna, Georgia EFRD would potentially save a maximum drain-down of 875 barrels resulting from a spill occurring in the first 5,000 feet of the Georgia ***special permit segment 2***. Additionally, this valve would provide a maximum drain-down savings of about 2,500 barrels from upstream outside of the ***special permit segment 2***.

- **PHMSA Note:** Colonial stated they already have EFRDs on either side of ***special permit segment 1*** as indicated above in **Condition 20(g)(i) A**. The referenced EFRDs in **Condition 20(g)(i) B** above at Smyrna Station and Dacula Station are to meet the requirement for either side of ***special permit segment 2***. Therefore, this condition will be met through having valves operable by remote control through a SCADA system.

iii) Remote control valves must include the ability to close and monitor the valve position (open or closed), and monitor upstream pressure of the mainline valve.

iv) Remote control valves must be inspected and partially operated as required in 49 CFR 195.420. Colonial must operate these remote-control valves as part of a pipeline with a SCADA system, they must meet applicable sections of 49 CFR 195.446(c) and (e) including point to point verification between SCADA displays and field remote control valves and inspection timing.

v) Colonial must initiate **Condition 20(g)(i)** within twelve (12) months of the grant of this special permit. If factors "beyond Colonial's control" prevent the completion of the valve conversion and installation within twelve (12) months, a letter justifying the delay and providing the anticipated date of completion must be submitted to the Director, PHMSA Southern Region no later than one (1) month prior to the end of the twelve (12) months completion date. Any extension schedule submitted to PHMSA from Colonial must receive a "no objection" from the Director, PHMSA Southern Region prior to proceeding.

- **PHMSA Note:** The valve changes keep valve location within existing facility fence lines for accessibility to power and SCADA control systems along with maintaining the security of the valve.

21) **<u>Documentation</u>**: Colonial must maintain documentation for the ***special permit segments 1 and 2*** as follows.

a) Colonial must maintain documentation of compliance with all the conditions of this special permit for the life of this special permit and must provide such documentation to PHMSA as set forth in this special permit and upon request by PHMSA.

b) Colonial must maintain documentation of mechanical and chemical properties (MTRs) showing that the pipe in ***special permit segments 1 and 2*** meets the wall thickness, yield strength, tensile strength and chemical composition of either the American Petroleum Institute Standard 5L, 5LX or 5LS, "Specification for Line Pipe" (API 5L) referenced in 49 CFR Part 195 at the time of manufacturing or if pipe was manufactured and placed in-service prior to the inception of 49 CFR Part 195, then the pipe meets the API 5L standard in usage at that time. Any ***special permit segment*** that does not have MTRs for the pipe cannot be authorized in accordance with this special permit and must be pressure tested in accordance with 49 CFR Part 195.

- **PHMSA Note:** Colonial has provided and maintains all MTRs related to ***special permit segments 1 and 2***.

22) **<u>Certification</u>**: A senior executive officer, vice president or higher, of Colonial must certify in writing the following:

a) That Colonial's Line 01 Pipeline in ***special permit segments 1 and 2*** will meet the conditions described in this special permit,

b) That Colonial's written O&M manual has been updated to include all additional O&M requirements of this special permit; and

c) Colonial has implemented a system to collect and preserve all documentation required by 49 CFR Part 195, including, but not limited to, pressure test documents required in 49 CFR 195.310 for the Colonial Pipeline system.

d) Within one (1) year of the grant of this special permit, Colonial must complete and send a copy of the certification required in **Condition 22** with the required senior executive signature and date of signature to the PHMSA OPS Associate Administrator with copies to the Director, PHMSA Southern Region; and the Director, PHMSA OPS Engineering and Research Division; and to the Federal Register Docket (PHMSA-2009-0390) at www.regulations.gov within one (1) year of the issuance date of this special permit.

Limitations:

This special permit is subject to the limitations set forth in 49 CFR 190.341, as well as the following limitations:

1) PHMSA has the sole authority to make all determinations on whether Colonial has complied with the specified conditions of this special permit. Failure to comply with any condition of this special permit may result in revocation of the permit.

2) Any work plans and associated schedules for the Line 01 Pipeline ***special permit segments 1 or 2*** are automatically incorporated into this special permit and are enforceable in the same manner.

3) Failure by Colonial to submit the certifications required by **Condition 22 (Certification)** within the time frames specified may result in revocation of this special permit.

4) As provided in 49 CFR 190.341, PHMSA may issue an enforcement action for failure to comply with this special permit. The terms and conditions of any corrective action order, compliance order or other order applicable to a pipeline facility covered by this special permit will take precedence over the terms of this special permit.

5) If Colonial sells, merges, transfers, or otherwise disposes of all or part of the assets known as the Line 01 Pipeline in the ***special permit segment 1 or 2***, Colonial must provide PHMSA with written notice of the change within 30 days of the consummation date. In the event of such transfer, PHMSA reserves the right to revoke, suspend, or modify the special permit if the transfer constitutes a material change in conditions or circumstances underlying the permit. Any notifications for this limitation must be sent to the PHMSA Associate Administrator for Pipeline Safety with copies to the Director, PHMSA Southern Region; and to the Director, PHMSA Engineering and Research Division.

AUTHORITY: 49 U.S.C. 60118 (c)(1) and 49 CFR 1.97.

Issued in Washington, DC on NOV 25 2019.

Alan K. Mayberry,

Associate Administrator for Pipeline Safety

Appendix A – Engineering Critical Assessment for Cracks

A.1) Engineering Critical Assessment for Cracks

An engineering critical assessment (ECA) is conducted on all ILI reported crack indications in the special permit section. For field discovered cracking indications, Colonial procedures dictate that all cracks be removed by buffing or repaired with a Type B sleeve.

Colonial must perform such ECAs in accordance with this Appendix A and **Condition 16**. The ECA must be performed to determine the predicted failure pressure of the as-discovered condition and the remaining life for the pipeline at the defect location. The ECA must use applicable fracture mechanics modeling techniques, pressure cycle analysis, crack growth fatigue models, and failure mode analysis (brittle, ductile, or both) for the microstructure (i.e., heat-affected zone, bond line, parent pipe, etc.).

A.2) Predicted Failure Pressure Calculation

The predicted failure pressure must be calculated using technically proven fracture mechanics evaluation methods that are known to be conservative and are appropriate for whether the crack defect is in ductile, brittle, or both material types.

A.3) Crack Growth Analysis

The crack growth analysis must determine the remaining life of the largest remaining critical crack flaw, based on the operating parameters of the pipeline; any pipe failure or leak mechanisms identified during any pressure testing or other operations; pipe characteristics; material mechanical properties (including toughness); failure mechanism for the microstructure (ductile and brittle or both); location and type of defect; operating environment; operation conditions, including pipe operating temperatures; and pressure cycling induced fatigue. The analysis must use proven methods and procedures for analyzing crack growth (both length and depth), and crack interactions, within the cluster of cracks in the identified defect.

A.4) Fatigue Analysis

Fatigue analysis must be performed using a recognized form of the Paris Law or other technically appropriate engineering methodology to give conservative predictions of flaw growth and remaining life.

A.5) Crack Degradation & Analysis

When assessing other degradation processes (other than pressure cycling), an operator must perform the analysis using recognized rate equations where the applicability and validity are demonstrated for the case being evaluated. The analysis must include conservative estimates of time to failure for any known or potential remaining cracks in the pipe.

The analysis to determine the time to failure for a crack must include operating history, pressure cycles, pressure tests, pipe geometry, wall thickness, strength level, flow stress, Charpy V-Notch energy values for the lowest operating temperature, other applicable operating conditions, and the operating environment for the pipe segment being assessed, including the role of the pressure-cycle spectrum and any significant changes in the actual versus predicted pressure-cycle spectrum.

A.6) Crack Analysis Data

Data used in the calculations must use all of the following as appropriate:

a) Mechanical Properties

Mechanical properties that are known or conservative assumptions of mechanical properties must be used in the analysis. The analysis must account for metallurgical properties at the location being analyzed.

Material strength and toughness values used in the analysis must reflect the local conditions at the defect location or segment being analyzed (such as in the properties of the parent pipe, weld heat-affected zone, or weld metal bond line) and use data that is applicable to the specific line pipe vintage and segment. When the strength and toughness and limits or ranges are unknown, the analysis must assume material strength and fracture toughness levels corresponding to the pipe vintage and type.

For pipe body or weld crack assessments, use the actual ranges of values of strength and toughness that are known from tests of similar material; conduct destructive material tests of the pipe; determine material properties based upon other appropriate nondestructive examination technology; or use conservative values based on technical research publications that an operator demonstrates provides conservative Charpy V-Notch energy values of the crack-related conditions and conservative strength values of the line pipe appropriate for the seam type.

Testing programs to determine pipe and seam material properties must conduct enough material testing to establish statistically valid mean and standard deviations from their results, and material property values used in ECAs, with a minimum of at least five (5) tests for each type or vintage of pipe.

b) Crack Dimensions

Crack length and depth dimensions must be obtained from *in situ* direct measurements on the pipe, from crack detection or ILI tools for cracking.

<u>ILI Tool Crack Detection</u>

For cases that analyze remaining flaw sizes measured using crack detection in-line inspection tool data, the analysis must use flaw dimensions and characteristics that conservatively account for ILI tool inaccuracies and measurement tolerances. The operator must confirm inaccuracies and measurement tolerances used through integrated historical data or direct in situ non-destructive examination. The operator must use technology that has been validated to detect and measure tight cracks. In-the-ditch examination tools and procedures for crack measurements (length and depth) must have performance, tool accuracy, tool tolerance, and evaluation standards, including pipe or weld surface cleanliness standards for the inspection, confirmed by subject matter expert qualified by knowledge, training, and experience in direct examination.

A.7) Failure Mode Analysis

The ECA must account for the likely failure mode of anomalies (such as brittle fracture, ductile fracture, or both). If the likely failure mode is uncertain or unknown, the analysis must analyze both failure modes and use the more conservative result.

a) Fracture Mechanics Modeling

Fracture mechanics modeling that is technically appropriate for the anomaly type must be used to determine failure stress pressures.

b) Brittle Failure Mode Analysis

Brittle failure mode analysis must use linear-elastic failure models such as the Raju/Newman stress-intensity solutions or other technically proven approaches.

c) Ductile Failure Mode Analysis

Ductile failure mode analysis must use technically appropriate failure models such as the Modified LnSec, CorLas, Pipe Axial Flaw Failure Criteria, API 579 Level-II, PipeAssess PI™, BS 7910, PRCI MAT-8 or other technically proven approaches.

d) Other Failure Mode Analysis

Other technically proven-equivalent engineering fracture mechanics models may be used, which can be shown to accurately predict the response for the feature of concern or the worst-case scenario, for determining conservative failure pressures for the specific failure mode.

A.8) ECA Reassessment Intervals

When establishing reassessment intervals for pipelines with known or suspected remaining cracks or crack-like defects; the maximum reassessment interval may not exceed one-half of the remaining life determined by an ECA. However, PHMSA will consider as "other technology," the use of a reassessment interval that is greater than one-half of the remaining life determined by the ECA or if impractical due to tool availability, if technically documented and justified.

If changes to annual operating conditions exceed the assumptions included in the remaining life analysis, then the remaining life must be reanalyzed and recalculated within 6 months of the change.

A.9) ECA Documentation Requirements

The following documentation must be retained from the ECA:

a) The technical approach used for the analysis, including procedures, evaluation methodology, and models used;
b) All data used and analyzed;
c) Pipe and weld properties including Charpy Impact values;
d) Direct in situ examination data, including in-the-ditch assessments;
e) In-line inspection tool run information evaluated, including any multiple in-line inspection tool runs;
f) Pressure test data and results, if applicable;
g) All measurement tool, assessment, and evaluation accuracy specifications and tolerances used in technical and operational results;
h) All finite element analysis results, where applicable;
i) The number of pressure cycles to failure, the equivalent number of annual pressure cycles, and the pressure cycle counting method, such that fatigue life models and fracture mechanics evaluation methods are documented;
j) Safety factors used for fatigue life and/or predicted failure pressure calculations;
k) Reassessment time interval and safety factors;
l) The date of the review;
m) Documentation confirming the results; and
n) Approval by responsible operator management personnel.

A.10) ECA Assessment Technology

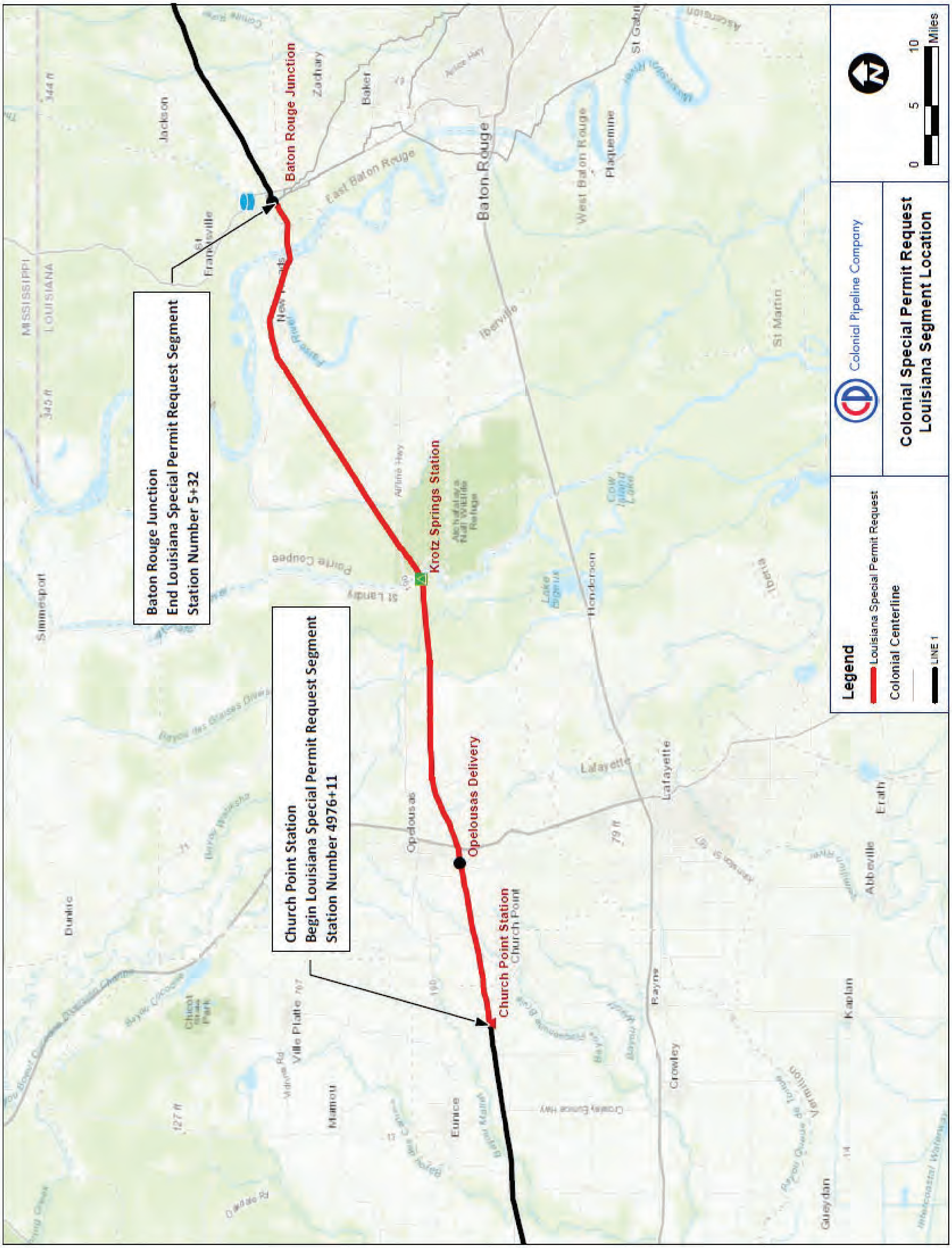
Other technology for ECAs may be used if the operator demonstrates that the assessment provides an equivalent understanding of the condition of the line pipe. Such "other technology" methodologies may include different or improved crack assessment methodologies, fracture mechanics evaluation methods, crack growth evaluation methods, fatigue models, and remaining life models, as well as differing or less-conservative assumptions for pipe and seam properties, or any other aspect of the operator's ECA methodology that does not comply with the requirements of this section.

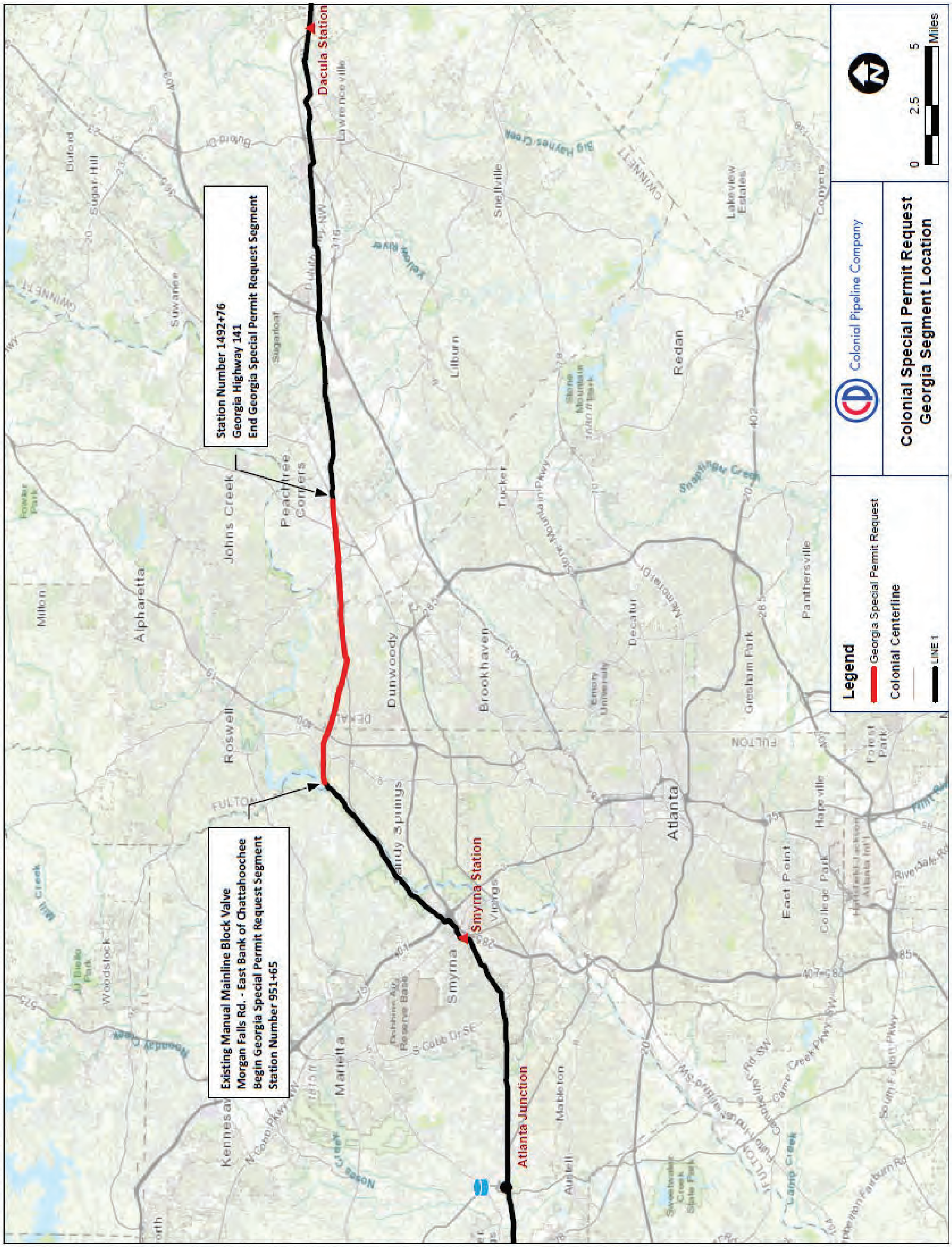
If the "other technology" option is selected, the Director, PHMSA Southern Region must be notified ninety (90) days before implementing the ECA and Colonial must receive a "no objection" letter from PHMSA prior to implementing the "other technology".

A.11) ECA Procedure Review by PHMSA

Colonial must submit the ECA procedure to the Director, PHMSA Southern Region and must receive a "no objection" letter from PHMSA prior to implementing Appendix A.

Appendix B: Special Permit Segment Location Maps




Station Number 1492+76
Georgia Highway 141
End Georgia Special Permit Request Segment
Existing Manual Mainline Block Valve
Morgan Falls Rd. - East Bank of Chattahoochee
Begin Georgia Special Permit Request Segment
Station Number 951+65
Dacula Station
Smyrna Station
Atlanta Junction
Atlanta
Legend
Georgia Special Permit Request
Colonial Centerline
LINE1
Colonial Pipeline Company
Colonial Special Permit Request
Georgia Segment Location
0
2.5
5
Miles

Appendix C – Corrosion Threat Reduction Program (as of 06-12-2019)

Program Overview

The Corrosion Threat Reduction Program utilizes close interval survey results to assess the corrosion threat of the pipeline segments and remediate cathodic protection deficiency appropriately.

This program includes detailed processes and timelines for conducting surveys, identifying deficiencies, and completing mitigative projects. The goal of this program is to reduce the risk of external corrosion in addition to preventive monitoring and mitigation programs. This program was modeled after the ILI program for a consistent approach between major integrity management elements utilizing integrated data sources, ensuring program continuity, efficiency, and alignment within the overall Integrity Management Program.

Depending on the results of the surveys and data integration analysis, deficiencies will be risk ranked and corrected within a reasonable time. If a condition is determined to require immediate attention, corrective actions will be implemented upon confirmed knowledge of the conditions existence. An example of an immediate condition might include a positive (anodic) potential reading, a significant interference condition, or a reversed rectifier.

Corrosion Assessment and Criteria

Before the CIS project begins, the survey technique and associated criteria identified and documented for each survey segment. An interrupted (on/off) survey is the preferred survey technique and utilizes the -850mV polarized/100mV polarization criteria as defined in NACE SP0169-2007. Segments where interrupted surveys cannot be performed or where it is not practical for voltage drop measurements to be obtained, the current applied or "ON" survey will be performed. A -850-mV current applied criterion will be utilized for current applied surveys.

The discovery of a deficiency to corrosion protection adequacy requires the completion of:

1. CIS data analysis
2. Review and validation of survey exception areas
3. Corrosion threat calculator (CTC) evaluation

The CTC utilizes data from the CIS, ILI, and risk model to calculate and assign a risk ranking score to each exception identified from the CIS. The CTC variables used to score are (related only to the specific length associated with individual exceptions):

Corrosion Threat Calculator - Current Applied Survey

CTC Factor	Score	Criterion	Calculation
Maximum Corrosion Rate	25	5 mpy (0.005" per year)	$MaxRate \times \frac{25}{0.005}$
Average Corrosion Rate	10	2 mpy (0.002" per year)	$AveRate \times \frac{10}{0.002}$
Close Interval Survey Value	25	-550 mV	$(1 - \frac{SurveyValue + 550}{-300}) \times 25$
Pits >20%/ft.	15	0.02 callouts/ft.	$PerFtValue \times \frac{15}{0.02}$
Total Anomalies/ft.	10	0.5 callouts/ft.	$PerFtValue \times \frac{10}{0.5}$
Maximum Pit Depth	10	40% wall loss	$MaxDepth \times \frac{10}{40}$
Risk Score	5	7	$RiskScore \times \frac{5}{7}$

Corrosion Threat Calculator – Interrupted Survey

CTC Factor	Score	Criterion	Calculation
Maximum Corrosion Rate	25	5 mpy (0.005" per year)	$MaxRate \times \frac{25}{0.005}$
Average Corrosion Rate	10	2 mpy (0.002" per year)	$AveRate \times \frac{10}{0.002}$
Polarization Value	25	100 mV Polarization	$\frac{-(SurveyOff - Static)}{90} \times 25$
Pits >20%/ft.	15	0.02 callouts/ft.	$PerFtValue \times \frac{15}{0.02}$
Total Anomalies/ft.	10	0.5 callouts/ft.	$PerFtValue \times \frac{10}{0.5}$
Maximum Pit Depth	10	40% wall loss	$MaxDepth \times \frac{10}{40}$
Risk Score	5	7	$RiskScore \times \frac{5}{7}$

All CIS values entered into the CTC are considered deficiencies. These deficiencies are prioritized and corrected according to the reasonable timelines described below.

Mitigation Methods

Mitigation methods for CIS deficiencies may include the following:

- Resurvey

- Adjustment to existing Cathodic Protection system
- Modification to existing Cathodic Protection system
- New Cathodic Protection installation
- Pipeline coating repair or rehabilitation

A prove up survey must be performed along the entire deficient segment upon completion of the remediation work to show that CIS readings have been brought up to acceptable levels and the deficiency has been effectively remediated
A deficiency may also be cleared if it is determined that the deficiency was generated due to an erroneous data spike. A follow up survey is not required in this scenario.

Deficiency Timelines
All discovered deficiency corrections will be completed according to the reasonable timeline as follows:

Deficiency Correction Timeline	CTC Score
1 Year	≥ 65
2 Years	> 25, but <65
3 Years	≤ 25

If a remediation attempt does not result in satisfactory cathodic protection levels per the defined criteria, then an additional year may be granted to the deficiency correction timeline so that additional remediation work can be performed.

1-Year Timeline Triggers

- All CIS exceptions documented on pipeline segments which are not piggable
- A corrosion rate of 5 mils/year or greater is identified by the CTC
- A polarization value is calculated or measured to be zero and the corrosion rate is greater than or equal to 1 mil/year for interrupted surveys
- The current applied pipe-to-soil potential is equal to or more positive than -550mV for current applied surveys

Appendix D – Modified Recoat Calculator (as of 06-12-2019)

Program Overview

The Modified Recoat Calculator (MRC) is an evaluation tool designed to identify active corrosion which can indicate coating failure and/or ineffective cathodic protection due to shielding. The MRC integrates datasets from Close Interval Survey (CIS), Inline Inspection (ILI) and the pipeline risk model for the scoring. The evaluation areas are normally broken up into 100 foot segments but can be evaluated at different segment lengths if needed. The purpose of this program is to evaluate the pipeline system for risk of corrosion and to identify disbonded coatings where cathodic shielding is occurring. When this phenomenon is identified, a coating rehabilitation project is initiated. This program evaluates the effectiveness of all coating on the pipeline system independent of cathodic protection deficiencies. Cathodic protection deficiencies are addressed and managed in the Corrosion Threat Reduction Program.

The MRC uses a scoring structure where each factor has a criterion and a point value which gives a maximum score of 100. Relative risk ranking is performed and used to prioritize corrosion threat. The MRC utilizes the ILI data from the most recent inspection but excludes areas where two-part epoxy coatings that have been applied and the pits under the new coating has been arrested.
After the scores are generated, manual verifications are performed to ensure the data is accurate. If there are any corrosion rates at 10 mils per year (MPY) or higher, they are manually investigated to validate the rate. Areas with accelerated corrosion rates and new corrosion development are prioritized and considered for coating rehabilitation.

The MRC scores for the entire coating system are calculated and evaluated on an annual basis but can be calculated on a more frequent basis dependent upon the availability of new CIS or ILI data sets.

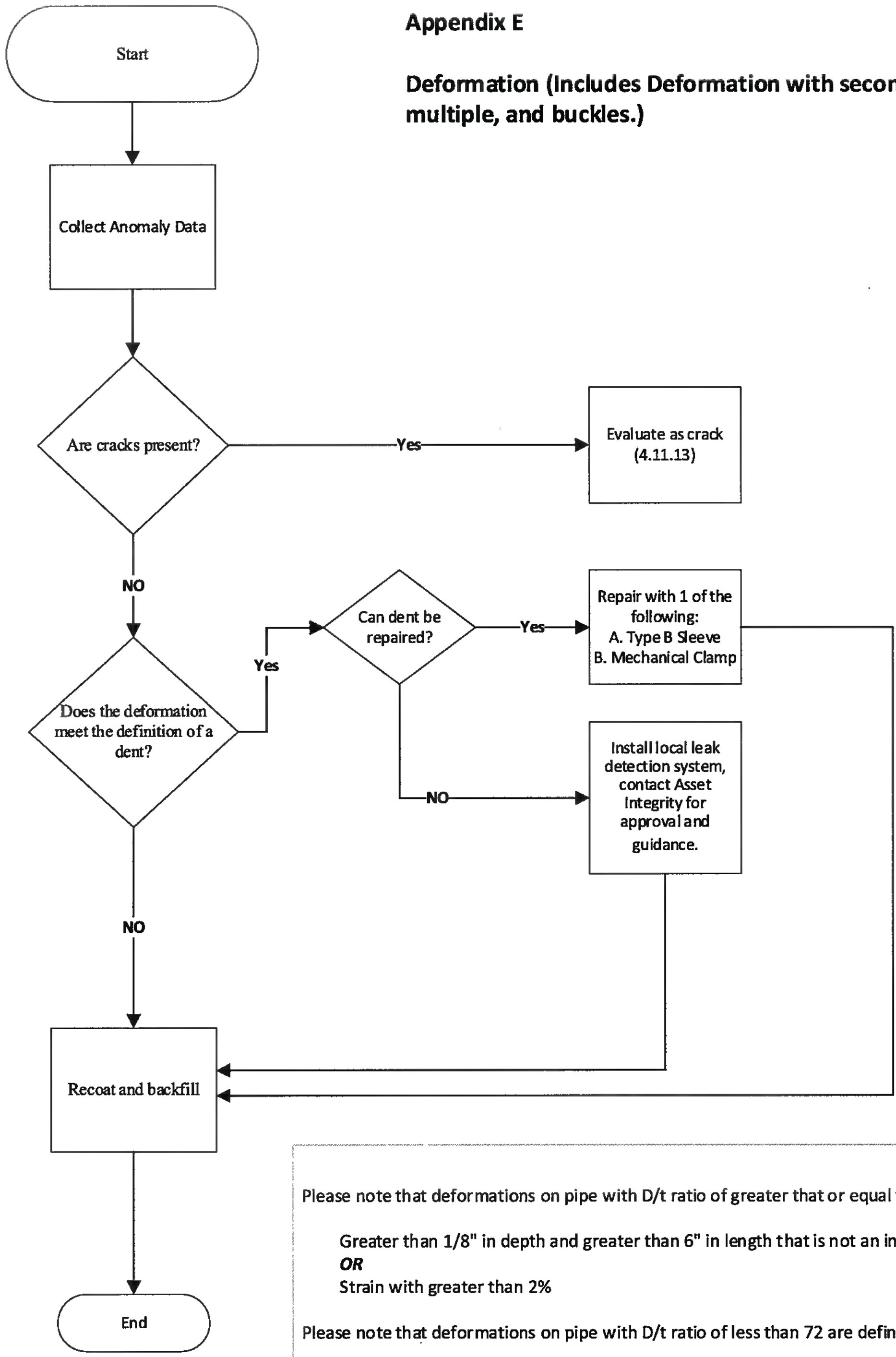
Other considerations given to potential coating rehabilitation sites that are **not** included in the MRC score would be previous excavations, Type A sleeves, dents, pressure cycling data and future regulatory anomaly digs.

Scoring and Calculations

MRC Factor	Score	Criterion	Calculation
Close Interval Survey Value	25	-550 mV	$(1-\frac{SurveyValue+550}{-300})\times 25$
Maximum Corrosion Rate	25	10 mpy (0.01" per year)	$MaxRate\times\frac{25}{0.01}$
Maximum Pit Depth	10	40% wall loss	$MaxDepth\times\frac{10}{40}$
Pits >=20% With Active Corrosion (>5mpy)	15	0.1 callouts/ft.	$PerFtValue\times\frac{15}{0.1}$
New Pits >=20%	10	0.2 callouts/ft.	$PerFtValue\times\frac{10}{0.2}$
New Pits <20%	5	1 callouts/ft.	$PerFtValue\times\frac{5}{1}$
Risk Score	10	7	$RiskScore\times\frac{5}{7}$

Appendix E

Deformation (Includes Deformation with secondary features, multiple, and buckles.)



Please note that deformations on pipe with D/t ratio of greater that or equal to 72 are defined below.

Greater than 1/8" in depth and greater than 6" in length that is not an intentionally installed field bend
OR
Strain with greater than 2%

Please note that deformations on pipe with D/t ratio of less than 72 are defined below.

Greater than or equal to 1% in depth and no other indications present that is not an intentionally installed field blend are considered dents and therefore repaired accordingly. All indications that do not exceed this criteria are considered flat spots and therefore non injurious indications.