IN THE UNITED STATES DISTRICT COURT
FOR THE WESTERN DISTRICT OF LOUISIANA

UNITED STATES OF AMERICA and LOUISIANA DEPARTMENT OF ENVIRONMENTAL QUALITY	)
Plaintiffs,	) **Civil Action No.** 5:19-cv-107
v.	) **Judge**
SUNOCO PIPELINE L.P. and MID-VALLEY PIPELINE COMPANY	)
Defendants.	)

<u>CONSENT DECREE</u>

Plaintiffs the United States of America, on behalf of the Environmental Protection Agency ("EPA"), and the Louisiana Department of Environmental Quality ("LDEQ") have jointly filed a Complaint in this action, concurrent with the lodging of this Consent Decree, alleging that Sunoco Pipeline L.P. ("Sunoco") and the Mid-Valley Pipeline Company ("Mid-Valley") (collectively, "Defendants") violated provisions of the Clean Water Act ("CWA") and Louisiana statutes and regulations. In particular, the Complaint seeks volume-based penalties, State response costs, and injunctive relief, alleging claims arising under the following:

A. Section 301(a) of the CWA, 33 U.S.C. § 1311(a);

B. Section 311(b) of the CWA, 33 U.S.C. § 1321(b);

C. Section 309(b) of the CWA, 33 U.S.C. § 1319(b);

D. La. R.S. 30:2076(A)(1) and (A)(3);

E. LAC 33:IX.501.A;

F. LAC 33:IX.1701.B;

G. LAC 33:I.3925.A.3; and

H. Defendants' Louisiana Pollutant Discharge Elimination System General Permit.

Defendants do not admit any fact, law, or liability arising out of the Releases (as defined in Section III), occurrences or violations alleged in the Complaint.

The allegations in the Complaint relate to three separate discharges of crude oil. The Complaint alleges that on February 23, 2013, approximately 550 barrels of crude oil spilled from the eight-inch Colmesneil-to-Chester Pipeline (the "Colmesneil Line") in Tyler County, Texas (the "Texas Spill"); on October 13, 2014, approximately 4,500 barrels of crude oil spilled from the Longview, Texas, to Mayersville, Mississippi, portion of the Mid-Valley Pipeline (the

"Longview to Mayersville Segment") in Caddo Parish, Louisiana (the "Louisiana Spill"); and on January 20, 2015, approximately 40 barrels of crude oil spilled from the four-inch gathering line (the "Wakita Gathering Line"), in Wakita, Oklahoma (the "Oklahoma Spill"). The Colmesneil Line, the Mid-Valley-owned Longview to Mayersville Segment, and the Wakita Gathering Line were all operated by Sunoco when the respective spills occurred, and the Longview to Mayersville Segment is currently operated by Sunoco.

Sunoco represents that it has abandoned the Colmesneil Line and the Wakita Gathering Line, consistent with the definition of "abandoned" found at 49 C.F.R. § 195.2, and as used in 49 C.F.R. Section 195.402(c)(10). As such, all crude oil has been removed from the lines, and the lines are currently inactive. Sunoco reserves the right to restart the Colmesneil Line and the Wakita Gathering Line, subject to the requirements of Section V (Injunctive Relief).

Sunoco also represents that, prior to lodging of this Consent Decree, Sunoco has taken the following actions on the Mid-Valley Pipeline in an effort to detect threats to the integrity of its pipelines and prevent future unauthorized discharges of crude oil from its pipeline facilities:

- Pipeline inspections using in-line inspection ("ILI") technology;
- Performance of "data integration," which entails considering ILI data, along with other information about Sunoco's pipeline assets, to identify necessary facility repairs that present oil spill risks;
- Beginning in 2015, commencement of a multiyear program to Hydrotest the entire length of the Mid-Valley Line, which, as of the date of lodging, is approximately 75% complete;
- Installation of a software-based pipeline integrity monitoring using "LeakWarn" at the Sunoco Houston, Texas, control room (provides continuous, real-time data about the crude oil flow in system pipelines); and
- Third-party assessment of Sunoco's current Houston, Texas, control-room leak-detection procedures.

The Parties recognize, and the Court by entering this Consent Decree finds, that this

Consent Decree has been negotiated by the Parties in good faith and will avoid continued litigation between the Parties on the claims addressed in the Complaint, and that this Consent Decree is fair, adequate, reasonable, and in the public interest.

NOW, THEREFORE, before the taking of any testimony, without the adjudication or admission of any issue of fact or law except as provided in Section I (Jurisdiction and Venue), with the consent of the Parties, IT IS HEREBY ADJUDGED, ORDERED, AND DECREED as follows:

I. JURISDICTION AND VENUE

1. This Court has jurisdiction over the subject matter of this action, pursuant to 28 U.S.C. §§ 1331, 1345, and 1355, and Section 311(b)(7)(E) and (n) of the CWA, 33 U.S.C. § 1321(b)(7)(E) and (n), and over the Parties. This Court has supplemental jurisdiction over the State law claims asserted by LDEQ pursuant to 28 U.S.C. § 1367.

2. Venue lies in this judicial district pursuant to Section 311(b)(7)(E) of the CWA, 33 U.S.C. § 1321(b)(7)(E), and 28 U.S.C. §§ 1391 and 1395(a), because the claims arose, and Defendants are doing business, in this district.

3. For purposes of this Decree, or any action to enforce this Decree, Defendants consent to the Court's jurisdiction over this Decree, any such action, and over Defendants, and further consent to venue in this judicial district.

4. For purposes of this Consent Decree, Defendants agree that the Complaint states claims upon which relief may be granted pursuant to Sections 301, 309(b), and 311(b) of the CWA, 33 U.S.C. §§ 1311, 1319(b), 1321(b).

II. APPLICABILITY

5. The obligations of this Consent Decree apply to and are binding upon the United States, LDEQ, and to and upon Defendants, jointly and severally, and any successors, assigns, or other entities or persons otherwise bound by law.

6. No transfer of ownership or operation of any of the Covered Facilities, whether in compliance with the procedures of this Paragraph or otherwise, shall relieve Defendants of their obligations to ensure that the terms of the Decree are implemented, unless: (1) the transferee agrees to undertake the obligations required by this Consent Decree and to be substituted for one or both of the Defendants as a Party under the Decree and thus be bound by the terms thereof, and (2) the United States consents to relieve the one or both of the Defendants of its or their obligations. The United States' decision to refuse to approve the substitution of the transferee for a Defendant shall not be subject to judicial review. At least 30 Days prior to any transfer, the relevant Defendant (or Defendants) shall provide a copy of this Consent Decree to the proposed transferee and shall simultaneously provide written notice of the prospective transfer, together with a copy of the proposed written agreement, to EPA Region VI, the United States Attorney for the Western District of Louisiana, and the United States Department of Justice, in accordance with Section XII (Notices). Any attempt to transfer ownership or operation of any of the Covered Facilities without complying with this Paragraph constitutes a violation of this Decree.

7. Defendants shall provide a copy of this Consent Decree to all officers, employees, and agents whose duties reasonably include compliance with any provision of this Decree, as well as to any contractor retained to perform work required under this Consent Decree. Defendants may also fulfill the obligation in the preceding sentence by providing the foregoing persons with instruction and briefing concerning portions of this Consent Decree for which they

have implementation responsibilities. To the extent a third party is retained by a Defendant to perform any tasks which are the subject of this Consent Decree, such Defendant shall condition any such contract upon performance of the work in conformity with the terms of this Consent Decree.

8. In any action to enforce this Consent Decree, neither Defendant shall raise as a defense the failure by any of its officers, directors, employees, agents, or contractors to take any action necessary to comply with the provisions of this Consent Decree.

III. DEFINITIONS

9. Terms used in this Consent Decree that are defined in the Act or in regulations promulgated pursuant to the Act shall have the meanings assigned to them in the Act or such regulations, unless otherwise provided in this Decree. Whenever the terms set forth below are used in this Consent Decree, the following definitions shall apply:

a. "60-Day Repair Condition" shall mean a pipeline condition meeting one of the criteria listed under the heading "60-Day Repair Condition" in Table 1 of Appendix C (Repair Condition Identification and Classification).

b. "180-Day Repair Condition" shall mean a pipeline condition meeting one of the criteria listed under the heading "180-Day Repair Condition" in Table 1 of Appendix C (Repair Condition Identification and Classification).

c. "Axial Magnetic Flux Leakage Corrosion Tool" shall mean a pipeline corrosion detection tool employing technology that provides a reliable means of detecting pipeline anomalies, including but not limited to: pipe wall thickness loss, general corrosion, or wide circumferential flaws.

d. "Caliper Tool" shall mean a pipeline inspection tool that is capable of and operates to measure, continuously, the inside diameter of a pipeline through sensors that are in contact with the pipe wall for the duration of the tool run, and through data collected by the sensors provides information about pipe wall thickness.

e. "Complaint" shall mean the complaint filed by the United States and LDEQ in this action.

f. "Consent Decree" or "Decree" shall mean this Decree and all appendices attached hereto (listed in Section V).

g. "Covered Facilities" shall mean the Longview to Mayersville Segment; the Colmesneil Line; and the Wakita Gathering Line.

h. "Day" shall mean a calendar day unless expressly stated to be a working day. In computing any period of time under this Consent Decree, the Parties will follow Rule 6(a) of the Federal Rules of Civil Procedure.

i. "Defendants" shall mean Sunoco Pipeline L.P. ("Sunoco") and Mid-Valley Pipeline Company ("Mid-Valley").

j. "Effective Date" shall have the definition provided in Section XIII.

k. "EPA" shall mean the United States Environmental Protection Agency and any of its successor departments or agencies.

l. "High Consequence Area" shall have the meaning set forth in 49 C.F.R. § 195.450.

m. "Hydrotest" shall mean a pipeline pressure test conducted according to the requirements described at 49 C.F.R. Part 195, Subpart E.

n. "Idle" shall mean, in connection with any of the Covered Facilities, that no crude oil has been transported through any Pipeline Segment for a period of over 120

Days.

o. "ILI Technology" shall mean a method or methods used to perform internal (in-line) pipeline inspection capable of detecting pipeline corrosion, deformation, or other anomalies occurring on the inside of a pipeline, including but not limited to: dents, gouges, or grooves.

p. "Immediate Repair Condition" shall mean a pipeline condition meeting one of the criteria listed under the heading "Immediate Repair Condition" in Table 1 of Appendix C (Repair Condition Identification and Classification).

q. "In Operation" shall mean, in connection with any of the Covered Facilities, that crude oil has been transported through a Pipeline Segment at any time during a period of 120 Days, except that in calculating this period, no Day prior to the Effective Date shall be included.

r. "LDEQ" shall mean the Louisiana Department of Environmental Quality and any of its successor departments or agencies.

s. "Louisiana" shall mean the State of Louisiana.

t. "Louisiana Spill" shall mean the discharge of approximately 4,500 barrels of crude oil from the Mid-Valley Pipeline in Caddo Parish, Louisiana, on October 13, 2014.

u. "Mid-Valley Pipeline" shall mean the Sunoco-operated pipeline from Longview, Texas to Lima, Ohio.

v. "Oklahoma Spill" shall mean the discharge of approximately 40 barrels of crude oil from the Wakita Gathering Line in Grant County, Oklahoma, on January 20, 2015.

w. "Paragraph" shall mean a portion of this Decree identified by an arabic numeral.

x. "Parties" shall mean the United States, LDEQ, and Defendants.

y. "Pipeline Segment" shall mean continuous run of pipe between adjacent stations, between a station and a block valve, or between adjacent block valves at any Covered Facility.

z. "PHMSA" shall mean the United States Pipeline and Hazardous Safety Administration and any of its successor departments or agencies.

aa. "Repair Condition" shall mean any Immediate Repair Condition, 60-Day Repair Condition, or 180-Day Repair Condition.

bb. "Releases" shall mean the Louisiana Spill, the Oklahoma Spill, and the Texas Spill.

cc. "SCADA" shall mean supervisory control and data acquisition system or an industrial control system used to obtain information about and control pipeline infrastructure operations.

dd. "Section" shall mean a portion of this Decree identified by a roman numeral.

ee. "Texas Spill" shall mean the discharge of approximately 550 barrels of crude oil from the Colmesneil Line in Tyler County, Texas, on February 23, 2013.

ff. "United States" shall mean the United States of America, acting on behalf of EPA.

gg. "Ultrasonic Crack Detection Tools" shall mean pipeline crack detection and inspection tools that use ultrasound to provide reliable means of detecting cracks and crack-like anomalies in pipelines.

IV. CIVIL PENALTIES; STATE RESPONSE COSTS

10. Neither Defendant may deduct or capitalize the civil penalties paid under this Section in calculating federal income tax or any state income tax.

Penalty to be paid to the United States:

11. Within 30 Days after the Effective Date, Sunoco shall pay to the United States $287,000 in civil penalties for the Texas and Oklahoma Spills. If this payment is not made within 30 Days of the Effective Date, then Sunoco will also pay to the United States an additional sum for interest, at the rate specified in 28 U.S.C. § 1961 as of the date of lodging, calculated as of the date of lodging and accruing through the date that payment is made. This amount for interest is to be paid in addition to any amount due for late payment pursuant to Section VI (Stipulated Penalties).

12. Within 30 Days after the Effective Date, Sunoco shall pay to the United States $4,713,000 as a civil penalty for the Louisiana Spill. If this payment is not made within 30 Days of the Effective Date, Sunoco will also pay to the United States an additional sum for interest, at the rate specified in 28 U.S.C. § 1961 as of the date of lodging, calculated as of the date of lodging and accruing through the date that payment is made. This amount for interest is to be paid in addition to any amount due for late payment pursuant to Section VI (Stipulated Penalties). Defendants' obligations to pay the federal civil penalty pursuant to this Paragraph are

joint and several. In the event of Sunoco's insolvency or its failure to pay that civil penalty, Mid-Valley shall make such payment.

13. Sunoco shall pay the civil penalty due by FedWire Electronic Funds Transfer ("EFT") to the U.S. Department of Justice in accordance with written instructions to be provided to:

Jim Wright
General Counsel
Energy Transfer Partners
1300 Main Street
Houston, TX 77002-6803
E-mail: Jim.Wright@energytransfer.com

With a copy to:

Kevin Dunleavy, Assistant General Counsel
2 Righter Parkway, Suite 200
Wilmington, DE 19803
kdunleavy@evergreenresmgt.com

following lodging of the Consent Decree, by the Financial Litigation Unit of the U.S. Attorney's Office for the Western District of Louisiana. Sunoco may change the individual to receive payment instructions on its behalf by providing written notice of such change to the United States in accordance with Section XI (Costs). Such monies are to be deposited in the Oil Spill Liability Trust Fund. The payment shall reference the Civil Action Number assigned to this case and DOJ Number 90-5-1-1-11673 and shall specify that the payment is made toward CWA civil penalties to be deposited into the Oil Spill Liability Trust Fund pursuant to 33 U.S.C. § 1321(s) and 26 U.S.C. § 9509(b)(8).

14. At the time of payment, Sunoco shall send a copy of the EFT authorization form and the EFT transaction record, together with a transmittal letter, which shall state that the payment is for the civil penalty owed pursuant to the Consent Decree in this case and shall

reference the Civil Action Number assigned to this case and DOJ Number 90-5-1-1-11673, to the United States in accordance with Section XII of this Decree (Notices) and to EPA via email at acctsreceivable.cinwd@epa.gov or via regular mail at EPA Cincinnati Finance Office, 26 Martin Luther King Drive, Cincinnati, Ohio 45268.

Penalties and costs to be paid to LDEQ:

15. Within 30 Days of the Effective Date, Sunoco shall pay to LDEQ $436,274.20 as a civil penalty and enforcement costs. In the event any payment required by this Section is not made when due, Sunoco shall pay interest on the balance at the rate specified in 28 U.S.C. § 1961 as of the Effective Date. The interest shall begin to accrue from the Effective Date through the date of full payment. Interest payments shall be paid in the same manner as the overdue principal amount, and shall be directed to the same fund or account as the overdue principal amount. Interest is in addition to any stipulated penalties accruing for late payments under Section VI (Stipulated Penalties). Payments of interest made under this Paragraph shall be in addition to such other remedies or sanctions available to Plaintiffs by virtue of Sunoco's failure to make timely payments under this Section including, but not limited to, payment of stipulated penalties pursuant to Section VI. Defendants' obligations to pay the civil penalty and enforcement costs pursuant to this Paragraph are joint and several. In the event of Sunoco's insolvency or the failure by Sunoco to make payment under this Paragraph, Mid-Valley shall make such payment.

16. Payment shall be made by check or EFT in accordance with instructions to be provided by LDEQ to:

Jim Wright
General Counsel
Energy Transfer Partners
1300 Main Street
Houston, TX 77002-6803
E-mail: Jim.Wright@energytransfer.com

With a copy to:

Kevin Dunleavy, Assistant General Counsel
2 Righter Parkway, Suite 200
Wilmington, DE 19803
kdunleavy@evergreenresmgt.com

Sunoco may change the individual to receive payment instructions on their behalf by providing written notice of such change to LDEQ in accordance with Section XI (Costs). If paying by check, the check shall be made payable to the Louisiana Department of Environmental Quality, referencing this Civil Action, and mailed to: Fiscal Director, LDEQ, Office of Management and Finance, P.O. Box 4303, Baton Rouge, LA 70821-4303.

V. INJUNCTIVE RELIEF

17. Pipeline Inspections. During the three-year period immediately following the Effective Date, Sunoco shall use all three of the following types of ILI Technology—with each tool used at least once—to inspect the entire length of any Covered Facility that is In Operation at any point during the three-year period:

a. A Caliper Tool;

b. An Axial Magnetic Flux Leakage Corrosion Tool; and

c. An Ultrasonic Crack Detection Tool.

18. ILI Technology Selection. Sunoco shall select the specific model of each type of ILI Technology required by Paragraph 17 in accordance with the procedure set forth in Appendix A (ILI Technology Selection).

19. ILI Technology Substitution. Sunoco may use a substitute tool, rather than one of the tools identified in Paragraph 17.a–c, if the following conditions are satisfied:

a. The substitute tool is as effective at detecting pipeline cracks and/or corrosion as one of the tools listed in Paragraph 17.a–c;

b. The substitute tool is readily available at the time of the scheduled inspection; and

c. In the next-due Semi-Annual Report, Sunoco describes the substitute tool, and explains why the substitute tool was used and how the conditions set forth in Paragraph 19.a–b were satisfied.

20. Data Integration. Following the performance of pipeline inspections pursuant to Paragraph 17 or 19, as applicable, Sunoco shall consider information from the sources identified, and in accordance with the procedures set forth, in Appendix B (Data Integration).

21. Identification and Remediation of Repair Conditions. Following the performance of the obligations set forth in Paragraph 20, Sunoco shall identify all Immediate Repair Conditions, 60-Day Repair Conditions, and 180-Day Repair Conditions discovered during the inspections conducted pursuant to Paragraph 17 or 19, as applicable, and address all identified repair conditions as follows:

a. Immediate Repair Condition Repair. Sunoco shall repair any Immediate Repair Condition as soon as possible and in no event later than 30 Days after identification pursuant to this Paragraph. Sunoco shall also reduce the operating pressure or shut down the Pipeline Segment until the operator completes the repair of the Immediate Repair Condition. Sunoco shall calculate the temporary reduction in operating pressure using the formulas set forth at 49 C.F.R. § 195.452(h)(4)(i)(B), and reduce operating pressure by a minimum of 20 percent (based on actual operating pressure for two months prior to the identification of the Immediate Repair Condition) until the Immediate Repair Condition is no longer present.

b. 60-Day Repair Condition Repair. Sunoco shall repair any 60-Day Repair Condition by no later than 60 Days following identification pursuant to this Paragraph. If Sunoco is unable to repair any 60-Day Repair Condition within 60 Days following identification, Sunoco shall reduce operating pressure on the affected line, in the manner required by 49 C.F.R. § 195.452(h)(1) & (3).

c. 180-Day Repair Condition Repair. Sunoco shall repair any 180-Day Repair Condition by no later than 180 Days following identification pursuant to this Paragraph. If Sunoco is unable to repair any 180-Day Repair Condition within 180 Days, Sunoco shall reduce operating pressure on the affected line, in the manner required by 49 C.F.R. § 195.452(h)(1) & (3).

22. Failure Risk Assessment. Sunoco shall assess the risk of future oil spills relating to any Repair Condition identified by the inspection performed pursuant to Paragraph 17 or 19, as applicable, by determining, in a manner consistent with the Stress Corrosion Cracking Study TTO Number 8, submitted by Michael Baker in January 2005 (Appendix D), the predicted remaining life and failure pressure of the Pipeline Segment(s) affected by the Repair Condition.

23. Idle Pipeline Segment Risk Mitigation. Within 180 Days after the Effective Date, and semi-annually thereafter, Sunoco shall determine whether any Pipeline Segments of any Covered Facility In Operation are Idle.

24. For any Pipeline Segment that is part of any Covered Facility that Sunoco identifies as Idle, Sunoco shall ensure that the Pipeline Segment is purged of crude oil; or

a. At least once during the three-year period immediately following the Effective Date, inject a corrosion prevention treatment;

b. Continuously monitor for leaks or ruptures using SCADA or other leak detection system(s); and

c. Identify and describe in each Semi-Annual Report the leak detection system(s) employed to monitor each Idle Pipeline Segment and an explanation of why the leak detection system(s) employed is or are effective for monitoring the Idle Pipeline Segment.

25. Hydrotesting. Sunoco will not return the Colmesneil Line to service without first conducting a Hydrotest on the Colmesneil Line.

26. Reporting Requirements. Sunoco shall submit Semi-Annual Reports to the United States and LDEQ, in accordance with Section XII (Notices), summarizing its progress in implementing the requirements of this Section ("Semi-Annual Reports"). Each Semi-Annual Report must include enough detail that the United States, after consultation with LDEQ, can evaluate whether Sunoco is in compliance with this Section of the Consent Decree. The Semi-Annual Reports shall be submitted per the following schedule:

a. First Semi-Annual Report: due within 30 Days of the date that is six months after the Effective Date;

b. Second Semi-Annual Report: due within 30 Days of the date that is 12 months after the Effective Date;

c. Third Semi-Annual Report: due within 30 Days of the date that is 18 months after the Effective Date;

d. Fourth Semi-Annual Report: due within 30 Days of the date that is 24 months after the Effective Date;

e. Fifth Semi-Annual Report: due within 30 Days of the date that is 30 months after the Effective Date;

f. Sixth Semi-Annual Report: due within 30 Days of the date that is 36 months after the Effective Date.

27. Each report, letter report, or certification submitted by Sunoco under this Section shall be signed by an official of the submitting party and include the following certification:

> I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

This certification requirement does not apply to emergency or similar notifications where compliance would be impractical.

28. The requirements of this Consent Decree do not relieve Defendants of any obligation required by the Clean Water Act or implementing regulations, or by any other federal, state, or local law, regulation, permit, or other requirement.

29. Any information provided pursuant to this Consent Decree may be used by the United States or LDEQ in any proceeding to enforce the provisions of this Consent Decree and as otherwise permitted by law.

30. If EPA in its sole discretion, after consultation with LDEQ, determines that Sunoco has failed materially to perform any obligation(s) required pursuant to this Section with respect to the Longview to Mayersville Segment, EPA will provide notice by email to Defendants at the email address provided in Section XII (Notices). Effective immediately upon the date and time the email notice is sent, Mid-Valley will become fully responsible for performance of the obligation(s), including payment of any stipulated penalties for non-performance specified in the notice, in accordance with the requirements and schedules set forth herein.

VI. STIPULATED PENALTIES

31. Defendants shall be liable for stipulated penalties as specified below, unless excused under Section VII (Force Majeure).

32. Late Payment of Civil Penalties.

a. If Sunoco fails to pay the federal civil penalties and interest to the United States as required under Paragraphs 11 or 12 when due, Sunoco shall be liable to the United States for stipulated penalties of $2,500 per Day for each Day the payment is late. Sunoco shall pay to the United States the full amount of any stipulated penalties due pursuant to this subparagraph within thirty Days of receiving a written demand. Defendants' obligations to pay stipulated penalties in connection with the requirements set forth in Paragraph 12 are joint and several. In the event of Sunoco's insolvency or the failure by Sunoco to pay such stipulated penalties, Mid-Valley shall make any payment due, along with any interest due pursuant to Paragraph 41.

b. If Sunoco fails to pay the amount for state civil penalty and enforcement costs to LDEQ as required under Paragraph 15 when due, Sunoco shall be liable to LDEQ for stipulated penalties of $2,500 per Day for each Day the payment is late. Sunoco shall pay to LDEQ the full amount of any stipulated penalties due pursuant to this subparagraph within thirty Days of receiving a written demand. Defendants' obligations to pay stipulated penalties in connection with the requirements set forth in Paragraph 15 are joint and several. In the event of Sunoco's insolvency or the failure by Sunoco to pay such stipulated penalties, Mid-Valley shall make any payment due, along with any interest due pursuant to Paragraph 41.

33. Stipulated Penalties for Non-Performance of Injunctive Relief.

a. For failure to perform any obligation required pursuant to Paragraphs 17-25 of Section V (Injunctive Relief), including failure to perform within or by a specified time schedule, Sunoco shall pay stipulated penalties as follows:

Penalty Per Violation	Per Day Period of Noncompliance
$750 penalty per Day	1st to 30th Day
$2,000 penalty per Day	31st to 60th Day
$3,000 penalty per Day	61st Day and beyond

b. For failure to perform any obligation required pursuant to Paragraphs 26-27 of Section V (Injunctive Relief), including failure to perform by a specified deadline, Sunoco shall pay stipulated penalties as follows:

Penalty Per Violation	Per Day Period of Noncompliance
$350 penalty per Day	1st to 14th Day
$750 penalty per Day	15th to 30th Day
$1,250 penalty per Day	31st Day and beyond

c. Sunoco shall pay stipulated penalties due pursuant to this Paragraph within thirty Days of a written demand.

d. Except for stipulated penalties for obligations that Sunoco is required to perform on the Longview to Mayersville Segment pursuant to Paragraphs 17-24, only the United States may issue a written demand for stipulated penalties relating to the injunctive relief provisions of Section V (Injunctive Relief), and Sunoco must pay to the United States the full amount of any stipulated penalties due and will not be liable to LDEQ for any such penalties.

e. For stipulated penalties for obligations that Sunoco is required to perform on the Longview to Mayersville Segment pursuant to Paragraphs 17-24, the United

States, or LDEQ, or both, may demand stipulated penalties by sending a joint written demand to Defendants, or by either the United States or LDEQ sending a written demand to Defendants, with a copy simultaneously sent to the other Plaintiff.

f. Where both Plaintiffs demand stipulated penalties for the same violation, Sunoco shall pay 50 percent to the United States and 50 percent to LDEQ. Where only one Plaintiff demands stipulated penalties, and the other Plaintiff does not join in the demand within 15 Days of receiving the demand, or joins in the demand within 15 Days but subsequently elects to waive or reduce stipulated penalties, in accordance with Paragraph 38 or 39, for that violation Sunoco shall pay the full stipulated penalties due for the violation to the Plaintiff making the demand less any amount paid to the other Plaintiff.

34. For all payments made pursuant to this Section, Sunoco must follow the payment instructions set forth in Section IV. Any transmittal correspondence shall identify the date of the written demand to which the payment corresponds.

35. For all payments of stipulated penalties due to the United States, Sunoco shall reference the Civil Action Number assigned to this case and DOJ Number 90-5-1-1-11673, and shall specify that payments are for stipulated penalties to be deposited into the United States Treasury.

36. For all payments of stipulated penalties due to LDEQ, Sunoco shall reference the Civil Action Number and submit payment as specified in Paragraph 16. All stipulated penalties paid to LDEQ shall be deposited in the Hazardous Waste Site Cleanup Fund.

37. Stipulated penalties under this Section shall begin to accrue on the Day after the performance is due and shall continue to accrue until performance is satisfactorily completed. Stipulated penalties shall accrue simultaneously for separate violations of this Consent Decree.

38. The United States may in the unreviewable exercise of its discretion, reduce or waive stipulated penalties otherwise due to the United States under this Consent Decree.

39. LDEQ may, in the unreviewable exercise of its discretion, reduce or waive stipulated penalties otherwise due to LDEQ under this Consent Decree.

40. Stipulated penalties shall continue to accrue as provided in Paragraph 37 during any Dispute Resolution, but need not be paid until the following:

a. If the dispute is resolved by agreement or by a decision of the United States that is not appealed to the Court, Sunoco shall pay accrued penalties determined to be owing, together with interest, to the United States within 30 Days of the effective date of the agreement or the receipt of EPA's or LDEQ's decision or order.

b. If the dispute is appealed to the Court and the United States prevails in whole or in part, Sunoco shall pay all accrued penalties determined by the Court to be owing, together with interest, within 60 Days of receiving the Court's decision or order, except as provided in subparagraph c, below.

c. If any Party appeals the District Court's decision, Sunoco shall pay all accrued penalties determined to be owing, together with interest, within 15 Days of receiving the final appellate court decision.

41. If Sunoco fails to pay stipulated penalties according to the terms of this Consent Decree, Sunoco shall be liable for interest on such penalties, as provided for in 28 U.S.C. § 1961, accruing as of the date payment became due. Nothing in this Paragraph shall be construed to

limit the United States or LDEQ from seeking any remedy otherwise provided by law for Sunoco's failure to pay any stipulated penalties.

42. The payment of stipulated penalties and interest, if any, shall not alter in any way Sunoco's obligation to complete the performance of the requirements of this Consent Decree.

43. Subject to the provisions of Section X of this Consent Decree (Effect of Settlement/Reservations of Rights), the stipulated penalties provided for in this Consent Decree shall be in addition to any other rights, remedies, or sanctions available to the United States or LDEQ for Defendants' violation of this Consent Decree or applicable law.

VII. FORCE MAJEURE

44. "Force Majeure," for purposes of this Consent Decree, is defined as any event arising from causes beyond Defendants' control, of any entity controlled by either Defendant, or of Defendants' contractors that delays or prevents the performance of any obligation under this Consent Decree despite Defendants' best efforts to fulfill the obligation. The requirement that Defendants exercise "best efforts to fulfill the obligation" includes using best efforts to anticipate any potential Force Majeure event and best efforts to address the effects of any potential Force Majeure event (a) as it is occurring and (b) following the potential Force Majeure, such that the delay and any adverse effect(s) of the delay are minimized. "Force Majeure" does not include Defendants' financial inability to perform any obligation under this Consent Decree.

45. If any event occurs or has occurred that may delay the performance of any obligation under this Consent Decree, whether or not caused by a Force Majeure event, Defendants shall provide notice orally and by electronic and facsimile transmission to EPA and LDEQ within 72 hours of when Defendants first knew that the event might cause a delay. Within seven Days thereafter, Defendants shall provide in writing to EPA and LDEQ an explanation and

description of the reason(s) for the delay; the anticipated duration of the delay; all actions taken or to be taken to prevent or minimize the delay; a schedule for implementation of all measures to be taken to prevent or mitigate the delay or the effect of the delay; Defendants' rationale for attributing such delay to a Force Majeure event if it intends to assert such a claim; and a statement as to whether, in the opinion of Defendants, such event may cause or contribute to an endangerment to public health, welfare or the environment. Defendants shall include with any notice all available documentation supporting the claim that the delay was attributable to a Force Majeure. Failure to comply with the above requirements shall preclude Defendants from asserting any claim of Force Majeure for that event for the period of time of such failure to comply, and for any additional delay caused by such failure. Defendants shall be deemed to know of any circumstance of which Defendants, any entity controlled by Defendants, or their contractors knew or should have known.

46. If the United States, after a reasonable opportunity for review and comment by LDEQ, agrees that the delay or anticipated delay is attributable to a Force Majeure event, the time for performance of the obligations under this Consent Decree that are affected by the Force Majeure event will be extended by the United States, after a reasonable opportunity for review and comment by LDEQ, for such time as is necessary to complete those obligations. An extension of the time for performance of the obligations affected by the Force Majeure event shall not, of itself, extend the time for performance of any other obligation. The United States will notify Defendants in writing of the length of the extension, if any, for performance of the obligations affected by the Force Majeure event.

47. If the United States, after a reasonable opportunity for review and comment by LDEQ, does not agree that the delay or anticipated delay has been or will be caused by a Force Majeure event, the United States will notify Defendants in writing of its decision.

48. If Defendants elect to invoke the dispute resolution procedures set forth in Section VIII (Dispute Resolution), they shall do so no later than 15 Days after receipt of the United States' notice. In any such proceeding, Defendants shall have the burden of demonstrating by a preponderance of the evidence that the delay or anticipated delay has been or will be caused by a Force Majeure event, that the duration of the delay or the extension sought was or will be warranted under the circumstances, that best efforts were exercised to avoid and mitigate the effects of the delay, and that Defendants complied with the requirements of Paragraphs 44 and 45. If Defendants carries this burden, the delay at issue shall be deemed not to be a violation by Defendants of the affected obligation of this Consent Decree identified to the United States and the Court.

VIII. DISPUTE RESOLUTION

49. Unless otherwise expressly provided for in this Consent Decree, the dispute resolution procedures of this Section shall be the exclusive mechanism to resolve disputes arising under or with respect to this Consent Decree. Defendants' failure to seek resolution of a dispute under this Section shall preclude Defendants from raising any such issue as a defense to an action by the United States or LDEQ to enforce any obligation of Defendants arising under this Decree.

50. <u>Informal Dispute Resolution.</u> Any dispute subject to Dispute Resolution under this Consent Decree shall first be the subject of informal negotiations. The dispute shall be considered to have arisen when Defendants send the United States a written Notice of Dispute.

Such Notice of Dispute shall state clearly the matter in dispute. The period of informal negotiations shall not exceed 20 Days from the date the dispute arises, unless that period is modified by written agreement of all of the Parties to the dispute. If the Parties cannot resolve a dispute by informal negotiations, then the position advanced by the United States shall be considered binding unless, within 20 Days after the conclusion of the informal negotiation period, Defendants invoke formal dispute resolution procedures as set forth below.

51. Formal Dispute Resolution. Defendants shall invoke formal dispute resolution procedures, within the time period provided in the preceding Paragraph, by serving on the United States a written Statement of Position regarding the matter in dispute. The Statement of Position shall include, but need not be limited to, any factual data, analysis, or opinion supporting Defendants' position and any supporting documentation relied upon by Defendants.

52. The United States shall serve its Statement of Position within 45 Days of receipt of Defendants' Statement of Position. The United States' Statement of Position shall include, but need not be limited to, any factual data, analysis, or opinion supporting that position and any supporting documentation relied upon by the United States. The United States' Statement of Position shall be binding on Defendants, unless Defendants file a motion for judicial review of the dispute in accordance with the following Paragraph.

53. Defendants may seek judicial review of the dispute by filing with the Court and serving on the United States, in accordance with Section XII (Notices), a motion requesting judicial resolution of the dispute. The motion must be filed within ten Days of receipt of the United States' Statement of Position pursuant to the preceding Paragraph. The motion shall contain a written statement of Defendants' position on the matter in dispute, including any supporting factual data, analysis, opinion, or documentation, and shall set forth the relief

requested and any schedule within which the dispute must be resolved for orderly implementation of the Consent Decree.

54. The United States shall respond to Defendants' motion within the time period allowed by the Local Rules of this Court. Defendants may file a reply memorandum, to the extent permitted by the Local Rules.

55. Standard of Review.

a. Disputes Concerning Matters Accorded Record Review. Except as otherwise provided in this Consent Decree, in any dispute brought under Paragraph 50 pertaining to the adequacy or appropriateness of plans or procedures to implement plans; the adequacy of the performance of work undertaken pursuant to this Consent Decree; and all other disputes that are accorded review on the administrative record under applicable principles of administrative law, Defendants shall have the burden of demonstrating, based on the administrative record, that the position of the United States is arbitrary and capricious or otherwise not in accordance with law.

b. Other Disputes. Except as otherwise provided in this Consent Decree, in any other dispute brought under Paragraph 50, Defendants shall bear the burden of demonstrating that their position complies with this Consent Decree and better furthers the objectives of the Consent Decree.

56. The invocation of dispute resolution procedures under this Section shall not, by itself, extend, postpone, or affect in any way any obligation of Defendants under this Consent Decree, unless and until final resolution of the dispute so provides. Stipulated penalties with respect to the disputed matter shall continue to accrue from the first Day of noncompliance, but payment shall be stayed pending resolution of the dispute as provided in Paragraph 40. If

Defendants do not prevail on the disputed issue, stipulated penalties shall be assessed and paid as provided in Section VI (Stipulated Penalties).

IX. INFORMATION COLLECTION AND RETENTION

57. The United States and its representatives, including attorneys, contractors, and consultants, shall have the right of entry or to inspect the Covered Facilities, at all reasonable times, upon presentation of credentials, to:

a. Monitor the progress of activities required under Section V (Injunctive Relief) this Consent Decree;

b. Verify any data or information submitted to the United States in accordance with the terms of this Consent Decree;

c. Obtain samples and, upon request, splits of any samples taken by Defendants or their representatives, contractors, or consultants;

d. Obtain documentary evidence, including photographs and similar data; and

e. Assess Defendants' compliance with this Consent Decree.

58. Upon a request by Plaintiffs, Defendants shall provide splits of any samples taken by Defendants or their representatives, contractors, or consultants;

59. Until three years after the termination of this Consent Decree, Defendants shall retain, and shall instruct their contractors and agents to preserve, all pipeline inspection data collected during the inspections performed pursuant to Paragraph 17 or 19 that are in their or their contractors' or agents' possession or control, or that come into their or their contractors' or agents' possession or control. Until one year after the termination of this Consent Decree, Defendants shall retain, and shall instruct their contractors and agents to preserve, all non-

identical copies of all documents and electronically stored information in their or their contractors' or agents' possession or control, or that come into their or their contractors' or agents' possession or control, and are created or generated as a result of Defendants' performance of their obligations under this Consent Decree. This information-retention requirement shall apply regardless of any contrary corporate or institutional policies or procedures. At any time during this information-retention period, upon request by the United States, Defendants shall provide, within 60 Days of such request, copies of documents and electronically stored information required to be maintained under this Paragraph.

60. At the conclusion of the information-retention period provided in the preceding Paragraph, Defendants shall notify the United States at least 90 Days prior to the destruction of any documents or electronically stored information subject to the requirements of the preceding Paragraph and, upon request by the United States, Defendants shall deliver any such documents or electronically stored information to EPA within 60 Days of such request. Defendants may assert that certain documents or electronically stored information is privileged under the attorney-client privilege or any other privilege or legal doctrine recognized by federal law. If Defendants asserts such a privilege or protection, it shall provide the following: (a) the title of the document, record, or information; (b) the date of the document, record, or information; (c) the name and title of each author of the document, record, or information; (d) the name and title of each addressee and recipient; (e) a description of the subject of the document, record, or information; and (f) the privilege or protection asserted by Defendants. However, no documents or electronically stored information created or generated pursuant to the requirements of this Consent Decree shall be withheld on grounds of privilege.

61. Defendants may also assert that information required to be provided under this Section is protected as Confidential Business Information ("CBI") under 40 C.F.R. Part 2. As to any information that Defendants seeks to protect as CBI, Defendants shall follow the procedures set forth in 40 C.F.R. Part 2. To assert that records, data or other information required to be submitted to LDEQ is entitled to be protected as confidential, Defendants shall follow the law and procedures as set forth in the applicable provisions of La. R.S. 30:2030; La. R.S. 30:2074.D; and LAC 33:I. Chapter 5.

62. This Consent Decree in no way limits or affects any right of entry and inspection, or any right to obtain information, held by the United States pursuant to applicable federal laws, regulations, or permits, nor does it limit or affect any duty or obligation of Defendants to maintain documents, records, or other information imposed by applicable federal or state laws, regulations, or permits.

X. EFFECT OF SETTLEMENT/RESERVATION OF RIGHTS

63. This Consent Decree resolves the civil claims of the United States and LDEQ for the violations alleged in the Complaint filed in this action through the date of lodging.

64. The United States and LDEQ reserve all legal and equitable remedies available to enforce the provisions of this Consent Decree.

65. The United States and LDEQ reserve all legal and equitable claims for, including but not limited to, injunctive relief, penalties, recovery of Oil Pollution Act ("OPA") response costs and damages including natural resource damages, criminal liability, and other appropriate relief, except as expressly provided in Paragraph 63. This Consent Decree shall not be construed to limit the rights of the United States or LDEQ to obtain penalties, injunctive relief, costs, damages, or other appropriate relief under the CWA or implementing regulations, or under other

federal laws, regulations, or permit conditions, except as expressly provided in Paragraph 63. The United States and LDEQ further reserve all legal and equitable remedies to address any imminent and substantial endangerment to the public health or welfare or the environment arising at, or posed by, Defendants' facilities or operations, whether related to the violations addressed in this Consent Decree or otherwise.

66. In any subsequent administrative or judicial proceeding initiated by the United States, LDEQ, or the State of Louisiana for injunctive relief, civil penalties, costs, damages, criminal liability, other appropriate relief relating to Defendants' violations, Defendants shall not assert, and may not maintain, any defense or claim based upon the principles of waiver, res judicata, collateral estoppel, issue preclusion, claim preclusion, claim-splitting, or other defenses based upon a contention that the claims raised by the United States, LDEQ, or the State of Louisiana in the subsequent proceeding were or should have been brought in the instant case, except with respect to claims that have been specifically resolved pursuant to Paragraph 63.

67. This Consent Decree is not a permit, or a modification of any permit, under any federal, State, or local laws or regulations. Defendants are responsible for achieving and maintaining complete compliance with all applicable federal, state, and local laws, regulations, and permits; and Defendants' compliance with this Consent Decree shall be no defense to any action commenced pursuant to any such laws, regulations, or permits, except as set forth herein. The United States and LDEQ do not, by consent to the entry of this Consent Decree, warrant or aver in any manner that Defendants' compliance with any aspect of this Consent Decree will result in compliance with provisions of the CWA or with any other provision of federal, state, or local laws, regulations, or permits.

68. This Consent Decree does not limit or affect the rights of Defendants, or of the United States, LDEQ, or the State of Louisiana against any third parties, not party to this Consent Decree, nor does it limit the rights of third parties, not party to this Consent Decree, against Defendants, except as otherwise provided by law.

69. This Consent Decree shall not be construed to create rights in, or grant any cause of action to, any third party not party to this Consent Decree.

70. Defendants hereby covenant not to sue and agree not to assert any claims related to the Releases or response activities in connection with the Releases against the United States, LDEQ, or the State of Louisiana pursuant to the CWA, OPA, or any other state or federal law or regulation for acts or omissions through the date of lodging of the Consent Decree. Defendants further covenant not to sue and agree not to assert any direct or indirect claim for reimbursement from the Oil Spill Liability Trust Fund or pursuant to any other provision of law.

XI. COSTS

71. The Parties shall bear their own costs of this action, including attorneys' fees, except that the United States and LDEQ shall be entitled to collect the costs (including attorneys' fees) incurred in any action necessary to collect any portion of the civil penalty or any stipulated penalties due but not paid by Defendants.

XII. NOTICES

72. Unless otherwise specified in this Decree, whenever notifications, submissions, or communications are required by this Consent Decree, they shall be made in writing and in an electronically searchable format and be transmitted by email as follows:

As to the United States by email:

To the U.S. Department of Justice:

eescdcopy.enrd@usdoj.gov
Re: DJ #90-5-1-1-110673

To the EPA Region VI:

quinones.edwin@epa.gov

(for Semi-Annual Reports only)
To PHMSA Southwest Region:

Mary McDaniel
Regional Director
mary.mcdaniel@dot.gov

As to LDEQ by email:

celena.cage@LA.gov

oscar.magee@LA.gov

As to Defendants by email:

kdunleavy@evergreenresmgt.com
Jim.Wright@energytransfer.com

73. If any email is returned as undeliverable or the party becomes aware by any means that the email was not delivered, the notifying Party shall, within two Days, submit the writing to the following addresses:

As to the United States:

As to the U.S. Department of Justice:

EES Case Management Unit
Environment and Natural Resources Division
U.S. Department of Justice
P.O. Box 7611
Washington, DC 20044-7611

As to EPA:

Oil Spill & Response Team Leader
U.S. Environmental Protection Agency, Region 6
1445 Ross Avenue, Suite 1200, 6SF-EO
Dallas, TX 75202-2733

Edwin Quinones
Assistant Regional Counsel
U.S. Environmental Protection Agency, Region 6
1445 Ross Avenue, Suite 1200, 6RC-S
Dallas, TX 75202-2733

As to the United States Attorney for the Western District of Louisiana:

U.S. Attorney's Office
Western District of Louisiana
300 Fannin Street, Suite 3201
Shreveport, LA 71101

As to LDEQ:

Celena Cage
Enforcement Administrator Office of Enforcement Compliance
La. Department of Environmental Quality
P.O. Box 4312
Baton Rouge, LA 70821-4312

Oscar Magee
Attorney, Legal Division
La. Department of Environmental Quality
P.O. Box 4302
Baton Rouge, LA 70821-4302

As to Defendants:

Jim Wright
General Counsel
Energy Transfer Partners
1300 Main Street
Houston, TX 77002-6803

74. Any Party may, by written notice to the other Parties, change its designated notice recipient or notice address provided above.

75. Notices submitted pursuant to this Section shall be deemed submitted upon mailing or emailing, as applicable, unless otherwise provided in this Consent Decree or by mutual agreement of the Parties in writing.

XIII. EFFECTIVE DATE

76. The Effective Date of this Consent Decree shall be the date upon which this Consent Decree is entered by the Court or a motion to enter the Consent Decree is granted, whichever occurs first, as recorded on the Court's docket.

XIV. RETENTION OF JURISDICTION

77. The Court shall retain jurisdiction over this case until termination of this Consent Decree, for the purpose of effectuating or enforcing compliance with the terms of this Decree.

XV. MODIFICATION

78. The terms of this Consent Decree, including any attached appendices, may be modified only by a subsequent written agreement signed by all the Parties. Where the modification constitutes a material change to this Decree, it shall be effective only upon approval by the Court. Where the modification does not materially alter Defendants' obligations pursuant to this Consent Decree, it shall be effective upon the written agreement of the Parties without the

consent of the Court, provided the parties first agree in writing that the modification is, in fact, non-material. Agreed extensions of time to comply with any obligation required pursuant to Paragraph 26 or Paragraph 60 by a period of not more than 30 Days shall not constitute a material change to this Decree.

79. Any dispute concerning modification of this Decree shall be resolved pursuant to Section VIII (Dispute Resolution), provided, however, that instead of the burden of proof provided in Paragraph 55, the Party seeking modification bears the burden of demonstrating that it is entitled to the requested modification in accordance with Federal Rule of Civil Procedure 60(b).

XVI. TERMINATION

80. After Defendants have completed the requirements of this Consent Decree, including injunctive relief, and has paid the civil penalties and any accrued stipulated penalties as required by this Consent Decree, Defendants may serve upon the United States and LDEQ a Request for Termination, stating that Defendants have satisfied those requirements, together with all necessary supporting documentation.

81. Following receipt by the United States and LDEQ of Defendants' Request for Termination, the Parties shall confer informally concerning the Request and any disagreement that the Parties may have as to whether Defendants have satisfactorily complied with the requirements for termination of this Consent Decree. If the United States after consultation with LDEQ agrees that the Decree may be terminated, the Parties shall submit, for the Court's approval, a joint stipulation terminating the Decree.

82. If the United States after consultation with LDEQ does not agree that the Decree may be terminated, Defendants may invoke Dispute Resolution under Section VIII. However,

Defendants shall not seek Dispute Resolution of any dispute regarding termination until 90 Days after service of its Request for Termination.

XVII. PUBLIC PARTICIPATION

83. This Consent Decree shall be lodged with the Court for a period of not less than 30 Days for public notice and comment in accordance with 28 C.F.R. § 50.7. The United States reserves the right to withdraw or withhold its consent if the comments regarding the Consent Decree disclose facts or considerations indicating that the Consent Decree is inappropriate, improper, or inadequate. Defendants consent to entry of this Consent Decree without further notice and agree not to withdraw from or oppose entry of this Consent Decree by the Court or to challenge any provision of the Decree, unless the United States has notified Defendants in writing that it no longer supports entry of the Decree.

84. Further, the Parties agree and acknowledge that final approval by LDEQ and entry of this Consent Decree is subject to the requirements of La. R.S. 30:2050.7, which provides for public notice of the Consent Decree in a newspaper of general circulation and the official journal of Caddo Parish, Louisiana, an opportunity for public comment of not less than 45 Days, consideration of any comments, and concurrence by the State Attorney General. Evidence of final approval of this Consent Decree by LDEQ shall be LDEQ's execution of a Motion to Enter the Consent Decree, and LDEQ reserves the right to withdraw or withhold consent based on information provided during the public comment period. In the event public comments raise issues over the content or terms of the Consent Decree, LDEQ may withdraw from this Consent Decree and will not join in the filing of a Motion to Enter the Consent Decree.

XVIII. SIGNATORIES/SERVICE

85. Each undersigned representative of Defendants, LDEQ, and the Acting Assistant Attorney General for the Environment and Natural Resources Division of the Department of Justice certifies that he or she is fully authorized to enter into the terms and conditions of this Consent Decree and to execute and legally bind the Party he or she represents to this document.

86. This Consent Decree may be signed in counterparts, and its validity shall not be challenged on that basis. Defendants agree to accept service of process by mail with respect to all matters arising under or relating to this Consent Decree and to waive the formal service requirements set forth in Rules 4 and 5 of the Federal Rules of Civil Procedure and any applicable Local Rules of this Court including, but not limited to, service of a summons.

XIX. INTEGRATION

87. This Consent Decree constitutes the final, complete, and exclusive agreement and understanding among the Parties with respect to the settlement embodied in the Decree and supersedes all prior agreements and understandings, whether oral or written, concerning the settlement embodied herein. The Parties acknowledge that there are no representations, agreements, or understandings relating to the settlement other than those expressly contained in this Consent Decree. The following appendices are attached to and incorporated into this Consent Decree: "Appendix A – ILI Technology Selection," "Appendix B – Data Integration," "Appendix C – Repair Condition Identification and Classification," and "Appendix D – Failure Risk Assessment."

XX. FINAL JUDGMENT

88. Upon approval and entry of this Consent Decree by the Court, this Consent Decree shall constitute a final judgment of the Court as to the United States, LDEQ, and Defendant.

Dated and entered this ________day of __________________, 2019.

____
UNITED STATES DISTRICT JUDGE

Signature Page to Consent Decree in *United States, et al. v. Sunoco Pipeline L.P., et al.*

FOR PLAINTIFF THE UNITED STATES OF AMERICA:

1/29/19
Date

JEFFREY BOSSERT CLARK
Assistant Attorney General
Environment and Natural Resources Division
U.S. Department of Justice

1/29/19
Date

R. SHEA DIAZ (D.C. Bar #1500278)
Trial Attorney
Environmental Enforcement Section
Environment and Natural Resources Division
United States Department of Justice
P.O. Box 7611
Washington, D.C. 20044-7611
Phone: (202) 514-3211
Fax: (202) 616-6584
E-mail: rebecca.diaz@usdoj.gov

DAVID C. JOSEPH
United States Attorney
Western District of Louisiana

/s/ Katherine W. Vincent

KATHERINE W. VINCENT (18717)
Assistant United States Attorney
U.S. Attorney's Office
Western District of Louisiana
800 Lafayette Street, Suite 2200
Lafayette, LA 70501

Signature Page to Consent Decree in *United States, et al. v. Sunoco Pipeline L.P., et al.,*
subject to the public notice and comment requirements of La. R.S. 30:2050.7

FOR PLAINTIFF UNITED STATES OF AMERICA (continued):

Dated: December 6, 2018

Anne L. Idsal
ANNE L. IDSAL
Regional Administrator
U.S. Environmental Protection Agency, Region 6
1445 Ross Avenue
Dallas, Texas 75202-2733

Dated: November 27, 2018

Edwin M. Quinones
EDWIN QUINONES
Assistant Regional Counsel
U.S. Environmental Protection Agency, Region 6
1445 Ross Avenue, Suite 1200, 6RC-S
Dallas, Texas 75202-2733

Signature Page to Consent Decree in *United States, et al. v. Sunoco Pipeline L.P., et al.,*
subject to the public notice and comment requirements of La. R.S. 30:2050.7

FOR PLAINTIFF UNITED STATES OF AMERICA (continued):

Dated: 12/11/18

SUSAN PARKER BODINE
Assistant Administrator
Office of Enforcement and Compliance Assurance
U.S. Environmental Protection Agency
Ariel Rios Building, 2201A
1200 Pennsylvania Ave., N.W.
Washington, DC 20460

Dated: 12/10/18

ROSEMARIE KELLEY
Director
Office of Civil Enforcement

Dated: 11/29/18

MARK POLLINS
Director
Water Enforcement Division

Dated: 11/11/18

KELLY BRANTNER
Water Enforcement Division

Signature Page to Consent Decree in *United States, et al. v. Sunoco Pipeline L.P., et al.,*
subject to the public notice and comment requirements of La. R.S. 30:2050.7

FOR PLAINTIFF LOUISIANA DEPARTMENT OF ENVIRONMENTAL QUALITY:

Dated: 11-13-18

LOURDES ITURRALDE
Assistant Secretary
Office of Environmental Compliance
Louisiana Department of Environmental Quality
P.O. Box 4302
Baton Rouge, Louisiana 70821-4312

Dated: 11/13/2018

OSCAR MAGEE, La. Bar #32302
Lead Counsel
DWANA C. KING, La. Bar #20590
Deputy General Counsel
Office of the Secretary, Legal Division
Louisiana Department of Environmental Quality
P.O. Box 4302
Baton Rouge, Louisiana 70821-4302

Signature Page to Consent Decree in *United States, et al. v. Sunoco Pipeline L.P., et al*.
FOR DEFENDANT SUNOCO PIPELINE L.P.

12/19/18
Date

Matt Ramsey, President
Sunoco Logistics Partners Operations GP LLC,
General Partner of Sunoco Pipeline L.P.

Counsel for Defendant:

Stephen E. Fitzgerald
Baker Botts L.L.P.
2001 Ross Avenue
Dallas, Texas 75201
Telephone: 214-953-6624
Email: Stephen.Fitzgerald@BakerBotts.com

Signature Page to Consent Decree in United States, et al. v. Sunoco Pipeline L.P., et al.
FOR DEFENDANT MID-VALLEY PIPELINE COMPANY

12/19/18
Date

Matt Ramsey, President
Sunoco Logistics Partners Operations GP LLC,
General Partner of Sunoco Pipeline L.P.

Counsel for Defendant:

Stephen E. Fitzgerald
Baker Botts L.L.P.
2001 Ross Avenue
Dallas, Texas 75201
Telephone: 214-953-6624
Email: Stephen.Fitzgerald@BakerBotts.com

United States, et al. v. Sunoco Pipeline L.P., et al.
Appendix A to Consent Decree

ILI Technology Selection

This document describes information Defendants must consider: (i) to identify threats to pipeline integrity and (ii) in selecting the appropriate ILI Technology to use to comply with Paragraph 17 of the Consent Decree.

I. Identification of Threats

Before selecting specific ILI Technology to comply with Paragraph 17 of the Consent Decree, Defendants will identify and consider known and potential threats to the applicable Covered Facility or Facilities. Sources for identifying threats may include, but are not limited to the following:

- Defendants' assessment closure documentation summaries
- Defendants' annual "continual assessment meetings"
- Defendants' most recent line-specific "risk analysis meeting"
- Current risk model factors, recent company and industry failures and/or near miss reports
- Industry/regulatory advisories and learnings
- PHMSA regulations and guidance.

II. Information to be Considered in Selecting ILI Tools

In selecting an ILI tool pursuant to the Consent Decree Paragraph 17, Defendants will consider the following sources of information for review (if available):

- The types and providers of available ILI tool technology
- Pipeline history documentation
- Pipeline construction records
- Pipeline alignment sheets
- Pipeline drawings
- Personnel interviews
- Prior ILI inspection reports
- Baseline assessment data (ILI, Hydrotest or other)
- Existing risk model information

- Corrosion growth rates
- External corrosion direct assessment records
- Records of pipeline dents or damage to pipelines from third party activity
- Locations where corrosion protection surveys indicate that there may be coating holidays (area of no coating)
- Benefits of running a gauging plate pig to assure ILI tool passage
- Pipe dimensions (including: internal diameter, outside diameter, wall thickness, presence of multi-diameter sections, segment lengths and locations, bend/ fitting geometry (radius, angle, etc.), and existing trap locations and dimensions (if applicable))
- Pipe material(s)
- Pipe grade
- Seam type
    - ➢ Electric-resistance welded ("ERW") pipe (pre-1970's ERW pipe or post-1970's ERW pipe) or flash-welded pipe (refer to 40 C.F.R. § 195.452(c) for inspection requirements)
    - ➢ Seamless
    - ➢ Other (lap-welded, spiral-welded, tubing)
- Pipe Analysis Reports (ERW seam tests, etc.)
- Pipe girth weld type and material (acetylene, shielded metal arc welding (SMAW), etc.)
    - ➢ Presence of chill rings, weld collars, etc.
    - ➢ Potential restrictions (valve types and bore, bends, tees, appurtenances, etc.)
    - ➢ Maximum operating pressure qualification basis
- History of Hydrotesting
- Operating pressure qualification(s)
- Pipeline Coatings
    - ➢ Locations of uncoated pipe
    - ➢ Locations of coated pipe
    - ➢ Coating type
    - ➢ Joint coatings at weld seams and bends
    - ➢ Internal coatings or linings
- Prior repairs

  - Type of sleeves used (Type A or Type B sleeves[1])
  - Composite material repairs (and marking methods)
  - Existing physical data of other repair methods and locations

- Existing magnet locations

- Existing casing locations

- Release History and Investigation reports and all past release history and failure modes, including:

  - Defective welds (girth, fillet)
  - Cracking (stress corrosion cracking, hydrogen induced cracking, fatigue)
  - Seam-related (cracking, selective seam corrosion)
  - Internal or external corrosion
  - External damage caused by third parties
  - Material failures
  - Earth movement or subsidence (bends, wrinkles, buckles)

- Product History

- Line operations (e.g., typical operating pressure(s) and flow rates)

- Prior ILI Reports

  - Potential restrictive locations (bends, deformations, stopples, long-bodied valves, etc.)
  - Types of tools run (crack, metal loss, etc.)
  - Vendor(s) utilized
  - Prior repair locations
  - Prior analysis methodologies
  - Anomaly data (metal loss, deformations, crack-like, etc.)
  - Above Ground Marking (AGM) locations

III. Factors Impacting ILI Tool Selection

Defendant will select the appropriate tool for use to achieve compliance with Paragraph 17 of the Consent Decree after taking into consideration the following factors, if applicable:

- Any applicable regulatory requirements

- Applicable and current American Petroleum Institute ("API") standards (e.g. API Standard 1160: In-Line Inspection Tools and Capabilities)

---

[1] Type B Sleeve: A full encirclement repair consisting of steel sections designed to fit over the carrier pipe. The sections are welded to each other and the ends are then fillet welded to the carrier pipe such that the sleeve is capable of containing any material or pressure that leaks from the pipe. Type A Sleeve: A full encirclement repair consisting of steel sections designed to fit over the carrier pipe. The sections are welded to each other on either side. The ends are not fillet welded to the carrier pipe.

- Proximity to high consequence areas ("HCAs")
- Proximity to a horizontal directionally drilled river crossings, road crossings, or any special locations where trenchless technology was employed
- Operational limitations (e.g. pressure/flow rate)
- Pipeline materials
- Pipeline length or pipeline segment length
- Inspection history
- Construction history
- Pipeline cleanliness
- Characteristics of pipeline contents (e.g., temperature, corrosiveness, toxicity, flammability)
- Known anomalies or anomaly types
- Available technology
- Health, Environmental and Safety (HES) Considerations
- Any other potential threats to pipeline integrity
- Failure history
- Maximum potential spill volume(s) of any future spill
- Threat to and cost of spill cleanup and restoration of sensitive sites (e.g. critical habitat areas, HCAs, public parks, wildlife preservation areas, sites with unique cultural or environmental features) threatened by any future spill

United States, et al. v. Sunoco Pipeline L.P., et al. **Appendix B to Consent Decree**

Data Integration

In performing Data Integration pursuant to Paragraph 20 of the Consent Decree, Defendants will consider (along with information contained in final ILI tool inspection reports created in connection with the ILI tools used pursuant to Paragraph 17 or 19 of the Consent Decree) the following information or from the following sources, if available:

- Historical records and documentation, including:
    - Leak history
    - Hydrotest records
    - Pipe tally records
    - Corrosion protection survey (such as Pearson and Close Interval Survey) results
    - Whether any of the following conditions are known to be present on any part of the relevant Covered Facility:
        - Disbonded coating,
        - Coating deficiencies, or
        - Inadequate corrosion protection (e.g., corrosion protection insufficient to prevent external mechanisms (such as microbial induced corrosion, general corrosion, crevice corrosion and stress corrosion cracking) to advance)
- Regional and district personnel
- Operation and maintenance contractors (e.g., corrosion protection experts and previous ILI contractors)
- Any of the following areas of Defendant's operations: Operations, Product Movement, Corrosion, Line Testing, One-Call/Relocations
- Utility and Pipeline Data Model (UPDM).
- Proactive database, an application to store information related to corrosion control inspections which is interfaced with UPDM.
- Data and results of the risk management application known as IRAS™ offered by Dynamic Risk (or a functional equivalent).

- Industry consultants
- Applicable PHMSA guidelines and advisories
- Applicable American Petroleum Institute (“API”) standards and recommended practices

United States, et al. v. Sunoco Pipeline L.P., et al.
Appendix C to Consent Decree

<u>Repair Condition Identification and Classification</u>

This document sets forth the criteria Defendants will evaluate in order to identify and classify Repair Conditions.

After conducting appropriate field verification activities to confirm the reliability of the ILI analysis data gathered through implementation of Paragraph 17 of the Consent Decree and performing Data Integration as required by Paragraph 20 of the Consent Decree and described in Appendix B to identify anomalies for possible remediation, Defendants must classify the anomalies as "Immediate Repair," "60-Day Repair" or "180-Day Repair" conditions, based on whether the criteria identified in Table 1, below, are present.

Table 1. Repair Condition Classification Criteria

Immediate Repair
Metal Loss feature > 80% of the nominal wall thickness regardless of dimension
Suitable remaining strength calculation methods include, but are not limited to, ASME/ANSI B31G (incorporated by reference, see §195.3) and PRCI PR-3-805 (R-STRENG) (incorporated by reference, see §195.3)
A dent on the top of the pipeline (above the 4 and 8 o'clock positions) that shows any indication of metal loss, cracking, or a stress riser
A dent on the top of the pipeline (above the 4 and 8 o'clock positions) with a depth > 6% of the nominal pipe diameter, if detected
An anomaly that poses a threat to pipeline integrity or otherwise requires, in Defendant's best engineering judgment, immediate action
60-Day Repair
A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) with a depth >3% of the nominal pipe diameter (or > 0.250 inches in depth for a pipeline diameter < NPS 12) if detectable
A dent on the bottom of the pipeline that has any indication of metal loss, cracking, or a stress riser

180-Day Repair
A dent with a depth > 2% of the pipeline's diameter (or = 0.250 inches in depth for a pipeline less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld, if detectable
A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) with a depth >2% of the pipeline's diameter (or = 0.250 inches in depth for a pipeline diameter less than NPS 12), if detectable
A dent located on the bottom of the pipeline with a diameter >6% of the pipeline's diameter, if detectable
A calculation of the remaining strength of the pipe ($P_{operating} = 0.72 \times P_{burst}$) shows an operating pressure that is less than the current established maximum operating pressure at the location of the anomaly
An area of general corrosion with predicted metal loss >50% of nominal wall thickness
Predicted metal loss >50% of nominal wall that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or is in an area that could affect a girth weld
A potential crack indication that is determined in fact to be a crack after performance of exploratory excavation
Corrosion of or along a longitudinal seam weld

Department of Transportation
Research and Special Programs Administration
Office of Pipeline Safety

TTO Number 8

Integrity Management Program
Delivery Order DTRS56-02-D-70036

Stress Corrosion Cracking Study

FINAL REPORT

Submitted by:
Michael Baker Jr., Inc.
January 2005

This page intentionally left blank.

TTO Number 8
Stress Corrosion Cracking Study

Table of Contents

List of Figures

List of Tables

List of Acronyms

ACFM	Alternating current field measurement
ACPD	Alternating current potential drop
AGA	American Gas Association
AOPL	Association of Oil Pipe Lines
API	American Petroleum Institute
APIA	Australian Pipeline Industry Association
AS	Australian Standard
ASTM	American Society of Testing and Materials
CEPA	Canadian Energy Pipeline Association
CFR	Code of Federal Regulations
CP	Cathodic protection
CSA	Canadian Standards Association
C-SCC	Circumferential stress corrosion cracking
CVN	Charpy V-notch
DOT	U.S. Department of Transportation
DSAW	Double submerged-arc welded
EAC	Environmentally-assisted cracking
ECA	Engineering critical assessment
ECDA	External corrosion direct assessment
EMAT	Electro Magnetic Acoustic Transducer
EPRG	European Pipeline Research Group
EPRI	Electric Power Research Institute
ERW	Electric resistance welded
ET	Eddy current testing
FATT	Fracture appearance transition temperature
FBE	Fusion-bonded epoxy
FFS	Fitness-for-service
FS	Factor of safety
GRI	Gas Research Institute
HAZ	Heat-affected zone
ILI	In-line inspection
IMP	Integrity management program
INGAA	Interstate Natural Gas Association of America
IPC	International Pipeline Conference
ISTC	International Science and Technology Center
LPI	Liquid penetrant inspection
MAOP	Maximum allowable operating pressure
MAWP	Maximum allowable working pressure
MFL	Magnetic flux leakage
MOP	Maximum operating pressure
MPI	Magnetic particle inspection
NAPSR	National Association of Pipeline Safety Representatives
NDE	Non-destructive examination
NEB	National Energy Board (Canada)
NPS	Nominal pipe size
NTSB	National Transportation Safety Board
OPS	United States Department of Transportation, Office of Pipeline Safety
PA	Phased array
PAFFC	Pipeline Axial Flaw Failure Criterion
PRCI	Pipeline Research Council International
QA/QC	Quality assurance/quality control
QT	Quenched and tempered
RA	Reduction in area
RSPA	Research and Special Programs Administration
SCC	Stress corrosion cracking

SCCDA	Stress Corrosion Cracking direct assessment
SCCLPM	Stress-corrosion-cracking life-prediction model
SDO	Standards development organizations
SMYS	Specified minimum yield strength
SSRT	Slow-strain-rate test
TCPL	TransCanada Pipelines Limited
TFI	Transverse Field Inspection
TMCP	Thermo-mechanical control process
TOFD	Time-of-flight diffraction
TSB	Transportation Safety Board (Canada)
UT	Ultrasonic testing
WFMT	Wet-fluorescent magnetic particle testing

Executive Summary

This report reviews the available information on stress corrosion cracking (SCC) in liquid and gas pipelines. The information is contained in a number of locations and, although generally consistent in approach, reveals the uncertainty in both the understanding and practical operational methods to effectively prevent, detect, assess, and/or remediate SCC in pipelines. Additional research needs are outlined and prioritized in this regard.

Along with the review of existing information, a questionnaire was circulated to operators, and several detailed operator interviews were conducted. In addition, the applicability of the current regulatory oversight, including Integrity Management program (IMP) review, was considered. A review of procedures for conducting SCC failure investigations was also performed.

In regard to preventing the initiation of SCC, the single most important recommendation is the emphasis on coatings that remain bonded to the pipeline, but allow the passage of cathodic protection (CP) current in the event of disbondment. Emphasis should also be placed on the quality assurance/quality control (QA/QC) of the surface preparation and field application. These considerations would apply to both new pipeline installations as well as to coating replacement projects. Apart from this consideration, there are limited practical recommendations for pipeline operation processes that can prevent SCC initiation.

In regard to SCC causal factors in pipelines and SCC prediction, the recommendations reflect the technical uncertainty surrounding the subject. Thus, emphasis is placed on written documents in operational and IM plans that stress awareness and the need for additional data collection to enhance understanding. The initial plan produced by an operator may follow several available references to prioritize the potential for SCC in pipeline segments of interest and develop a consequent ranking and/or segment risk. However, the emphasis must be such that procedures, especially the collection and integration of data specific to SCC development from in-line inspection (ILI) and direct examinations, are identified and implemented to refine and update this model over time, which will help operators gain a better understanding of the SCC susceptibility. Therefore, it is recommended that operator plans reflect this need for continued data and knowledge development and sharing.

When SCC is identified, recommendations are made for data collection, data analysis, and planning for further action based on the assessment of the threat to pipeline integrity with an emphasis on written documentation that clearly establishes the decision flow from discovery to field action. Depending on the field conditions, a number of potential mitigation techniques are available and should be considered as alternatives for implementation by an operator. Linking the site-specific SCC data back to the operator's linewide model for SCC is recommended for identifying analogous line situations and consequent direct examination needs.

Finally, written contingency plans, such as designation of pre-qualified personnel, data collection requirements, and return to service plans, for in-service failures due to SCC are recommended. Again, any plan should include linking the site-specific data to the operator's linewide model for identification of additional potential SCC occurrences.

This page intentionally left blank.

1 Introduction

This report has been developed in accordance with the Statement of Work and proposal submitted in response to RFP for Technical Task Order Number 8 (TTO 8), “Stress Corrosion Cracking Study.”

1.1 SCC Overview

The pipeline industry and regulatory oversight agencies are well familiar with stress corrosion cracking (SCC). Report No. DTRS56-“Stress Corrosion Cracking Study” by General Physics Corporation was prepared for the Office of Pipeline Safety in May 1999 (Hall and McMahon 1999). Based on a study conducted for that report, the Interstate Natural Gas Association of America (INGAA) reported that SCC accounted for 1.5 percent of the reportable incidents for pipelines within the United States. This was compared to 17 percent of the service ruptures attributed to SCC on pipelines operated by members of the Canadian Energy Pipeline Association (CEPA) from 1985 to 1995 (NEB 1996). While direct comparison of these percentages may lead some to believe that SCC is a more serious problem in Canada than in the United States, it is important to note the fundamental difference between the bases for each, reportable incidents and service ruptures for the 1.5 percent and 17 percent figures, respectively. Thus, the General Physics report further investigated average incident rates for Canada and the United States for gas transmission pipelines, and found comparable values leading to the conclusion:

> Comparing the incident rates shows that a stress corrosion cracking failure is almost as likely to occur on a gas transmission pipeline within the United States as in Canada. Additionally, the extensive funding provided by pipeline operators for stress corrosion cracking clearly indicates that stress corrosion cracking is a serious pipeline integrity issue of concern to operators of pipelines within the United States. The fact that stress corrosion cracking represents only 1.5 percent of reportable incidents in the United States versus 17 percent in Canada is due to the far greater occurrence of third party damage in the United States.

1.2 SCC in Perspective

At an SCC workshop hosted by Research and Special Projects Administration (RSPA) – Office of Pipeline Safety (OPS) in Houston, TX on December 2, 2003, information was presented which included Figure 1-1. The figure indicates that SCC is a relatively small causal factor for gas transmission pipeline incidents in the U.S. The other factors contributing to pipeline failures are being addressed in various research programs, IM initiatives, and regulatory oversight directives in both the gas and liquid pipeline industry. The SCC incident rate is relatively small, yet it is a widespread phenomenon. Moreover, SCC remains a significant issue largely because the industry’s understanding of this phenomenon is still evolving and practical methods of addressing SCC are not as mature as methods for addressing other failure causes. Finally, there have been several recent occurrences of SCC failures in the United States, underlining the need for a coherent approach using the knowledge and tools currently available, as well as the need for further research.

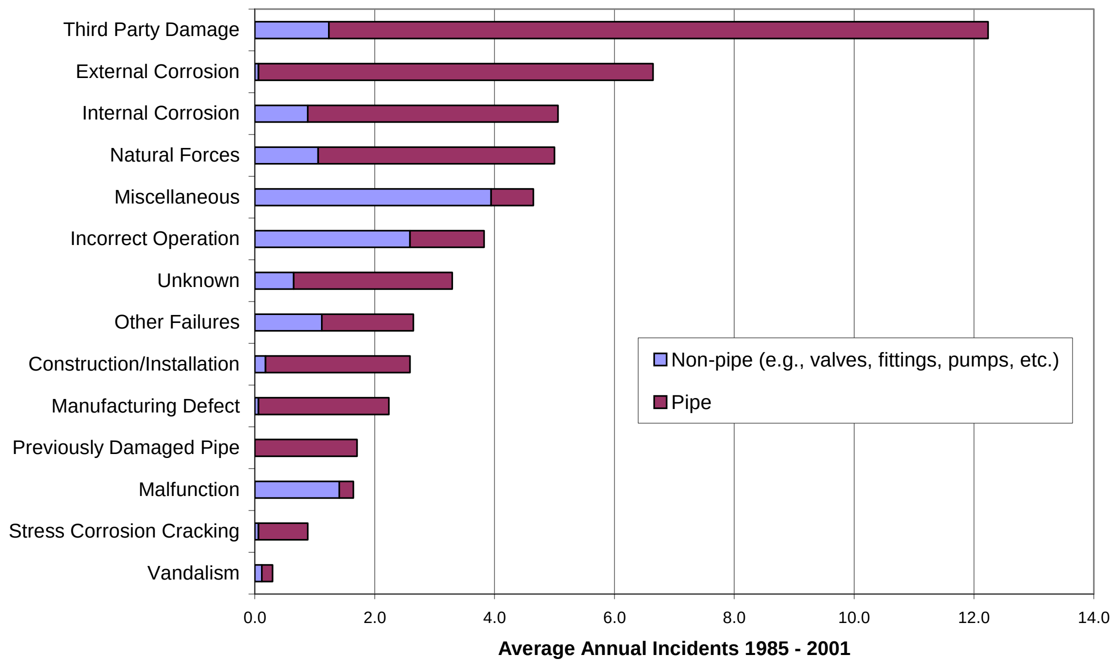


Figure 1-1 Causes of Gas Transmission Incidents (from OPS Workshop 12/2003)

1.3 References

Hall, R.J. and M.C. McMahon. 1999. *Stress Corrosion Cracking Study*. General Physics Corporation for U.S. Department of Transportation, Research and Special Programs Administration, Office of Pipeline Safety. Report No. DTRS56-96-C-0002-004. May.

NEB. 1996. *Stress Corrosion Cracking on Canadian Oil and Gas Pipelines*. *Report of the Inquiry*. National Energy Board. MH-2-95. December.

2 Background

Recent incidents throughout North America and the world, including Australia, Russia, Saudi Arabia, and South America, have highlighted the threats to pipelines from SCC. In the United States, SCC failures on hazardous liquid pipelines have been less frequent when compared with SCC occurrences on natural gas pipelines. However, three failures of hazardous liquid pipelines during 2003 were attributed to SCC. Another hazardous liquid pipeline operator has reported finding near-critical[1] SCC defects.

Extensive industry research has been conducted related to understanding the mechanism(s) by which SCC affects pipelines and the many factors that pertain to the initiation and growth of SCC. Other research has been performed regarding detection methods, evaluation procedures, and mitigation measures. While much remains to be learned about the factors affecting cracking behavior and methods to detect, evaluate, and mitigate SCC, an understanding is developing within the pipeline industry about how to effectively manage the SCC integrity threat. This industry understanding is being documented by organizations such as ASME and NACE International (NACE).

The OPS issued an Advisory Bulletin on October 2, 2003 that reminds owners and operators of gas transmission and hazardous liquid pipelines to consider SCC as a risk factor when developing and implementing Integrity Management Plans (IMP).

2.1 Problem Statement

Federal regulations require pipeline operators to identify and address the range of risks to which pipelines are subjected, including risks associated with SCC. Inspectors need further guidance in determining if operator risk mitigation efforts are adequate. OPS recognizes the need for the industry to develop a standard procedure or procedures to assure SCC issues are handled in a consistent and appropriate manner. OPS also realizes that there is a need for federal inspectors and auditors to have guidance by which to assess the information provided by the various pipeline operators under their integrity programs.

Questions that need to be addressed include:

- What do we already understand about SCC and what do we need to know? (i.e., a knowledge gap analysis)
- Where is SCC found?
- What are the frequency and consequence of SCC-related failures?
- How is SCC detected and characterized?
- What are the susceptibility parameters of SCC?
- What tools exist for detecting SCC and what is their reliability?

1 A near-critical stress corrosion crack is defined in this report as one that could potentially fail a hydrostatic test and pose a future integrity threat to the pipeline if not mitigated. A significant stress corrosion crack is used in this report following the CEPA definition.

To accomplish these goals, RSPA/OPS requested that a comprehensive study of SCC be completed.

2.2 Project Scope Overview

The scope of the project is to conduct an overall "umbrella" study of SCC issues relating to pipeline integrity for both gas and liquid lines, including the history of SCC, level of risk, indicators of potential for SCC, detection methods, mitigation measures, assessment procedure, and regulatory procedures for evaluation of industry assessments.

The study was comprehensive in scope and involved coordination with major industry trade organizations, pipeline operators, pipeline regulators, and industry experts, both here in the United States and internationally. Known information on the subject of SCC has been assembled or identified, and any gaps in the efforts to understand, identify, assess, manage, mitigate, and regulate enforcement of SCC effects and efforts were identified.

Support of the study by all stakeholders has been critical for the successful outcome of the effort. The study was structured in such a way that public comment period(s) were allowed to ensure the outcome of those publicly reviewed portions of the study would be met with broad acceptance.

2.2.1 Phase 1

The first phase of the study was to prepare for an OPS-hosted SCC workshop held in Houston on December 2, 2003. RSPA/OPS and the National Association of Pipeline Safety Representatives (NAPSR) co-sponsored this workshop on SCC with the pipeline industry trade and technical associations (American Gas Association (AGA), Association of Oil Pipe Lines (AOPL), American Petroleum Institute (API), INGAA, Pipeline Research Council International (PRCI), and NACE) to provide a forum for the discussion of SCC phenomena in both gas and hazardous liquid pipelines.

In preparation, initial consultation of government and industry contacts was conducted. After the workshop, comments and feedback were incorporated into the draft scope. The study outline was revised as needed in response to feedback provided during and after the workshop; Phase 1 efforts concluded on December 31, 2003.

2.2.2 Phase 2

The following activities were developed for Phase 2 of this study:

- Literature Review: Review existing documentation with regard to SCC history, research conducted to understand the mechanisms causing or contributing to SCC, and prevention, detection, and mitigation of SCC.
- SCC Detection, Science, and History: Compile a report summarizing the history of SCC on pipelines, explaining the causes and factors contributing to SCC initiation and growth, and discussing methods for prevention, detection, and mitigation of SCC on pipelines, including effectiveness of in-line inspection (ILI) tools and other in-the-bell-hole examination methods to detect SCC.
- Research Gap Analysis: Determine SCC-related R&D issues that warrant further research.

- Application of SCC Principles**:** Develop a practicable procedure regarding how to assess SCC in operating pipelines within the context of integrity management.
- Regulatory Practices in Foreign Countries**:** Summarize regulatory practices outside of the United States (i.e., Canada, United Kingdom, Norway, Australia, Russia, Saudi Arabia, and South America).
- Recommended Actions for Operator Response and Remediation**:** Identify recommended actions to be taken by pipeline operators to facilitate response and assure appropriate remedial measures are implemented following an SCC-related incident.
- Guidelines for Regulatory Response**:** Develop guidelines for regulatory oversight response in the event of SCC-related incidents.

2.3 Report Outline

As discussed in Chapter 3 of this report, the Literature Review uncovered a large body of documents available on various aspects of SCC. For organization purposes, a database was developed to classify these documents as described in Chapter 3. The understanding of the various aspects of SCC, stemming from the information contained in these documents, is included in following chapters. Note that laboratory research, material testing, and detailed analytical investigations were not a part of this scope.

The understanding of the current knowledge base and associated practices concerning SCC was considered too broad a topic to be summarized in one chapter. Accordingly, this second scope item was broken into four separate chapters – Chapter 4; Understanding Stress Corrosion Cracking (SCC) in Pipelines; Chapter 5, Prevention of an SCC Problem; Chapter 6, Detection and Assessment of SCC; and Chapter 7, Mitigation of SCC. The regulatory practices in the United States and other foreign countries are discussed in Chapter 8. Chapter 9 concludes the SCC review with a summary of the research needs related to the SCC problem.

Chapter 10 synthesizes the current knowledge base concerning SCC, both from the results of a questionnaire circulated to industry and information from interviews with a number of pipeline operators.

Chapter 11 presents a review of the OPS inspection protocols for an IM plan referencing SCC and discusses guidelines for oversight of the operator responses to these protocols.

Chapter 12 discusses the response to an in-service failure due to SCC.

Chapter 13 is a summary chapter concluding this study.

This page intentionally left blank.

3 Literature Review

3.1 Scope Statement

"Review existing documentation with regard to SCC history, research conducted to understand the mechanisms causing or contributing to SCC, and prevention, detection and mitigation of SCC."

3.2 Literature Search and Database

A literature search of technical papers, reports, and articles discussing SCC in pipelines was conducted in an attempt to identify the most current and informative documents about understanding and managing SCC. The complete results of the literature review were included in an SCC literature database. The authors wish to thank PRCI, in particular, for freely providing their wealth of SCC Research reports as a significant portion of the literature review conducted during this study. This Microsoft Access® database was compiled using a database developed for the OPS from 1998-1999 by General Physics (Hall and McMahon 1999). A few of the reports considered most informative for understanding and managing SCC are discussed in Section 3.3.

A description of the complete database system containing over 300 references is presented in Section 3.4.

3.3 Recommended References

The majority of documentation available focuses on understanding the mechanisms of SCC and conditions conducive to SCC, and is of interest for researchers and others wanting to understand the science of SCC. However, there are a few papers that provide a useful comprehensive overview of understanding and managing SCC, and are valuable for the operator, regulator, and others interested in developing a more general knowledge of SCC.

Perhaps the best of these reports is the *Report of the Inquiry* [on] *Stress Corrosion Cracking on Canadian Oil and Gas Pipelines* by the Canadian National Energy Board (NEB). Composed in 1996, this report is not the most recent; however it is a well-written, readable, and comprehensive piece. While the main focus is on near-neutral pH SCC, the predominate type experienced in Canada, high pH SCC is addressed adequately, making this document a very good basic reference, and one that anyone interested in understanding and managing SCC should read.

Another helpful reference is *Stress Corrosion Cracking–Recommended Practices* published by CEPA (CEPA 1997a). An effort to revise and update the document is currently underway, and is expected to be available in late 2005. This is possibly the only publicly available document that presents "practices" to help operators manage longitudinal, near-neutral pH SCC. While being specifically written to address near-neutral pH SCC, the document is still applicable to all types of pipeline SCC. The document presents an excellent model for pipeline operators who are setting up procedures for preventing, controlling, and mitigating external SCC.

CEPA produced an additional report that specifically addresses circumferential SCC, a less common form of SCC (CEPA 1997b). This report documents the experiences of NOVA Gas Transmission

Ltd., Northwestern Limited, Federated Pipe Lines Ltd., and the SNAM system in Italy in investigating and mitigating leaks due to circumferential SCC. Subsequently, CEPA issued an addendum to the *Stress Corrosion Cracking—Recommended Practices* addressing circumferential SCC (CEPA 1998). Circumferential SCC occurs when axial (longitudinal) stress, not hoop stress, is the major stress component and is typically associated with ground movement. Circumferential SCC can be classified as either near-neutral or high pH SCC.

In their report, *Protocol to Prioritize Sites for High pH Stress-Corrosion Cracking on Gas Pipelines*, Eiber and Leis (1998) document the development of a simple form for evaluating the susceptibility of a pipeline segment to high pH SCC. An example of an SCC IMP is also presented. This document provides detailed descriptions of the variables considered to be vital when determining the degree of susceptibility of a pipeline to high pH SCC and presents summary level supporting historical data. On the whole, this paper is easy to read and presents good information for use in assessing and managing high pH SCC.

Another good reference is the recently released NACE International Publication 35103, *External Stress Corrosion Cracking in Underground Pipelines* (NACE 2003). This document contains much of the same information as the NEB report, MH-2-95 (NEB 1996), but also incorporates information learned in the last few years.

3.4 Database Description

The SCC Microsoft Access® database contains basic bibliographic information for over 300 documents, as well as a brief abstract and a number of associated keywords for each report to facilitate searches of the data. Searches can also be performed on the other information contained in the database. Upon entry to the database, the menu shown in Figure 3-1 is displayed, allowing either a general review of the information contained on the database, or the available search options for more specific information.

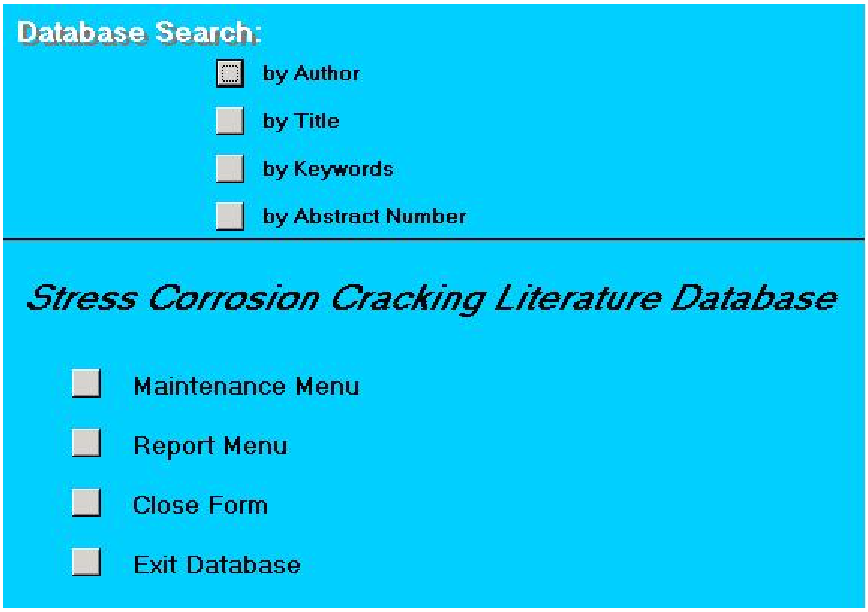


Figure 3-1 Database Main Menu

A typical report is displayed in Figure 3-2. The database is not locked, so users can perform their own updates, edits, commenting as desired through a maintenance system, with the menu shown in Figure 3-3.

Stess Corrosion Cracking Database

TITLE	10th International Conference on Pipe Protection (BHR PUB # 7)		
ID	14		
AUTHOR	Wilson, A.		
SOURCE DOCUMENT	10th International Conference on Pipe Protection		
ORGANIZATION	ASME	**KEYWORD1**	coatings
CATALOG	BHR Publication No. 7	**KEYWORD2**	pipeline
PROJECT		**KEYWORD3**	repairs/rehabilitation
ISSN	852988753	**KEYWORD4**	stresses
		KEYWORD5	sulfide
		KEYWORD6	
DATE	1993		

Abstract Data Contents: foreword coating systems the development and application of protective pipe coatings for the gas industry in the United Kingdom; selection and experience with different pipeline coatings; the development IN the use of FRE (fiber reinforced epoxy) pipe systems for industrial and offshore application: heat fused polyolefin systems for fusion bonded epoxy coated pipe; novel field joint coating techniques match the latest multi-layer polymeric factor applied coatings; the application of protective coatings over fusion bonded epoxy coatings for the water services in-service behavior of buried zinc coated ductile iron water pipes; a new cement lined sleeve for complete protection of small diameter cement-lined steel pipe joints (pipes up to 22) corrosion, erosion and fire control effect of pressure and flow velocity on sweet corrosion in high pressure horizontal multiphase pipelines; durability of epoxy coating systems under a temperature gradient condition: artificial seaweed controlling pipeline scour-basic investigations and design criteria; the study of sulfide stress cracking on internally coated steel pipe under H2S-H20 environments; durability of polyethylene coated steel pipe at elevated temperature; fire protection of pipes quality assurance and control coal tar enamels-the coating for the future; factors affecting the success of in-situ rehabilitation of high temperature pipelines; information to be gained by the monitoring of the electrical characteristics inherently possed by laminate structured composite pipe components editors: A. Wilson

Figure 3-2 Typical Document Report from Database

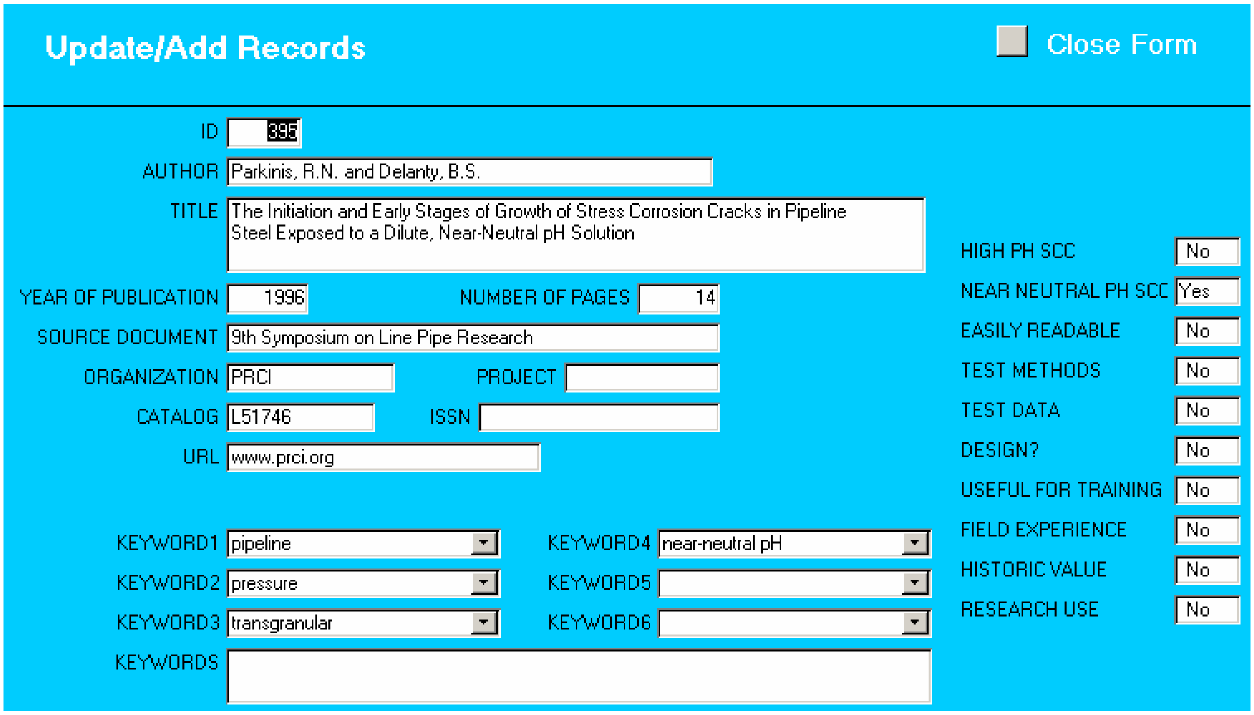


Figure 3-3 Maintenance Menu of Database

3.5 References

(The references listed below are used in this chapter narrative, and are not inclusive of database references).

CEPA. 1997a. *Stress Corrosion Cracking—Recommended Practices*. Canadian Energy Pipeline Association.

CEPA. 1997b. *The CEPA Report on Circumferential Stress Corrosion Cracking. Submitted to the National Energy Board*. Canadian Energy Pipeline Association. December.

CEPA. 1998. *Stress Corrosion Cracking—Recommended Practices. Addendum on circumferential SCC*. Canadian Energy Pipeline Association.

Eiber, R. J., and B.N Leis. 1998. *Protocol to Prioritize Sites for High pH Stress-Corrosion Cracking on Gas Pipelines*. PRCI. Project PR-3-9403, L51864.

Hall, R.J. and M.C. McMahon. 1999. *Stress Corrosion Cracking Study*. General Physics Corporation for U.S. Department of Transportation, Research and Special Programs Administration, Office of Pipeline Safety. Report No. DTRS56-96-C-0002-004. May.

NACE. 2003. *External Stress Corrosion Cracking of Underground Pipelines*. Publication 35103. NACE International. October.

NEB. 1996. *Stress Corrosion Cracking on Canadian Oil and Gas Pipelines. Report of the Inquiry*. National Energy Board. MH-2-95. December.

This page intentionally left blank.

4 Understanding Stress Corrosion Cracking (SCC) in Pipelines

4.1 Scope Statement

"Compile a report summarizing the history of SCC on pipelines, explaining the causes and factors contributing to SCC initiation and growth, and discussing methods for prevention, detection and mitigation of SCC on pipelines, including effectiveness of ILI tools and other in-the-bell hole examination methods to detect SCC."

The scope statement was broken down into components of Understanding Stress Corrosion Cracking (SCC) in Pipelines (Chapter 4); Prevention of an SCC Problem (Chapter 5); Detection and Assessment of SCC (Chapter 6); and Mitigation of SCC (Chapter 7).

This chapter summarizes the current state of knowledge of understanding the mechanism and characterization of SCC – both classical (high pH SCC) as well as near-neutral pH SCC.

4.2 General Characterization (NEB 1996)

SCC in pipelines is a type of environmentally-assisted cracking (EAC). EAC is a generic term that describes the formation of cracks caused by various factors combined with the environment surrounding the pipeline. Together these factors reduce the pressure carrying capacity of the pipeline. When water (electrolyte) comes into contact with steel, the minerals, ions, and gases in the water can attack or corrode the steel. These chemical or electrochemical reactions may result in general wall thinning, corrosion pits, and/or cracks.

EAC includes two mechanisms that should be distinguished: Corrosion fatigue and SCC. "Corrosion fatigue" occurs when chemically reactive agents penetrate fatigue cracks. These agents can accelerate crack progression. The chemical condition within the crack can be more aggressive than on the free surface. Even if the metal surface at the crack tip passivates (forms an inert barrier) the next fatigue loading cycle can crack the brittle deposit and reactivate the process. Thus, corrosion fatigue is the joint action of a *cyclic stress and a corrosive environment that decreases the number of cycles to failure*. Compared to the life of the pipeline when no corrosion is present, the corrosive environment generally decreases the life of the component. Similarly, SCC involves corrosive mechanisms and depends on both an *aggressive environment and tensile stress*. The tensile stress opens up cracks in the material and can be either directly applied or residual in form. Therefore, SCC occurs under tension loads, while corrosion fatigue occurs under cyclic loading. Appendix A indicates several research areas (see for example Section A.1.2) wherein the difference was difficult to distinguish.

SCC in pipelines is further characterized as "high pH SCC" or "near-neutral pH SCC," with the "pH" referring to the environment on the pipe surface at the crack location and not the soil pH. (pH is the measure of the relative acidity or alkalinity of water. It is defined as the negative log (base 10) of the hydrogen ion concentration. Water with a pH of 7 is neutral; lower pH levels indicate an increasing acidity, while pH levels above 7 indicate increasingly basic solutions.)

The most obvious identifying characteristics of SCC in pipelines, regardless of pH, is the appearance of patches or colonies of parallel cracks on the external surface of the pipe. There may be several of these colonies on a single joint of pipe and many joints of pipe may be involved. The cracks are closely spaced and of varying length and depth. These cracks may coalesce to form larger and longer cracks, which in some cases can lead to rupture. If the cracks are sparsely spaced, they might grow through the wall and leak, before they reach a length that is sufficient to cause a rupture.

In order for SCC to occur, three conditions must be satisfied simultaneously. They are listed below and in Figure 4-1:

1. A tensile stress higher than the threshold stress, frequently including some dynamic or cyclic component to the stress;
2. A material that is susceptible to SCC; and
3. A potent cracking environment.

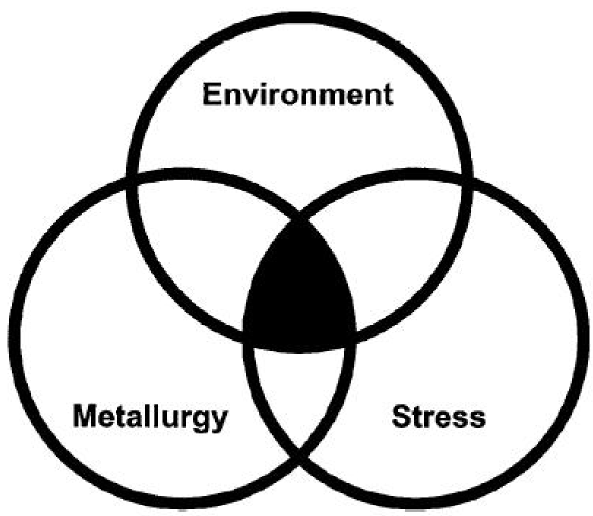


Figure 4-1 Three Conditions Necessary for SCC

Historically, SCC has been found on onshore buried pipelines, which is consistent with the information presented in Figure 4-1. SCC cracking is usually oriented longitudinally, normal to the hoop stress of the pipeline, which is usually the dominant stress component resulting from the internal pressure (see Figure 4-2). Additional examples of SCC colonies on steel pipe are presented as Figure 4-3, Figure 4-4, Figure 4-5, and Figure 4-6. However, SCC may also occur in the circumferential direction (C-SCC) when the predominant stress is an axial stress. Incidents resulting from C-SCC have been reported due to stresses induced by soil creep and localized bending from slope movements, and rock dents. Residual stresses at girth welds may also produce a resultant axial load within a pipeline.

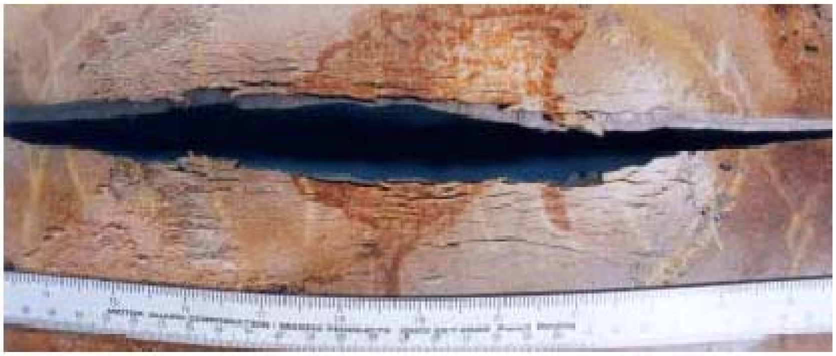


Figure 4-2 SCC Colony on a Large-Diameter, High-Pressure Transmission Gas Pipeline

(http://www.corrosioncost.com/pdf/gasliquid.pdf)

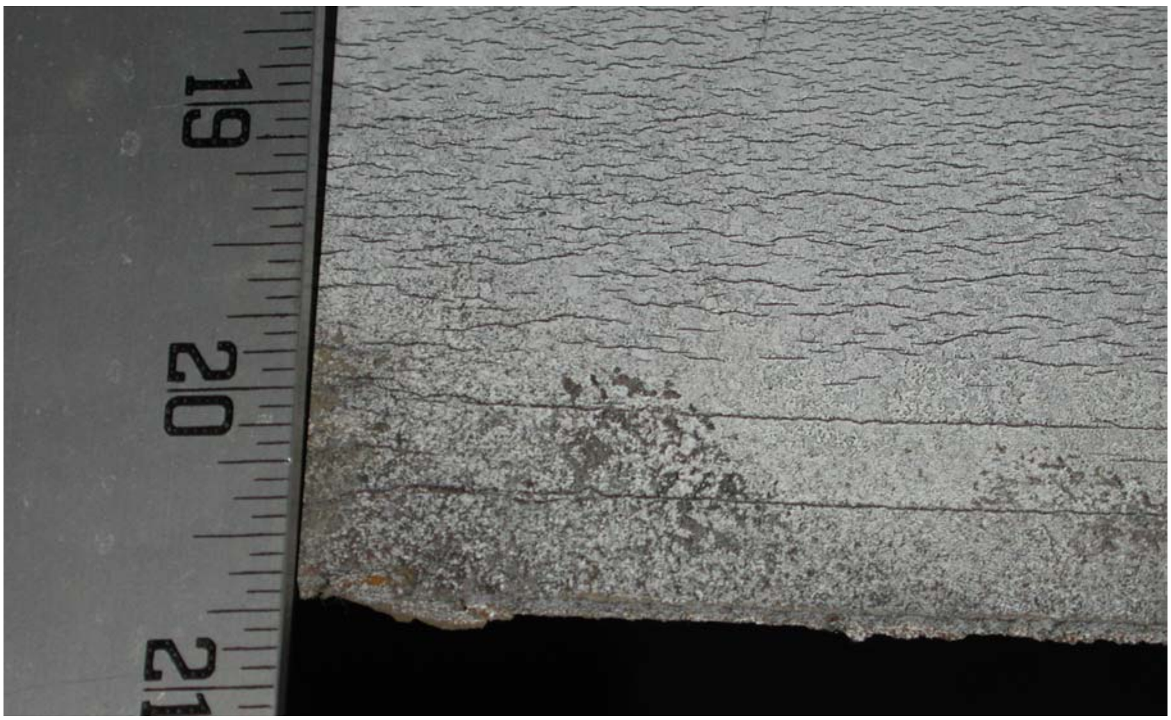


Figure 4-3 SCC Colony – Example One

Figure 4-4 SCC Colony – Example Two

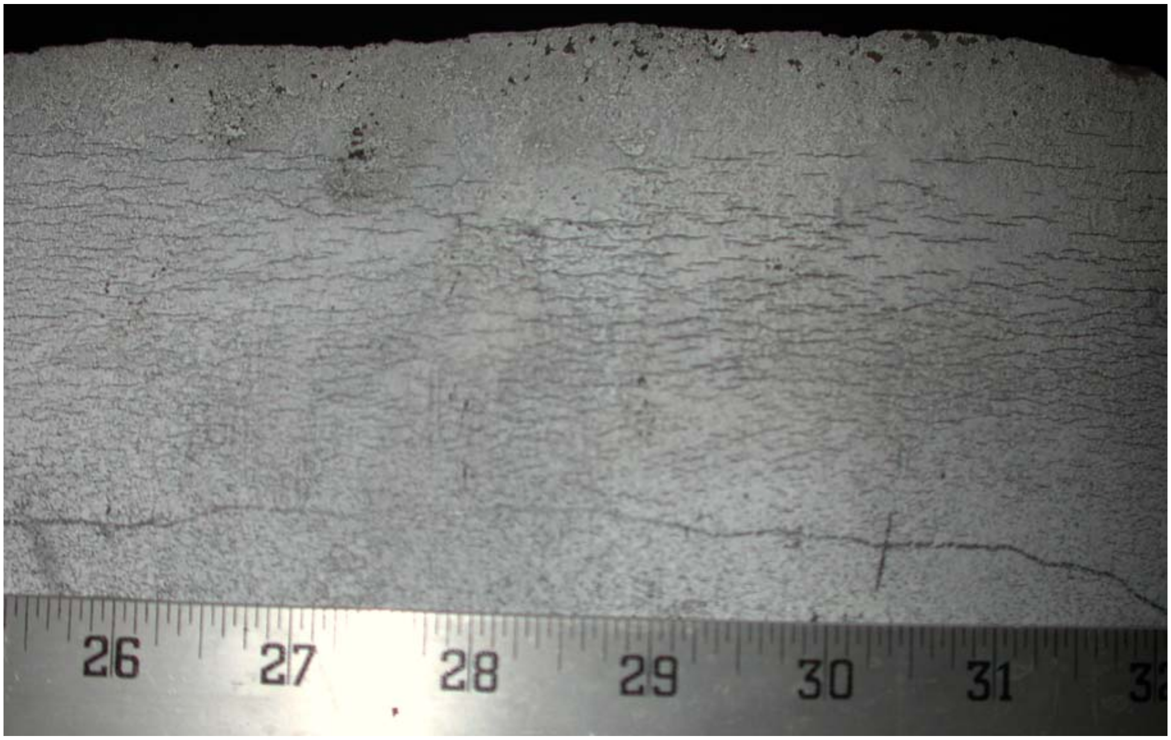


Figure 4-5 SCC Colony – Example Three

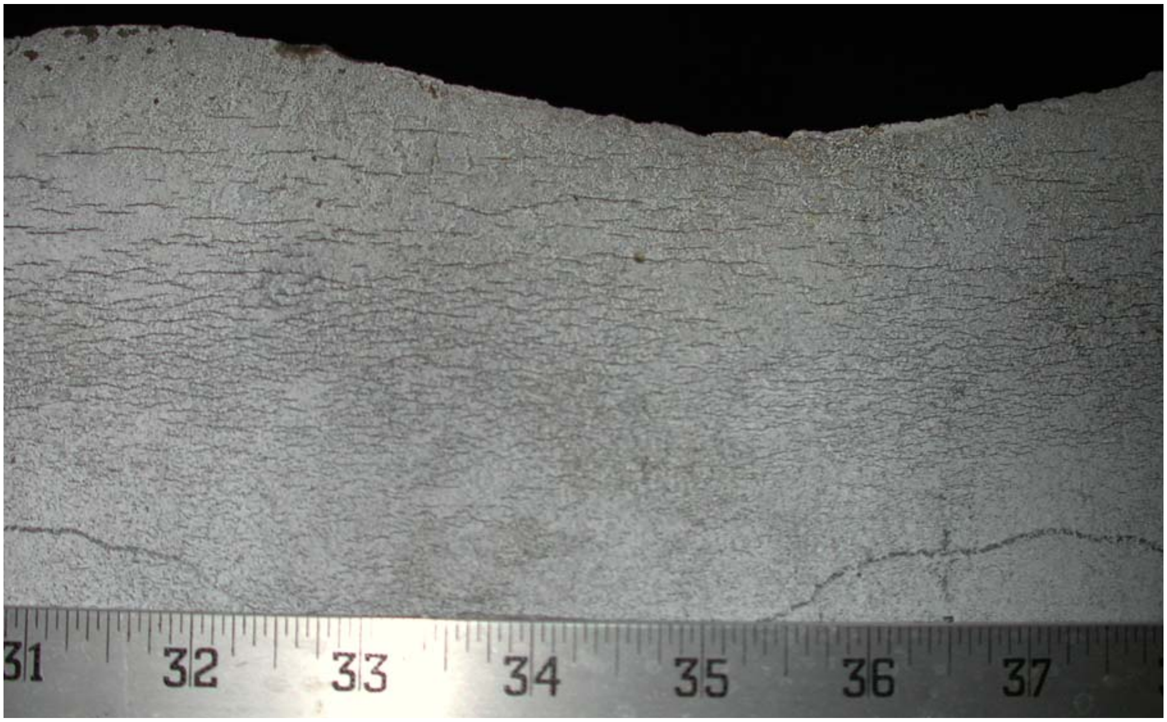


Figure 4-6 SCC Colony – Example Four

4.2.1 High pH SCC (NEB 1996)

When pipeline steel is exposed to the surrounding environment due to some form of coating failure, it is vulnerable to corrosion. Because soil corrosion is an electrochemical reaction, CP is used to mitigate corrosion by passing an electrical current through the soil thus giving the pipeline a cathodic potential. A concentrated carbonate-bicarbonate (CO_3-HCO_3) solution has been identified as the most probable environment responsible for high pH SCC. This environment may develop as a result of the interaction between hydroxyl ions produced by the cathode reaction and carbon dioxide (CO_2) in the soil generated by the decay of organic matter. CP current causes the pH of the electrolyte beneath disbonded coatings to increase, and the carbon dioxide readily dissolves in the elevated pH electrolyte, resulting in the generation of the concentrated carbonate-bicarbonate electrolyte. The pH of this electrolyte depends on the relative concentration of carbonate and bicarbonate, and the cracking range is between pH 8 and 11.

The fractured surface of the cracks normally exhibits a dark, discolored coating of oxidized material (primarily magnetite) at the mouth of the crack. The last portion of the pipe wall to fracture, i.e., the rapid fracture region, remains a shiny silver color. The presence of multiple black thumbnail-like flaws on the fracture surface normally is an indicator that SCC caused the failure (see Figure 4-7).

Figure 4-7 Matching Fracture Faces Showing Several Co-linear High pH Stress Corrosion Cracks Broken Open to Reveal the Black Oxide on the Crack

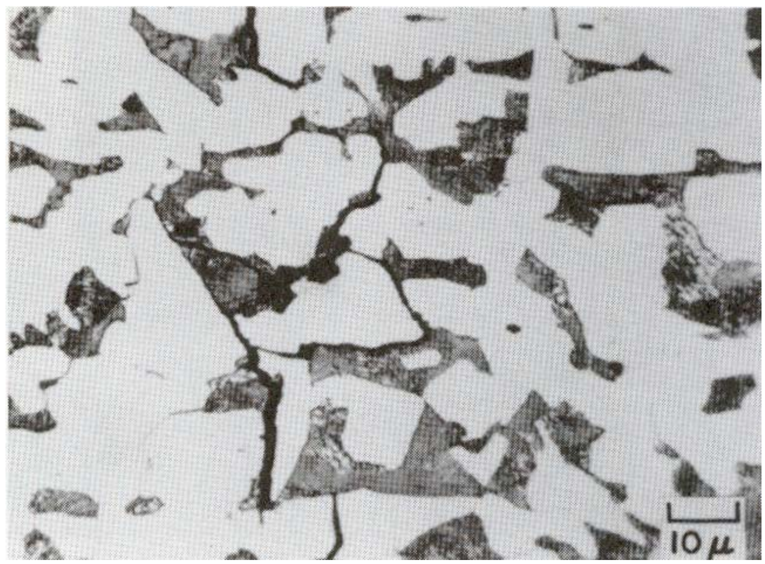


Figure 4-8 An Example of Intergranular Cracking of Pipeline Steel (Revie 2000)

Analysis of the liquid trapped in the disbonded area or in the crack itself indicates a carbonate-bicarbonate solution with a pH of 8 to 9, or higher. Metallographic examination of a section across the crack shows the fracture path to be intergranular, often with small branches, as shown in Figure 4-8. Laboratory simulation with small test specimens indicates that this form of SCC is temperature sensitive and occurs more frequently at higher temperature locations above 100°F. This supports field reports that demonstrate a greater likelihood of SCC immediately downstream of the compressor stations where the operating temperature might reach 150°F.

4.2.2 Near-Neutral pH SCC (NEB 1996)

This form of SCC was not documented until the mid 1980s and was first identified on buried pipelines in Canada coincident with water having a pH between 5.5 and 7.5 trapped in wrinkles in the tape wrapped pipe coating. In the case of near-neutral pH SCC, the cracking environment appears to be a diluted groundwater containing dissolved carbon dioxide. The source of the carbon dioxide is typically the decay of organic matter and geochemical reactions in the soil. This form of cracking occurs under conditions where there is little, if any, CP current reaching the pipe surface over a prolonged period, either because of the presence of a shielding coating, a highly resistive soil, or ineffective CP. Typically, the SCC colonies initiate at locations on the outside surface where there is already pitting or general corrosion, which is sometimes obvious to the unaided eye and other times very difficult to observe.

Metallographic examination of near-neutral pH SCC reveals the cracks are predominately transgranular (see Figure 4-9) and are wider (more open) than the high pH form, i.e. the crack sides have experienced metal loss from corrosion. This morphology implies that the fracture mechanism is different; however, the direct visual appearance of a pipe fracture surface is similar to that of high pH SCC.

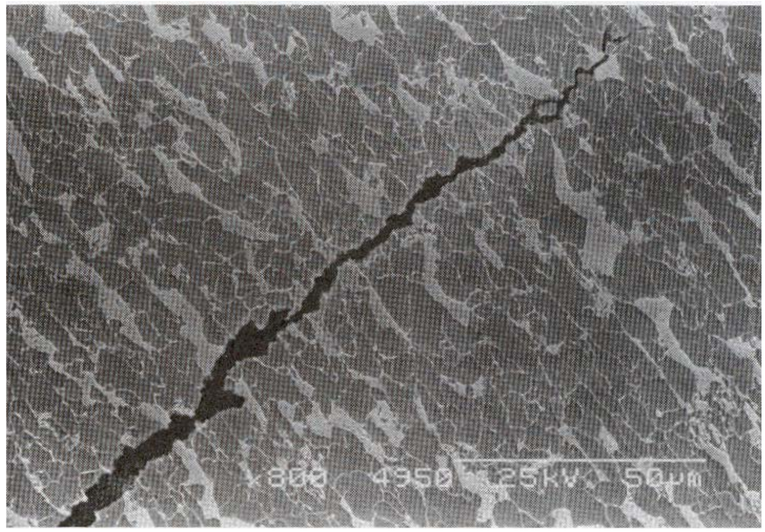


Figure 4-9 Transgranular Cracking in Pipeline Steel (Revie 2000)

4.2.3 Crack Characteristics

There are many similarities between the two forms of SCC. Both occur as colonies of multiple parallel cracks that are generally perpendicular to the direction of the highest stress on the external pipe surface. These cracks can vary in depth and length and grow in two directions. They increase in depth and length and tend to coalesce, or link together, to form longer cracks. At some point these cracks may reach a critical depth and length combination that can result in a rupture. A leak will occur if a crack grows through the pipe wall before it reaches a critical length for rupture. Note that critical size stress corrosion cracks do not need to fully penetrate the pipe wall for a rupture to occur, i.e., a shallow crack may reach a length that becomes critical. The strength and ductility of the remaining wall determines the critical size at which the crack behavior changes from a slowly growing stress corrosion mechanism to an extremely rapid brittle or ductile stress overload.

The most obvious differences between the two forms of SCC are the temperature sensitivity of high pH SCC, the fracture morphology, and the pH of the environment in contact with the pipe surface. The characteristics of high pH and near-neutral pH SCC are summarized in Table 4-1.

Table 4-1 Characteristics of High pH and Near-Neutral SCC in Pipelines (NEB 1996)

Factor	Near-neutral pH SCC	High pH SCC (Classical)
Location	• 65 percent occurred between the compressor station and the 1st downstream block valve (distances between valves are typically 16 to 30 km) • 12 percent occurred between the 1st and 2nd valves • 5 percent occurred between the 2nd and 3rd valves • 18 percent occurred downstream of the 3rd valve • SCC associated with specific terrain conditions, often alternate wet-dry soils, and soils that tend to disbond or damage coatings	• Typically within 20 km downstream of pump or compressor station • Number of failures falls markedly with increased distance from compressor/pump and lower pipe temperature • SCC associated with specific terrain conditions, often alternate wet-dry soils, and soils that tend to disbond or damage coatings
Temperature	• No apparent correlation with temperature of pipe • Appear to occur more frequently in the colder climates where CO_2 concentration in groundwater is higher	• Growth rate increases exponentially with temperature increase
Associated Electrolyte	• Dilute bicarbonate solution with a neutral pH in the range of 5.5 to 7.5	• Concentrated carbonate-bicarbonate solution with an alkaline pH greater than 9.3
Electrochemical Potential	• At free corrosion potential: –760 to –790 mV ($Cu/CuSO_4$) • Cathodic protection does not reach pipe surface at SCC sites	• –600 to –750 mV ($Cu/CuSO_4$) • Cathodic protection is effective to achieve these potentials
Crack Path and Morphology	• Primarily transgranular (across the steel grains) • Wide cracks with evidence of substantial corrosion of crack side wall	• Primarily intergranular (between the steel grains) • Narrow, tight cracks with almost no evidence of secondary corrosion of crack wall

4.2.4 Crack Growth

The cycle of SCC crack growth is normally modeled as a four-stage process as shown in Figure 4-10. The first stage is the development of conditions conducive to SCC and is followed by the crack "initiation" stage. These cracks then continue to grow and coalesce, while additional crack initiation also occurs during stage 3. Finally, in stage 4, large cracks coalesce and failure occurs. Appendix A discusses the background and research of the crack growth rate in more detail.

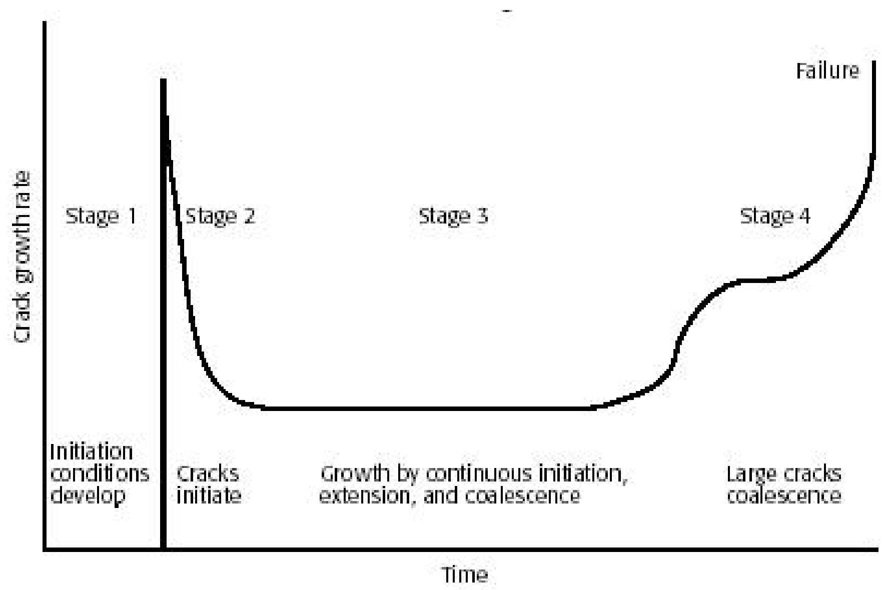


Figure 4-10 Four Stage Process of SCC Growth

While a single crack might grow large enough to cause a leak, coalescence typically is necessary for the defect to grow long enough to cause a rupture. If cracks form close to one another, crack growth may be dominated by coalescence into collinear cracks and can occur throughout the SCC life cycle. A combination of environmental and mechanical forces can cause cracks to grow. In the final stage of growth, after cracks have coalesced sufficiently for tearing to begin, the environment no longer plays a role. In some cases, tearing is preceded by a stage of crack growth in which fatigue is the dominant crack propagation mechanism.

The geometry of the crack colonies resulting from near-neutral pH SCC is important in determining whether the cracks coalesce and grow to failure (NEB 1996). Colonies of cracks that are long in the longitudinal direction yet narrow in the circumferential direction are a greater risk to pipeline integrity than colonies of cracks that are shorter in the longitudinal direction and wide in the circumferential direction. The individual cracks in long, narrow colonies are oriented head to tail and tend to link together, leading to rupture. However, for colonies that are about as long as they are wide, growth occurs mainly near the edges. Cracks located deeper within these colonies with circumferential spacing less than 20 percent of the wall thickness are generally shielded from stress and become dormant (NACE 2003).

4.3 History of SCC in Pipelines

The first documented case of SCC causing a pipeline failure was the Natchitoches, Louisiana, incident in the mid 1960s. This rupture was caused by high pH SCC and resulted in a gas release, explosion and fire with several fatalities. Spurred by this discovery, research on high pH SCC in pipelines has been ongoing since that time. In the late 1960s, a concentrated carbonate-bicarbonate solution was identified as the most likely environment for SCC and evidence of this solution at the pipe surface was found in a limited number of cases (Fessler 1969).

According to the NEB report *Stress Corrosion Cracking on Canadian Oil and Gas Pipelines*: "Since 1977, SCC has caused 22 pipeline failures in Canada. These failures include 12 ruptures and 10 leaks on both natural gas and liquids pipeline systems. Most of the SCC-related failures occurred since 1985 on pipelines that were coated with polyethylene tape and installed between 1968 and 1973." (NEB 1996).

4.3.1 Canada/International (NEB 1996)

In the Introduction to *Stress Corrosion Cracking on Canadian Oil and Gas Pipelines* the NEB notes: "Our awareness of SCC on the Canadian pipelines we regulate began in 1985. TransCanada had three failures on the Northern Ontario portion of the pipeline between March 1985 and March 1986… These failures were attributed to stress corrosion cracking and were considered at the time to be the first evidence of SCC in Canada, although subsequently it was determined that SCC had been detected on other pipelines in the 1970s. The type of SCC which caused these failures was different from the 'high pH' SCC that had been found on other pipelines in the world." (NEB 1996).

The NEB conducted an inquiry into SCC on pipelines in 1993, concluding that the situation was being managed appropriately. However, ruptures on the TransCanada Pipelines (TCPL) system in 1995 caused the NEB to reconsider SCC and begin a new inquiry. The result was a series of 27 recommendations to promote public safety as described in *Stress Corrosion Cracking on Canadian Oil and Gas Pipelines* (NEB 1996). Each pipeline company under NEB jurisdiction was required to develop and begin maintenance of an SCC integrity management program by June 1997, and additional research was to be conducted on SCC.

4.3.2 United States

Until recently, the United States concentrated on high pH SCC. Recent failures, however, have been attributed to near-neutral pH SCC. No specific regulations pertaining to either design or operational assessment for SCC detection or control in pipelines existed in the United States until recently. With the publication of ASME B31.8S *Managing System Integrity of Gas Pipelines* in 2002, which was incorporated by reference into Title 49 Code of Federal Regulations (CFR) Part 192 (49 CFR 192), there is now some guidance regarding high pH SCC, at least for gas pipelines. Liquid operators may choose to follow these guidelines as well, with the appropriate modifications because codes for liquid pipelines do not currently address SCC in this detail. ASME B31.8S describes risk assessment procedures and outlines inspection and examination procedures for SCC, although it does not supply analytical or theoretical guidance for high pH or near-neutral pH SCC threat assessment. Development of other guidance documents is currently ongoing; in particular, NACE has recently published a Direct Assessment Recommended Practice for SCC. This is discussed further in Chapter 6 and Chapter 8 of this report.

4.4 Contributing Factors to SCC in Pipelines

4.4.1 Metallurgy

Metallurgy can affect SCC through chemical composition and microstructure. However, pipeline steels, and certainly the conventional steels that have historically been used in the last 50 years, do not typically contain elements not found in similar carbon-manganese steels used in literally hundreds of construction applications without reports of SCC.

More recently, the yield strength of line pipe has gradually increased by the addition of micro-alloying elements such as vanadium, columbium, and/or titanium. The addition of these elements tends to produce a finer grain in the microstructure, increasing both strength and toughness. Controlled rolling and cooling of the steel plate used to manufacture line pipe has resulted in finer-grained bainitic microstructures.

A number of research investigations involving small-scale, laboratory-reproduced SCC and using both high and near-neutral pH environments have been conducted without achieving a meaningful correlation between steel composition or microstructure and susceptibility to SCC. Danielson and Jones (2001) discuss the high pH SCC testing of six different heats of API 5L X52, as well as three heats (X65, X70, and X80) of modern steels. Their paper concludes: "In general, the microstructure/microchemistry had a small effect on the SCC behavior."

Nevertheless, certain batches of pipeline steel have been found to be much more susceptible to SCC than other batches with similar compositions and microstructures (Beavers and Harper 2004). A full understanding of this remains to be developed, but current research suggests that other characteristics of the steel, such as creep response to cyclic loading, may be important.

4.4.2 Manufacturing

Carbon steel line pipe is manufactured using multiple forming and joining processes and may be seamless or have a welded seam. Seamless line pipe is hot formed into cylinders by piercing solid bars of steel. The obsolete manufacturing process of forming and lap welding plates into cylinders was also performed at an elevated temperature to permit pressure welding of the overlapped edges of a steel plate. Modern seam-welded line pipe is formed at ambient temperature from flat-rolled plates or strip from coils. Longitudinal seams may be electric-resistance welded (ERW) or double submerged-arc welded (DSAW) in line pipe formed from strip and plate, respectively. An obsolete process, electric-flash welded, was also used to produce longitudinal seams in line pipe formed from plate. DSAW helical seams are also used to produce line pipe rolled from both strip and plate. The vast majority of line pipe for large diameter pipelines is produced by one of the seam-welded processes, while smaller-diameter pipeline are typically constructed from either seamless or ERW line pipe.

The strength of hot-formed seamless and lap-welded line pipe is primarily due to alloy additions during steelmaking, but seamless line pipe with SMYS 60 ksi and higher is typically quenched and tempered (QT) after forming to achieve the required strength. The strength of vintage line pipe with welded seams was also primarily due to alloy additions, but advances in both steelmaking and rolling practices over several decades permitted strip and plate to achieve some of its strength from controlled rolling procedures rather than alloy additions. Production of modern strip and plate for manufacture of line pipe may be described as a Thermo-mechanical Control Process (TMCP), in which both rolling temperature and degree of thickness reduction are controlled. Although TMCP was developed to produce line pipe grades with higher strength and toughness, some producers may employ TMCP on lower strength grades.

Because of the evolution of both steelmaking and forming practices for carbon steels converted to line pipe, the microstructure of existing line pipe may contain varying amounts of ferrite, pearlite, and bainite with significant variation in the grain size. In spite of both significant and subtle differences in the chemical composition and microstructure of existing line pipe, there is no strong evidence that any of the differences either promote or inhibit SCC.

The first reported cases of SCC exhibited intergranular cracking (high pH SCC) in steels with a microstructure that consisted of grains of low-carbon ferrite and higher carbon colonies of pearlite. Typically, the more recently detected near-neutral pH SCC has occurred on slightly higher yield strength steels with a much finer grain size and a higher toughness. However, there are a number of cases of near-neutral pH SCC in older, large grained, lower-strength steels and cases of high pH SCC in newer, fine-grained steels. Thus, regarding reported cases of SCC, no generalizations regarding manufacturing process can be made.

4.4.3 Mechanical Properties

The mechanical properties of greatest interest for onshore gas transmission pipelines are the specified minimum yield strength (SMYS) and the toughness. Generally, the most cost-effective design of large-diameter onshore pipelines results from selecting the highest strength line pipe grade that still provides a wall thickness and diameter-to-thickness ratio that are constructible. As improved manufacturing procedures are being developed, higher-strength grades of line pipe are being purchased when the combination of diameter and maximum allowable operating pressure (MAOP) or maximum operating pressure (MOP) is suitable for the specific application. There is no strong evidence that increasing SMYS through 70 ksi increases susceptibility to SCC initiation or growth.

Increases in toughness, which have generally occurred in parallel with increasing SMYS, have significantly increased the critical size of cracks that can result in ruptures. The use of toughness values in engineering evaluations of critical flaw sizes is discussed further in Sections 6.4 and 8.2.5.

There is a growing body of evidence to suggest that tensile residual stresses in the line pipe play a significant role in SCC and that cracking can be minimized or prevented by reducing these stresses during manufacturing, as well as during installation and operation.

4.4.4 Pipeline Operating Conditions

As previously discussed, SCC requires three conditions to be satisfied simultaneously: 1) a tensile stress above the threshold stress, 2) an appropriate environment at the steel surface, and 3) a susceptible material.

Below some value of tensile stress, referred to as the threshold stress, crack initiation does not occur. The threshold stress is difficult to accurately define but, depending on the range of stress fluctuation, is on the order of 60 to 100 percent of the yield strength for high pH SCC based on laboratory results of tapered tensile tests. A threshold stress for near-neutral pH SCC has not been established (Beavers 1993).

Relating threshold stress determined by laboratory testing to stresses in service is challenging. Stresses reported for laboratory testing are generally uniaxial tension applied by the test fixture. Actual services stresses that can promote SCC include residual tension stresses and stresses from external forces, in addition to the stress applied by internal pressure. Consequently, comparison of the stress applied by internal pressure, as a percent of SMYS, with a threshold stress determined by laboratory testing is inappropriate, and may be misleading.

The operator has some control of the applied tension stress that is the result of internal pressure. Unfortunately, residual tension stresses from manufacture and field bending, bending stresses from pipeline movement, overburden loads from soil, dents or gouges, or from heavy equipment can cause as much or more tension stress as that caused by internal pressure, all of which is beyond the control of the operator.

The longitudinal stress caused by pressure can be up to half of the hoop stress. However, pipeline flexure can result in additional longitudinal stress, so that the toal longitudinal stress can exceed the hoop stress, with the maximum/minimum values at the extreme fibers of bending. The C-SCC cases reported by CEPA are associated with undulating terrain where pipeline loading resulted from soil creep or localized bending. Localized bending may also occur at dents resulting in higher longitudinal stresses in the local region.

A pipeline that is exposed to cyclic pressure fluctuations may experience cyclic softening. Cyclic softening is a phenomenon in which the application of stress cycles at maximum stress levels below the yield stress causes the steel to exhibit local micro-plastic deformation after a period of load cycles. This phenomenon manifests itself as a loss of yield strength and can significantly reduce the threshold stress. The operator has little control over the metallurgical susceptibility of a line pipe steel to cyclic softening but can, in some instances, monitor the magnitude and frequency of pressure cycles on a pipeline.

In addition, the operator has little control over the pH of the groundwater and is unable to control the aggressiveness of the environment, except for new construction by installing a premium coating system applied under carefully controlled and monitored conditions in a coating plant. Unfortunately, these mill applied coating systems require preparation and application methods that may not be considered applicable for recoating in the ditch. Note also that the pH of the groundwater will be modified by the electrochemical reaction at the pipeline surface.

The operator does have some control over the operating temperature. For example, some operators have installed cooling towers to help control high pH SCC.

4.4.5 Coating

Coating type and condition have a profound effect on SCC. SCC will not occur beneath an intact coating that prevents contact of groundwater with the pipe surface. Coatings can fail by disbonding from the pipe surface (i.e. the coating comes away from the pipe but does not break), the formation of holidays (i.e., breaks or gaps in the coating), or general degradation. Disbondment is the most severe form of degradation with respect to SCC susceptibility because the cathodic protection current can be shielded beneath the disbonded coatings.

Construction and operating practices can have a significant influence on coating performance. For example, coatings typically will not bond well to poorly prepared surfaces, leading to increased susceptibility to disbondment. Damage during construction can create coating holidays. Operating a pipeline at elevated temperatures can accelerate general coating degradation. Cathodic disbondment of a susceptible coating can occur in the presence of excessive CP current.

Tape coatings, such as the polyethylene-backed tapes, which were used predominantly in the early 1960s to 1980s, have particularly poor resistance to disbondment. These tapes are spirally wrapped around the pipe with an overlap at the helix line. “Tenting” occurs between the pipe surface and the tape along the ridge created by longitudinal, spiral, and girth welds. Tenting also occurs at the overlap between the helix of the wrap as illustrated in Figure 4-11.

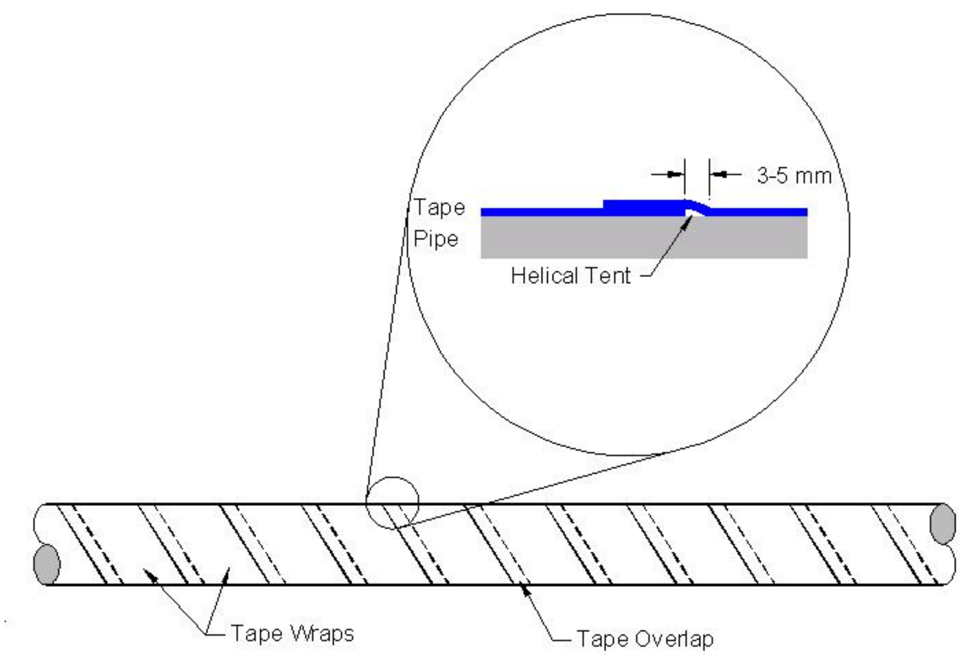


Figure 4-11 Polyethylene Tape Helical Tent

When the tape disbonds from the pipeline, moisture can accumulate beneath the tape surface. The tape itself has fairly high electrical insulation properties, thus preventing CP current from reaching entrapped moisture between the tape and the pipe surface. At the time of the NEB SCC inquiry, it was reported that about three-quarters of near-neutral pH SCC-related service incidents occurred under these tape coatings. The cracks tend to occur at or near the toe of the seam weld where stress is concentrated and water has access, as well as where the coating has been damaged or disbonded (NEB 1996).

Asphalt and coal tar coatings may also disbond, especially due to poor surface preparation. However, since these coatings tend to become saturated with moisture, or if brittle may break into pieces, CP current is often able to reach the pipe surface in the disbonded area. SCC might still occur when the soil is so resistive that the CP current cannot reach the pipeline. For these coating types, there is no preferential location, but SCC might occur wherever disbondment occur (NEB 1996).

It is generally agreed that fusion-bonded epoxy (FBE) coatings, which are often the coating of choice for newly installed pipelines in the United States, are an effective protection against SCC. Extruded polyethylene, because the coating system is monolithic, also appears to be effective, except possibly at tape-wrapped girth welds.

4.4.6 Soil Conditions

In 1973, Wenk described results of analyses of soil and water extracts (from the soil) taken from high pH SCC locations (Wenk 1974). While supporting data were not provided, it was stated that SCC had occurred in a wide variety of soils, covering a range in color, texture, and pH. No single characteristic was found to be common to all of the soil samples. Similarly, the compositions of the water extracts did not show any more consistency than did the physical descriptions of the soils, according to Wenk. On several occasions, small quantities of electrolytes were found beneath disbonded coatings near locations at which stress corrosion cracks were detected. The principal components of the electrolytes were sodium carbonate and bicarbonate. Sodium bicarbonate crystals were also found on pipe surfaces near some SCC colonies (Fessler, et al. 1973). Based on the presence of the sodium-based carbonates and bicarbonates, it is likely that these were high pH SCC sites. Therefore, it is not surprising that these results are not consistent with the results of the TCPL studies performed in the 1980s and 1990s, when near-neutral pH SCC was found.

Mercer described the results of a field study conducted by British Gas Corporation in 1979 (Mercer 1979). Soil data from both the UK and U.S. were collected and analyzed. As in the study by Wenk, detailed information on the soil analyses was not provided, but it was concluded that soil chemistry had no obvious direct influence on high pH SCC. The moisture content of the soil, the ability of the soil to cause coating damage, and localized variation in the level of CP were the primary soil-related factors identified.

Delanty and O'Beirne (1991, 1992) reported on the results of more than 450 investigative excavations performed on TCPL's system in the mid- to late-1980s. In the tape-coated portions of the system, near-neutral pH SCC was found in all of the various types of terrains and soils (e.g., muskeg, clay, silt, sand, and bedrock) present on the system. There was no apparent difference in the soil chemistry for the SCC and non-SCC sites. However, the SCC was predominantly located in imperfectly to poorly drained soils in which anaerobic and seasonally reducing environmental conditions were present.

In the same system, near-neutral pH SCC was found in the asphalt-coated portions of the system, predominantly (83 percent) in extremely dry terrains consisting of either sandy soils or a mixture of sand and bedrock. There was inadequate CP in these locations, based on pipe-to-soil potential measurements or pH measurements of electrolytes found beneath disbonded coatings. The remainder of the SCC sites on the asphalt-coated portions of the system had localized areas of inadequate CP, based on pH measurements of electrolytes.

Delanty and Marr developed an SCC severity rating model for near-neutral pH SCC for the tape-coated portions of TCPL's system in eastern Canada (Delanty and Marr 1992; Marr 1990). The predictors in that model were soil type, drainage, and topography. The soil classifications were based on method of deposition. The most aggressive soil types were lacustrine (formed by deposits in lakes), followed by organics over glaciofluvial (formed by deposits in streams fed by melting glaciers), and organics over lacustrine. The prevalence of SCC in glaciofluvial soils was about 13 percent of that in lacustrine soils, and about 17 percent of that in soils with organics over glaciofluvial or lacustrine. Very poorly or poorly drained soils were found to be the most aggressive, while level-depressed soil was found to be the most aggressive topography. The SCC model did not contain parameters associated with soil chemistry because the results of previous geochemical projects were inconclusive.

As described above, neither the early field studies conducted on high pH SCC, nor the later field studies conducted on near-neutral pH SCC, detected a correlation between the occurrence of SCC and soil chemistry. On the other hand, high pH SCC was not reported where the extensive field study of near-neutral pH SCC was performed in Northern Ontario (Delanty and O'Beirne 1991, 1992), suggesting that the soil conditions were not conducive to this form of cracking. Furthermore, no near-neutral or high pH SCC was found in Northern Ontario where elevated pH electrolytes were detected, possibly because the soil conditions could not support the development of concentrated carbonate-bicarbonate solutions, even when the CP conditions were conducive to such development. These observations suggest that a further analysis of field soil data might provide insight into the role of soil/groundwater chemistry on the occurrence of SCC (Beavers and Garrity 2001).

Near-neutral pH SCC may be associated with local topographical depressions, e.g., at the base of hills or streams, where the groundwater either channels along the pipeline or across it. Flowing water may help to maintain the near-neutral pH environment by supplying carbon dioxide to the electrolytic solution in a disbonded area. The majority of laboratory investigation has been performed in an NS4 electrolyte solution containing 5 percent carbon dioxide. NS4 is a simulated trap water that is typical of liquids found beneath disbonded polyethylene tape coatings at locations where near-neutral pH SCC was found. Research shows that the crack growth rate increases with increasing carbon dioxide concentrations, and that the cracking becomes dormant in carbon dioxide free environments (Beavers, et al. 2001).

4.5 References

Beavers, J.A. 1993. *On the Mechanism of Stress Corrosion Cracking of Natural Gas Pipelines*. Eighth Line Pipe Symposium. PRCI. L51680. Paper 17.

Beavers, J.A., and K.C. Garrity. 2001. *100 mV Polarization Criterion and External SCC of Underground Pipelines.* NACE International CORROSION/2001. Paper No. 01592.

Beavers, J.A., C.L. Durr, B.S. Delanty, D.M. Owen, and R.L. Sutherby. 2001. *Near-Neutral pH SCC: Crack Propagation in Susceptible Soil Environments*. NACE International CORROSION/2001. Paper No. 01217.

Beavers, J.A. and W.V. Harper. 2004. *Stress Corrosion Cracking Prediction Model*. NACE International CORROSION/2004. Paper 04189.

Danielson, M.J., and R.H. Jones. 2001. *Effect of Microstructure and Microchemistry on the SCC Behavior of Archival and Modern Pipeline Steels in a High pH Environment*. NACE International CORROSION/2001. Paper No. 01211.

Delanty, B.S., and J.E. Marr. 1992. Stress Corrosion Cracking Severity Rating Model. In *Proceedings from the International Conference on Pipeline Reliability*. CANMET. June.

Delanty, B.S., and J. O'Beirne. 1991. Low-pH Stress Corrosion Cracking. In *Proceedings from the 6th Symposium on Line Pipe Research*. PRCI. L30175.

Delanty, B.S., and J. O'Beirne. 1992. Major Field Study Compares Pipeline SCC with Coatings. *Oil and Gas Journal* 90, 24.

Fessler, R.R. 1969. Stress-Corrosion-Cracking. In *Proceedings from the Fourth Symposium on Line Pipe Research.* PRCI. L30075. p. F-1 to F-18.

Fessler, R.R, T. Groeneveld, and A. Elsea. 1973. Stress-Corrosion and Hydrogen-Stress Cracking in Buried Pipelines. *International Conference on Stress Corrsoion Cracking and Hydrogen Embrittlement of Iron Base Alloys*. June. Published in *Stress Corrosion Cracking and Hydrogen Embrittlement of Iron Base Alloys*. NACE. 1977

Marr, J.E. 1990. The Relationship Between External Pipeline Stress Corrosion Cracking and the Environment Within TCPL's Facilities Across Canada. Unpublished TCPL Research Report. May.

Mercer, W.L. 1979. Stress Corrosion Cracking — Control Through Understanding. In *Proceedings from the 6th Symposium on Line Pipe Research*. PRCI. L30175

NACE. 2003. *External Stress Corrosion Cracking of Underground Pipelines*. NACE International. Publication 35103. October.

NEB. 1996. *Stress Corrosion Cracking on Canadian Oil and Gas Pipelines. Report of the Inquiry*. National Energy Board. MH-2-95. December.

Revie, R. Winston, ed. 2000. *Uhlig's Corrosion Handbook*. 2nd Edition. Sponsored by the Electrochemical Society, Inc. John Wiley & Sons, Inc.

Wenk, R.L. 1974. Field Investigation of Stress Corrosion Cracking. In *Proceedings of the Fifth Symposium on Line Pipe Research*. PRCI. L30174.

This page intentionally left blank.

5 Prevention of an SCC Problem

5.1 Scope Statement

"Compile a report summarizing the history of SCC on pipelines, explaining the causes and factors contributing to SCC initiation and growth, and discussing methods for prevention, detection and mitigation of SCC on pipelines, including effectiveness of ILI tools and other in-the-bell hole examination methods to detect SCC."

The scope statement was broken down into components of Understanding Stress Corrosion Cracking (SCC) in Pipelines (Chapter 4); Prevention of an SCC Problem (Chapter 5); Detection and Assessment of SCC (Chapter 6); and Mitigation of SCC (Chapter 7).

This chapter summarizes the current state of knowledge for understanding how to prevent SCC, or perhaps more directly, how to prevent an SCC problem in pipelines.

5.2 Coatings

Inadequate coating performance is a major contributing factor for increased SCC susceptibility of an underground pipeline. The majority of high pH SCC failures have been associated with bituminous coatings (coal tar or asphalt), while the near-neutral pH SCC failures have occurred most frequently on tape-coated pipelines. The surface preparation conditions, degradation modes, and electrical behavior of these coatings are responsible for the type and prevalence of SCC on pipelines. The effectiveness of a coating system in preventing SCC is related to three factors:

1. the resistance of a coating to disbondment,
2. the ability to pass CP current should the coating fail, and
3. the type of surface preparation used with the coating.

Requirements for SCC-resistant coatings can be established, based on these factors, as described below.

In the early 1990s, PRCI funded a three-year research program to investigate the role of these three factors on resistance to high pH SCC of common pipeline coatings (Beavers 1992; Beavers, et al. 1993a, 1993b). The ability of a coating to resist disbonding is a primary performance property of coatings and affects all forms of external pipeline corrosion. An intact coating that prevents contact of electrolyte with the steel surface will mitigate all integrity threats associated with external corrosion, including SCC. Coatings with good adhesion properties are generally resistant to the mechanical action of soils from wet/dry cycles and freeze/thaw cycles. They also are better able to resist the effects of water transmission and cathodic disbondment (CEPA 1997). Cathodic disbondment of a susceptible coating can occur in the presence of excessive CP current.

The ability of a coating to pass CP current, should it fail, is the inverse of shielding the CP current beneath a disbonded coating. Shielding is of special significance to the occurrence of both forms of SCC. Near-neutral pH SCC is more frequently found with coatings that shield CP current, such as tape coatings. In the case of high pH SCC, the potential range for SCC lies between the native potential of steel in most soils and adequate CP of –850 mV copper sulfate electrode (CSE) (Berry 1974). Partial shielding by disbonded coatings can cause the pipeline to lie in the potential range for cracking, even for pipelines apparently protected by CP.

In the PRCI program on coatings, coating impedance tests were performed to evaluate the ability of the different coatings to conduct CP current in the absence of actual holidays (Beavers 1992). Single-layer FBE coatings were found to conduct CP current in the absence of holidays, whereas polyethylene tape coating completely shielded the CP. Coal tar enamel coating exhibited intermediate behavior, allowing CP current to flow after long exposure periods (greater than one year). Blister formation in FBE has been traced to surface contamination prior to coating application. The conduction of CP currents through the FBE coating can lead to the formation of a high pH (greater than 12) electrolyte in these blisters. This pH is higher than the pH range for high pH SCC such that this form of cracking is unlikely to occur even if the potential range were appropriate for cracking. Liquid urethanes and epoxies were not tested in the study, but similar behavior would be expected with these and other coatings that are water-permeable.

The relationship between surface condition of a line pipe steel and SCC has been the subject of several previous PRCI laboratory research programs (Barlo and Fessler 1981; Beavers 1992; Beavers et al. 1993a). The research indicates that grit-blasted surfaces are generally more resistant to high pH SCC initiation than mill-scaled surfaces, primarily because grit blasting imparts a compressive residual stress at the pipe surface and also removes mill scale. The majority of single-layer FBE coatings are applied in coating mills over grit-blasted surfaces prepared to a white (NACE No. 1/SSPC-SP 5) or near-white (NACE No. 2/SSPC-SP 10) surface finish. The older bituminous coatings were frequently applied over the ditch on mill-scaled surfaces. More recently, bituminous coatings have been applied in the mill using a commercial blast cleaning (NACE No. 3/SSPC-SP 6). The surface preparation necessary for FBE coating was found to be highly resistant to high pH SCC, in comparison with mill-scaled surfaces. On the other hand, the lower quality grit blast that is commonly used with plant-applied bituminous coatings actually decreased SCC resistance compared to that found with a mill-scaled surface, primarily by creating stress raisers at imbedded mill scale particles. Clean grit-blasted surfaces are also readily polarized in the presence of CP such that the potential is not likely to remain in the cracking range for long periods of time. While the above research was performed on initiation of high pH SCC, it is possible that the beneficial effects of grit blasting extend to near-neutral pH SCC initiation as well.

In summary, field experience and related research demonstrate that prudent coating selection and proper application are effective tools to prevent SCC of underground pipelines. The CEPA member companies have recommended that the following coatings be consider for new construction based on SCC performance (CEPA 1997):

- FBE
- Liquid Epoxy
- Urethane
- Extruded Polyethylene
- Multi-Layer or Composite Coatings

FBE, liquid epoxies, and urethane coatings meet all three requirements of an effective coating; they have high adhesive strength and are resistant to disbondment, they conduct CP current should they fail, and they are typically applied over a white or near white grit-blasted surface. Extruded polyethylene coatings meet the first and third requirements, but will shield CP current should damage occur. Furthermore, improper surface preparation and application of field joint coatings on extruded polyethylene coated pipelines has resulted in the formation of external corrosion and SCC. Multilayer or composite coatings typically consist of an FBE inner layer and a polyolefin outer layer with an adhesive between the two layers. These new coatings are promising from the standpoint of resistance to disbondment, mechanical damage, and soil stresses, but the polyolefin outer layer will shield CP current should disbondment occur. Additional field experience is needed to establish the performance of these coatings.

Tape coatings and bituminous coatings have been shown to be more susceptible to SCC than the above coatings and should be used only with careful consideration of all of the factors affecting SCC susceptibility.

Regardless of the coating selected, the line pipe surface should be prepared to a white (NACE No. 1/SSPC-SP 5) or near white (NACE No. 2/SSPC-SP 10) finish to remove mill scale and to impart sufficient residual compressive stresses to retard SCC initiation. A lower quality commercial blast (NACE No. 3/SSPC-SP 6) should not be used under any circumstances.

Following the NEB SCC Inquiry, the Canadian Standards Association (CSA) expanded the requirements for both plant and filed applied coatings to prevent SCC from occurring on underground pipelines. The current standard (CSA Z662-03 Oil and Gas Pipeline Systems) includes requirements for coating selection (Clause 4); application of several types of plant-applied external coatings (Clause 5); protection of the integrity of coatings during construction and installation (Clause 6); properties, application and inspection of coatings (Clause 9); and a guide for test methods for the evaluation of coating properties (Annex L).

5.3 Line Pipe Steel Selection

Field studies of high pH SCC have not identified any unique characteristics of failed line pipe (Wenk 1974). At the time of the study, most of the failures occurred in API 5L X52 line pipe steel, but this was the most common grade for larger diameter line pipe. The chemical compositions of the failed pipes were typical for the vintage and grade, and there were no obvious unique metallurgical characteristics associated with the failures. Similarly, in laboratory studies, no correlation has been found between the concentration of impurities in the steel, such as phosphorus and sulfur, and high pH SCC susceptibility (Beavers and Parkins 1986). It has been shown that major alloy additions, such as chromium, nickel, molybdenum, and titanium, to steel in amounts of between 2 to 6 percent decrease SCC susceptibility (Parkins, et al. 1981) but such additions are impractical because of cost considerations. Resistance to high pH SCC increases with increasing carbon content (Parkins, et al. 1981), but high-carbon steels are difficult to weld.

Data from pipeline failures caused by near-neutral pH SCC showed that this form of SCC has developed on multiple types and grades of line pipe from a variety of pipe mills. Pipe failures have occurred on grades with SMYS from 35 to 65 ksi (NEB 1996). Both ERW and DSAW line pipe have been involved in SCC-related failures revealing that both strip and plate steels can be susceptible to SCC. Near-neutral pH SCC failures have initiated in the pipe body and in or near the welds but the welds typical are more susceptible to failure than the pipe body. In older, low-frequency ERW pipe, the welds typically have low fracture toughness, resulting in failure of relatively small SCC colonies at the weld. In DSAW pipe, the toe of the weld is a stress raiser, which is more prone to crack initiation. There also is evidence that crack growth rates are higher in the heat affected zone (HAZ) of the DSAW than in the base metal. (Beavers and Harle 2001). CEPA funded a research program to determine whether the initiation of near-neutral pH SCC could be correlated with line pipe metallurgical factors (Beavers et al. 2000).

Fourteen samples from susceptible pipe joints, ranging in size from nominal pipe size (NPS) 8 to 42 and API 5L X52 to X70, were examined. The results of this study indicate a strong correlation between residual stress and the presence of near-neutral pH SCC colonies. No statistically significant correlation was found between the occurrence of SCC on the pipes and the other factors evaluated in the study: chemical composition, cyclic stress-strain behavior, inclusion population (number, area, and composition), and local galvanic behavior. Surkov et al. (1994) observed a relationship between susceptibility to near-neutral pH SCC and the length of nonmetallic inclusions in the steel.

One gas transmission company developed an SCC prediction model via a statistical analysis of an extensive database containing information on the construction and operation of the pipeline system (Beavers and Harper 2004). Three parameters were found to be key predictive variables in the model; pipe manufacturer, coating type, and soil type. Fourteen pipe manufacturers were used in the construction of the pipeline system, and the relative probability of finding near-neutral pH SCC varied by more than a factor of 20 depending on the pipe manufacturer. While the cause of this large difference was not established, it is possible that residual stresses introduced by pipe manufacture played a role, given the other available field and laboratory data.

There is a growing body of evidence to suggest that tensile residual stresses in the line pipe play a significant role in SCC and that cracking can be minimized or prevented by reducing these stresses during manufacturing, as well as during installation and operation. The laboratory and field data do not provide any clear guidance with respect to chemistry or other aspects of the pipe manufacturing process and prevention of SCC. The trend in steel manufacturing is to improve the mechanical properties by micro alloying and controlled rolling, and by decreasing the carbon content. Limited research results suggest that these newer steels may not necessarily have greater susceptibility to high pH SCC even though they have higher yield strengths and lower carbon contents. These results indicate that a more important variable for assessing initiation of SCC is the ratio of the applied stress to the actual yield strength (Parkins et al. 1981).

Depending on the metallurgy, the susceptibility of higher strength steel to crack initiation or growth may be higher or lower than that for lower strength steel. For pipe of the same diameter and operating pressure, a higher strength pipe would require a thinner wall. Assuming the fracture toughness of the pipe is identical, the critical flaw size of the thinner wall pipe would be smaller. However, in both cases SCC can only develop if the pipeline coating disbonds in a way that renders CP ineffective.

5.4 *Operating Pressure*

The predominant longitudinal orientation of both forms of SCC on underground pipelines demonstrates the importance of the hoop stress produced by the internal pressurization on the cracking process. Laboratory studies of initiation of high pH SCC have shown that stress corrosion cracks initiate above an applied stress level referred to as the threshold stress (Barlo 1979), reported as a percent of the yield stress. This threshold stress is affected by the surface condition, the potency of the environment and cyclic stresses.

In the NEB inquiry (NEB 1996), significant SCC was not reported by Canadian pipeline operators in Class 2 and 3 pipeline locations. CEPA suggested that line pipe installed in Class 2 and 3 locations is less susceptible to SCC because it operates at lower stress levels than pipe in Class 1 locations. The majority of SCC failures on Canadian pipelines have been the near-neutral pH form of cracking. In Class 1 locations, the extent and severity of SCC was found to decrease with decreasing stress, due to the internal operating pressure. On TCPL Line 2, the number of SCC colonies decreased from 0.014 to 0.0005/m (3.56×10^{-4}/in. to 1.27×10^{-5}/in.) inspected as the stress dropped from 75 to 67 percent SMYS. A similar trend was found for crack depth.

Based on laboratory and field data, it is reasonable to conclude that reducing the operating stress as a percentage of the yield stress can reduce the likelihood of initiation of stress corrosion cracks. Reducing the operating stress has the added advantages of increasing the critical flaw size, as well as increasing the critical leak/rupture length. Research has not been able to establish a threshold stress level below which SCC will not initiate or grow. It is likely that such a value exists, however, it is likely to be so low as to not be of practical engineering value (NEB 1996).

5.5 *Operating Temperature*

Fessler evaluated the effect of temperature on high pH SCC (Fessler 1979). Field data available at the time along with laboratory research on the subject were summarized. Service failures were reported at temperatures as low as 13°C (55°F), but 90 percent of the service and hydrostatic test failures occurred within 16 km (10 miles) downstream from the compressor stations, where the highest temperatures were present. This behavior is associated with a decrease in the width of the potential range for cracking, coupled with a decrease in the maximum cracking velocity with decreasing temperature.

Laboratory data and field experience indicate that there is less temperature dependence for near-neutral pH SCC than for high pH SCC. Delanty and O'Beirne (1991) reported that 50 percent of near-neutral pH SCC failures on TCPL Line 2 occurred within 10 miles downstream of compressor stations versus 90 percent for high pH SCC. More recent data was presented in the NEB SCC inquiry (NEB 1996) showing that 65 percent of near-neutral pH SCC occurred between a compressor station and the first downstream block valve. This behavior suggests that temperature or some other factor affects the occurrence of near-neutral pH SCC, just not to the extent that it occurs with high pH SCC. The higher temperature promotes more extensive and rapid coating disbondment, for example. It is also possible that the higher stresses or larger stress fluctuations near a compressor station produce more frequent near-neutral pH SCC failures.

Based on laboratory and field data, it is reasonable to conclude that reducing the operating temperature of a pipeline can reduce the likelihood of stress corrosion crack initiation by several processes, including reduced crack velocities, reduced probability of crack initiation (high pH SCC) and improved coating performance. One method of temperature control that has been implemented by some operators is the installation of cooling towers.

5.6 Construction

Proper construction practices, such as minimizing fit-up stresses, and avoiding dents and mechanical damage to the pipe, can reduce the likelihood of SCC initiation. The surface preparation and field-applied coatings for girth welds should be selected and applied with the same care as used in the shop-applied coating. Damage to the coating should be avoided and repaired when it does occur, to avoid holidays, which can act as initiation sites for disbondment.

5.7 Operations and Maintenance

5.7.1 Cathodic Protection

CP is closely related to the high pH cracking process. It has been suggested that the CP current collecting on the pipeline surface at disbondments, in conjunction with dissolved carbon dioxide in the groundwater, generates the high pH SCC environment. CP can also place the pipe-to-soil potential in the potential range for cracking. The potential range for cracking generally lies between the native potential of underground pipelines and the potential associated with adequate protection (–850 mV CSE) (Parkins 1974; Fessler 1979). Based on field pH measurements of electrolytes associated with near-neutral pH SCC colonies, it has been concluded that this form of SCC occurs in the absence of significant CP either because of the presence of a shielding coating or high-resistivity soils that limit CP current to the pipeline surface (Delanty and O'Beirne 1991).

Potentially susceptible segments can be assessed using ASME B31.8S Appendix A3 for gas pipelines, which considers historical information, coating type, operating temperature, age, operating stress, and distance downstream from the compressor station. For liquid pipelines, the distance downstream of the pump station can be used in the ASME assessment (NACE 2004). The other CP criteria (100mV polarization or –850 mV with CP applied) should be used with caution on potentially susceptible segments. Consideration should be given to seasonal fluctuations in the potential to minimize the likelihood that the pipeline falls into the cracking range on a seasonal basis.

Near-neutral pH SCC is most prevalent on pipelines with shielding coatings (e.g. tape) and has occurred where the pipeline is apparently protected based on CP information. Nevertheless, it is worthwhile to maintain adequate protection to avoid SCC and corrosion at or near holidays. Effective CP also will minimize the occurrence of near-neutral pH SCC with non-shielding coatings.

5.7.2 Recoating Existing Pipelines

The factors that affect SCC performance of a coating system, described above, are applicable to recoating of existing pipelines as well as new construction. These are:

1. the resistance of a coating to adhesion/disbondment,
2. the ability to pass CP current should the coating fail, and
3. the type of surface preparation used with the coating.

As described above, it is imperative that the surface is prepared to a white or near white finish prior to coating application and that the coating applied have desirable performance characteristics, such as good adhesion, resistance to disbondment and the ability to conduct CP current should the coating fail. Care should be taken to insure residual oils, greases, and salts are removed from the cleaned pipe surface prior to coating application.

There are several other factors that must be considered in the selection of field coatings. These include the ambient weather and environmental conditions required for application, compatibility with existing coatings, equipment requirements, and access to the field site and pipeline. Further discussion of these issues is provided in the CEPA SCC Recommended Practice (CEPA 1997). CSA Z662-03 provides requirements for coating selection (Clause 4.1.7), coating properties, application, and inspection (Clause 9.2.7), and a guide for test methods for the evaluation of coating properties (Annex L).

5.7.3 Other Operational Considerations

Reducing cyclic pressure fluctuations may minimize the growth rate of both forms of SCC. These fluctuations reduce the threshold stress for the initiation of cracks and increase the propagation rate of SCC (Parkins and Greenwell 1977; Beavers and Jaske 1998). Furthermore, final failure of SCC colonies can occur by pressure cycle fatigue for large deep flaws or large pressure cycles.

5.8 References

Barlo, T. J. 1979. Stress Corrosion Cracking Steel Susceptibility. In *Proceedings from the 6th Symposium on Line Pipe Research.* PRCI. L30175.

Barlo, T. J., and R. R. Fessler. 1981. *Shot Peening,* Grit Blasting Make Pipe Steels More Resistant to Stress-Corrosion Cracking. *The Oil and Gas Journal* 79, 46: p. 68.

Beavers, J. A. and R. N. Parkins. 1986. Recent Advances in Understanding Factors Affecting Stress-Corrosion Cracking of Line-Pipe Steels. In *Proceedings from the 7th Symposium on Line Pipe Research.* PRCI. L51495.

Beavers, J. A. 1992. *Assessment of the Effects of Surface Preparation and Coating on the Susceptibility of Line Pipe to Stress Corrosion Cracking*. PRCI. L51666.

Beavers, J. A., N. G. Thompson, and K. E. W. Coulson. 1993a. *Effects of Surface Preparation and Coatings on SCC Susceptibility of Line Pipe: Phase 1—Laboratory Studies*. CORROSION/1993, Paper No. 93597.

Beavers, J. A., N. G. Thompson, and K. E. W. Coulson. 1993b. *Effects of Surface Preparation and Coatings on SCC Susceptibility of Line Pipe: Phase 2—Field Studies*. Proceedings of the 12th International Conference on Offshore Mechanics and Arctic Engineering, June.

Beavers, J. A., and C.E. Jaske. 1998. *Near-Neutral-pH SCC In Pipelines: Effects of Pressure Fluctuations on Crack Propagation.* CORROSION/1998, Paper No. 98257.

Beavers, J. A., J. T. Johnson, R. L. Sutherby. 2000. *Materials Factors Influencing the Initiation of Near-Neutral-pH SCC on Underground Pipelines*.

Beavers, J. A., and B.A. Harle. 2001. *Mechanisms of High pH and Near Neutral pH SCC of Underground Pipelines*. Journal of Offshore Mechanics and Arctic Engineering. August.

Beavers, J.A. and W.V. Harper. 2004. *Stress Corrosion Cracking Prediction Model*. NACE International CORROSION/2004. Paper 04189.

Berry, W. E. 1974. Stress Corrosion Cracking Laboratory Experiments. In *Proceedings from the Fifth Symposium on Line Pipe Research*. PRCI. L30174.

CEPA. 1997. *Stress Corrosion Cracking – Recommended Practices*. Canadian Energy Pipeline Association.

Delanty, B. S. and J. O'Beirne. 1991. Low-pH Stress Corrosion Cracking. In *Proceedings from the 18th World Gas Conference*.

Fessler, R. R. 1979. Stress Corrosion Cracking Temperature Effects. In *Proceedings from the 6th Symposium on Line Pipe Research*. PRCI. L30175.

NACE No. 1/SSPC-SP 5 (Reaffirmed 1999). *White Metal Blast Cleaning*. NACE International.

NACE No. 2/SSPC-SP 10 (Reaffirmed 1999). *Near-White Metal Blast Cleaning*. NACE International.

NACE Standard RP 0204. 2004. *Stress Corrosion Cracking (SCC) Direct Assessment Methodology*. NACE International.

NEB. 1996. *Stress Corrosion Cracking on Canadian Oil and Gas Pipelines. Report of the Inquiry*. National Energy Board. MH-2-95. December.

Parkins, R. N. 1974. The Controlling Parameters in Stress Corrosion Cracking. In *Proceedings of the Fifth Symposium on Line Pipe Research.* PRCI. L30174.

Parkins, R. N., and B. S. Greenwell. 1977. *The Interface Between Corrosion Fatigue and Stress Corrosion Cracking.* Metal Science Volume 11: p. 405.

Parkins, R. N., P. W. Slattery, B. S. Poulson. 1981. *The Effects of Alloying Additions to Ferritic Steels upon Stress-Corrosion Cracking Resistance.* Corrosion 37, 11: p.650.

Surkov, J. P. et al. 1994. *Corrosion Crack Initiation in Gas Pipelines.* The Physics of Metals and Metallography 78, 1: p. 102.

Wenk, R. L. 1974. Field Investigation of Stress Corrosion Cracking. In *Proceedings of the Fifth Symposium on Line Pipe Research*. PRCI. L30174.

This page intentionally left blank.

6 Detection and Assessment of SCC

6.1 Scope Statement

"Compile a report summarizing the history of SCC on pipelines, explaining the causes and factors contributing to SCC initiation and growth, and discussing methods for prevention, detection and mitigation of SCC on pipelines, including effectiveness of ILI tools and other in-the-bell hole examination methods to detect SCC."

The scope statement was broken down into components of Understanding Stress Corrosion Cracking (SCC) in Pipelines (Chapter 4); Prevention of an SCC Problem (Chapter 5); Detection and Assessment of SCC (Chapter 6); and Mitigation of SCC (Chapter 7).

This chapter summarizes the current state of knowledge of understanding how to detect SCC, or perhaps more directly, how to detect a SCC problem in pipelines.

6.2 Detection Methods

6.2.1 Hydrostatic Testing

Hydrostatic testing has been used to locate stress corrosion cracks of critical size at the test pressure and, when properly implemented, assures that such critical defects are removed at the time of the test. Because of its straightforward approach and interpretation, it is the mainstay of all regulatory codes, and is the most commonly utilized technique to ensure the integrity of the pipeline at the time of testing. However, pressure testing does not provide information about either the presence or severity of cracks that survive a test. Stress corrosion cracks can result in overload failures during a hydrostatic test. Hydrostatic testing failures occur when stress corrosion cracks reduce the load carrying capability of a pipeline sufficiently to allow either fracture toughness dependent or plastic collapse rupture, depending upon the toughness of the material. Near-critical imperfections in relatively high toughness material are slower to respond to test pressures than near-critical imperfections in low toughness material. Consequently, a strategy for hydrostatic testing should consider the toughness of the material, both in the pipe body and seam weld, if present. Hydrostatic testing ruptures do not propagate a significant distance because water is essentially non-compressible and, therefore, the stress level drops rapidly after a rupture occurs.

The U.S. federal safety regulations (49 CFR 192 Subpart J and 49 CFR 195 Subpart E) require that pipelines that operate at pressures at or above 30percent of SMYS and are used to transport natural gas or hazardous liquids be pressure tested at a pressure 110 to 150 percent of the MAOP in the case of gas pipelines and 125 percent of the MOP in the case of hazardous liquid pipelines, following construction or replacement. Water as a test medium is required for the pressure test except in cases where the pipeline is remote to buildings intended for human occupancy. In the latter case, air or inert gas can be used for testing. For pipelines operating at an MAOP/MOP of 72 percent of SMYS, a minimum test pressure of 90 percent of the SMYS will achieve the minimum requirements. The federal regulations require that this test pressure be maintained for 8 hours.

Periodic hydrostatic testing also is a common method used to ensure the integrity of operating pipelines that contain growing defects, such as general or pitting corrosion, fatigue, corrosion fatigue, or stress corrosion cracking. The testing protocol varies for different pipeline operators, depending on details of the system, but most meet the minimum federal requirements for new construction. Typically, a desired pressure range is established, with the minimum pressure selected to ensure integrity and the maximum test pressure designed to minimize failure of non-injurious features, such as stable weld flaws, in the pipeline. Factors considered in the selection of a pressure range include the estimated population of defects in the pipeline, the estimated growth rate of these defects, and the MAOP/MOP of the pipeline. If there are a large number of slow-growing defects[2] and the MAOP/MOP of the pipeline is relatively low compared to the SMYS, it may be desirable to establish a relatively low maximum test pressure to avoid a large number of hydrostatic test failures. On the other hand, a relatively high minimum test pressure is needed to avoid frequent retesting for fast-growing defects and high operating pressures.

Some pipeline companies use a short duration high-pressure spike (e.g., 100 to 110 percent of SMYS for 1 hour) to remove long flaws capable of producing a rupture, followed by a long duration low-pressure test (e.g., 90 percent of SMYS for 24 hours) to locate leaks in the pipeline (Brongers, et al. 2000). The purpose of pressurizing to a high level for one hour is to remove potentially deleterious defects, while the purpose of holding at a reduced pressure for a long period is to avoid pressure reversals. A pressure reversal is where a defect survives hydrostatic testing at a high pressure only to subsequently fail at a lower pressure upon repressurization. PRCI studies (Kiefner 1986) have shown that a rupture at MAOP/MOP, as a result of a pressure reversal, is highly unlikely (<1/10,000) when the test pressure is at least 1.25 times the MAOP/MOP. If MAOP/MOP equals 72 percent of SMYS, this implies a minimum test pressure of 90 percent of SMYS. Furthermore, experimental fracture mechanics studies of specimens from ERW API 5L X52 and X65 steel line pipe showed that the amount of ductile crack tearing (crack advance) at loads up to 110 percent of SMYS is less than 25 percent of the typical amount of SCC growth expected in one year. Thus, this typical test procedure is not likely to cause significant ductile crack tearing or pressure reversals (Brongers, et al. 2000).

6.2.1.1 Benefits

Because of its straightforward approach and interpretation, hydrostatic testing is the mainstay of all regulatory codes, and is the most commonly utilized technique to ensure the integrity of the pipeline at the time of testing. It will remove axial defects, regardless of geometry, that have critical dimensions at the test pressure. Hydrostatic testing also might open up incipient leaks so that they can be detected. In the case of in-line inspection and other integrity programs, such as SCC direct assessment (SCCDA), there is a finite probability that a near-critical defect will be missed by the

[2] The definition of a slow growing defect or a fast growing defect is pipeline specific and depends on the dimensions, mechanical properties and operating pressure. These parameters, along with the planned hydrostatic test pressure, are used to define the acceptable remaining growth of the defect. The acceptable remaining growth is divided by the hydrostatic retest interval to obtain a crack velocity. Flaw growth rates that are significantly lower than this value would be considered slow growing defects because surviving flaws with this growth rate would be unlikely to fail in service between the hydrostatic tests. Surviving flaws with growth rates higher than this value would be likely to fail, requiring a change to the hydrostatic test plan, which could include an increase in the test pressure or a decreasing the retest interval.

assessment method. In the case of crack-like defects, such as fatigue cracks and stress corrosion cracks, hydrostatic testing also will blunt and impart a compressive residual stress at the crack tip of sub-critical defects that remain in the pipeline following testing. The blunting and compressive residual stresses will inhibit subsequent fatigue or SCC crack growth (Hohl and Knauf 1999, Beavers and Hagedorn 1996). However, some of the blunted stress corrosion cracks may eventually re-initiate and therefore periodic retesting is required to ensure integrity of pipelines containing SCC.

6.2.1.2 Limitations

Following a hydrostatic test, sub-critical cracks will still remain in the pipeline and, potentially, may be just smaller than the size that would have failed in the hydrostatic test. As described above, hydrostatic testing can cause tearing of these sub-critical flaws leading to a pressure reversal, where the pipeline fails in service or at a lower pressure in a subsequent hydrostatic test. Typically, the amount of tearing and the magnitude of these pressure reversals are small but, in rare circumstances, large pressure reversals exceeding 100 psig can occur. At operating pressure, these remaining sub-critical cracks also may continue to grow by SCC, fatigue or corrosion fatigue. Therefore, hydrostatic retesting, or other detection methods, must be periodically performed on a pipeline containing growing defects to ensure pipeline integrity.

For older pipelines and those containing low-frequency ERW seams, high-pressure tests (e.g., above 100 percent of SMYS) may not be practicable because the testing could potentially fail large numbers of non-injurious weld flaws. With lower pressure tests, the hydrostatic retest period may be short enough to make hydrostatic retesting impracticable. An example of remaining life as a function of test pressure for a 3-inch long flaw in a 12.75-inch diameter, 0.213-inch wall thickness, API 5L X60 pipeline operating at 72 percent of SMYS (1440 psig), and an assumed flaw growth rate of 0.012 inches per year (0.3 mm/y), a typical growth rate for a growing SCC defect, is presented in Figure 6-1. In this example, the retest frequency would have to be approximately 3 years for a hydrostatic test at 90 percent of SMYS (1800 psig) to avoid further failures of the pipeline.

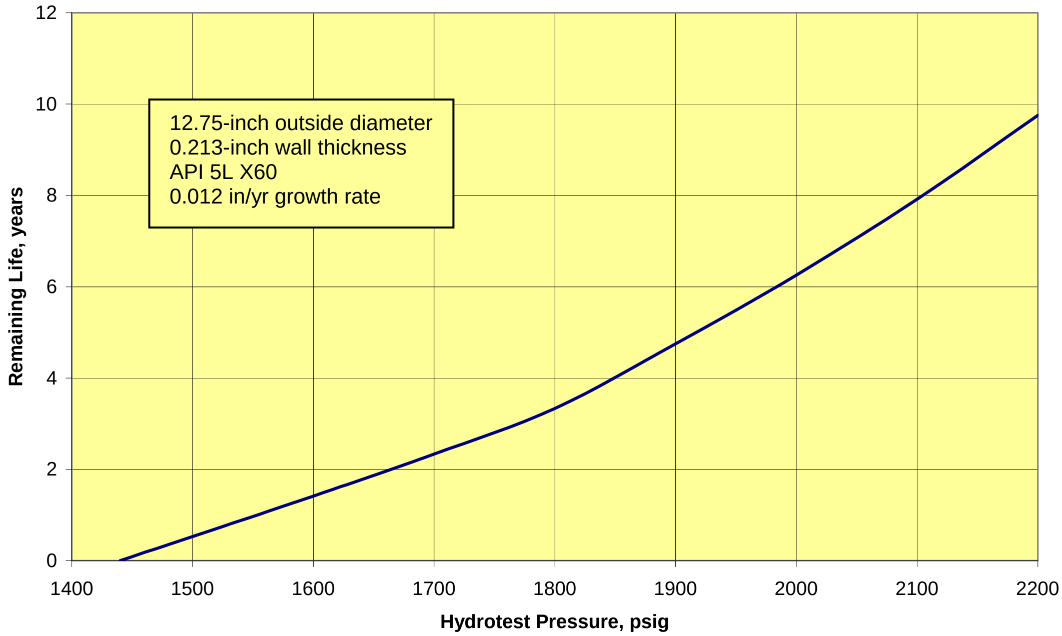


Figure 6-1 Example of Remaining Life versus Hydrostatic Test Pressure (Using CorLAS™)

Hydrostatic testing is not effective against circumferential flaws because the maximum axial stress produced by internal pressurization is less than one-half the circumferential stress. While hydrostatic testing is capable of locating leaks, it is not effective in removing short flaws that ultimately will produce leaks. Leaks can occur shortly after a hydrostatically tested line has been returned to service.

Additional factors are worthy of consideration. Hydrostatic testing may be relatively expensive compared to the number of flaws that are removed, since the pipeline must be taken out of service. ILI may be more cost-effective from the standpoint that a larger number of sub-critical flaws may be identified and potentially removed. There are issues with water disposal, especially for liquid lines where the test water may contain some contamination from the product, and a good source of water is sometimes hard to find.

6.2.2 In-Line Inspection (ILI)

ILI tools can be employed to detect SCC, but application of technology and analysis that is different from the ILI technology applied for detection and classification of wall loss is required. Furthermore, the need to detect cracks oriented both longitudinally and circumferentially requires consideration in the design of ILI tools for detection of SCC.

Both magnetic flux leakage (MFL) and ultrasonic testing (UT) methods have been attempted for detection of cracks, but the design of ILI tools must be significantly different from those for detection of wall loss.

6.2.2.1 ILI Technologies

ILI using piezoelectric UT methods has been applied for detection of SCC in hazardous liquids pipelines, but the use of these methods are more challenging when applied to gas pipelines, due to the need for a liquid couplant to provide a pathway for transmission of the ultrasonic wave to the pipe wall. In the opinion of the Gas Liquid Pipeline Industry SCC Working Group (SCC Working Group): "[Piezoelectric] UT technology is [the] only reliable in-line inspection tool technology (i.e. TFI and EMAT not proven)." MFL Transverse Field Inspection (TFI) has been used in gas pipelines to attempt detection of SCC and, in the opinion the SCC Working Group: "...has not had a high success rate." Electro Magnetic Acoustic Transducer (EMAT), another form of UT, is a newer non-destructive examination (NDE) technology used for ILI tools to detect SCC.

Detection of anomalies oriented in the longitudinal direction is best accomplished with the shear wave UT tool, which introduces shear waves in the circumferential direction. Liquid coupled tools are the most accurate and common tools used for crack detection. The quality of the inspection is a function of both the ability to detect small cracks and also the ability to assess the range of flaw sizes. UT ILI is most commonly used in liquid pipelines where the transported fluid acts as the couplant between the ultrasonic transducers and the pipe wall.

There are two types of ILI piezoelectric shear wave UT tools available to the pipeline industry today. The first of these two, the wheel-coupled tool was originally developed by British Gas, can be run in a gas pipeline since it does not require a liquid couplant as do other piezoelectric UT tools. The basic technology employed by a wheel-coupled tool is conventional shear wave transducers in liquid-filled polyurethane wheels which come in contact with the pipe surface to establish the coupling required to transmit and receive the UT signals (see Figure 6-2). These wheels are arranged in an array of pairs and the sound path through the pipe wall between the two transducers in a pair is approximately 230 mm. The shear wave signals are induced into the pipe at a 65-degree angle to the pipe surface.

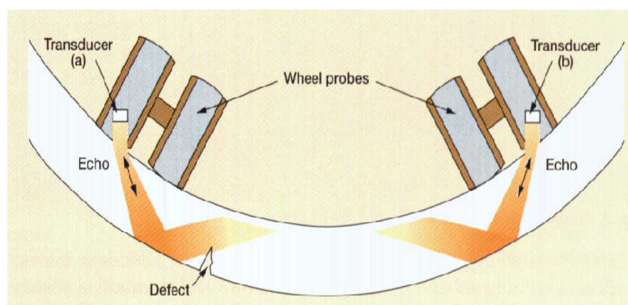


Figure 6-2 Wheel-Coupled UT Concept

According to the SCC Working Group the wheel-coupled UT tool "…provides poor discrimination between SCC and other reflectors, thus giving a very high positive rate [i.e., rate of false positives]. Such performance is unacceptable, as the cost of an examination dig can range from $5-10,000 to well over $100,000 in congested or difficult areas. With an approximate ratio of false positives to true positives of 10:1 [5:1 stated in CEPA/GRI reports], this becomes an unacceptable drain on an operator's staff, equipment and financial resources." However, other operators have indicated that, based on their experience, the wheel-coupled UT tool can be cost-effective depending on factors such as the cleanliness of the pipe steel and the relative cost of alternative options.

A second type of piezoelectric shear wave UT tool, liquid-coupled UT, uses the transported fluid as the couplant but employs a different approach than the wheel-coupled UT tool in applying basically the same technology (see Figure 6-3). The liquid-coupled UT tool induces a pulse at a 45-degree angle and the sound path is approximately 25 mm long, yielding a much more reliably received signal. The liquid-coupled UT tool has significantly more transducers than the wheel-coupled UT tool—a critical component for interpretation credibility. The liquid-coupled UT tool has a minimum crack length detection capability of 30 mm, while the wheel-coupled tool can only detect a 50 mm long crack.

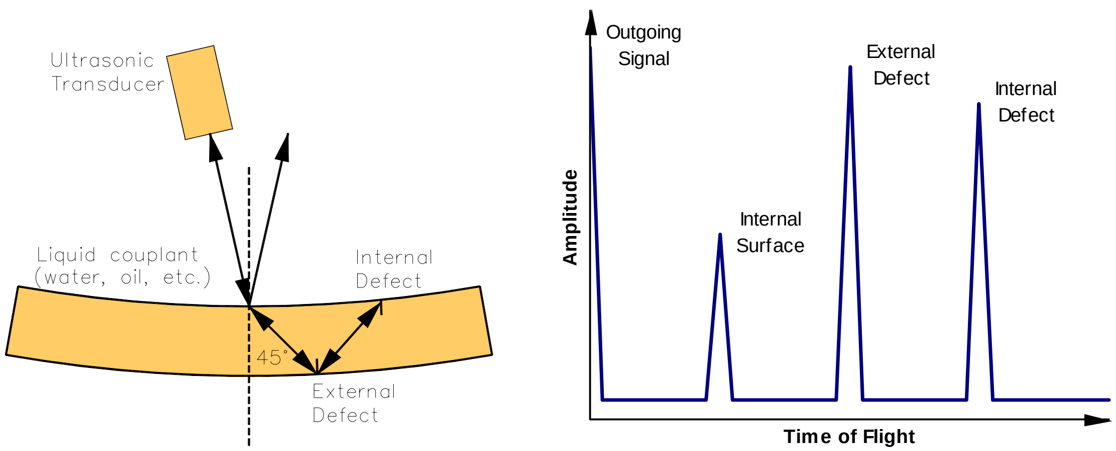


Figure 6-3 Liquid Coupled UT Concept and Resulting A-Scan

The detection capability of both types of piezoelectric UT tools depends upon multiple characteristics of both the pipe and the tool. Two significant tool-related characteristics are the pulsing rate and the travel speed. Reliable detection of a crack typically requires that the combination of pulsing rate, travel speed and crack length permit capture of three or four reflections from the crack. Although it may be shown that indications correlate with subsequent direct examinations, there is insufficient information to determine if cracks may have been missed. It was reported that one operator has conducted several hundred field validation excavations and has confirmed that no detection threshold defects missed by the liquid-coupled UT tool have been observed. In the opinion of the SCC Working Group: "Although this [liquid-coupled UT] tool has a demonstrated capability to detect sub-critical cracks, further studies and dissemination and review of results are needed to determine the actual reliability ranges." Thus, while the technology is promising, the reliability of detection needs further verification for general acceptance within the operator community.

Even though MFL tools have been used for many years in the detection of three dimensional defects in pipelines such as corrosion, mill origin defects, and mechanical damage, it has only been in the last few years that the concept has been used for longitudinally oriented defects such as cracks, longitudinal weld defects, and narrow axial corrosion. With the advent of improved higher resolution capabilities, orienting the magnetic flux circumferentially allowed detection of flux leakage when passing over longitudinally oriented defects (see Figure 6-4). TFI tools can be used to detect cracks, lack of fusion in the longitudinal weld seam, and significant SCC clusters, though some operators do not consider TFI a proven technology.

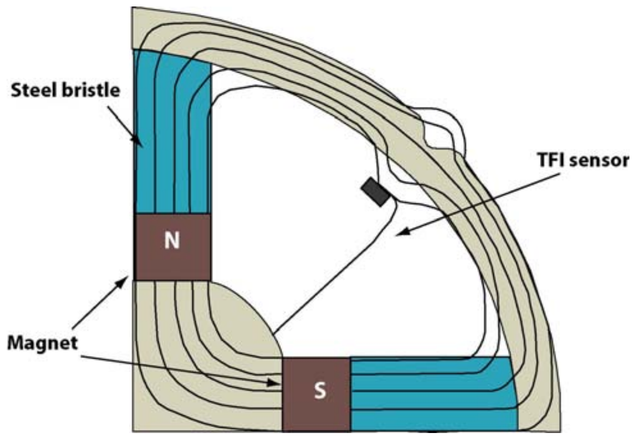


Figure 6-4 TFI Principle

There are multiple variables relating to a TFI tool, a defect and a pipeline that influence the results obtained using TFI technology. As with piezoelectric UT tools, tool velocity and sample rate are also significant variable for a TFI tool. Variables relating to a defect include the profile, length, depth and width, while those relating to the pipeline include material properties, wall thickness, stress levels, location (base metal versus HAZ), etc.

One of the most significant variables affecting a TFI tool's sensitivity to SCC is the size of the crack opening. Typically, longer and deeper cracks have a greater crack opening, which normally increases with increasing hoop stress level. Therefore, one can conclude that maintaining the hoop stress at the highest practical level during TFI runs should improve the sensitivity of the TFI tool.

The newest technology being applied in ILI equipment is EMAT. The basic principle of EMAT is the generation of an ultrasound pulse using a magnetic field at the internal surface of the pipe wall (see Figure 6-5). Alternating current passed through the coil induces a current in the pipe wall, causing Lorentz forces, which in turn generate ultrasound (NACE 2000). Anomalies are identified by either "pulse echo" transmission or "through" transmission. Pulse echo transmission detects anomalies by a receiver on the same side of the defect as the transmitter picking up an echo of the transmitted pulse after it has reflected from a defect. Through transmission identifies anomalies by a receiver on the opposite side of the defect from the transmitter detecting attenuation in the signal caused by scattering of the ultrasonic energy as it passes through the defect.

While EMAT technology is not new, its use in self-contained ILI tools is relatively new and is being pursued by three major ILI vendors at this time. Two of these vendors have performed initial surveys in operating pipelines and both have found initial design considerations that must be improved before the EMAT technology can be offered on a commercial basis.

The issues identified relate to mechanical considerations unique to these specific primary devices (flat coils) that are quite fragile in harsh operating pipeline environments. As with all new ILI technology, the on-board data storage and decision-making algorithms will require development. Furthermore, the EMAT concept does not require a liquid couplant and therefore should perform equally well in gas and hazardous liquid pipelines.

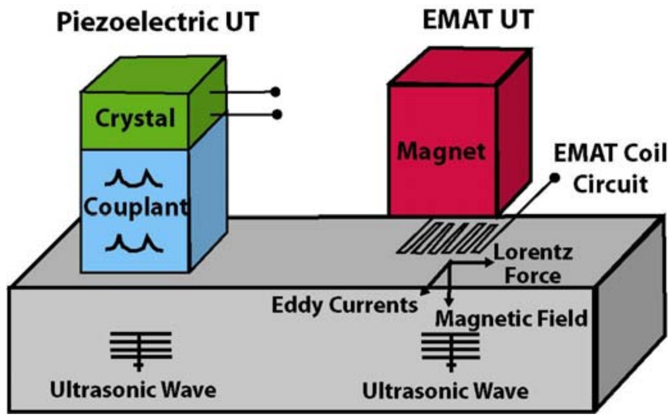


Figure 6-5 Piezoelectric UT versus EMAT UT Principle

In the opinion of the SCC Working Group: "…the vendors of these technologies, TFI and EMAT, note that they are not to the point of considering them commercially available or adequate for detecting and managing SCC. Operators meet with them regularly…[Piezoelectric] UT technology is [the] only reliable in-line inspection tool technology (i.e. TFI and EMAT not proven)." Others operators have indicated that, while piezoelectric UT is reliable for liquid lines, there is no equally reliable ILI technology of detecting SCC in gas pipelines.

A general comparison of typical crack detection ILI tools is presented in Table 6-1 (NACE 2000, www.gepower.com). Performance characteristics of ILI tools may be revised as the result of tool modifications or collection of additional field verification data, thus performance characteristics should be verified with the vendor for each potential application.

Table 6-1 Comparison of Crack Detection ILI Tools

Tool	Liquid-coupled UT	Wheel-coupled UT	TFI	EMAT
Media	Liquid[1]	Gas or liquid	Gas or liquid	Gas
Detection Limits				
Detectable defects				
Minimum length	30 mm (1.2 in)	50 mm (2 in)	25 mm (1 in)	30 mm (1.2 in)
Minimum width	—	—	0.1 mm (0.004 in)	—
Minimum depth	1 mm (0.04 in)	25% WT	25% WT	1 mm (0.04 in)
Defect alignment	±15° of the pipe axis	±10° of the pipe axis	±15° of the pipe axis	
Inspection speed	Up to 1.0 m/s (2.3 mph)	0.5 to 3 m/s (1.1 to 6.7 mph) in liquid 1 to 3 m/s (2.2 to 6.7 mph) in gas	0.2 to 4 m/s (0.45 to 9 mph)	Up to 2.0 m/s (4.5 mph)
Available sizes (NPS)	10 to 40	24 to 36	6 to 56	24 to 36
Sizing accuracy				
Length	±10% WT (for features >100 mm [4 in]) ±10 mm (for features <100 mm [4 in])	—	±25 mm (1 in)	—
Width (for crack fields)	±50 mm (2 in)			
Depth	classification by categories <12.5% WT 12.5 to 25% WT 25 to 40% WT >40% WT		±20% WT	
Location accuracy				
Axial	100 mm (4 in)	100 mm (4 in)	200 mm (8 in)	—
Circumferential	±5°	±5°	±7.5°	—
Confidence level	80%	80%	80%	—

[1] Gas pipelines can be inspected running the tool in a liquid slug.

6.2.2.2 Tool Availability

Equipment availability is a current issue with all four ILI tools discussed above. Based on publicly available information, the wheel-coupled tool is available in most common NPS from 24 to 36, while the liquid-coupled tool is available in NPS 10 to 40, with an NPS 8 tool reportedly available in 2005. The TFI tool is available in most common NPS from 6 to 56. The EMAT tools are not currently commercially available, but the prototypes are reported to be NPS 24 to 36. ILI vendors are expected to continue to expand the available diameters and number of tools as market demand justifies.

6.2.2.3 ILI Crack Characterization

Once detected, crack-like indications that may be SCC must be systematically separated from indications that are more likely to be surface imperfections originating during manufacturing. The screening process for the separation of likely SCC from surface imperfections is typically by a stepwise evaluation of the dimensions of the indication. For example, algorithms can scan indications to identify those indications with a width greater than a selected threshold value. The threshold width for an indication can be selected to assure identification of indications that may be a cluster of multiple cracks rather than a single manufacturing imperfection. Indications with a width that may be characteristic of a cluster of cracks can then be scanned to identify those with a length greater than a threshold length. The threshold length can be based upon multiple characteristics, such as the typical aspect ratio of cracks, but is intended to identity indications that appear to contain multiple cracks of sufficient length to present a potential threat to the integrity of the pipeline segment. Finally, the maximum depth is determined for indications that were identified as more likely to be SCC than a surface imperfection on the basis of indication width and length.

6.2.2.4 ILI Deployment

Control of tool velocity can be a significant consideration for UT ILI tools. For example, the combination of pulse rate and tool velocity determines the minimum length of an indication that will generate sufficient reflecting pulses to be identified as a crack-like indication. Planning for UT ILI runs should include comparing the maximum tool speeds with the normal operating velocity of the pipeline segments to be examined, since the specified maximum speed for crack detect tools (typically 1 to 4 m/s, though higher velocities may be accommodated by some tools containing a means to allow gas bypass) may be significantly lower than the normal operating velocity of a pipeline.

UT tools that rely on a liquid couplant to provide a sound path between the transducer and the pipeline are not applicable for ILI of natural gas pipeline unless the tool can be surrounded by an appropriate liquid slug for the duration of the survey as illustrated in Figure 6-6.. The length of the slug required must be designed with consideration for the length of pipeline to be inspected, the number and severity of bends, the roughness of the inside surface, the sealing capabilities of the leading and trailing pigs employed, and the differential pressure required across the slug system. Due to the compressibility of the gas upstream and downstream of the liquid slug, changes in elevation can result in significant variations in the velocity of the slug. A less attractive alternative is to deinventory a gas pipeline and run the tool totally in liquid service using external pumps. Preventing liquid intrusion into compression facilities can present a significant challenge.

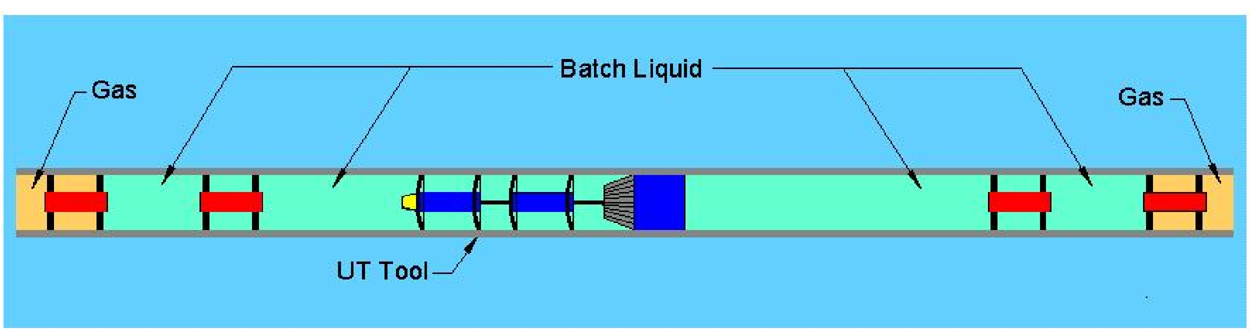


Figure 6-6 Ultrasonic Tool in Liquid Slug

Norris, Ashworth, Yeomans and Uzelac (2001) discuss the use of a liquid-coupled UT tool by TCPL for SCC detection on the Western Alberta System Extension since hydrotesting was considered to be impractical due to terrain issues. A special 33-meter long launch barrel with multiple ports for filling and purging air from the system was designed and fabricated specifically for this investiagtion. The overall length of the liquid slug was in excess of 1 mile.

In order to ensure the best axial resolution a maximum inspection speed of less than 1 m/s was targeted. An actual average speed of 0.5 m/s was attained, however, due to factors such as the elevation profile of the pipeline and valve spacing, speeds in excess of the target velocity were experienced at various times during the run.

Based on the results of the inspection 14 crack-like features were investigated resulting "…in 9 SCC features, 4 narrow axial corrosion features, and one manufacture defect with pitted corrosion. Recognizing that narrow corrosion can create a signal similar to SCC, the results were discriminated correctly in all but one feature (the manufacturing defect)." It is also noted that even in areas where the tool speed exceeded the targeted maximum, correlation between the actual measurements and the analytical predictions was good.

6.2.3 Direct Examination

Once SCC has been identified by ILI or by hydrostatic test failures in the pipeline, direct examination is the best way to evaluate the extent and severity of the SCC. If SCC is suspected, the pH of the water under the external coating near the suspected SCC colonies should be measured if practical (i.e., it is not practical to measure the pH of electrolytes where a hydrostatic test failure has occurred). In addition, the level of cathodic protection on the pipeline should be measured at the burial depth.

Whenever possible, representative samples of a failed pipeline should be considered for metallurgical evaluation. Metallurgical evaluation should include:

- Photo-macrographs of the orientation and distribution of the cracks on the pipe surface;
- Tension testing to determine ultimate tensile strength, yield strength, and elongation;
- Toughness testing to determine Charpy V-notch (CVN) impact energy transition curve, which identifies the fracture-appearance transition temperature (FATT) lower-shelf impact energy, upper-shelf impact energy and CVN at operating temperature;
- Chemical analysis; and
- Metallurgical microstructure and mode of cracking (intergranular or transgranular) analysis.

The metallurgical data along with the site data should be used to estimate the remaining life of similar defects left in the pipeline.

The following sections discuss the most widely used direct examination techniques. Visual examination is essential for documenting the presence and characteristics of mechanical damage, corrosion, regions of disbonded coating, and the presence of deposits and water. This information is needed to establish if any of these features interact with any SCC that may be found. Visual acuity is also a critical aspect of the magnetic particle inspection (MPI) process, and it should noted that visual examination alone is not adequate for making a determination whether or not SCC is present. MPI is typically employed rather than liquid penetrant inspection (LPI) to delineate the surface extent of SCC, while other techniques are used to estimate crack depth. Unfortunately, the presence of multiple cracks makes these techniques uncertain. To date, grinding has been the only reliable technique to measure crack depths in the field.

6.2.3.1 Visual Examination

Visual inspection is the oldest and most common form of NDE used to inspect for corrosion. Visual inspection is a quick and economical method of detecting various types of defects before they cause failure. Its reliability depends upon the ability and experience of the inspector. The inspector must know how to search for significant flaws and how to recognize areas where failure could occur.

The main disadvantage of visual inspection is that the surface to be inspected must be relatively clean and accessible to the unaided eye. Surface preparation can range from wiping with a cloth to blast cleaning and treating with chemicals to show the surface details. Surface preparation for visual examination, especially wire brushing or blasting, should be performed with caution to prevent interference with other NDE methods. Typically, visual inspection is less sensitive than other surface NDE methods. In fact, in most cases, SCC colonies are not visible to the unaided eye.

6.2.3.2 Magnetic Particle Inspection

MPI is an NDE method primarily used to detect surface-breaking flaws in ferromagnetic materials such as steel and iron. MPI can also be used to locate sub-surface flaws; however, its effectiveness quickly diminishes depending on the flaw depth and type.

The MPI method, along with LPI, is one of the oldest and most widely utilized forms of NDE. Magnetic particle testing uses magnetic fields and small magnetic particles, such as iron filings, to detect flaws in components. The technique uses the principle that magnetic lines of force (flux) will be distorted by the presence of a flaw in a manner that will reveal the flaw's presence. The flaw (for example, a crack) is then located from the "flux leakage," following the application of fine iron particles, to the area under examination. There are variations in the way the magnetic field is applied, but they are all dependant on the above principle. The magnetic particles can be applied dry, or wet by suspending them in a colored or fluorescent liquid. A comparison of the sensitivity, advantages, and disadvantages of three types of MPI employed for direct examination of pipe for SCC in presented in Table 6-2.

Table 6-2 Magnetic Particle Inspection Technique Comparison (Hall and McMahon 1999)

Type of MPI	Sensitivity	Advantages	Disadvantages
Dry Powder	2-5 mm long cracks	Easiest	Lowest sensitivity
Wet Fluorescent	1 mm long cracks	Highest sensitivity	Requires UV lamp Can only be used in low light
Black on White Contrast	1-2 mm long cracks	Easily photographed	Requires application of white contrast paint

Surface irregularities and scratches can give misleading indications. Therefore, it is necessary to ensure careful preparation of the surface before MPI is undertaken. Note that some preparation techniques applicable in other circumstances (e.g., wire brushing or abrasive blasting with common commercial grits) can mask defects by peening over the SCC cracks and should be applied with caution.

MPI indications allow for the location, length and spacing of SCC to be documented, but cannot reveal the depth. Qualified personnel should perform MPI in accordance with documented inspection procedures. Each operator should establish guidance documentation for the selection and application of the MPI method(s) that are to be used.

6.2.3.3 Liquid Penetrant

LPI is one of the most widely used NDE methods and is used to reveal surface breaking flaws by bleedout of a colored or fluorescent dye from the flaw. Its popularity can be attributed to its relative ease of use and its flexibility.

The technique is based on the ability of a liquid to be drawn into a "clean" surface-breaking flaw by capillary action. After a period of time called the "dwell," excess surface penetrant is removed and a developer applied, which acts as a “blotter.” The developer draws the penetrant from the flaw to reveal its presence. Colored (contrast) penetrants require good white light while fluorescent penetrants need to be used in darkened conditions with an ultraviolet ("black") light.

Penetrant inspection can be used on nonporous metallic materials, such as line pipe. It is essential that the surface be carefully cleaned, but without wire brushing or blasting that could prevent the penetrant from getting into the defect. If excessive surface penetrant is not fully removed, misleading indications will result.

6.2.3.4 Eddy Current

Eddy current testing (ET) is an electromagnetic technique and can only be used on conductive materials. Its applications range from crack detection, to the rapid sorting of small components for flaws, size variations or material variation.

When an energized coil is brought near to the surface of a metal component, eddy currents are induced into the specimen. These currents set up a magnetic field that tends to oppose the original magnetic field. The impedance of the coil in close proximity to the specimen is affected by the presence of the induced eddy currents in the specimen.

When the eddy currents in the specimen are distorted by the presence of the flaws or material variations, the impedance in the coil is altered. This change is measured and displayed in a manner that indicates the type of flaw or material condition.

6.2.3.5 Ultrasonic Shear Wave

Ultrasonic inspection uses sound waves of short wavelength and high frequency to detect flaws or measure material thickness. Usually, pulsed beams of high frequency ultrasound are used via a hand held transducer (probe), which is placed on the specimen. Any sound from the pulse that is reflected and returns to the transducer (like an echo) is shown on a screen, which gives the amplitude of the pulse and the time taken to return to the transducer. Flaws anywhere through the specimen thickness reflect the sound back to the transducer.

Using the ultrasonic shear wave technique, the depth and length of a stress corrosion crack can, in principle, be measured. However, a stress corrosion crack is rarely isolated, and other nearby cracks in a cluster can cause interference that can lead to erroneous readings. In a recent critical evaluation of ten technologies for measuring crack size in the ditch, ultrasonics appeared to have the most promise, but it was not considered to have satisfactory accuracy in general (Francini, et al. 2000). While ultrasonic shear wave inspections can produce variable results due to its complexity, accurate sizing of individual cracks in an SCC colony can be achieved provided proper procedures and considerable technician training skill and experience are employed.

6.2.3.6 Time-of-Flight Diffraction and Phased-Array Ultrasonic

In 1998 the Gas Research Institute (GRI) funded the Electric Power Research Institute (EPRI) to participate in the "SCC Depth Measurement Program," an exercise in which several inspection companies attempted to measure the depth of SCC in line pipe. EPRI then commissioned AEA Technology to perform crack depth measurements on three specimens using the ultrasonic time-of-flight diffraction (TOFD) technique. Subsequent to this work GRI once again funded EPRI to examine samples of line pipe containing stress corrosion cracks using phased array (PA) UT (both manual and automated techniques). Results of both the TOFD and PA UT examinations are presented in the GRI report *GRI-00/0064 Sizing Stress Corrosion Cracking in Pipeline Specimens* (Selby and Spanner 2000).

With regard to TOFD, the conclusions were:

> Stress corrosion cracking produces very complicated defects. The through-wall crack extent of such cracks is not well defined. This complexity produces problems for TOFD measurement as it does for any inspection technique. However, this work shows that a robust inspection procedure for the measurement of the through-wall extent of SCC in thin-walled pipe is possible.

While the conclusion based on the results of the PA UT examination were:

1. PA UT is effective for imaging and sizing SCC in natural gas pipeline material. It could be applied "in the ditch" to measure cracking that had been detected using inspection pigs. The equipment is expensive.
2. PA imaging does a good job of imaging cracking whose morphology is complex both at the surface and under the surface.
3. The manual PA application was effective for detection and sizing of the cracking. It would be faster than the automatic application if the number of measurement points is small.
4. The automated PA application provides far better documentation and more detailed characterization of the cracking.

OPS is currently sponsoring a project to develop an ILI tool that utilizes PA UT, "Stage 2 Phase Array Wheel Probe for In-Line Inspection."

6.2.3.7 Potential Drop

Both direct current and alternating current potential drop techniques can be used to determine fatigue crack depth (Donald and Ruschau 1991). The two techniques require electrical contact with the metal surface to inject the current and to measure the potential difference across the crack. By virtue of the skin effect, alternating current potential drop (ACPD) has the advantage of lower current requirements and greater sensitivity to surface-breaking cracks than its direct current counterpart. In the case of uniform field ACPD measurements, it is possible to deduce crack depths and crack shapes without the use of calibration blocks, and there is a well-developed theoretical base for this variant. Calibration blocks are required if smaller hand-held ACPD units are used because the incident field is highly non-uniform.

6.2.3.8 Alternating Current Field Measurement

Alternating current field measurement (ACFM) is an electromagnetic technique, which offers the capability of detection and sizing of surface-breaking cracks without the need for calibration or cleaning to bare metal (see for example Zhou, et al. 1999). ACFM is a natural extension of ACPD with the uniform injected current replaced by a uniform field induced by a driver coil, and the contact electrodes replaced by a set of orthogonal pick-up coils. The measurements are performed by scanning the probe along the crack, using a sophisticated mathematical model to deduce the crack depth and length from the field perturbations via a portable computer. Like ACPD, ACFM is well suited to the sizing of surface cracks (length and width, but not depth) in magnetic steels and has been adapted for underwater use in the offshore industry.

6.2.4 Predictive Modeling

Predictive modeling, in the context of SCC detection, is a methodology for the identification and ranking of sections along a pipeline system that are most likely to have SCC based on factors known to contribute to SCC susceptibility. Two general types of models have been used, expert models and statistical models, and the approaches for model development are closely linked to the SCCDA process. For example, prior to conducting any digs, an expert model typically will be developed for a pipeline system to select and prioritize dig sites. The input parameters in the expert model typically will be those that are available line wide and are known to contribute to SCC susceptibility. These include coating type, year of installation, operating stress, operating temperature (for high pH SCC), location with respect to a pump or compressor station, operating history and terrain conditions. Specific dig sites frequently are selected within those susceptible segments at locations where there is evidence of coating disbondment and inadequate cathodic protection. As dig data become available, these expert models can be further refined to better predict the likelihood of finding SCC. If a sufficient number of field digs are conducted, the available data can be statistically trended to provide predictions of the likelihood of finding SCC along the pipeline.

6.2.5 Comparison

The methods described above have varying degrees of effectiveness in investigating SCC, but each method has limitations. Hydrostatic testing will identify critical flaws, but will provide no information about the number, location or severity of sub-critical flaws. Nevertheless, the technique has the advantage of ensuring integrity throughout the segment immediately after the hydrostatic test. Critical cracks at the hydrostatic test pressure will be smaller than critical cracks at MAOP/MOP. The time required for critical cracks at the hydrostatic test pressure to grow to critical cracks at MAOP/MOP is very important to the analysis of SCC. Direct examination is effective for external flaw identification, but the operator must have well-defined locations for excavation for direct examination for SCC to be practical. ILI tool runs for crack detection are limited by the tool speed and pipe size, require expert oversight and have extra considerations for gas pipelines (e.g. the need for a liquid couplant for UT tools).

In general, direct examination focuses first on crack location, followed by determination of crack length, and finally crack depth. Some NDE techniques determine only crack location, and provide limited information for crack characterization. None of the available technique reliably locate SCC, as well as characterizing both crack length and depth.

Analytical approaches to predicting SCC occurrence may be useful in some situations, but have significant limitations unless integrated with other types of data.

6.3 Direct Assessment

SCCDA is a structured process that is intended to assist pipeline operators in assessing the extent of SCC on a section of buried pipeline, thus contributing to improved safety by reducing the impact of external SCC on pipeline integrity. SCCDA requires the integration of data from historical records, indirect surveys, field examinations, and from pipe surface evaluations (i.e., direct examinations) combined with the physical characteristics and operating history of the pipeline. SCCDA is a continuous improvement process. Through successive applications, SCCDA should identify and address locations where SCC has occurred, is occurring, or might occur. SCCDA provides the advantage and benefit of locating areas where SCC might occur in the future rather than only areas where SCC has already occurred.

NACE currently is developing a recommended practice for SCCDA. SCCDA, as described in this standard, is specifically intended to address buried onshore petroleum (natural gas, crude oil, and refined products) production, transmission, and distribution pipelines constructed from line pipe steels. This recommended practice addresses the situation in which a pipeline company has identified a portion of its pipeline as an area of interest with respect to SCC based on its history, operations, and risk assessment process, and has decided that direct assessment is an appropriate approach for integrity assessment. This procedure is designed for application to both forms of external SCC (near-neutral pH SCC and high pH SCC).

The standard provides guidance for managing SCC by selecting potential pipeline segments, selecting dig sites within those segments, inspecting the pipeline, collecting and analyzing data during the dig, establishing a mitigation program, defining the reevaluation interval, and evaluating the effectiveness of the SCCDA process.

SCCDA is complementary with other inspection methods such as ILI or hydrostatic testing, and is not necessarily an alternative or replacement for these methods in all instances. SCCDA also is complementary with other direct assessment procedures such as those given in NACE Standards RP0502-2002 and RP0104-2004, "Internal Corrosion Direct Assessment (ICDA) Methodology for

Pipelines Carrying Normally Dry Natural Gas." ILI or hydrostatic testing may not be warranted if the initial SCCDA indicates that "significant"[3] and extensive cracking is not present on a pipeline system. SCCDA can be used to prioritize a pipeline system for ILI or hydrostatic testing if significant and extensive SCC is found. SCCDA also may detect other pipeline integrity threats, such as mechanical damage, external corrosion, microbiologically-influenced corrosion, etc. When such threats are detected, additional assessments and/or inspections should be performed.

In the NACE SCCDA process, initial selection of pipeline segments on gas pipelines for assessment of risk for high pH SCC is based on Appendix A3 of ASME B31.8S, Section A3.3. Appendix A3 considers the following factors: operating stress, operating temperature, distance from compressor station, age of pipeline, and coating type. A pipeline segment is considered susceptible to high pH SCC (i.e., conditions are right for the formation of high pH SCC) if all of the following factors are met.

- The operating stress exceeds 60 percent of specified minimum yield strength (SMYS);
- The operating temperature exceeds 38ºC (100º F) (Note: it is reported that temperature criteria will be removed in the next version of B31.8S);
- The segment is less than 32 km (20 mi.) downstream from a compressor station;
- The age of the pipeline is greater than 10 years; and
- The coating type is other than fusion-bonded epoxy.

ASME B31.8S addresses gas pipelines, but the same factors and approach are used for liquid petroleum pipelines in the NACE SCCDA document, considering the distance downstream from a pump station as one of the factors for selecting potentially susceptible segments.

Appendix A3 of ASME B31.8S addresses near-neutral pH SCC in the statement:

> Near-neutral type SCC similarly would require an inspection and alternative mitigation plan. Integrity assessment and mitigation plans for both phenomena are discussed in published research literature.

Unlike high pH SCC, B31.8S Appendix A.3 does note provide a step-by-step assessment and mitigation plan for near-neutral pH SCC. However, it is clear the standard recommends an inspection and mitigation plan.

The same factors and criteria given in B31.8S for high pH SCC are used in NACE RP0204 SCCDA for the selection of pipeline segments for assessment of risk of near-neutral pH SCC, with exception of the temperature criterion.

The SCCDA process (NACE 2004) consists of four steps: Pre-Assessment, Indirect Examinations, Direct Examinations, and Post Assessment. Further details of each step are given below.

3. An SCC cluster is assessed to be "significant" based on the CEPA definition, if the deepest crack, in a series of interacting cracks, is greater than 10 percent of the wall thickness and the total interacting length of the cracks is equal to or greater than 75 percent of the critical length of a 50 percent through-wall flaw that would fail at a stress level of 110 percent of SMYS. CEPA also defines the interaction criteria. Note that these definitions are currently being reviewed by CEPA.

6.3.1 Pre-Assessment Step

In the Pre-Assessment Step, historic and current data are collected and analyzed to prioritize the segments within a pipeline system with respect to potential SCC susceptibility and to select specific sites within those segments for direct examinations. The types of data collected are typically available from in-house construction records, operating and maintenance histories, alignment sheets, corrosion survey records, other aboveground inspection records, government sources, and inspection reports from prior integrity evaluations or maintenance actions. These data can be divided into five categories; pipe related, construction related, soils/environmental, corrosion protection, and pipeline operations. The most relevant pipe-related parameters for mill-coated line pipe are surface preparation and coating type. The type of seam weld also may be significant. The most relevant construction-related factors for pipeline segments coated over the ditch are surface preparation and coating type. Weather conditions and factors contributing to residual stresses may also be important. With respect to soils/environment, moisture content and soil type have been correlated with locations of SCC in some cases. With respect to corrosion protection, CP-related parameters are contributing factors because adequate CP can prevent SCC except under certain disbonded coatings (which can shield the current from the pipeline). With respect to pipeline operations, SCC history and pressure fluctuations are important. Temperature history also is important for high pH SCC. For liquid lines, changes in product can influence operating conditions, such as the dynamic pressure profile between pumping stations (e.g., during the batching of products with different viscosities/specific gravities).

Ideally, the specific sites for direct examination (i.e., dig sites) should be selected to maximize the probability of finding SCC if it does exist on a pipeline segment. Unfortunately, there are no well-established methods for predicting with a high degree of certainty the presence of SCC, based on above ground measurements. However, industry experience can provide some guidance for selecting more probable sites. The critical factors for high pH SCC and near-neutral pH SCC are similar, but some differences exist. Also, the most relevant factors may differ from one pipeline to another, or even one segment to another, depending on the history of the line. Some companies have found that predictive models can be effective at identifying and ranking areas along a pipeline that are susceptible to near-neutral pH SCC. Such models can be effective only if reliable pipeline and terrain conditions are used and the predictive model is verified and enhanced through investigative excavations. For site selection, the following factors should be considered for locating SCC.

- A history of SCC in area of interest
- Unique characteristics associated with previous SCC locations
- Locations with coating anomalies
- ILI indications of dents or other deformations
- ILI indications of general corrosion (with shielding coatings). It is reported that many operators currently look at areas with less than 20 percent metal loss or at bends as part of their site selection criteria.
- Locations where the stresses, pressure fluctuations, and temperatures were highest (Note: To date, no correlation between temperature and occurrence of near-neutral pH SCC has been

found, thus temperature need only be considered for identifying potential locations of high pH SCC.)

- Locations where there has been a history of coating deterioration

6.3.2 Indirect Inspection Step

In the Indirect Inspection Step, additional data are collected, as deemed necessary by the pipeline operator, to aid prioritization of segments and site selection. The necessity to conduct indirect inspections and the nature of these inspections depends on the nature and extent of the data obtained in the pre-assessment step and the data needs for site selection. Typical data collected in this step may include close-interval survey data, direct current voltage gradient data, alternating current voltage gradient data, Pipeline Current Mapper data, C-scan data, and information on terrain conditions (soil type, topography, and drainage) along the right of way.

6.3.3 Direct Examination Step

The Direct Examination Step includes procedures to field verify the sites selected in the first two steps, and conduct the field digs. Above ground measurements and inspections are performed to field verify the factors used to select the dig sites. For example, the presence and severity of coating faults may be confirmed. If predictive models based on terrain conditions are used, the topography, drainage, and soil type require verification. The digs are then performed and if any SCC is detected, the severity, extent, and type of SCC at the individual dig sites are assessed. The data that can be used in post assessment and predictive model development are then collected.

The types and extent of data collected at the dig sites are at the discretion of the pipeline operator and depends on the planned usages of the data. Limited data, consisting of the assessment of cracking, may be appropriate in cases in which the operator is assessing a pipeline segment for the presence or absence of SCC. More extensive data collection procedures would be required if the operator is attempting to develop a predictive model for SCC on a pipeline system. If cracks are found, at a minimum, their dimensions should be recorded to confirm continued serviceability of the pipeline.

6.3.4 Post Assessment Step

In the Post Assessment Step, data collected from the previous three steps are analyzed to determine whether SCC mitigation is required. If mitigation is deemed necessary, the operator prioritizes the mitigative actions, defines the interval to the next full integrity reassessment and evaluates the effectiveness of the SCCDA approach. Each pipeline company is responsible for selecting post-assessment options, including developing, implementing, and verifying a plan to define reassessment intervals, and evaluating the effectiveness of the SCCDA approach.

There are two types of mitigation: discrete mitigation and general mitigation. Discrete mitigation is selected to address isolated locations at which significant SCC has been detected during the course of the field investigation program. Typically, this form of mitigation is limited to areas where the affected segment is relatively short—less than 91 m (300 ft) in length. Mitigation options include repair or removal of the affected pipe joints, hydrostatically testing the pipeline segment, and performing an engineering critical assessment (ECA) to evaluate the risk and identify further mitigation methods.

General mitigation is selected to address pipeline segments when the risk of significant SCC could potentially be widespread within a particular segment or segments of a pipeline. Typically, this form of mitigation is used to address areas in which the affected segment is relatively long. General forms of mitigation include hydrostatic testing of the affected segment or segments, ILI when appropriate tools are available, extensive pipe replacements and re-coating.

Periodic reassessment is the process in which segments of a pipeline are re-investigated at an appropriate time interval. It is at the operator's discretion to establish the number of additional investigations required on a given segment and the reassessment intervals based on information such as the extent and severity of the SCC detected during the original investigation, the estimated rate of propagation of the crack clusters, remaining life of the pipe containing the clusters, the total length of the pipeline segment, the total length of potentially susceptible pipe within the segment, and the potential consequences of a failure within a given segment.

Methods used to assess SCCDA effectiveness include comparison of results for selected dig sites with results for control digs, comparison of results of SCCDA for selected segments with results of ILI using crack detection tools, statistical analysis of data from SCCDA digs to identify statistically significant factors associated with the occurrence and/or severity of cracking, successive applications of SCCDA to a pipeline segment, and assessment of SCC predictive models with respect to reliability of predicting locations and severity of SCC.

In the post-assessment step, it also is important to evaluate the criteria used for initial selection of susceptible segments. It might be necessary to modify these criteria for a pipeline or system based on the results of SCCDA digs.

6.4 Numerical Assessment Methods

There are a number of techniques available by which to assess failure criteria for crack-like defects in pipelines. All these techniques predict the relationship between critical defect size and failure pressure. Probably the best-known and most widely utilized method is the AGA NG-18 ln-secant formula. However, other techniques, such as the Pipe Axial Flaw Failure Criterion (PAFFC), the Level 2 Strip Yield Model, and the CorLAS™ model, are also available. Each of these methods is mentioned in *Public Inquiry Concerning Stress Corrosion Cracking on Canadian Oil and Gas Pipelines* (NEB 1996), and described in further detail in the following sections. The more recent publication of API RP 579 provides an assessment methodology that is gaining wider usage among pipeline operators. API RP 579 is discussed in Section 8.2.5.

6.4.1 NG-18 ln-secant Formula

In the early 1970s, Battelle developed an assessment methodology for analyzing axial flaws in pipelines based on an extensive series of burst tests. The Battelle method, or ln-secant criterion, was based on a strip-yield model and empirically derived for surface axial flaws and is given as:

$$\frac{C_V \pi E}{4 A_C L_e \sigma_f^2} = \ln\left[\sec\left(\frac{\pi M_S \sigma_H}{2\sigma_f}\right)\right]$$ **Equation 6.1**

where:

E is the elastic modulus,

L_e is an effective flaw length equal to the total flaw length multiplied by π/4 for a semi-elliptical flaw shape common in fatigue,

σ_f is the flow stress typically taken as the yield strength plus 10 ksi or else as the average of yield and ultimate tensile strengths,

σ_H is nominal hoop stress due to internal pressure,

C_V is the upper shelf CVN impact toughness,

A_c is the cross-sectional area of the Charpy impact specimen. (Note that a constant for compatibility of units between C_V and A_c may be necessary.)

The term M_S is a stress magnification factor for a surface-breaking axial flaw, calculated as:

$$M_S = \frac{1-(a/t)(M_T)^{-1}}{1-a/t}$$ **Equation 6.2**

where

a is flaw depth, and

t is the pipe wall thickness.

The term M_T is Folias' original bulging factor for a through-wall axial flaw, written as:

$$M_T = \sqrt{1+1.255\left(\frac{L_e^2}{2Dt}\right)-0.0135\left(\frac{L_e^4}{4D^2t^2}\right)}, \text{ for } \left(\frac{L_e^2}{Dt}\right) \leq 50$$ **Equation 6.3a**

or

$$M_T = 0.032\left(\frac{L_e^2}{Dt}\right)+3.3, \text{ for } \left(\frac{L_e^2}{Dt}\right) > 50$$ **Equation 6.3b**

This method only applies to flaws that existed in the pipe prior to pressurization and does not consider possible growth due to the effects of pressure, either in-service or hydrostatic testing.

In addition, in a study conducted by Battelle for TCPL, it was concluded that the ln-secant criterion is not appropriate for obtaining a very accurate assessment of pipeline failure pressures for lines containing SCC, such as has occurred on the TCPL system. The overly conservative predictions of failure pressure were attributed primarily to the effect of multiple cracking that is associated with SCC, as compared to the single rectangular axial flaw assumed in deriving the ln-secant criterion. The study also identified the empirical calibration of the criterion as contributing to the observed conservatism and inconsistency. "In another study conducted by Battelle for TCPL, the results suggest that the presence of multiple cracks effectively reduces the crack driving force below that for a single crack. Therefore, failure criteria based on a single crack will tend to underestimate failure pressures where multiple cracks are present." (NEB 1996) Since the ln-secant technique typically results in a conservative assessment of remaining life, it is an appropriate method for assessing crack severity though the use of more accurate methods may be desirable in some cases.

6.4.2 Pipe Axial Flaw Failure Criterion

The ln-secant criterion: "…was based on flaw sizes that existed prior to depressurization and did not address possible growth due to pressure in service or in a hydrostatic test or during the hold time in a hydrotest…However, with the advent of newer steels and the related increased toughness that supported significant stable flaw growth, it became evident that this criterion should be updated." (Leis and Ghadiali 1994). This updating resulted in the development of the PRCI ductile flaw growth model "…which specifically accounted for the stable growth observed at flaws controlled by the steel's toughness and a limit-states analysis that addressed plastic-collapse at the flaw." Due to the increased complexity (when compared to the ln-secant formula) of this model, which made it difficult for day-to-day use, a computer program was developed to enhance the usability of the method. This program was titled Pipe Axial Flaw Failure Criterion or PAFFC and is available for download from the PRCI Web site.

PAFFC can be used to determine the effect of a single external axial flaw on the failure pressure in a pipeline, given the pipe diameter and wall thickness, yield and ultimate (flow) stress, and upper shelf CVN toughness.

6.4.3 Level 2 Strip Yield Model

The Level 2 Strip Yield Model is a collapse-modified strip yield model for axial surface cracks in line pipe developed at CANMET in the early 1990s. The model is an alteration of the approaches in the British R6 (a detailed single failure curve analysis) approach, and the somewhat similar PD6943 approach. Note that PD6943 has been superceded by BS7910:1999.

"Briefly, the model interpolates between a brittle fracture limit, (dependent on the stress intensity factor), and a collapse limit, (dependent on the flaw size and flow stress)…The approach follows the basic premise of a strip yield model, where failure occurs for K_r and S_r on the 'failure curve.' K_r is the ratio of the applied (elastic) crack driving force to the material toughness and measures the proximity to fracture, and S_r is the ratio of the applied net section stress to the flow stress and measures the proximity to plastic collapse…The overall approach has been validated against the results from the original Battelle work, and is applicable for oil and gas pipelines with an $R/t \geq 20$." (CEPA 1997)

6.4.4 CorLAS™

The general approach used for ECA of crack-like flaws using CorLAS™ is illustrated in Figure 6-7. The first step is characterization of the initial flaw type and size. This includes determining if the flaw is crack-like. Next, the critical or final flaw size at failure under operating or upset conditions is

ChallengeUs.

predicted. Remaining life is computed based on growth from the initial to the final flaw size. If the final flaw size is not greater than the initial one, no remaining life is predicted. If the flaw growth rate cannot be estimated, remaining life cannot be predicted, and monitoring is recommended to assure safe pipeline operation.

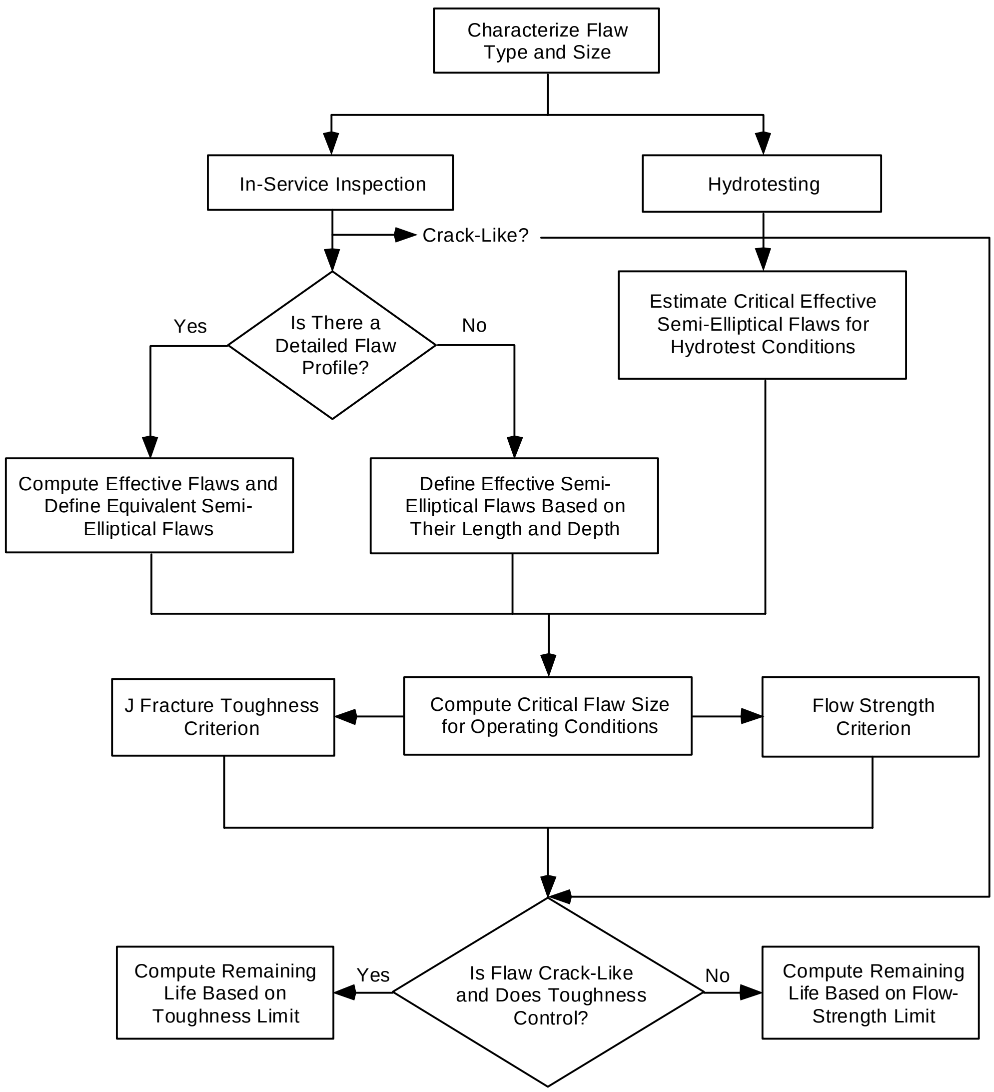


Figure 6-7 General Approach for Engineering Critical Assessment (ECA) of Crack-Like Flaws in Pipelines Using CorLAS^{TM}

The size of the flaw is characterized by means of in-service inspection or hydrostatic pressure testing. In-service inspection may yield a detailed profile or contour of the flaw depth as a function of its length or only the flaw length and depth. When a detailed flaw depth profile is available, an effective surface flaw is determined from this profile using the procedures described in detail by Kiefner and Vieth (1993). The effective flaw area is defined by its effective length and actual cross-sectional depth. The effective flaw depth is then defined based on a semi-elliptical flaw shape and equivalent flaw area.

When a detailed flaw profile is not available, the effective flaw is characterized as having a semi-elliptical shape with the maximum measured depth and length. When hydrostatic pressure testing is used to characterize the surface flaw, the effective flaw size is estimated to be the largest flaw that would have survived the test. In practice, these effective flaw sizes are estimated as a function of L/d (flaw length/flaw depth), because this ratio affects the critical flaw depth.

It must be determined if the flaw is crack-like. Inspection data usually provide this information. If the inspection cannot clearly identify the flaw type, it is conservative to assume a crack-like flaw of the measured size for ECA. However, when hydrostatic testing is employed, the flaw type must be inferred from other data. If this cannot be done with confidence, then a non-crack-like flaw should be used for computing the initial size from the hydrostatic testing data and a crack-like flaw should be used to predict failure conditions to yield a conservative ECA.

The critical flaw size is computed for two different failure criteria: flow strength and J_c. J_c is an elastic plastic fracture mechanics parameter and is used because typical pipeline steels are quite ductile and tough. Both flow strength and fracture toughness must be considered as possible failure criteria for crack-like flaws. The smaller of the two calculated critical flaw sizes is the one predicted to result in failure. Remaining life is the time required for the flaw to grow from its initial to final size. It is computed by integrating a flaw-growth relationship from the initial to final flaw size.

The critical flaw size for the flow-strength failure criterion is determined by solving the following equation for A (effective flaw area):

$$\sigma_f = S_{fl} \cdot RSF = S_{fl} \cdot \left(\frac{1 - A/A_o}{1 - A/(M \cdot A_o)} \right)$$ **Equation 6.4**

where:

σ_f is the applied nominal stress at failure,

S_{fl} is the material flow strength,

A_o is the flaw length times wall thickness, and

M is the Folias (bulging) factor.

Values of M are computed using the relationship given by Kiefner and Vieth (1993). For a specific relation among A, L, and d, such as a semi-elliptical shape with a constant L/d, L and d are uniquely defined by the value of A obtained from solving Equation 6.4. Because M is a function of L, Equation 6.4 is solved iteratively. The value of S_{fl} is determined from *TYS* (Tensile Yield Strength) or from a combination of *TYS* and *TUS* (Tensile Ultimate Strength) using one of the following two expressions:

$S_{fl} = TYS + 10$ ksi (68.95 Mpa) **Equation 6.5a**

$S_{fl} = TYS + C_{fl}\,(TUS - TYS)$ **Equation 6.5b**

C_{fl} is a constant between 0 and 1.0 and is usually taken to be 0.5. Equation 6.5a is based on burst tests of steel pipe specimens (Kiefner, et al. 1973), while Equation 6.5b with $C_{fl} = 0.5$ is usually used in plastic collapse analysis.

The following formulation for a semi-elliptical surface flaw is used to compute values of applied J as a function of a (flaw size) and stress, σ:

$$J = Q_f \cdot F_{sf} \cdot a \cdot \left(\frac{\sigma^2 \cdot \pi}{E} + f_3(n)\varepsilon_p \sigma \right)$$ **Equation 6.6**

where:

Q_f is the elliptical flaw shape factor,

F_{sf} is the free-surface factor,

a is the flaw depth,

σ is the stress,

E is the elastic modulus,

n is the strain hardening exponent, and

ε_p is the plastic strain.

The function $f_3(n)$ in Equation 6.6 is from stress analyses performed by Shih and Hutchinson (Shih and Hutchinson 1975). A power law with the exponent n characterizes σ as a function of ε_p. Values of *TYS* and n are used to determine the power law coefficient.

Several improvements have been made to the CorLAS™ model since the original development. Tearing instability was added to the fracture toughness failure criteria, formulations for computing values of the J integral for surface cracks were improved, interaction criteria were developed for co-planar flaws, and relationships for estimating values of the strain-hardening exponent were developed.

In the original model, described above, fracture was predicted to occur when applied J reached J_c. For tough pipeline steels, this approach is conservative because a significant amount of stable crack tearing occurs before fracture instability is reached. For this reason, the tearing instability criterion of Paris, et al. (1979) was incorporated into the failure model.

Tearing instability is predicted to occur when applied T (crack tearing parameter) equals or exceeds T_{mat} (tearing modulus) of the pipeline steel. T_{mat} is defined by the following equation:

$$T_{mat} = {}^{dJ}\!/_{da} \cdot {}^{E}\!/_{\sigma_{fl}{}^2}$$ **Equation 6.7**

T_{mat} is determined from a standard laboratory fracture toughness test. The applied ${}^{dJ}\!/_{da}$ is a function of applied load, pipeline configuration, crack size, and crack shape and is determined by stress analysis. Applied T is calculated in the same manner as T_{mat} is calculated in Equation 6.7.

Descriptions of the other improvements are summarized in a recent paper presented at the fourth biennial International Pipeline Conference (IPC) (Jaske and Beavers 2002a).

6.4.4.1 Application

The application of these failure criteria results in curves showing critical flaw depth versus length for a given pressure. An example is shown in Figure 6-8. Normally, curves generated for MAOP/MOP and the maximum hydrostatic test pressure are compared to determine the amount of growth in depth that is necessary for a defect to fail in service. Unless data are available to support an assumption of a specific critical crack length, the minimum value of growth in depth that is necessary for a defect to fail in service should be used as a conservative value for determining a safe retest interval. Usually the assumption of a crack with infinite length results in a conservative estimate of allowable growth in depth.

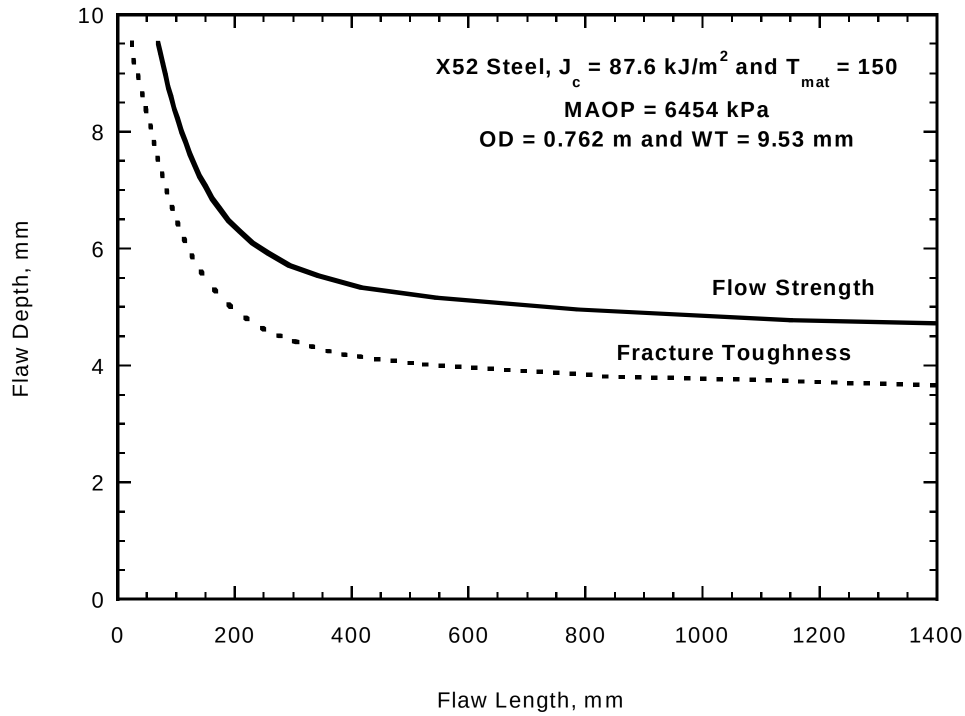


Figure 6-8 Example of Calculated Critical Flaw Depth as a Function of Length Using CorLAS™

6.4.4.2 Comparison

A comparison of a series of evaluations using each of the four methods described above performed by CEPA was reported in the NEB report, *Stress Corrosion Cracking on Canadian Oil and Gas Pipelines* (NEB 1996). This comparison indicated that the ln-secant formula and the Level 2 Strip Yield Model could be very conservative, with significant variances in the level of conservatism, though, unlike the ln-secant formula, the Level 2 Strip Yield Model was not consistently conservative. On the other hand, the predictability for both the PAFFC and CorLAS™ criteria was shown to be much better, with CorLAS™ being the more accurate of the two.

The NEB report states:

> It must be emphasized that the observations noted above with respect to each failure criterion are valid for a specific set of field data for which calculations were made and may not

necessarily hold true for other sets of data. Each failure criterion described above is developed on the basis of certain assumptions and generally has a limited range of applicability. The predictive capability of a failure criterion improves if the specific situation under consideration is consistent with those assumptions and is within that range of applicability.

The failure predictions for CorLAS™ are shown as solid circles in Figure 6-9, where the predicted failure stress is plotted as a function of the actual failure stress and the 45-degree dashed line indicates an exact correlation between the two values. Both stresses are given as a percentage of the SMYS of the line pipe. The predictions were made using an effective flaw characterized by only the maximum flaw size (depth and length). Except for one case, the predicted failure stresses were very close to the actual failure stresses. Examination of the data for that case revealed that the SCC flaw was much deeper at its central portion than near its ends, so its effective size was not well characterized by the maximum flaw size. The predicted failure stress was very close to the actual failure stress when the actual flaw-depth profile was used to characterize its effective size, as indicated by the open circle in Figure 6-9.

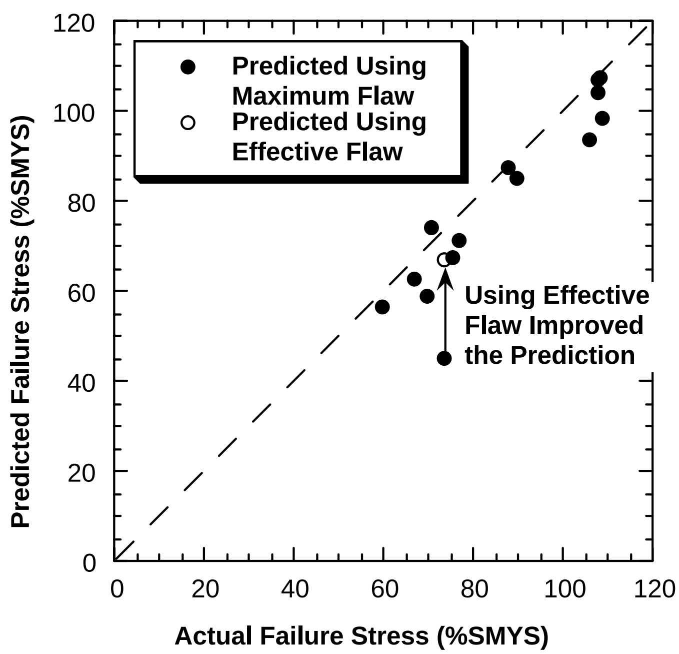


Figure 6-9 Predictions of Failure Stress for Field Failures

6.5 References

Beavers, J.A. and E.L. Hagerdorn. 1996. *Low pH SCC; Mechanical Effects on Crack Propagation.* PRCI. L51760.

Brongers, M.P.H., J.A. Beavers, C.E. Jaske, and B.S. Delanty. 2000. *Effect of Hydrostatic Testing on Ductile Tearing of X-65 Line Pipe Steel with Stress Corrosion Cracks*. NACE International CORROSION/2000. Paper No. 00355.

CEPA. 1997. *Stress Corrosion Cracking—Recommended Practices*. Canadian Energy Pipeline Association.

Donald, J.K. and J. Ruschau. 1991. "Direct Current Potential Difference Fatigue Crack Measurement Techniques" *Fatigue crack measurement: techniques and applications* K J Marsh, R A Smith and R O Ritchie (eds), EMAS, Warley, West Midlands, 11-38.

Francini, R.B., B.N. Leis, J.B. Nestleroth, and David W. Detly. 2000. *Stress Corrosion Crack Depth Measurement*. Final Report to PRCI on Project PR-3-8718.

Hall, R.J. and M.C. McMahon. 1999. *Stress Corrosion Cracking Study*. General Physics Corporation for U.S. Department of Transportation, Research and Special Programs Administration, Office of Pipeline Safety. Report No. DTRS56-96-C-0002-004. May.

Hohl, G. and G. Knauf. 1999. Field Hydrotesting and its Significance to Modern Pipelines. In *Proceedings EPRG/PRCI 12th Biennial Joint Technical meeting on Pipeline Research*. Paper 32. May.

Jaske, C.E. and J.A. Beavers. 2002a. Development and Evaluation of Improved Model for Engineering Critical Assessment of Pipelines. In *Proceedings of IPC 2002*. Paper IPC02-27027.

Kiefner, J.F., W.A. Maxey, R.J. Eiber, and A.R. Duffy. 1973. *Failure Stress Levels of Flaws in Pressurized Cylinders*. Progress in Flaw Growth and Fracture Toughness Testing, STP 536, ASTM International, West Conshohocken, PA, pp. 461-481.

Kiefner, J.F. 1986. Evaluating Pipeline Integrity – Flaw Behavior During and Following High Pressure Testing. In *Proceedings from the Seventh Symposium on Line Pipe Research*, PRCI. L51495.

Kiefner, J.F., and P.H. Vieth. 1993. The Remaining Strength of Corroded Pipe. In *Proceedings of the Eighth Symposium on Line Pipe Research*. PRCI. L51680.

Leis, B.N. and N.D. Ghadiali. 1994. *Pipe Axial Flaw Failure Criteria---PAFFC, Version 1.0 User's Manual and Software*. PRCI. L51720.

NACE. 2000. *In-Line Nondestructive Inspection of Pipelines*, NACE International. Publication 35100.

NACE Standard RP 0104. 2004. *Internal Corrosion Direct Assessment (ICDA) Methodology for Pipelines Carrying Normally Dry Natural Gas*. NACE International.

NACE Standard RP0204. 2004. *Stress Corrosion Cracking (SCC) Direct Assessment Methodology*. NACE International.

NACE Standard RP0502. 2002. *Pipeline External Corrosion Direct Assessment Methodology*. NACE International.

NEB. 1996. *Stress Corrosion Cracking on Canadian Oil and Gas Pipelines. Report of the Inquiry*. National Energy Board. MH-2-95. December.

Norris, J.D., B.P. Ashworth, M. Yeomans and N.I. Uzelac. 2001. *Reconfirming the Integrity of a Gas Transmission Pipeline Following an SCC Induced Incident*. NACE International CORROSION/2001. Paper No. 01631.

Paris, P.C., H. Tada, A. Zahoor, and H. Ernst. 1979. *The Theory of Instability of the Tearing Mode of Elastic-Plastic Crack Growth.* Elastic-Plastic Fracture, STP 668, ASTM International, West Conshohocken, PA, pp. 5-36.

Selby, G. and J. Spanner. 2000. *Sizing Stress Corrosion Cracking in Pipeline Specimens*. GRI-00/0064.

Shih, C.F., and J.W. Hutchinson. 1975. *Fully Plastic Solutions and Large Scale Yielding Estimates for Plane Stress Crack Problems.* Report No. DEAP S-14, Harvard University, Cambridge, MA.

Zhou, J., M.C. Lugg and R. Collins. 1999. *A Nonuniform Model for Alternating Current Field Measurement of Fatigue Cracks in Metals.* Int. J. Appl. Electromag. Mech. **10** 221-235.

This page intentionally left blank.

7 Mitigation of SCC

"Compile a report summarizing the history of SCC on pipelines, explaining the causes and factors contributing to SCC initiation and growth, and discussing methods for prevention, detection and mitigation of SCC on pipelines, including effectiveness of ILI tools and other in-the-bell hole examination methods to detect SCC."

The scope statement was broken down into components of Understanding Stress Corrosion Cracking (SCC) in Pipelines (Chapter 4); Prevention of an SCC Problem (Chapter 5); Detection and Assessment of SCC (Chapter 6); and Mitigation of SCC (Chapter 7).

This chapter summarizes the current state of knowledge of understanding how to mitigate SCC.

7.1 Repair and Mitigation Options

ASME B31.8S presents acceptable repair methods for SCC in Table 4. These methods are:

- Pressure reduction;
- Replacement;
- Grind repair/ECA;
- Type B, pressurized sleeve; and
- Type A, reinforcing sleeve.

If the grind repair/ECA method is utilized, the area is then evaluated in a similar manner to general metal-loss for which composite sleeves and epoxy filled sleeves may then used to provide any required reinforcement after the stress corrosion cracks have been removed by grinding.

API Standard 1160, *Managing System Integrity for Hazardous Liquid Pipelines*, presents a summary of commonly used permanent pipeline repairs in Table 9-2 for various anomaly types and locations, and describes numerous repair strategies in Appendix B. However, note 9 to Table 9-2 states: "Other repair methods may be used provided they are based on sound engineering practice," and section 9.7 states: "The information in this standard should not be considered a complete summary of every type of repair, but an overview of some of the more frequently used techniques in the industry today." The standard goes on to state: "In the absence of detailed company procedures for pipe replacement or repair the "Pipeline In-service Repair Manual" should be consulted."

The PRCI *Pipeline Repair Manual* (Kiefner, et al. 1999) presents a summary of repair applications in Table 1. The methods listed for repair of SCC are:

- Grinding (requires inspection as well);
- Deposited metal (requires grinding and inspection as well);
- Type A sleeve;
- Type B sleeve;

- Mechanical Bolt-on-Clamp; and
- Hot Tapping.

The table contains a note regarding composite sleeves for repair of SCC that states: "The use of composite sleeves for these defects may be feasible and is being studied. However, as this document went to press the manufacturer was still limiting their use to corrosion-caused metal loss."

7.1.1 Pressure Reduction

Though it is not a long-term solution, pressure reduction can be used to decrease the likelihood of an immediate or near-term SCC failure. The pressure reduction provides time for the operator to assess the pipeline integrity and determine a long-term mitigation and management strategy.

Reduction in pressure increases the critical crack size necessary to cause failure and reduces the driving force for crack growth. Typically, a 20 percent reduction is specified following a pipeline incident. The logic is that the previous operating pressure is equivalent to a "test" pressure which is 125 percent (5/4) of the new operating pressure. Therefore, the new operating pressure should be 80 percent (4/5) of the last "test" pressure. The maximum operating pressure may be raised back to the previous level if the integrity of the pipeline can be assured through some means of inspection, such as hydrostatic testing or ILI.

7.1.2 Hydrostatic Testing and Repair

Hydrostatic testing and repair can be used to reduce the likelihood of a stress corrosion failure. Hydrostatic testing will cause critical cracks (at the test pressure) to fail. By repairing these failures, critical cracks are eliminated, although near-critical cracks at the test pressure could remain undetected.

Using hydrostatic testing alone requires retest on a regular basis to catch any stress corrosion cracks that may have grown since the previous test. Establishing an appropriate retest interval remains a challenge for operators.

While there are data that suggest hydrostatic tests inhibit subsequent SCC crack growth by imparting a compressive residual stress at the crack tip, some of the surviving cracks may continue to grow. Barlo reported that two leaks were discovered in a pipeline operating at 71 percent SMYS, two and four months following a retest at 90 percent SMYS (Barlo 1979). He also reported six ruptures that occurred 1.7 to 8.3 years following retests. There was a general correlation between higher retest pressures and longer times to rupture. Many other portions of the pipelines had survived 10 to 12 years following a retest without an additional failure. The field behavior is consistent with the theoretical predictions of Leis, which showed that, while retesting to 95 percent SMYS produces almost no benefit in terms of increasing remaining life, test pressures above this level can be very beneficial (Leis and Kurth 1999). Pressures between 105 and 110 percent SMYS appear to be most beneficial for SCC mitigation. A pressure test on a pipeline system that subjects the pipeline to a significantly higher test pressure than a normal 49 CFR 192, Subpart J or 49 CFR 195, Subpart E requirement for a short duration is considered a "spike test" (see Section 6.2.1). It should be noted that higher than normal test pressures can have an adverse effect of other types of failure mechanisms (i.e., fatigue cracks).

7.1.2.1 Selective Crack Blunting

Blunting of cracks may be obtained by hydrostatically testing the pipeline. The hydrostatic pressure is held in a range where yielding can occur at the crack tip of large cracks that survive the hydrotest. Yielding at the crack tip causes compressive residual stresses around the crack tip and rounding, or blunting, of the crack tip. Once the crack tip is blunted, additional crack growth is minimal until a new crack grows at the end of the blunted crack.

The blunting effect may be reinforced by the residual compressive stress that is created immediately below the crack tip when the pressure is relieved.

7.1.3 Recoating

Disbonded coating or tape is frequently a contributor to SCC. In addition, mill scale remaining on the surface of line pipe after surface preparation for coating has also been linked to SCC.

Recoating a pipeline can improve the resistance of the pipe to SCC. During recoating, any remaining mill scale can be removed during surface preparation and the pipe recoated. Grit blasting conducted during the surface preparation process increases resistance to SCC by imparting a compressive residual stress on the pipe surface (Koch, et al. 1983).

Coatings selected for recoating of pipelines must resist cathodic disbondment, adhere well to the pipe, resist mechanical damage, and resist moisture degradation. Additionally, these coatings should not shield cathodic protection if they do disbond. Many protective coatings are available for use in reconditioning existing lines in the ditch, including cold-applied tapes, hot-applied tapes, and liquid-based coatings (CEPA 1997). Often, performance testing of several coatings is necessary to select a coating for each reconditioning application.

Unfortunately, the current coating of choice by most operators for initial application, FBE, is not typically practical for recoating applications. FBE application requires a controlled environment to apply the powder and heat the surface to properly fuse the coating to the pipe. In lieu of this, other recoating systems must be applied as mentioned above.

A written procedure for the recoating is strongly recommended to ensure the integrity of the pipeline and protective coating. It is further recommended that the operator review this procedure with the contractor prior to field implementation. The procedure should address, as a minimum: 1) surface preparation requirements, 2) appropriate ambient weather conditions conducive to proper coating, 3) compatibility with existing coatings, 4) geographical and physical location, 5) health and safety codes and considerations, and 6) quality assurance/quality control (QA/QC).

CSA Z662-03 provides requirements for coating selection (Clause 4.1.7), coating properties, application and inspection (Clause 9.2.7), and a guide for test methods for the evaluation of coating properties (Annex L).

7.1.4 Grinding

"Grinding" is addressed in the PRCI *Pipeline Repair Manual* (Kiefner, et al. 1999). ASME B31.8S also contains provisions for grinding repair of SCC. When SCC can be definitively located, excavation and inspection, with consequent grinding/buffing of the stress corrosion cracks and recoating, is recommended: "…if (1) the stress-concentrating effect of the defect or imperfection is eliminated, (2) all damaged or excessively hard material is removed, and (3) the amount and distribution of metal removed does not significantly reduce the pressure-carrying capacity of the pipe." B31G/RSTRENG can be used to determine whether the remaining wall is adequate to resist operational loads (see Section 8.2.4). Note that most of the operators interviewed (see Section 10.4) mention grinding as the preferred repair technique. As per the *Pipeline Repair Manual*: "The operating pressure should be reduced to 80 percent of that at which the defect was discovered (or to 80 percent of a recently demonstrated high pressure)." Subsequent to grinding, the pipe must be recoated (see Section 7.1.3).

7.1.5 Repair Sleeves

Repair sleeves and bolt-on clamps that are able to permanently restore the serviceability of the pipe can also be used. A repair sleeve may be installed if grinding of an excavated section of pipeline results in a wall thickness less than the minimum required for the MAOP/MOP. The ground area should be filled with an incompressible filler when a repair sleeve is used to mitigate SCC.

The expectation is that the repair system used should restore the integrity of the pipeline segment equivalent to replacing the damaged or corroded pipe with new line pipe. Only full-encirclement sleeves should be used for repair of SCC. The main types of full-encirclement sleeves are: Type A (Reinforcing), Type B (Pressure containing), Mechanical (bolt-on) and Composite Reinforced.

Type A sleeves consist of two halves of a cylinder of pipe or curved plate that are placed around the carrier pipe and joined by welding the side seams. This type of sleeve's role is solely to restrain bulging of the defective area. The main disadvantages of Type A sleeves are:

- It is not useful for circumferential-oriented defects.
- It cannot be used to repair a leak.
- It creates a potential corrosion problem by the formation of an annular space between the sleeve and the carrier pipe that may be difficult to cathodically protect (no failures in this manner are known).

Compressive sleeves are Type "A" sleeves, and are lap welded with a fillet weld on both sides of the pipe in lieu of a groove weld that uses the pipe as backing. This type of sleeve is installed in a similar fashion to Type A and B sleeves, but actually induce a compressive stress into the carrier pipe and rely on a high-strength epoxy to bond them to the carrier pipe. Compressive sleeves are currently not recommended for repair of leaks.

Type B sleeves are similar to Type A sleeves, but in addition to the side seams, circumferential welds are applied to join the sleeve and the carrier pipe. Because this type of sleeve may contain pressure and/or longitudinal stress, it must be designed and installed in a manner to ensure its structural integrity. Since Type B sleeves are designed to contain pressure, they may be installed to repair leaks, though they are often used to repair non-leaking defects as well.

API 1160 refers to mechanical bolt-on clamps as split sleeve reinforcing clamps and states: "…are a widely used method to repair anomalies to restore full pipeline MOP and may be considered a permanent repair in most situations."

Extensions of the traditional pipe sleeve concept include some composite reinforcement systems. These are currently strictly for pipe wall reinforcement and should only be applied once the stress corrosion cracks have been removed (e.g., ground out). This may consist of a uniaxial fiberglass/epoxy resin material that results in monolithic composite pipe reinforcement. The composite material has been proven by extensive lab testing, with the basic materials proven by over 30 years of field experience in the petro-chemical and related industries. Another type of encirclement system consists of a fiberglass/polyester composite material coiled with adhesive in layers that reinforce steel pipe having certain non-leaking defects. According to tests and analyses by GRI, when properly installed, the system permanently restores the pressure-containing capability of the pipe. Based on GRI field and lab performance data, OPS concluded that this technology provides at least the same level of safety on high-stress transmission lines as pipe replacement or a full encirclement split sleeve. As a result, OPS allows operators to use this repair system on their pipelines.

7.1.6 Pipe Replacement

Replacement of selected joints of pipe can be used to eliminate stress corrosion colonies. When ILI or hydrostatic testing indicates the presence of SCC, removing the affected joint or joints of pipe is often the most effective method of repair. The joints of pipe removed can be subjected to metallurgical evaluation to better understand the SCC mechanism (e.g. high pH or near-neutral pH SCC) for possible use in subsequent SCCDA. Whatever the case, the joints of the pipe affected by SCC can be replaced and the pipeline returned to normal operation.

7.1.7 Options Discussion

As discussed, SCC is typically preceded by coating disbondment. Therefore, new or replacement design should consider the use of FBE coating (FBE has been shown to be an effective barrier to the SCC susceptible environment) or possibly other coating systems that have not been associated with SCC. However, for existing pipelines, replacement of pipe with failed coating is seldom realistic except for specific pipe joints that are known to have suffered significant SCC.

If SCC can be definitively located, excavation and inspection, with consequent grinding/buffing of the stress corrosion cracks and recoating, is recommended if the remaining wall is adequate to resist operational loads.

The most problematic case is an existing pipeline, which has been found to be generally susceptible to SCC, but where detailed investigation and remedial action is not practical, and specific locations are difficult to detect and assess. In this case, the choice is usually between ILI and hydrostatic testing (or both), accompanied by the equivalent of an ECA to ensure that the measures and/or testing intervals will be effective in proactively identifying SCC before it becomes critical and/or otherwise affects pipeline integrity.

7.2 References

Barlo, T.J. 1979. Effects of Hydrostatic Retests on Stress-Corrosion Cracking. In *Proceedings from the Sixth Symposium on Line Pipe Research*. PRCI. L30175.

CEPA. 1997. *Stress Corrosion Cracking—Recommended Practices*. Canadian Energy Pipeline Association.

Keifner, J.F., W.A. Bruce, and D.R. Stephens. 1994, revised 1999. *Pipeline Repair Manual*. PRCI. L51716. December.

Koch, G.H., T.J. Barlo, W.E. Berry, and R.R. Fessler. 1983. *Effects of Shot Peening and Grit Blasting on the Stress-Corrosion-Cracking Behavior of Line-Pipe*. PRCI. L51451. April.

Leis, B.N., and R.E. Kurth. 1999. *Hydrotest Parameters to Help Control High pH SCC in Gas Transmission Lines*. PRCI Project PR-3 9404.

8 Regulatory Practices – United States and Foreign

8.1 Scope Statement

"Summarize regulatory practices outside of the United States (i.e., Canada, United Kingdom, Norway, Australia, Russia, Saudi Arabia, and South America)."

In addition to foreign regulatory practice, this scope statement was expanded to include a summary of U.S. standards, regulations, and recommended practice guidelines in the following section. Then the regulatory procedures and guidelines on this subject from different sources can be more readily compared.

8.2 U.S. Regulations and Industry Standards

8.2.1 49 CFR 192 and 195

49 CFR 192 and 195 are the governing regulations for transportation of gas and hazardous liquids by pipeline and present the minimum federal safety standards that must be met in design and operations of pipeline systems within the United States.

Minimum requirements for the protection of gas lines constructed of metallic line pipe from external, internal, and atmospheric corrosion are given in 49 CFR 192, Subpart I. However, SCC is not explicitly covered. Generally, Subpart I requires pipelines to have an external protective coating and a cathodic protection system. Monitoring methods and intervals to verify the proper functioning of the cathodic protection system are also outlined. In addition, remedial measures are discussed for those instances when general or localized pitting corrosion is identified.

49 CFR 195 has similar requirements for protective coatings (§195.238) and cathodic protection systems (§195.242), as well as monitoring and mitigation measures (§195.414, §195.416 and §195.418). Although SCC is not explicitly discussed in 49 CFR 192 and 195, multiple requirements relating to design, construction, operation and maintenance of pipelines have a direct or indirect effect on preventing SCC.

Both 49 CFR 192 and 195 incorporate numerous publications or specific parts of publications by reference (e.g., parts of ASME B31.4) and the applicable standards are discussed below.

8.2.2 ASME B31.4 and API 1160

The ASME Code for Pressure Piping B31.4, *Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids* (B31.4) is the current industry standard for design and operations of liquid pipelines and is incorporated by reference in 49 CFR 195. As with 49 CFR 195, Chapter VIII of B31.4 details minimum requirements and procedures for protection of ferrous line pipe from external and internal corrosion; however, it too does not explicitly discuss SCC. Although SCC is not specifically discussed in B31.4, multiple requirements relating to design, construction, operation and maintenance of pipelines have a direct or indirect effect on preventing SCC.

API Standard 1160 *Managing System Integrity for Hazardous Liquid Pipeline* (API 1160) addresses integrity management for hazardous liquid pipelines, but is not incorporated by reference in 49 CFR 195. API 1160 contains information relating to SCC in multiple locations.

Section 9 of API 1160 includes information about ILI technology and tools in general and Paragraph 9.3.1.2 Crack Detection Tools discusses tools for detection of longitudinally oriented cracks and crack-like features, including SCC. Paragraph 9.4 Determination of Inspection Interval/Frequency includes information relating to SCC, among other types of imperfections. Paragraph 9.5 Limitations of Hydrostatic Testing suggests that hydrostatic testing could initiate growth of time-dependent defects, including fatigue, SCC or corrosion, so that periodic hydrostatic testing may be required to remove defects that have extended over time.

Appendix A Anomaly Types, Causes, and Concerns of API 1160 includes A.1.6.3 Stress Corrosion that provides a brief description of both types of SCC.

Appendix C of API 1160 lists the data fields collected in the Pipeline Performance Tracking System sponsored by API and AOPL. The data fields in Part CD. Conditions Related to Release includes an opportunity to indicate whether a crack tool had been run at the point of failure and the year of the latest ILI. The data fields in Part CR. Corrosion includes stress corrosion cracking as a type of external corrosion related to a release.

8.2.3 ASME B31.8 and B31.8S

The ASME Code for Pressure Piping B31.8, *Gas Transmission and Distribution Piping Systems* (B31.8), and ASME B31.8S, *Managing System Integrity of Gas Pipelines* (B31.8), are the current industry standards for design and operation of gas pipelines and are incorporated by reference in 49 CFR 192 (Portions of B31.8 are also incorporated by reference in 49 CFR 195). As with 49 CFR 192, Chapter VI of B31.8 details the minimum requirements and procedures for corrosion control of exposed, buried, and submerged metallic piping. In addition, B31.8 discusses corrosion protection issues related to pipelines in arctic environments and high-temperature service and, of particular interest for this report, briefly discusses environmentally induced and other corrosion-related phenomena, including SCC in Paragraph 866.

However, the statements made are very general in nature and essentially only acknowledge the phenomena and that operators should be aware of the potential for SCC to occur. The knowledge that has been gathered and current research to better understand the phenomena are mentioned and, in the end, B31.8 "suggests that the user refer to the current state of the art."

The supplement to B31.8, B31.8S, outlines an IMP to address SCC in Appendix A3, *Stress Corrosion Cracking Threat*. This plan only addresses "the threat, and methods of integrity assessment and mitigation for high pH type SCC of gas line pipe." It acknowledges that near-neutral pH SCC would require its own plan. The appendix is divided into six sections:

- Scope
- Gathering, Reviewing, and Integrating Data

- Criteria and Risk Assessment
- Integrity Assessment
- Other Data
- Performance Measures

B31.8S, Appendix A3, discusses two inspection and mitigation activities deemed acceptable for addressing pipeline segments on which a risk of SCC has been identified through the risk assessment process. These methods are Bell Hole Examination and Evaluation, and Hydrostatic Testing. However, if there is an in-service leak or rupture attributed to SCC, the procedure requires the segment to be hydrostatically tested within 12 months.

In Section 6 of B31.8S the use of ILI for SCC threat assessment is generally discussed, with Section 6.2.2 noting the effectiveness of Ultrasonic Shear Wave Tool and the Transverse Flux Tool. Table 4 presents a number of acceptable threat prevention and repair methods for numerous potential pipeline threats, including SCC.

8.2.4 ASME B31G and RSTRENG

ASME B31G, *Manual for Determining the Remaining Strength of Corroded Pipelines* (B31G), is based on research completed by Battelle Memorial Institute in 1971. This work examined the fracture initiation behavior of metal-loss defects caused by corrosion in line pipe to better understand failure mechanisms associated with these defects. ASME B31G, Section 1.2, *LIMITATIONS*, specifically notes: "This Manual applies only to defects in the body of line pipe which have relatively smooth contours and cause low stress concentrations (e.g. electrolytic or galvanic corrosion, loss of wall thickness due to erosion)." However, these methods can be used to evaluate the remaining strength of a length of pipe from which stress corrosion cracks were removed by grinding or buffing, leaving a smooth depression in the pipe wall.

Subsequent to the initial Battelle research, the AGA Pipeline Research Committee assumed responsibility for further research and began developing procedures for predicting the pressure strength of line pipe containing various sizes and shapes of corrosion defects.

The main goal of the research was to "examine the fracture initiation behavior of various sizes of corrosion defects by determining the relationship between the size of a defect and the level of internal pressure that would cause a leak or rupture." The procedure is based on a total of 47 full-scale tests on sampled of line pipe containing actual corrosion defects and was further validated in tests conducted by British Gas.

B31G was later modified to reduce perceived conservatism in the model. A total of 86 burst tests on samples of line pipe containing corrosion defects were conducted to validate the Modified B31G method. RSTRENG (Remaining Strength of Corroded Pipe) was developed from the B31G method to allow assessment of a river bottom profile of the corroded area to provide more accurate predictions of remaining strength.

A comparison of how the three methods determine the area of metal loss associated with a corrosion defect is presented in Figure 8-1.

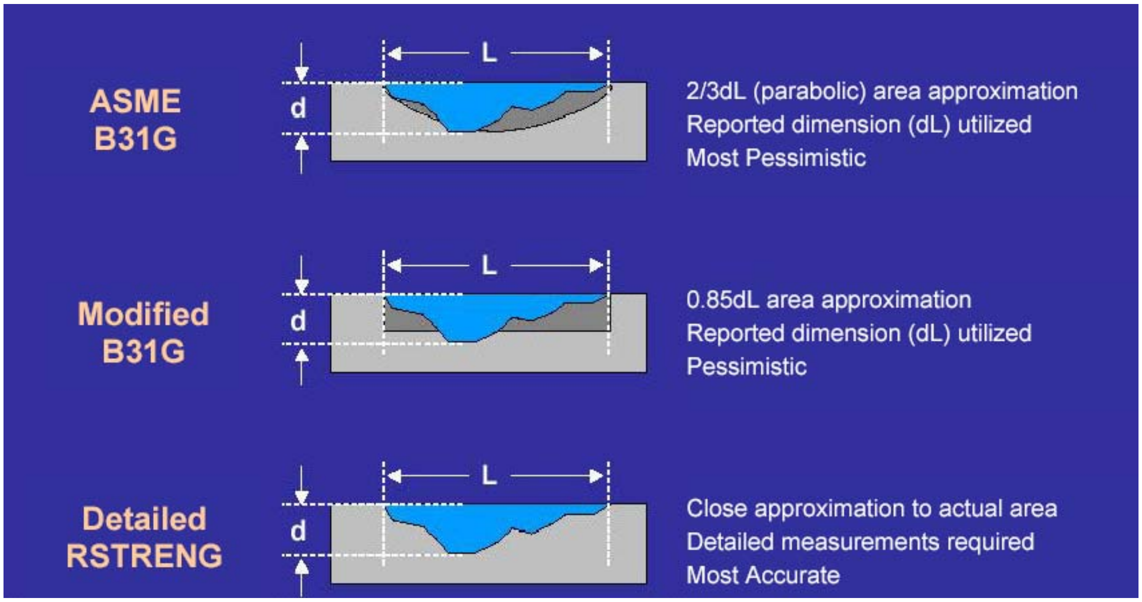


Figure 8-1 Comparison of B31G and Related Methodology

RSTRENG is an iterative technique that computes the "effective area" for a flaw, which is a close approximation of the actual "river bottom" profile of the defect, using a combination of "n" pit readings with a sequence of "m" terms. Thus for a flaw with twenty-four pit readings, RSTRENG takes each pit reading one at a time, then a combination of two at a time, then three at a time, up to twenty-four pit readings at one time, yielding 276 calculations. The lowest failure pressure of the 276 calculations is the failure pressure of the component. The B31G method is a single mathematical expression that produces a conservative result using an assumed parabolic profile for short corrosion ($B \leq 4.0$, where B is determined using a formula that is based primarily on the ratio of the depth of the defect to the wall thickness of the pipe) and a rectangular profile for long corrosion. The Modified B31G is also a single mathematical formula that assumes a rectangular profile with a depth of 0.85 of the maximum depth recorded.

All three methods allow a maximum defect depth of 80 percent of nominal wall thickness and predict failure stress based on an assumed flow stress (1.1 SMYS for B31G and SMYS plus 10 ksi for Modified B31G) and the ratio of area of metal loss to original area with an applied geometry correction factor (Folias Bulging Factor). A defect is considered acceptable if the predicted failure stress level is greater than or equal to SMYS (i.e., burst pressure of defect is greater than the pressure equivalent to 100 percent SMYS).

A general description of the acceptable application of these methods is presented in Figure 8-2. The figure schematically shows the progression of defects with size: from "cracks," then to "grooves" then to "general or areal corrosion." ("Holes" are generally characterized with small equal dimensions in both the circumferential and axial direction, progressing to "pitting" and once again to general or areal corrosion). As shown, B31G and its variations are valid for evaluation of general and areal corrosion, pitting and wall thinning, and *not* cracks, grooves, or holes including SCC. Thus, these methods are *not* applicable for the evaluation of SCC. B31G and other flow strength failure criteria will give non-conservative estimates of the failure pressure for crack-like defects when the failure is fracture toughness dependent. However, as stated above, these methods can be used to evaluate the remaining strength of a length of pipe from which stress corrosion cracks were removed by grinding or buffing, leaving a smooth depression in the pipe wall.

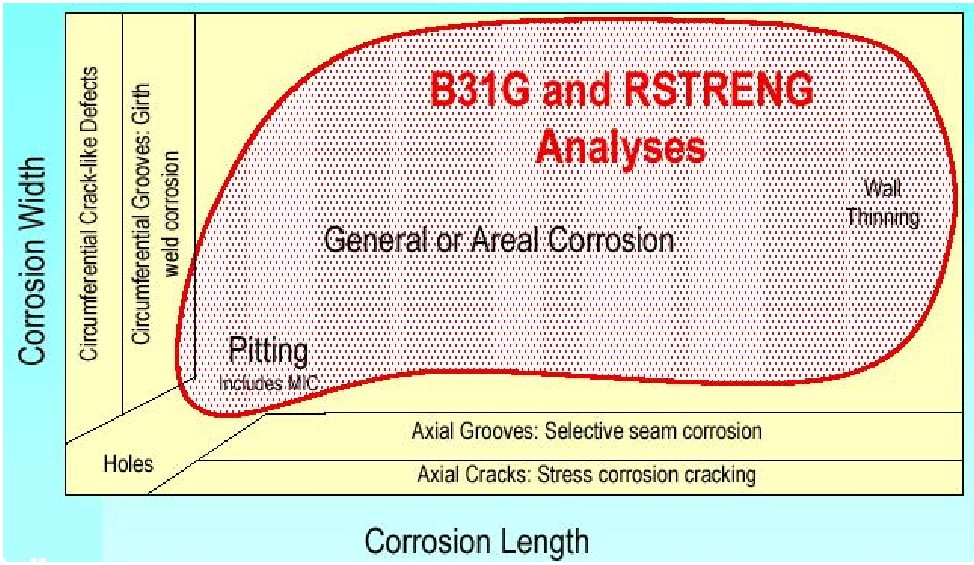


Figure 8-2 Applications Area of B31G and RSTRENG (Battelle)

8.2.5 API RP579

API Recommended Practice 579 (RP579), *Fitness-For-Service*, "provides guidance for conducting Fitness-For-Service (FFS) assessments using methodologies specifically prepared for equipment in the refining and petrochemical industry." FFS assessments are "quantitative engineering assessments which are performed to demonstrate the structural integrity of an in-service component containing a flaw or damage." RP579 is written specifically for ASME and API codes other than B31.4 and B31.8. However, application to pressure containing equipment constructed to other codes is discussed, though the referenced appendix for the primary method is still in development.

Several sections of RP579 are applicable to assessment of flaws or damages of in-service pipelines. In particular, Sections 4, 5, and 6 cover the procedures for assessment of general and local metal loss resulting from corrosion/erosion, mechanical damage, or pitting corrosion. These assessments are geared towards re-rating a line by identifying an acceptable reduced maximum allowable working pressure (MAWP) and/or coincident temperature. Use of these procedures is applicable in cases where "the original design criteria were in accordance with a recognized code or standard."

Section 9 provides guidance on assessment of crack-like flaws that include "branch type cracks associated with environmental cracking" such as SCC. The procedures presented can be applied to SCC "provided a predominant crack whose behavior largely controls the structural response…can be identified." Three levels of assessment procedures are presented.

A Level 1 assessment follows a series of basic steps and does not take into consideration the pipeline material fracture toughness (a measure of its ability to resist failure by the onset of a crack extension to fracture). Therefore, a Level 1 assessment typically results in a conservative solution. It is also limited to the assessment of materials with SMYS lower than 40 ksi.

Level 2 assessments follow a more rigorous procedure based on more detailed material properties, including material toughness, to produce a more exact solution. Level 2 assessments also account for stress distributions near the cracked region including residual stresses (categorized as secondary stresses) from welding. If actual steel yield strengths are available for the pipeline being assessed, the calculations for residual stresses take this into account. However, if only the minimum yield strength is available, an acceptable alternate method for calculating the residual stresses is provided.

Both Level 1 and Level 2 assessments assume that the crack-like flaw is subject to loading conditions and/or an environment that will not result in crack growth. Therefore, Level 1 or 2 assessments can only be used to evaluate SCC if the operator can prove that the SCC colony has become dormant.

The Level 3 assessment provides the best estimate of structural integrity and is the assessment level that is required if sub-critical crack growth is possible. In cases where sub-critical crack growth is possible, a remaining life assessment is also required, along with crack growth monitoring, either in-service or at a shutdown inspection.

8.2.6 NACE International

8.2.6.1 Publication 35103 – External Stress Corrosion Cracking of Underground Pipelines

This report provides a good overview of the SCC phenomenon and how various factors (metallurgical, environmental and stress related) affect the initiation and growth of SCC on pipelines. It also briefly discusses prevention, detection and mitigation. However, as this document was a technical committee report, and not a recommended practice, recommendations and/or guidelines for use by pipeline operators in developing and maintaining an SCC IMP was outside the focus of the report.

8.2.6.2 RP0204 – Stress Corrosion Cracking Direct Assessment Methodology

This recommended practice provides a direct assessment procedure for determining whether a pipeline is susceptible to SCC. The general procedure is essentially the same as that given in B31.8S, Appendix A3; however, additional details, including an expanded discussion of near-neutral pH SCC, are presented. A pipeline is considered susceptible to SCC if all of the criteria for either form of SCC in Table 8-1 are met.

As presented by Dr. J.A. Beavers at the OPS SCC Workshop in Houston, Texas, December 3, 2003, the program consists of a four-step process: pre-assessment, indirect inspections, direct examinations and post-assessment. The pre-assessment and indirect inspections steps entail gathering, reviewing and integrating applicable data on line pipe materials and coatings, and operating conditions, and then performing a risk assessment. The risk assessment consists of comparing the data to the appropriate criteria.

Table 8-1 Direct Assessment Criteria

Description	Criteria
High pH SCC	
Age of Pipe	>10 years
Operating Stress	>60%of SMYS
Operating Temperature	>100ºF
Distance from Compressor Station	<20 miles
Coating Systems	All but FBE
Near-neutral pH SCC	
Age of Pipe	>10 years
Operating Stress	>60%of SMYS
Distance from Compressor Station	<20 miles
Coating Systems	All but FBE

Step 3 entails performing direct examinations (i.e., field digs) to validate the results of the risk assessment. Step 4 then evaluates the results of the risk assessment and the direct examinations to determine whether a mitigation plan is required, determine appropriate reassessment intervals, and validate the effectiveness of the SCCDA method.

Further discussion is presented in Chapter 6.3.

8.2.7 Summary of U.S. Codes and Standards

While research papers, reports and other documentation regarding SCC are voluminous, the majority of current U.S. codes and standards are largely silent on the subject. RP579 provides detailed procedures for evaluating a system once SCC has been identified; however, as stated above, the procedures are not specifically applicable to systems designed and constructed to B31.4 or B31.8, and the referenced validation discussion is not yet available. Similarly, the recently published NACE SCCDA recommended practice, RP0204, does not have the level of detail needed by many operators to implement an effective SCC integrity program.

8.3 Canadian Regulations and Standards

8.3.1 Canadian Standards Association

The National Standards System is the system for developing, promoting and implementing standards in Canada. The Standards Council of Canada coordinates the National Standards System. The Standards Council of Canada is a Federal crown corporation comprising representatives from the federal and provincial governments, as well as from a wide range of public and private interests. It prescribes policies and procedures for developing National Standards of Canada, coordinates Canada's participation in the international standards system, and accredits more than 250 organizations involved in standards development, product or service certification, testing and management systems registration activities in Canada.

There are four accredited standards development organizations (SDO) in Canada: the CSA, the Underwriters' Laboratories of Canada, the Canadian General Standards Board, and the Bureau de normalisation du Québec. Each SDO develops standards according to the procedures stipulated by the Standards Council of Canada, including the use of a multi-stakeholder committee, consensus-based decision making, and public notice and comment requirements. An SDO may submit standards they develop to the Standards Council of Canada to be recognized as National Standards of Canada. SDOs also develop other standards-related documents, such as codes and guidelines (non-mandatory guidance and information documents). CSA develops standards for pipelines.

The CSA Z662-03 Oil and Gas Pipeline Systems standard treats SCC as any other cracking mechanism that poses a threat to the integrity of a pipeline. Some of the requirements in CSA Z662 that would be specifically applicable to SCC include:

- the selection for both field-applied and plant applied coatings (Clause 4);
- the application of several types of plant-applied external coatings (Clause 5);
- the protection of the integrity of coatings during construction and installation (Clause 6);
- properties, application and inspection of coatings (Clause 9);
- the assessment and repair of cracks, including pipe body cracks (Clause 10);
- the development and implementation of an integrity management program (Clause 10); and
- a guide for test methods for the evaluation of coating properties. (Annex L).

CSA started developing pipeline standards in the early 1960s. The CSA Committee on Oil Pipe Line Code started work in early 1962, followed by the Gas Pipe Line Code Committee about a year later. In June 1967, the first edition of CSA Standard Z183, Oil Pipe Line Transportation Systems, was published. In March 1968, CSA Z184, Gas Transmission and Distribution Piping Systems, was also published. The CSA Z183 and CSA Z184 standards were based extensively on the provisions of ASA B31.4 and B31.8, respectively.

Revised editions of both the CSA Z183 and Z184 standards were published until the early 1990s, at which time the two standards were combined. In 1994, the first edition of CSA Standard Z662, Oil and Gas Pipeline Systems, was published after amalgamating the provisions of three standards: CAN/CSA Z184-M92, Gas Pipeline Systems; CAN/CSA Z183-M90, Oil Pipeline Systems; CAN/CSA Z187-M87 (R1992), Offshore Pipeline Systems.

The CSA Standard Z662, Oil and Gas Pipeline Systems, sets out the technical requirements for the design, construction, operation and maintenance of oil and gas industry pipeline systems. The CSA Z662-03 standard is the fourth edition of the standard, and supersedes the 1999 edition.

The standard has been adopted by federal and provincial regulatory agencies that exercise jurisdiction over oil and gas pipelines in Canada. Accordingly, the requirements set out in the CSA standard apply to over 750,000 km of pipelines in Canada.

8.4 Australian Regulations and Standards

In Australia, most standards are published by Standards Australia. Standards Australia is the trading name of Standards Australia International Limited. Standards Australia is an independent, non-government organization. However, through a Memorandum of Understanding, Standards Australia is recognized by the Commonwealth Government as the main non-government standards body in Australia. It is Australia's representative on the International Organization for Standardization, the International Electrotechnical Commission, and the Pacific Area Standards Congress. Standards applicable to pipelines include:

- AS 2885.1 Pipelines – Gas and Liquid Petroleum – Design and Construction
- AS 2885.2 Pipelines – Gas and Liquid Petroleum – Welding
- AS 2885.3 Pipelines – Gas and Liquid Petroleum – Operations and Maintenance
- AS 2885.4 Pipelines – Gas and Liquid Petroleum – Offshore Submarine Pipeline Systems
- AS 2885.5 Pipelines – Gas and Liquid Petroleum – Field Pressure Testing

8.4.1 AS 2885.1 Design and Construction

AS 2885.1, Appendix G, Section G4 "Environmental Related Cracking" gives a brief listing on factors influencing the propensity for high pH and near-neutral pH SCC. Appendix H, also titled "Environmental Related Cracking," gives a more informative description of SCC, including a brief description of the factors listed in Section G4. Appendix A also gives a brief discussion of the conditions necessary for susceptibility of pipeline steel.

8.4.2 AS 2885.3 Operations and Maintenance

AS 2885.3 in Chapter 5, "Pipeline Structural Integrity," Section 5.2, "Operating and Design Conditions," states four base conditions that the operating authority must ensure. It is noteworthy that the fourth condition is:

> d) ensure that operating conditions are such that the likelihood of stress corrosion cracking initiation or growth is minimized.

Again, in Section 5.3, "Pipeline Inspection and Assessment," four items are specified to be included in the inspection program with the fourth condition:

> d) Inspections of any sections on the pipeline identified in the ongoing risk assessment as being of higher propensity for development of stress corrosion cracking.

There is no specific methodology or determination for SCC in this standard aside from these references.

Section 5.4.2.2, "Safety Precautions," discusses measures to be taken when work is carried out on a corroded pipeline. The first sentence notes: "The operating pressure shall either not exceed the pressure at which the corroded portion was subjected at the time of identification, or it should be reduced to a safe level (initially 80 percent of normal operating pressure)."

8.4.3 Australian Pipeline Industry Association

The Australian Pipeline Industry Association (APIA) has ongoing research, including a number of position papers that may be reflected in future AS 2885 editions. AS 2885.1, Issue Number 6.1, Stress Corrosion Cracking (APIA 2003), addresses the implications of a proposed change in design factor from 0.72 to 0.80 with regards to SCC. It is acknowledged that SCC is found on some Australian pipelines, which has resulted in pipeline failures in the past. The Issue paper reviews some of the effects of conditions (e.g., temperature) on SCC.

The paper concludes: "Operating a pipeline with a stress level higher than 72 percent of SMYS can be expected to increase the frequency of occurrence of SCC if other factors relating to SCC remain unchanged." However, the author notes that it can be controlled by compensating measures and concludes that no substantial change to the Standard is necessary.

8.5 European Practices

The European Pipeline Research Group (EPRG) is a leader in investigating SCC, often cited as working in conjunction with PRCI. An example of the reports produced by EPRG is one that deals with the research of a standardized methodology for laboratory evaluation of near-neutral pH SCC. The two major objectives of the report are: 1) to identify the areas with the highest risk of near-neutral pH SCC on existing pipelines so that appropriate measures can be taken: and 2) to produce guidelines for line pipe materials, coating, environment and operating service to reduce the risk of near-neutral pH SCC on future pipelines. It is noted that one major obstacle to effective progress in research is the difficulty to reproduce, in a consistent and reliable way, the cracking pattern and the mechanism actually observed in the field experience.

Another research project was launched in late 1996 under the supervision of EPRG Corrosion Committee involving four laboratories (British Gas R&D, British Steel Swinden Lab, Saltzgitter [former Preussag Stahl] and CSM) with a first phase scope of defining and developing a standardized experimental methodology to obtain reliable data for crack initiation and propagation.

8.6 Other Regulations, Standards and Practices

A pipeline operator in Saudi Arabia reports multiple occurrences of external SCC over the years, with the first occurrence going back to the late 1970s. All the occurrences have been associated with disbonded tape-wrap and associated CP in subka areas (subka is an area with a high water table that from the surface looks dry, but where brine is encountered within approximately one foot of the surface). When the tape wrap disbonds from the pipeline, an alkaline environment forms next to the pipe, and external SCC occurs. The operator reports that use of tape-wrap was discontinued (early 1980s) and all new pipelines are protected by mill-applied FBE external coatings. The operator knows of no FBE-coated pipelines that have experienced external SCC. Recommendation for best practice in Saudi Arabia is to avoid pipeline burial in subka areas, placing the pipeline aboveground or in a berm, and to use FBE coating and CP.

The International Science and Technology Center (ISTC) was established by international agreement in November 1992 as a forum for scientists from Russia and the Commonwealth of Independent States. One of their research abstracts states:

> All countries dealing with exploration of gas and oil face serious problems associated with stress corrosion cracking (SCC) in gas and oil pipelines, which becomes often a

cause of fires, explosions and even of death of people. SCC-related failures lead also to great economical and ecological losses. There is a tendency for increase of the number of accidents on main pipelines because of natural aging of the latter. In Russia, Canada, USA and countries of the European Community, such accidents are reported mostly frequent.

Stress corrosion cracking of pipelines was first detected 30 years ago. But until now, in spite of intensive investigations being carried out in this field, mechanisms of stress corrosion cracking and cause accountable for its development in pipe steel remain poorly studied. This concerns first of all a complex character of the process of stress corrosion, in which a variety of factors interact. It is known now that SCC initiates as a result of the interaction of three conditions:

– cyclic tensile stress;

– metallurgic inherited heterogeneity of pipe steel;

– corrosiveness of the pipe environment.

Analysis of mechanisms of stress corrosion made by us in the framework of Project #1344-D (ISTC) has shown a possibility of the involvement of a great variety of microorganisms in initiation and development of cracks in pipe steel. Evidences in favor of our observations were found in papers on microbial corrosion in metal and alloys. Moreover, there are a number of latest papers describing a possibility of direct participation of some microorganisms in such a specific mechanism of corrosion as hydrogen embrittlement.

8.7 References

49 CFR 192—*Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards*.

49 CFR 195—*Transportation of Hazardous Liquids by Pipeline*.

API Recommended Practice 579 (RP579). 2000. *Fitness-For-Service*.

API Recommended Practice 1160 (RP1160). 2001. *Managing System Integrity of Hazardous Liquid Pipelines*.

APIA. 2003. Revision to AS 2885.1 – Issue Paper No. 6.1, Stress Corrosion Cracking. by Geoff Cope. APIA. April 3, 2003.

AS 2885.1-2001. *Pipelines–Gas and liquid petroleum. Part 1:Design and Construction*. Prepared by Committee ME-038, Petroleum Pipelines. Standards Australia International Ltd. May 5, 1997. (Amdt 1-2001. April 19, 2001).

AS 2885.2-2002. *Pipelines–Gas and liquid petroleum. Part 2:Welding Pipelines.* Prepared by Committee ME-038, Petroleum Pipelines. Standards Australia International Ltd. June 21, 2002

AS 2885.3-2001. *Pipelines–Gas and liquid petroleum. Part 3:Operations and Maintenance*. Prepared by Committee ME-038, Petroleum Pipelines. Standards Australia International Ltd. August 6, 2001.

AS 2885.4-2003: *Pipelines–Gas and liquid petroleum. Part 4:Offshore submarine pipeline systems*. Prepared by Committee ME-038, Petroleum Pipelines. Standards Australia International Ltd. December 22, 2003.

AS/NZS 2885.5-2002. *Pipelines–Gas and liquid petroleum. Part 5:Field pressure testing*. Prepared by Committee ME-038, Petroleum Pipelines. Standards Australia International Ltd. April 4, 2002.

ASME B31.4-2002, *Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids*.

ASME B31.8-2003, *Gas Transmission and Distribution Piping Systems.*

ASME B31.8S-2001, *Managing System Integrity of Gas Pipelines*.

ASME B31G-1991, *Manual for Determining the Remaining Strength of Corroded Pipelines*.

CAN/CSA-Z662-03, *Oil and Gas Pipeline Systems Standard*.

CEPA. 1997. *Stress Corrosion Cracking—Recommended Practices*. Canadian Energy Pipeline Association.

NACE. 2003. *External Stress Corrosion Cracking of Underground Pipelines*. NACE International. Publication 35103. October.

NACE Standard RP 0204. 2004. *Stress Corrosion Cracking (SCC) Direct Assessment Methodology*. NACE International.

NEB. 1996. *Stress Corrosion Cracking on Canadian Oil and Gas Pipelines. Report of the Inquiry*. National Energy Board. MH-2-95. December.

9 Research Gap Analysis

9.1 Scope Statement

"Determine SCC related R&D issues that warrant further research."

The purposes of this section are to 1) identify gaps in the current understanding of SCC of pipelines and ways to manage the problem, 2) identify R&D that could be conducted to fill those gaps, and 3) prioritize the R&D topics based upon qualitative cost/benefit considerations. This section addresses the complete spectrum of R&D from basic research to understand the mechanisms of SCC in line pipe steels through applied research to understand the causes of SCC in pipelines to very applied R&D directed toward developing ways to manage the problem in the field. For each of those areas of research, this section summarizes the results of prior research, identifies remaining gaps, and discusses future R&D directions.

Four factors are considered in terms of the potential benefits of each R&D topic:

- **Safety** of the pipeline system clearly is the most important factor, so the relevance of the R&D to reducing the number of service failures is the first criterion.
- The potential impact on **cost reduction** is important to the pipeline industry and to the general public, because the costs of failures and the costs of prevention or mitigation eventually affect the cost of the product.
- The **size of the knowledge gap** also should be considered. If the level of understanding is relatively high, additional R&D may have a comparatively small effect on decisions regarding safety and cost.
- The **probability of success** in terms of a viable R&D approach that has a good potential for answering the remaining questions also should be considered.

It is not possible to quantify the above benefits, but considering them, with more emphasis on the first two, will allow various R&D topics to be ranked relative to each other in terms of potential benefits.

Quantification of the costs of required future R&D also is not possible without specific knowledge of the approaches that might be proposed by organizations that will conduct the R&D. However, based upon experience conducting R&D on SCC, judgments about the order of magnitude of probable R&D costs have been made.

9.2 SCC R&D Needs Discussion

Appendix A contains discussion of the history of R&D relating to both high pH and near-neutral pH SCC in several areas:

- Mechanisms of SCC
- Causes of SCC

- Methods for Managing SCC
    - Site-Selection Models
    - Crack-Growth Models
    - ILI Technologies
    - In-the-Ditch Sizing
    - Effect of Temperature
    - Steel Susceptibility

Each discussion area presents a summary of the background of R&D in the area, along with a discussion of gaps in the effort in each area. Generally, the discussion is targeted at making distinctions based on the four factors presented in Section 9.1 for each R&D area.

9.3 Prioritization of R&D Gaps

9.3.1 Criteria for Prioritizing

The research approaches to address the various knowledge gaps identified in Appendix A can be grouped into the following eight topics:

1. Develop improved site-selection models. Traditionally, most models have focused heavily on soil and terrain characteristics. In order to be more reliable and more broadly applicable, such models probably also should include some or all of the following: operating pressure and temperature history, cathodic-protection history, coating condition, manufacturing records (mill and year of production), and construction records. In addition to research directed specifically at model development, this topic also would include basic research into the role of hydrogen in near-neutral pH SCC and the field environments that cause near-neutral pH SCC, because both of those subjects are related to identifying probable locations of SCC. This topic also is directly related to SCCDA.
2. Develop improved crack-growth models. This topic would include research into the effect of stress fluctuations on crack growth and should deal with both high pH SCC and near-neutral pH SCC.
3. Develop or identify new approaches or technologies for ILI, particularly for gas pipelines. This would involve a search for technologies other than the traditional approaches that rely upon magnetic-flux leakage or ultrasonics.
4. Develop new tools based upon emerging technologies such as EMAT.
5. Develop improved methods for sizing cracks in the ditch.
6. Determine the effects, if any, of temperature on near-neutral pH SCC.
7. Correlate SCC susceptibility with the composition and microstructure of the steel. The purpose would be to provide guidance for developing steels that are highly resistant to SCC. In this approach, the correlations would be based upon statistical analysis of the

SCC behavior of a number of different experimental or production steels, and it would not necessarily result in a fundamental understanding of the reasons for improved resistance.

8. Develop a fundamental understanding of the relationship between SCC susceptibility and the composition, processing, microstructure, and mechanical properties of steels. Compared with the empirical approach of Item 7, this approach would provide a true understanding of the relationships among the important variables and thus produce a higher level of confidence in the results. However, it would be much more time consuming and expensive.

The following section discusses the benefits of conducting more research into each of those topics in terms of the potential impact on safety, the potential for reducing cost, the size of the knowledge gap, and the probability that the research will be successful.

9.3.2 Benefit Analysis

Site-Selection Models. The ability to predict where SCC is likely to occur would be valuable in terms of safety because it would allow pipeline operators to focus their attention on areas of highest risk and to prioritize their actions. Even an incomplete model that is not entirely predictive could be useful. For example, a possible correlation between terrain data and coating condition might help narrow the regions of interest. Just as important would be the ability to predict where SCC is not possible, because it could eliminate wasted efforts and costs of dealing with portions of the pipeline that are not susceptible to SCC.

Because of the many factors that affect the probability of SCC and the difficulty of measuring some of them, SCC detection and mitigation is challenging for operators. For example, soil chemistries and geological conditions are extremely complex, the condition of the coating may be unknown, the susceptibility of the steel probably will be unknown, and the history and relevance of prior operating conditions such as pressure fluctuations and cathodic protection levels may be difficult to interpret. Thus, the probability of developing a comprehensive, highly accurate predictive model may not be high, but even limited success could be very useful, especially with respect to direct assessment.

Crack-Growth Models. Once stress corrosion cracks are discovered in a pipeline, it would be very beneficial from a safety standpoint to be able to predict how long those cracks could be left in the line, either under normal operating conditions or modified operating conditions. The ability to relate crack growth to operating conditions also would be very important for direct assessment, as operating history would be one of the factors to consider in evaluating the probability of SCC in an area of interest. Improved crack-growth models also could have a large impact on cost reduction because they would be the basis for calculating optimum intervals between hydrostatic tests or ILI runs, and for areas where the maximum crack growth rate could be shown to be very low, the need for any remedial measures might be eliminated. Although simplified crack-growth models currently exist and are useful, significant technical challenges remain for making the models more accurate, especially involving issues such as the relationship of crack growth to pressure fluctuations, time-dependent changes in the creep resistance of the steel, and predicting the environmental conditions at the surface of the pipeline. Nevertheless, reasonable approaches to those issues have been suggested and further improvements in the models, therefore, can be expected.

New ILI Technologies. Probably the ideal way to manage SCC would be to use a low-cost ILI technology that could locate cracks, differentiate them from other anomalies, and provide an accurate description of their sizes.

Unfortunately, current commercial tools are very expensive to run, and the most reliable ones are only applicable to liquid-filled pipelines. Therefore, there is a strong desire from both safety and cost perspectives to find a new, lower cost alternative, especially for gas pipelines. There is a significant challenge to conceive an approach that has not already been pursued by the ILI industry. However, several new concepts currently are being investigated, and other ideas should be encouraged and explored.

Develop and Evaluate Tools for Emerging ILI Technologies. An ILI tool for a pipeline must be extremely sensitive in order to detect the very small defects of interest and, at the same time, be very rugged to survive the journey through the pipeline. Therefore, the development of a tool can require tens of millions of dollars. New tools based upon technologies such as EMAT and circumferential MFL are appearing on the market, but their reliability and accuracy have not been confirmed. If successful, these technologies could have a major impact on safety, but will be very expensive for operators to purchase and maintain.

In-the-Ditch Measurements. From a safety standpoint, it should not be necessary to remove very small stress corrosion cracks from a pipeline, especially since many probably are dormant, and it certainly would not be economical to do so. However, current methods of measuring or estimating the sizes of the cracks are either very expensive and time consuming or unreliable. Development of a reliable nondestructive technique would be very desirable. Ultrasonic techniques appear to offer the most promise, but they need to be made more reliable and less cumbersome and expensive. Electromagnetic techniques also offer some promise, but their reliability must be increased, probably through improved technology, calibration methods, and cleaning procedures.

Temperature Effects. Temperature effects on high pH SCC are well enough understood that further R&D probably would not improve safety or reduce costs. While temperature effects on near-neutral pH SCC are less well established, field experience by the industry would suggest that temperature probably is not a significant factor for that form of SCC.

Correlate Steel Susceptibility with Composition and Microstructure. Although recent research suggests that the susceptibility of a steel to near-neutral pH SCC might be related to the microstructure, the correlations are based upon a very limited number of batches of steel. Data from many more batches will be necessary to confirm the correlations, if they are valid. The priority for this topic is somewhat lower than for other topics because other approaches for future pipelines such as improved coatings and surface treatments (shot peening or grit blasting) are relatively low-cost alternatives.

Develop Fundamental Understanding of Relationship Between Steel Susceptibility and Composition, Processing, Microstructure, and Mechanical Properties. Empirical correlations, as described above, always leave some doubt as to their reliability and range of conditions over which they are valid. A fundamental understanding of the factors that affect steel susceptibility would provide a much better basis for designing a resistant steel than would an empirical correlation. However, developing such a fundamental understanding would require lengthy basic and applied research and large budgets.

The potential benefits related to each of the suggested research areas are summarized in Table 9-1.

9.3.3 Cost Analysis

The probable costs to complete each of the research areas mentioned above have been estimated based upon experience with similar previous research efforts. Because precise cost estimates would depend upon the specific approaches chosen for each area and the organization that would conduct the research, only order-of-magnitude estimates are possible at this time. The estimated costs are summarized in Table 9-2, where the following definitions apply:

Very High: Greater than 10 million dollars

High: Several hundred thousand to 2 million dollars

Medium: 1 hundred thousand to several hundred thousand dollars

Low: 50 to 100 thousand dollars

Table 9-1 Qualitative Rating of Potential Benefits from Various Research Areas

Research Area	Magnitude of Benefit			
	Safety	Cost Reduction	Size of Gap	Probability of Success
Site-Selection Models	High	Very High	High	Medium
Crack-Growth Models	Very High	Very High	High	High
ILI – New Technology	Very High	Very High	Very High	Medium
ILI – Develop Tool	Very High	Medium	Medium	High
In-the-Ditch Measurement	High	Medium	Medium	High
Temperature Effects	Low	Low	Low	High
Steel – Empirical Approach	Medium	Low	Very High	Medium
Steel – Fundamental Approach	Medium	Low	Very High	High

Table 9-2 Qualitative Rating of Costs to Complete Various Research Areas

Research Area	Cost
Site-Selection Models	High
Crack-Growth Models	High
ILI – New Technology	Medium
ILI – Develop Tool	Very High
In-the-Ditch Measurement	Medium
Temperature Effects	Low
Steel – Empirical Approach	Medium
Steel – Fundamental Approach	High

9.3.4 Summary of R&D Priorities

Based upon the benefit and cost analysis described above, each of the suggested research areas has been represented in Figure 9-1 in terms of a qualitative cost/benefit ranking. By necessity, the axes do not contain numerical values, and the positioning of each point is highly judgmental. It would be appropriate to think of the axes as logarithmic scales.

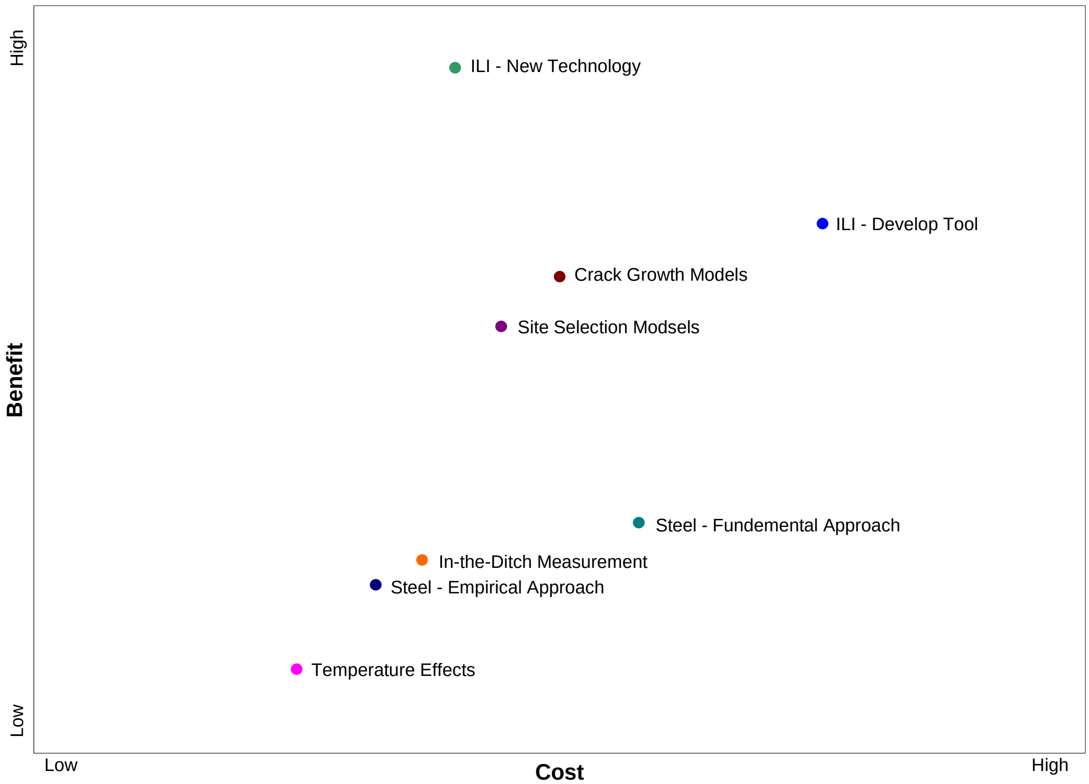


Figure 9-1 Qualitative Ranking of Research Areas by Cost/Benefit Ratio

9.4 References

(References to the R&D areas are contained at the end of Appendix A).

10 Industry Practice Regarding SCC

10.1 Scope Statement

"Develop a practicable procedure regarding how to assess SCC in operating pipelines within the context of integrity management."

This work item is addressed first in Chapter 10 and concluded in Chapter 11. This first chapter addresses both the capabilities of current practice and through an operator survey and operator interviews, the current methods of implementation by the industry. Chapter 11 addresses the same issues, but from the viewpoint of how these practices fit within and address the regulatory requirements of an Integrity Management (IM) program.

10.2 Questionnaire Concerning Current Assessment Procedures

In order to understand and assess the practices employed by operators to address SCC, Baker prepared a survey document to assist in gathering information from pipeline operators on SCC occurrence history and operating company practices for SCC detection, management and mitigation. The survey was drafted by Baker and reviewed by a working committee of AGA, AOPL, API, and INGAA, headed by Dave Johnson of Cross Country Energy Services, LLC, which made suggestions for improvement. The comments aided in streamlining the survey in order to provide for the rapid gathering of relevant information. The survey and cover letter were sent to member companies by the trade associations themselves. A copy of the survey and cover letter is included as Attachment A.

In endorsing the completion of the survey, INGAA and API, in their cover memo to member companies, stressed the importance of industry input into the process. The AGA also distributed the survey to their member companies who operate a reasonable amount of transmission pipelines that could be affected by SCC.

Forty-two survey forms were returned, with one additional response made via email only. These responses represent 34 distinct operating entities, representing 45 natural gas and liquid pipelines. Note that one form addressed multiple pipeline systems, while other forms covering separate pipelines were reported by the same person or group. Also, note that not all respondents answered every survey question. Because the trade associations distributed the survey forms, the percentage of respondents from the original distribution cannot be determined. In general, however, the level of response was considered good, and appreciation is given to AGA, AOPL, API and INGAA for their support.

10.3 Summary of Questionnaire Responses

10.3.1 SCC Occurrence Information

Twenty-three of the responses indicated that SCC had been detected, with the earliest detection noted as 1965. The years since installation at the time of first detection ranges from 7 years to 70 years, with an average of 29 years. It is important to note that, typical of such responses with a relatively small data base, numerical averages are skewed by disproportionate numbers that may be attributed to a relatively small sampling of pipelines. For example, one operator reported 46 SCC in-service failures. Five other operators reported over 30 hydrostatic test failures apiece, with the highest reported by two operators being, coincidentally, 61. Thus, the numerical average numbers developed from this operator survey, such as of SCC in-service and hydrostatic failures (six and fifteen, respectively) can be misleading, and should not be construed as representative of industry averages.

Based on the responses received, the number of main line valve sections where SCC has been detected ranged from 48 percent down to 0.1 percent of the total number of mainline valve sections comprising each pipeline system. Approximately 45 percent of the SCC occurrences found were during inspections specifically for SCC, another 35 percent of the SCC occurrences were noted as found during an inspection specifically for SCC or during an inspection for other reasons, while the remaining 20 percent were found during an inspection not specifically looking for SCC.

Of the pipelines where SCC was noted by the respondents as having been detected (23 pipelines), 65 percent (fifteen pipelines) are natural gas lines and 35 percent (eight pipelines) are liquids lines. Since mitigation, 20 of these pipeline were reported as not having experienced additional in-service or hydrostatic test failures.

10.3.2 SCC Detection Methods

There are several NDE methods available for identifying SCC on a pipeline system. The most common include:

- Visual – The pipeline is exposed and the external coating is examined for soundness and performance. The coating is then removed at locations where disbonding is suspected and a technician examines the pipe surface for evidence of cracking. Note that normally SCC colonies cannot be detected by the unaided eye.
- Magnetic Particle Inspection – The pipe is examined visually with the assistance of MPI.
- Liquid Dye Penetrant – The use of dyes on the surface of the pipe to enhance the visualization of cracks.
- Eddy Current Testing – The use of ET to detect cracking.
- ILI Tool – MFL, TFI, EMAT, etc.

On the survey form, the respondents could make multiple selections as to the methods employed. The percentages of distinct operator entities utilizing each of the NDE methods for SCC detection described above are summarized in Table 10-1.

Table 10-1 NDE Methods Used for SCC Detection

NDE Method	Number of Operators	Percent of Operators
Visual	21 (of 34 operators)	62%
Magnetic Particle	18	53%
Liquid Dye Penetrant	5	15%
Eddy Current	1	3%
ILI	10	29%
Other	5	15%

For the "other" category, operators comments included: Destructive laboratory methods, metallurgical examination and optical microscopy; 100 mV Shift close-interval survey, direct current voltage gradient; field ultrasonic techniques; and, metallography.

Of the operators that responded as to whether or not they had written procedures for NDE evaluation, physical field practices for SCC detection, and/or reassessment intervals if SCC is detected, 81 percent (26 of 32), 73 percent (24 of 33) and 50 percent (16 of 32) responded "yes," respectively.

10.3.3 SCC Management

There are a number of management practices available for SCC. The following is a list of management practices specifically noted on the survey form:

- Failure History Characterization – Use information of past SCC failures as an indication of the specific conditions that may result in the future occurrence of SCC.
- Coating Type Characterization (Coal Tar, Tape, etc.) – Characterizes the condition and type of coating, and correlates the information with the occurrence of SCC.
- Pipe Material Characterization (API Grades, Pipe Mill, etc.) – Characterizes the type of line pipe and correlates it to the occurrence of SCC.
- Operation Characterization (Pressure, Temperature, etc.) – Correlates the specific operating conditions of the pipeline with the occurrence of SCC.
- Location Characterization – Correlates the environmental conditions near the pipeline with the occurrence of SCC.
- Age Characterization – Correlates the age of the facilities with the occurrence of SCC.
- Bell Hole Characterization – Results of buried pipe inspection reports are utilized to determine if there are common characteristics in pipe with SCC compared to pipe with no SCC utilizing trending analysis.
- Magnetic Flux Leakage ILI Characterization – Utilization of MFL ILI tools to detect SCC.
- Other ILI Characterization – Utilization of other ILI tools to detect SCC.
- Cathodic Protection Level Characterization (Voltage Levels) – Monitoring of CP voltage levels at locations with and without active SCC for use as a predictive tool.

- Hydrostatic Retest Program – Testing pipe to determine presence of SCC. If test pressure critical size cracks are present, a rupture of the line will likely occur.
- External Corrosion Direct Assessment
- Risk Assessment Ranking (Segment by Segment Comparison)

On the survey form, the respondents could make multiple selections as to the methods employed. The percentages of distinct operator entities utilizing each of the SCC management practices described above are summarized in Table 10-2.

Table 10-2 SCC Management Practices

SCC Management	Number of Operators	Percent of Operators
Failure History Characterization	20 (of 34 operators)	59%
Coating Type Characterization	20	59%
Pipe Material Characterization	9	26%
Operation Characterization	21	62%
Location Characterization	13	38%
Age Characterization	15	44%
Bell Hole Characterization	13	38%
Magnetic Flux Leakage ILI Characterization	13	38%
Other ILI Characterization	8	24%
Cathodic Protection Level Characterization	13	38%
Hydrostatic Retest Program	14	41%
External Corrosion Direct Assessment	9	26%
Risk Assessment Ranking	13	38%

Approximately 48 percent (16 of 33) of the operators who responded when asked whether or not they had written procedures for SCC management answered “yes.” Of the 14 distinct operators who indicated how long these written procedures had been in place, four stated that they have had a written procedure for 30 or more years on at least one of their pipeline systems. Six operators indicated implementation of written procedures within only the last four years on at least one of their pipeline systems.

10.3.4 SCC Mitigation

SCC mitigation techniques identified in the survey include:

- Operating Condition Modification (Pressure or Temperature Reductions, etc.)
- Selective Sleeve Installation
- Clean Pipe and Recoat
- Grind Pipe and Recoat
- Soil Condition Modification (Drainage Pattern Change, Replacement or Chemical Treatment of Soil, etc.)

On the survey form, the respondents could make multiple selections as to the techniques employed. The percentages of distinct operator entities utilizing each of the SCC mitigation techniques described above are summarized in Table 10-3.

Table 10-3 SCC Mitigation Techniques

SCC Mitigation	Number of Operators	Percent of Operators
Operating Condition Modification	17 (of 34 operators)	50%
Selective Sleeve Installation	17	50%
Clean Pipe and Recoat	12	35%
Grind Pipe and Recoat	15	44%
Soil Condition Modification	2	6%
Other	15	44%

Of the 31 operators that responded as to whether or not they had written procedures for SCC mitigation, approximately 52 percent (16 operators) responded "yes."

10.4 Operator Interviews

A series of operator interviews were conducted subsequent to receipt of the responses to the questionnaire. The operators were very cooperative in supplying information regarding their procedures and policies. Results from the interviews are summarized in Table 10-4 with additional details in the following sections.

Table 10-4 Summary of Operator Interviews

	Operator						
	A	B	C	D	E	F	G
Operates hazardous liquid (L) or gas (G) transmission pipelines.	G	G	L	G	G	G	L
Has operator experienced in-service failures (leaks or ruptures) attributed to SCC? Yes (Y) or No (N)	Y	Y	N	N	Y	Y	Y
Has operator experienced hydrostatic testing failures (leaks or ruptures) attributed to SCC? Yes (Y) or No (N)	Y	Y	N	Y	Y	Y	Y
Has operator discovered SCC using ILI (I) or MPI (M)?	I/M	I/M	I/M	M	I/M	M	
Has operator attributed observed SCC to high pH SCC? Primarily (P), Mixed (M), None (N)	P	M		P		P	P
Has operator attributed observed SCC to near-neutral pH SCC? Primarily (P), Mixed (M), None (N)		P	P	N	P	N	N
Does operator consider ILI reliable for detection of SCC? Yes (Y) or No (N)	N	N	Y	N	N	N	
Does operator rely primarily upon hydrostatic testing for detection of SCC? Yes (Y) or No (N)		N	N	Y	Y	Y	Y

10.4.1 Operator A

Operator A operates several major gas pipelines. A southern pipeline had 14 in service failures. All of these were at tape coating sections. Since they instituted a spike test, followed by normal hydrotest, they have experienced no further in-service failures in this line, although there have been some test failures. They established their re-inspection interval based on an early Life Prediction Model developed by Brian Leis/PRCI. Currently they are using a 7-year re-test interval.

One of their northern lines had instances of SCC detected by inspection of sites selected as potentially favorable for occurrence of SCC, based upon the experiences of TCPL. Crack depth in all instances was less than 10 percent of the wall, and the repair procedure was to grind out the SCC indications.

Generally, FBE external coating has performed well and Operator A concludes that FBE should be viewed as a mature coating that consistently performs well given good application procedure. They specify 14-16 mils thickness for FBE.

Operator A has issued an internal safety advisory bulletin on SCC while a procedure for inspection of pipe under disbonded coating for SCC is being developed. Operator A performs wet fluorescent magnetic particle inspection (WFMT) whenever there is evidence of a disbonded coating. They are currently training in-house corrosion technicians/engineers to the latest draft of their SCC procedure and expect to adopt it as an operating procedure once their in-house resources are fully trained to the procedure. The instances and evaluation of these excavations will be added to their in-house database.

The idea of operators sharing their individual databases relating to occurrence of SCC with the pipeline industry was discussed. Operator A believes an industry-wide SCC database might be helpful, and would consider participation if individual corporate names associated with the data need not be attributed within the database. An industry organization such as PRCI might be a good "clearinghouse" for an SCC database.

Concerning ILI, Operator A has concluded that the ILI industry does not offer an effective tool for detecting SCC in gas pipelines. Operator A tried and abandoned use of the liquid coupled elastic wave tool, and mentioned that running tools in slugs is expensive and disruptive to operations, requiring drying the line in addition to the other considerations. The possibilities of EMAT were discussed, though no specifics were available.

Operator A recognizes that initiation of SCC, as well as reactivation of dormant SCC, is related to strain rates imposed by pressure cycles being within a critical range; however, they note that control of pressure cycles to avoid the critical range of strain rate is not feasible.

To summarize, Operator A asked that SCC be characterized in perspective to a number of operational considerations, including not only other more frequent failure modes, but also concerns over supply reliability. Pipelines that cannot be pigged must be shut down in order to perform an integrity assessment using hydrostatic testing. Interrupting operation of a single pipeline that supplies power plants or local distribution companies may have significant economic impact upon a community and result in other public concerns and safety issues. Direct assessment for identification of SCC has not proven sufficiently reliable to substitute for hydrostatic testing.

Operator A identified a need for collaborative funding for improvement in ILI tools for detection of SCC, and for development and validation of direct assessment methods for SCC.

10.4.2 Operator B

Discussion with Operator B was limited to their interstate gas pipelines. The original pipeline was constructed in 1931 and was assembled by oxy-fuel welding and couplings, and has since been phased out of operation. The remaining looped pipeline segments date from the 1940s to 1970s and is predominately NPS 30 and 36.

This portion of Operator B's system experienced two in-service failures identified as classic or high pH SCC in 1973 and 1984. These two failures were classic in that they were located in the first valve section downstream from a compressor station. After these two SCC failures, Operator B initiated a program of hydrostatic testing for the first valve sections downstream from compressor stations. Initially these hydrostatic tests were spike tested at 105 percent of SMYS followed by 7 hours at 93 to 100 percent SMYS. Later the test procedure was revised to spike-type tests at 100 to 110 percent of SMYS for 1 hour followed by 100 percent of SMYS for 7 hours.

Operator B has not experienced hydrostatic test failures attributed to classic SCC, nor have they identified other classic SCC incidents as a result of inspection of exposed pipe.

Operator B has experienced multiple in-service failures attributed to near-neutral pH SCC on NPS 26, 30 and 36 pipeline segments coated with asphalt enamel external coating. Subsequent hydrostatic testing and direct examination has revealed other instances of near-neutral pH SCC associated with disbonded asphalt enamel coating.

Operator B has observed the following characteristics of near-neutral pH SCC on their large-diameter system:

- Asphalt enamel coating that has disbonded, typically around the full circumference of the pipeline, and for a significant distance along the length of the pipe, but remains intact as a shell around the pipe.
- A film of water between the disbonded external coating and the pipe surface.
- Adherent surface deposits containing:
    - rust-colored iron oxide,
    - powdery white calcium carbonate, and
    - pasty white iron carbonate.
- Shallow pitting corrosion.
- Families or colonies of parallel cracks aligned with the axis of the pipeline (circumferential SCC has not been observed). Most cracks are relatively shallow, but linked cracks have been sufficiently deep to cause the in-service failures at normal operating pressures.

Operator B has prepared an SCC Comparator that is distributed to field personnel who may be present at excavation sites and have occasion to observe and report on the condition of the pipeline. The SCC Comparator is a laminated sheet printed front and back that includes color photographs of known instances of SCC that field personnel can reference during direct examination of excavated pipe. Field personnel who observe the characteristics in the above bullet list are instructed to request that a corrosion specialist inspect the pipe further for SCC.

After the second in-service failure attributed to near-neutral pH SCC, Operator B contracted with GE-PII to perform an ILI with their Elastic Wave Tool on the pipeline that experienced the failure. Subsequent direct examination revealed that while the Elastic Wave Tool can detect SCC, other surface conditions that are not injurious to integrity are also reported. The number of indications that are not SCC may exceed the number of SCC indications by three to ten.

Operator B has invested considerable effort to identify other information that can be integrated with the results from the Elastic Wave Tool to increase the probability of identifying near-neutral pH SCC at a dig site. Operator B reports that integration of results from:

- a high-resolution MFL tool, graded for external corrosion depths up to 10 percent pipe body wall penetration,
- the Marr Associates Soil Characterization/SCC predictive model, and
- close-interval CP survey,

combined with the results from the Elastic Wave Tool significantly increases the probability of correctly predicting the location of near-neutral pH SCC on their system.

The MFL tool results are graded to identify indications of pitting corrosion with up to 10 percent wall loss (different from grading for identification of significant wall loss) but with no deeper corrosion. Locations with relatively minor pitting corrosion are likely to be associated with disbonded, but intact external coating with corrosive water between the coating and pipe surface.

The Marr Soil Model identifies locations where near-neutral pH SCC may occur if disbonded coating is present.

Acceptable results from close interval surveys at locations with pitting are consistent with absence of extensive coating holidays, but are an indication that the coating is disbonded, intact, and shielding the pipeline from cathodic protection.

By application of all of the above criteria, Operator B identifies locations with otherwise minor pitting corrosion that could occur under disbonded coating, soil conditions that may cause SCC and indications of surface conditions that may be SCC.

During excavation and direct examination of locations selected by the screening method, the pipe surface is evaluated by visual examination for deposits. The pipe surface is cleaned with a brush-off blast and examined for shallow pitting corrosion and with MPI, typically using the wet black powder on white background.

Operator B employs manual UT to evaluate depth of near-neutral pH SCC revealed by MPI.

Depending upon depth of identified SCC, Operator B may or may not grind the cracks to sound metal and abrasive shot blast the pipeline followed by epoxy coating, or replace the section with new line pipe.

Operator B reports application of epoxy coating to all large diameter pipe exposed for direct examination and considers that to be a permanent solution to avoiding SCC at the recoated locations, even if minor surface cracks remain.

Operator B hydrostatically tests each valve section where near-neutral pH SCC has been identified, examined and repaired. Operator B acknowledges that shallow near-neutral pH SCC under disbonded coating that was not removed for direct examination may survive hydrostatic testing and may eventually grow deeper.

Operator B has a 3-year contract with GE-PII for ILI services and works closely with GE-PII to improve reliability of their tools for detection of SCC in gas transmission pipelines. Operator B has previously been an active member of the AGA-Pipeline Research Committee (now Pipeline Research Council International, Inc.) for decades and favors cooperative funding of the improvement of ILI technology for detection of SCC.

10.4.3 Operator C

Operator C operates thousands of miles of large diameter lines through out Canada and the US. These lines range in size from NPS 10 to 48. The system transports liquids with roughly 50 different commodities from jet fuel to crude oil. Another group operates the gas transportation side of their business.

The dates of construction for the system range from the 1940s to the present. The coating type varies with somewhere between 30 and 40 percent being polyethylene tape wrap. The current coating of choice for new construction is FBE, though the use of a three-part powder polyethylene coating was mentioned. Nearly all of their system is designed to allow passage of ILI tools.

Operator C employs approximately 30 people within their integrity management group. The overall program is driven by the company's main goal of NO leaks.

They approach SCC as just one portion of an overall defect management program, which attempts to prevent the occurrence of defects, locate defects that do occur and mitigate defects as appropriate. They use ILI as the primary source of data gathering. In particular, the use of high-resolution UT tools has been used effectively for detection of SCC. While they rely upon the ILI tool vendors for initial data processing, they apply in-house knowledge to validate and improve ILI data interpretation. This has resulted in reducing the number of false positive anomaly reports. They anticipate conducting nearly 6,000 miles of ILI this year.

They do not utilize a specific hydrostatic testing program for defect management as they feel that ILI is more accurate and cost effective.

Operator C performs approximately 1,000 digs per year based on ILI results. Whenever the pipe is exposed, MPI (black-on-white) and ultrasonic testing (shear wave) is conducted. The lack of a specific American Society of Nondestructive Testing training manifest for pipeline inspectors was mentioned as an area of potential improvement.

They currently base SCC FFS analysis on the AGA NG-18 ln-secant formula for critical flaw size, though they noted that this is not entirely appropriate since this formula is for analysis of a semi-elliptical flaw, which is somewhat different than what occurs within an SCC colony. They have been conducting burst tests on cut-out sections of pipe containing SCC with results being collected in an empirical database, which can then be used to refine the FFS analysis.

Operator C feels that the pressure cycle/profile or, in actuality, the strain rate associated with pressure fluctuations has a direct effect on the growth and dormancy of SCC. High strain rates equates to high occurrences of SCC.

The majority of SCC found has been the near-neutral pH type, which is consistent with the general findings that near-neutral pH SCC occurs more on pipelines that experience low soil temperatures. It was postulated that related to the higher solubility of carbon dioxide at lower temperatures.

If SCC is found, the cracks are ground out if possible with pressure capacity checks being made using RSTENG. If necessary, full encirclement, pressure-containing sleeves are installed over the area, or if SCC is present over a large area, an entire section may be replaced. In any case, the repaired section is recoated with the recoating extending virtually the entire length of the excavation.

While Operator C has not had any failures related to SCC (they have experienced corrosion fatigue incidents), they indicated that post-incident response would initially be the same as any incident. They have procedures in place on accident investigation including transportation of failed sections and laboratory examination. If the forensic investigation concludes that the cause was SCC, then their integrity management program is used to determine an appropriate long-term response. In the opinion of Operator C, a pressure reduction to 80 percent of the level at which the failure occurred, which is widely applied when responding to an SCC incident, is effective approximately 80 percent of the time; however, additional site-specific analysis is needed to determine the final long-term response.

Operator C cooperates with and supports both PRCI and CEPA in basic research, but also performs substantial in-house research on ILI, repair techniques and non-destructive evaluation.

10.4.4 Operator D

Operator D operates multiple pipeline systems that include thousands of miles of pipeline transporting gas from the Gulf Coast to the Northeast USA. One of these systems is nearly 100 percent piggable and has been entirely pigged. Another of the systems is approximately 75 percent piggable, and all of the piggable sections have been pigged. The systems include approximately 170 valve sections that are immediately downstream from compressor stations.

The Integrity Management Program for Operator D is organized under a Director of Pipeline Integrity & Operational Compliance who reports to the Vice President of Operations. Responsibility for mitigation of SCC is assigned across three groups headed by Managers reporting to the Director.

- Manager - Operational Compliance
- Manager - Pipeline Integrity
- Manager - Metallurgical Services

Operator D was proactive in initiating a hydrostatic testing program of the first valve sections downstream from compressor stations in 1986 without suffering an in-service failure. To date, Operator D has tested 63 valve sections containing approximately 1,343 miles of pipeline. Operator D employs a spike hydrostatic test program with the test pressure for the first hour producing a hoop stress greater than 100 percent of SMYS, and the remaining seven hours at a test pressure producing a stress greater than 90 percent to SMYS. Operator D routinely employs a flame-ionization leak survey immediately after return-to-service from hydrostatic testing, followed by one or two subsequent leak surveys after two or three month intervals. Operator D considers the post-test flame-ionization leak surveys technically superior for detection of small leaks compared to the seven-hour hold period of hydrostatic testing.

Operator D has experienced approximately 12 pipeline failures (leaks and ruptures) during hydrostatic testing that were attributed to SCC, but no in-service failures have been attributed to SCC. Operator D considers that the hydrostatic testing program has demonstrated success in avoiding in-service failures due to SCC.

When a hydrostatic testing failure attributed to SCC has occurred in a valve section, that valve section is characterized as an SCC Susceptible Site for purposes of retesting. The next downstream valve section may also be included in the test program. Valve section characterized as SCC Susceptible Sites are scheduled for retesting, with the first interval being 3 years. If the re-test of a valve section classified as an SCC Susceptible Site does not result in a failure attributed to SCC, the retesting interval is extended one year. Consequently, the re-testing intervals could increase from 3 years to 4, 5, etc. years as long as no other failures were attributed to SCC. The hydrostatic retest criteria have been effective, but will require some changes to accommodate the next integrity assessment criteria of the federal IMP regulations.

All SCC that Operator D has observed has been confined to approximately 6 valve sections and classified as classic or high pH SCC. All observed SCC has been oriented longitudinally, or no circumferential SCC has been observed. Observed SCC has generally been on the lower portion of NPS 26 and 30 pipes, and associated with disbonded coal tar enamel (80 percent of incidents) or asphalt coating (20 percent).

Operator D has attempted ILI for SCC using both the elastic wave and EMAT tools, but the experience was unsatisfactory. Operator D's experience with both types of ILI tools was that the tool provided false-positive indications of SCC that were not SCC, and SCC was not identified in some cases where colonies were known to exist. Consequently, Operator D will continue to rely upon hydrostatic testing for the near future as the most reliable method for determining if a valve section has suffered SCC that is a threat to pipeline integrity.

Operator D is currently revising their SCC management program for compliance with the gas integrity rule and considers the following five factors as the most significant for assessing the SCC threat on a pipeline segment:

1. High operating temperature.
2. High operating pressure.
3. Coating condition.
4. Location (i.e., downstream from compressor station as well as geographic location).
5. Cathodic protection effectiveness.

While other factors may be useful for threat assessment, Operator D considers them secondary to these five factors.

A corrosion technician is typically present at an excavation for visual examination of pipeline condition. Operator D has employed MPI of exposed pipe surfaces in the past, but not as a routine practice for all exposed pipe with disbonded coating. The revised SCC management program will include use of wet, black magnetic particles on white contrast for examination of pipe under disbonded coating. Contract inspectors will perform the MPI in the near term, but Operator D anticipates training and equipping in-house employees, such as the corrosion technicians, for MPI.

When SCC has been discovered, Operator D has employed grinding to remove the cracking and determine depth. Operator D has not found manual UT useful for determining depth of SCC colonies.

Operator D is an active member of PRCI. Operator D has investigated soils and site characterization for prediction of the location of classic or high pH SCC, but has not found either useful.

New construction and replacements are installed with line pipe that is externally coated with FBE.

Multiple possibilities for industry initiatives were discussed:

- Improved ILI of gas transmission pipelines for SCC

  Resources should be committed to development of reliable ILI for detection of SCC in gas pipelines (without use of liquid slug trains to facilitate use of UT pigs).

- Database of SSC-related Information

  The potential for developing an industry-wide database of information related to the SCC threat in gas pipelines was discussed in some detail. Challenges to development of such a database include development of an industry standard for collection of data associated with (1) in-service and hydrostatic testing SCC failures, and (2) excavations for direct examination. An industry standard for data collection would need to be developed under the direction of an industry group (INGAA, PRCI, etc.) with funding.

  The perceived benefit of an industry-wide database could be more cost-effective assessment of the SCC threat of each pipeline system where trends from the database were applied. Given the cost of hydrostatic testing and excavation for direct examination, more cost-effective assessment of the SCC threat could conserve significant resources for addressing other threats that are more significant to public safety.

- Post-Failure Response

  An industry standard for Incident Response and Return-to-Service after an in-service failure attributed to SCC is desirable.

10.4.5 Operator E

Operator E operates thousands of miles of natural gas pipelines in Canada and the US. The coating systems on their pipelines, which vary widely in diameter, are approximately equally divided between tape, asphalt, FBE, and yellow jacket.

Operator E has been very involved in all issues relating to SCC, especially near-neutral pH SCC. They noted that they view SCC as a series of factors; i.e. as a continuum of events, rather than a single isolated event. The series includes:

- Incubation
- Disbondment
- Initiation
- Growth
- Coalescence
- Mechanical drivers, possibly including fatigue

They initially used soils models to provide estimates of SCC possible locations. They now view such models as a tool to correlate with potential coating disbondment segments. Drainage, local topography, soil disposition and similar aspects of soil models, tied with time in service, are seen as predictors of potential coating failures, though not necessarily SCC areas. Further pipeline operating information such as temperature and/or pressure information are used to aid the assessment.

They have performed thousands of digs since 1986. All excavations are checked for the existence of SCC. Contractors trained in SCC assessment and associated data gathering perform these digs. Operator E has never seen SCC under FBE disbondment and note that FBE does not shield CP. They have not seen any cracking at the girth welds for FBE coated pipe, where various girth weld coatings are employed including shrink sleeves and field-applied epoxies.

While Operator E cooperates with and supports organizations such as PRCI in basic research, they also perform additional in-house research relating to operational issues.

They extensively use risk-based models, with calibration against field data. With its extensive system of pipelines, they are able to develop and maintain reliable in-house statistics for these models. The calibration with actual field experience was underlined as a requirement for meaningful model development and predictions. The models include not only a stochastic estimate of failure, but also of potential consequences such as injury, societal risk, financial cost, and regulatory/perception impact. Digs are prioritized based on this model. Locations are often re-inspected to determine growth rates, if any.

Especially for gas lines, Operator E does not view any ILI tool as effective for SCC detection at this time. Hydrostatic testing is the current tool of choice, although they see promise in emerging ILI technology. They have used a UT tool in a liquid slug, but note the laborious process and costs as well as difficulty in speed control. Initial hydrostatic testing is a 1-hour strength test at 100-110 percent SMYS, followed by a 2-hour leak test of 90 to 100 percent SMYS. They noted that they are concerned with crack growth during a long duration spike test, so are considering moving to a spike test limited to a 5-minute hold. They use their risk management procedures to establish retest intervals. The distribution of crack sizes and rates are developed stochastically (i.e. in distributions rather than single deterministic estimates). The risk decision is based on the outcome of this model. They have found that the use of a Paris crack-growth model under-predicts the amount of damage.

They have correlated near-neutral pH SCC with distance from the stations with most instances occurring in the first third, very few in the middle third, and maybe one in the last third.

Operator E performs WFMT whenever there is evidence of a disbonded coating at inspection or repair excavations. They will grind out cracks if required and practicable, and assess the remaining strength using standard procedures (e.g. RSTRENG or similar). As required, they may employ a pressure containment sleeve with no standoff. They do not employ composite wraps, noting that, in their experience, it is less cost effective than installation of steel sleeves.

If an incident occurs, they will evaluate the situation to employ the correct pressure reduction before final implementation of their return-to-service plan. A rule-of-thumb is to examine the operating records and reduce to 90 percent of the 60-day high pressure or 80 percent of the failure pressure. Additional information, such as the presence of swamp weights, may cause further reductions. This reduction will be re-evaluated if the interval to return of service is prolonged. They work closely with regulatory groups in that time. They also noted that they meet twice a year with interested regulatory groups in any case to discuss upcoming plans.

Operator E cautioned that a central database may not produce much benefit and instead stressed that regular communication between interested groups is of greater value. They support and sometimes participate in the development of ILI tools but recognize this is a lengthy process.

10.4.6 Operator F

Operator F is a part of a larger pipeline group. The interview was limited to the still extensive gas transmission pipeline experience, encompassing most of the common pipe sizes that transport gas from the Gulf Coast to the Northeast U.S. and points in between.

Operator F has experienced in-service and hydrostatic testing failures attributed to classic or high pH SCC oriented in the longitudinal direction. Longitudinal near-neutral pH SCC has not been observed in the Operator F system. The classic SCC has been associated with disbonded coal tar enamel coating. Operator F was an early adopter of FBE coating and has over 30 years of experience with FBE, and has observed no SCC of pipe coated with FBE.

SCC has been observed in line pipe of multiple diameters, wall thicknesses and grades, supplied by multiple manufacturers and installed in multiple years with multiple MAOP/MOPs. Operator F has observed SCC in multiple states and in multiple types of soils and moisture conditions.

Operator F relies upon hydrostatic pressure testing and MPI for detection of SCC. Operator F has concluded that current ILI technology for detection of SCC in gas pipelines is not reliable and that use of liquid slugs to permit UT inspection is not cost effective.

Operator F uses spike hydrostatic testing in which the aim stress is 105 percent of SMYS, the minimum stress at the high point of a segment is 100 percent SMYS and the maximum stress at the low point is no more than 110 percent SMYS. The initial test period is 1 hour followed by 7 hours at a stress of 90 percent of SMYS or greater. Operator F may follow hydrostatic testing with a flame-ionization leak survey on a case-by-case basis. For example, detection of a leak during a spike hydrostatic test could be cause to follow up with a flame-ionization leak survey.

Operator F employs MPI of all bare pipe surfaces exposed for direct examination. Operator F uses MPI with multiple types of magnetic particles (dry, wet visible, wet fluorescent, black on white, etc.), but concludes that MPI with dry powder is sufficient to detect SCC on dry pipe surfaces when operators are properly trained. Wet visible magnetic particles are the preferred method for wet pipe surfaces. Application of dry powder to the bottom of the pipe is recognized to require more training and skill than the top of the pipe or other types of magnetic particles, but has proven satisfactory.

Operator F developed and presents weeklong workshops that address all types of direct examination of exposed pipeline segments as a part of the operator qualification program. Typical topics include assessment of external and internal corrosion, mechanical damage, SCC, etc. The weeklong workshops include both lecture and hands-on sessions focused upon detection of SCC as well as distinguishing SCC from other types of surface anomalies. The workshops include repair methods, including hands-on training for the grinding of pipe imperfections.

Operator F is an active member of PRCI. Operator F does not consider soils characterization models applicable to assessing the likelihood of classic SCC.

Operator F observes that visual appearance of SCC colonies is generally related to depth of penetration. For example, a colony of relatively short, unlinked cracks is likely to be relatively shallow. On the other hand, a colony that contains linked cracks with significant linear extent is likely to penetrate a significant portion of the pipe wall. Advanced NDE techniques such as focused UT, ET, etc. have been employed to estimate maximum depth of SCC, but have proven unreliable, apparently due to interference of nearby cracks. Consequently, Operator F considers grinding as the most reliable method to estimate depth of SCC.

If grinding is sufficient to remove shallow SCC detected by MPI, Operator F re-coats the exposed pipe and returns to service. If SCC is too deep to repair by grinding, Operator F either installs a Type B (pressure containing) sleeve or replaces the section containing the SCC.

If a pipeline segment experiences an in-service leak or rupture attributed to SCC, adjacent pipe joints are subjected to MPI until pipe joints free of SCC are located on either side of the failure. All observed SCC is repaired and the segment returned to service. A risk assessment is performed and an Integrity Assurance Plan is developed to remediate the possibility of SCC in the area. Operator F applies the criteria in ASME B31.8S Appendix A3 for assessing the threat of SCC.

Operator F is in the process of developing a procedure for direct assessment of pipelines for SCC based on the existing draft version of the NACE SCCDA recommended practice.

Operator F would not be inclined to contribute to, or draw from an industry-wide SCC database. Beyond the difficulty of implementing an industry-wide database, Operator F has a significant internal database that is directly related to their system. An industry-wide database would likely have more potential value for an operator with less experience in dealing with SCC.

10.4.7 Operator G

Operator G operates approximately 7,700 miles of pipeline in 360 testable segments to transport a variety of products. The product mix is approximately one-third crude oil, one-third refined products and one-third highly volatile liquids and chemicals. Pipe sizes ranges from NPS 2 through 40.

Operator G has observed SCC in two testable pipeline sections located in southern Louisiana. One of the pipeline sections is NPS 8 and the other is NPS 16, both were installed in 1954 and coated with coal tar.

The first observed SCC was a hydrostatic test rupture in the NPS 8 section in 1985. No further SCC has been observed in the NPS 8 segment. The NPS 16 section suffered an in-service failure in 1993 and six hydrostatic testing failures attributed to SCC in 1994. Another hydrostatic testing failure occurred during a retest in 1999, potentially indicating that SCC remained active at least a portion of the time between the 1994 and 1999 tests.

All these SCC incidents were attributed to high pH or classical SCC. These SCC incidents were generally associated with disbondment of the coal tar coating possibly attributed to soil stresses or possibly due to the quality of coating installation during initial construction. The operating temperature of these pipeline segments rarely, if ever, exceeds 100°F, which leads Operator G to believe that disbondment is not attributed to elevated temperature of transported fluids. No records have been located relating to soil and water samples collected at the time of the SCC failures for detailed characterization of the soil associated with the SCC.

The procedure for returning a pipeline to service after an in-service failure is determined on a case-by-case basis, depending upon the cause of the failure. If the cause of a failure were not apparent i.e. associated with mechanical damage, external corrosion, etc., the pipe would be sent to a laboratory for analysis in an attempt to determine the cause of the failure.

Should SCC be detected by MPI, a typical repair plan would involve lowering the operating pressure to 80 percent of the highest operating pressure experienced during a 4-hour period in the two months prior to the time of discovery of the SCC per DOT guidance. If the SCC can be removed by grinding without reducing the pressure carrying capacity of the segment, the location would be recoated and returned to service following grinding. If the SCC can be removed by grinding, but the depth of grinding reduces the pressure carrying capacity of the pipeline, a composite sleeve, a steel welded sleeve, or a fabricated mechanical device may be applied to restore the desired pressure rating. If the SCC depth is such the SCC cannot be removed by grinding, a temporary repair will be installed until the line can be taken out of service for a permanent pipe replacement. (Operator G's repair criterion does not currently allow longitudinally oriented crack defects to remain in the pipe permenantly.)

Operator G has employed several ILI tools, including caliper for deformation conditions, UT and MFL for wall loss and TFI for seam imperfections, but has not used the UT tools designed to detect SCC yet. Application of special UT crack detection tools (or hydrostatic pressure testing) in pipeline segments susceptible to SCC is planned.

Operator G has screened approximately 360 testable pipeline segments for potential susceptibility to high pH or classical SCC using the five SCC screening criteria in ASME B31.8S Appendix A3.3 with minor modification to adapt the criteria from gas to liquid pipelines, specifically converting distance downstream from compressor station to distance from pump station.

Operator G also has access to the draft version of the NACE SCCDA recommended practice, which recommends that screening for potential susceptibility to near-neutral pH SCC not consider operating temperatures above 100°F as a criterion. Therefore, Operator G has screened for potential high pH SCC using the five SCC screening criteria identified in ASME B31.8S, but has also screened for potential near-neutral pH SCC using four of the five criteria identified in ASME B31.8S (without the 100°F temperature criterion). The screening process identified 24 segments at this time as potentially having susceptibility to near-neutral pH SCC, including the two segments that had suffered high pH SCC. Segments where either high or near-neutral pH SCC has been detected will be assessed using specialized ILI technology or hydrotesting. Segments that are identified as potentially susceptible to either type of SCC will be subjected to additional NDT including MPI during routine maintenance or integrity management activities where external coating is being removed in an attempt to locate any other SCC occurring on these pipeline segments.

Operator G has identified a need for and is planning for additional training of company personnel in SCC awareness and MPI for detection of SCC.

Operator G is also considering the application of ECDA to approximately 28 pipeline segments (not the 24 segments identified as potentially susceptible to SCC) that are not amenable to either hydrostatic testing or ILI. They are employing a consultant to perform black-on-white MPI for cracks when a pipeline segment is excavated for direct examination. Although MPI is not employed solely to detect SCC, any SCC present in the locations examined directly should be revealed. If SCC is detected in any of these ECDA segments, they will be moved into the "susceptible to SCC" category and will be assessed by either hydrotesting or ILI. Operator G is considering the application of SCCDA in the future, but is currently awaiting completion of the NACE SCCDA document.

New construction and replacements are installed with line pipe that is externally coated with FBE at a coating plant and FBE joint systems are applied to girth joints during construction. Operator G also has specifications in place for line pipe procurement, hot bends manufactured from line pipe, pipeline construction, CP design and operation, as well as the FBE coating specifications mentioned to also help eliminate the cause of the SCC phenomena in new pipeline construction.

Operator G is an active member of PRCI and reviews the results of research into pipeline integrity management for possible inclusion in its IMP. Operator G also has representatives on multiple API committees and NACE International committees developing other integrity-related technology.

The potential value of an industry database for collection of SCC related information was discussed. Operator G observed that the API Pipeline Performance Tracking System (PPTS) sponsored by the API Operators Technical Committee already contains integrity-related information that is useful to operators of hazardous liquid pipelines. The data fields collected in PPTS track accidents on hazardous liquid, carbon dioxide, and anhydrous ammonia pipelines attributed to approximately 40 possible failure causes, including SCC.

Operator G supports the API initiative requesting a revision of §195.452 to align the repair criteria and other issues for hazardous liquid pipelines with those applicable to gas transmission pipelines. Operator G also supports a possible revision of API Standard 1160: *Managing System Integrity for Hazardous Liquid Pipelines* to incorporate revisions to the IMP Regulations and possible inclusion of the concepts in ASME B31.8S.

Operator G also encourages pipeline regulators to consider a more performance-based rather than a prescriptive- and procedural-based perspective when reviewing integrity management programs. Operator G feels this approach will provide pipeline operators with greater flexibility to produce more efficient and effective integrity management programs and demonstrate that the performance of the programs meets the desired objectives.

Operator G desires from this SCC research project:

1. Confirmation that ASME B31.8S and NACE SCCDA are accurate for SCC screening applicability (or development of better tools if they are not accurate).

2. Identification of better ILI technology for more accurate SCC sizing and locating.

3. Knowledge of accurate mathematical models with easy to use analysis to determine fitness for purpose of pipe with SCC.

10.5 Canadian National Energy Board Interview

The NEB regulates about 45,000 km of inter-provincial and cross-border pipelines (approximately 6 percent of the over 750,000 km of pipelines in Canada). Provincial agencies such as the Alberta Energy and Utilities Board and the Ontario Technical Standards and Safety Authority regulate intra-provincial pipelines. The NEB employs approximately 300 personnel, 70 of which are in the pipeline operations business unit. The number of ruptures caused by corrosion and SCC ranked ahead of those caused by third party on the NEB regulated pipelines over the past 20 years (Jeglic 2004). (There are a few provincial jurisdictions, notably Ontario, where recent line strikes have disturbed the trend, but by and large throughout Canada corrosion and SCC-related failures dominate.)

According to the NEB, the occurrence of SCC on Canadian pipelines is a serious matter. Concern about SCC on the TCPL system led the Board to conduct an earlier inquiry in 1993. From that inquiry, the Board concluded that the SCC situation was being managed appropriately by the affected pipeline companies, considering the extent of the problem as then recognized. However, there were two more major ruptures and fires on the TCPL system in February and July 1995, the last one at a location where it was not believed that SCC could occur. These two pipeline failures, together with further evidence of the more widespread nature of SCC and awareness that research was producing new insights into SCC, led the Board to initiate an Inquiry in August 1995 and the *Report of the Inquiry* [on] *Stress Corrosion Cracking on Canadian Oil and Gas Pipelines* (NEB 1996) mentioned in Chapter 3.

An interview at the NEB offices in July 2004 was conducted to provide an update to the published results of the inquiry. The remainder of this section's remarks are based on that interview.

The CEPA Recommended Practice (RP) (CEPA 1997) satisfied the Board's findings that the industry produce a documented approach to SCC. The Board neither approves nor disapproves technical detail in the approach. An updated version of the CEPA RP document is expect to be released in 2005. Operators are required to report significant SCC as defined in the CEPA RP. The NEB noted that after the first incidents and this RP, they have been informed of a number of investigative digs with one operator reportedly performing over 90 corrosion-related digs per year arising from in-line inspections. Thus, SCC continues to be a serious consideration and an object of continuing oversight and research. A number of personnel and companies (e.g. University of Calgary, CANMET) were mentioned in this regard.

The NEB noted that soil models are a good place to start an operator's consideration of SCC. Although this approach must be updated through experience, such a model generally supplies the oversight framework to begin consideration of SCC. FBE has proved, to date, to be an effective coating to prevent SCC. If there is any concern, it might be at weld joints, especially for larger diameter lines.

The NEB follows ILI advancements and looks forward to a tool for crack detection in gas lines, which has a high degree of confidence and repeatability. Ultrasonic tools can be used for SCC detection in liquid lines and appear acceptable although, due to the need for liquid coupling, the methodology is more difficult to implement for gas lines.

Generally, SCC analysis and oversight are approached on a site-specific basis. No generally accepted procedure of defining what level of reduction in factor of safety (FS) from the original FS is established.

Regarding the response to SCC incidents, the Transportation Safety Board (TSB) has the responsibility of incident investigation, while the NEB has the responsibility for return-to-service plans. This is analogous to the roles of the National Transportation Safety Board (NTSB) and OPS in the U.S. Actually, an NEB inspector would typically also be at the site when the TSB is there to facilitate the eventual handover of responsibility. The operator will typically take the lead in public contact, repair plans, and return-to-service plans. Regulatory leadership is provided when the operator's plans fail to meet regulatory requirements and/or expectations.

10.6 References

Internally developed material and operator interview responses.

CEPA. 1997. *Stress Corrosion Cracking—Recommended Practices*. Canadian Energy Pipeline Association.

Jeglic, F. 2004. Analysis of Ruptures and Trends on Major Canadian Pipeline Systems. In *Proceedings of IPC 2004*.

NEB. 1996. Stress Corrosion Cracking on Canadian Oil and Gas Pipelines. Report of the Inquiry. National Energy Board. MH-2-95. December.

11 SCC in Integrity Management

11.1 Scope Statement

"Develop a practicable procedure regarding how to assess SCC in operating pipelines within the context of integrity management."

This work item is addressed first in Chapter 10 and concluded in this Chapter.

11.2 Assessment of SCC Risk Factor in Integrity Management Plans

The OPS IMP protocols establish the general procedure for regulatory oversight of an operator's IMP.

11.2.1 Natural Gas Pipelines – Protocol Review

There are four draft OPS Gas Integrity Management inspection protocols that specifically mention SCC. The first of these is Protocol C.1, Threat Identification. Item a. states:

> …verify that at least the following nine categories of threats have been evaluated:
>
> i. Time-dependent threats: (1) external corrosion, (2) internal corrosion, and (3) stress corrosion cracking;…

The next two are Protocol D.12, SCCDA Data Gathering & Evaluation, and Protocol D.13 SCCDA, Assessment, Examination, & Threat Remediation. Protocol D.12 states:

> Verify that the operator's SCCDA evaluation process complies with ASME/ANSI B31.8S, Appendix A3 in order to identify whether conditions for SCC of gas line pipe are present and to prioritize the covered segments for assessment.
>
> a. Verify that the operator has a process to gather, integrate, and evaluate data for all covered segments to identify whether the conditions for SCC are present and to prioritize the covered segments for assessment.
>
> i. Verify that the operator gathers and evaluates data related to SCC at all sites it excavates during the conduct of its pipeline operations (not just covered segments) where the criteria indicate the potential for SCC.
>
> ii. Verify that the data includes, as a minimum, the data specified in ASME/ANSI B31.8S, Appendix A3.
>
> iii. Verify that the operator addresses missing data by either using conservative assumptions or assigning a higher priority to the segments affected by the missing data, as required by ASME/ANSI B31.8S, Appendix A3.2.

While Protocol D.13 states:

> Verify that covered segments (for which conditions for SCC are identified) are assessed, examined, and the threat remediated.
>
> a. Verify that, if conditions for SCC are present, that the operator conducts an assessment using one of the methods specified in ASME/ANSI B31.8S, Appendix A3.
>
> b. Verify that the operator's plan specifies an acceptable inspection, examination, and evaluation plan using either the Bell Hole Examination and Evaluation Method (that complies with all requirements of ASME B31.8S Appendix A3.4 (a)) or Hydrostatic Testing (that complies with all requirements of A3.4 (b)).
>
> i. Verify, that the operator's plan requires that for pipelines which have experienced an in-service leak or rupture attributable to SCC, that the particular segment(s) be subjected to a hydrostatic pressure test (that complies with ASME/ANSI B31.8S, Appendix A3.4 (b)) within 12 months of the failure, using a documented hydrostatic retest program developed specifically for the affected segment(s), as required by ASME/ANSI B31.8S, Appendix A3.4.
>
> c. Verify that assessment results are used to determine reassessment intervals in accordance with §192.939(a)(3); (see Protocol F).

And the last inspection protocol that references SCC is Protocol F.4, Reassessment Intervals, which states:

> Verify that the requirements for establishing the reassessment intervals are consistent with section §192.939 and ASME B31.8S…

It goes on to state: "If the reassessment method is external corrosion direct assessment, internal corrosion direct assessment, or SCC direct assessment refer to Protocol D for evaluating the operator's interval determination."

49 CFR 192.939(a)(3) describes the required method for determining the reassessment interval if SCC direct assessment is used, but limits the maximum interval to that specified in AMSE B31.8S, Section 5, Table 3.

Other Protocols that are related in varying degrees to addressing an SCC threat include:

- Protocol B.1, Assessment Methods,
- Protocol F.1, Periodic Evaluations,
- Protocol F.2, Reassessment Methods, and
- Protocol H.6, Corrosion.

A description of SCC and the threat it poses to pipelines is presented in Section 4 of this report. Prevention, Detection and Mitigation of SCC are discussed in Sections 5, 6 and 7, respectively.

The most discussed subject related to SCC in the Protocols is SCCDA. The forthcoming NACE recommended practice on SCCDA is discussed in Section 6.3 and, to a lesser extent, Section 8.2 of this report. A part of the SCCDA process is determining appropriate reassessment intervals.

The use of ILI for detection of SCC is discussed in Section 6.2.

11.2.2 Hazardous Liquids Pipelines – Protocol Review

The current Hazardous Liquids Integrity Management Inspection Protocols specifically mention SCC in two locations. Protocol #5.01, Risk Analysis: Comprehensiveness of Approach, states:

> An effective operator program would be expected to have the following characteristics:
>
> 1. Inclusion of all relevant important factors that might constitute a threat to pipeline integrity, such as:
>   - external and internal corrosion
>   - stress corrosion cracking
>   - materials problems
>   - third party damage
>   - operator or procedures errors
>   - equipment failures
>   - natural forces damage
>   - construction errors
> 2. Inclusion of all important relevant factors that affect the consequences of pipeline failures, such as
>   - health and safety impact
>   - environmental damage
>   - property damage
> 3. Integration of results from the analysis of how pipeline failures could affect high-consequence areas from the segment identification process.

Protocol #6.02, Preventive & Mitigative Measures: Risk Analysis Application, states:

> Operators must conduct a risk analysis as part of the evaluation of preventive and mitigative measures, including a number of specific risk factors. In addition to the required set of factors, there are other factors that are relevant to the preventive and mitigative measures evaluation. An effective operator program would be expected to have the following characteristics:

1. Consideration of all risk factors required by §195.452(i)(2) in the risk analysis applied to the preventive and mitigative measures evaluation. If all required factors are not considered, a documented basis provided for the exclusion of certain listed factors.
2. A risk analysis process that addresses all other relevant factors that constitute a threat to pipeline integrity (e.g., external and internal corrosion, third party damage, operator or procedures error, equipment failures, natural forces damage, stress corrosion cracking, materials problems, construction errors, various operating modes).
3. A risk analysis process that addresses all other relevant important consequences of pipeline failures (e.g., population impacts, environmental damage, property damage).
4. Measures to assure that the analysis are up to date prior to use (e.g., pipeline data and configuration assumptions verified to be current prior to evaluating the relative impact of a proposed preventive or mitigative measure).

Similar to the Natural Gas Inspection Protocols, there are several other protocols that are related in varying degrees to addressing an SCC threat:

- Protocol #2.01, *Baseline Assessment Plan: Assessment Methods*,
- Protocol #3.05, *Integrity Assessment Results Review: Identifying and Categorizing Defects*,
- Protocol #3.07, *Integrity Assessment Results Review: Hydrostatic Pressure Testing*,
- Protocol #3.08, *Integrity Assessment Results Review: Results from the Application of Other Assessment Technologies*,
- Protocol #4.01, *Remedial Action: Process*,
- Protocol #4.01, *Remedial Action: Implementation*,
- Protocol #5.02, *Risk Analysis: Integration of Risk Information*, and
- Protocol #5.03, *Risk Analysis: Input Information*.

11.3 Specific Protocol Issues to be Addressed Regarding SCC

Based on the protocols discussed above, an operator's IMP, whether liquid or gas, should contain the following information with respect to SCC:

1. ***Data collection Procedure***:

Plan Document: A written program that includes the data required to be collected to evaluate SCC susceptibility; a procedure to collect, collate and maintain such data; a procedure that determines and justifies conservative estimates made in lieu of field data; and procedures, as appropriate, to be used in the data collection methodology and/or qualification of personnel assigned to gather the data.

Comments: Data collection is essential to a robust pipeline IMP. For evaluation of SCC susceptibility, such data would include changes in cathodic protection requirements that may indicate degradation of the coating system. Leak history and failure evaluations can lead to trends in the performance of the pipeline. The presence of SCC as detected by ILI can indicate areas of potential problems. Pressure cycles and the magnitude of pressure cycles during normal and abnormal operation are important to crack growth prediction and remaining life estimates.

There are three general sources of data to consider in examination of SCC: 1) Historical data including leak and rupture history, ILI and hydrostatic tests, 2) Pipe data including geometrical (NPS, wall), mechanical and metallurgical properties, as well as the operating characteristics and 3) On site data such as observations from examinations of digs. All three sources of data must be carefully examined to consider the available options.

2. ***SCC Threat Assessment Procedure:***

Plan Document: A written procedure for collection and evaluation of information, including data from ILI, past hydrostatic tests and/or direct examination, that operators can use in conjunction with their route mapping and pipeline system operational characteristics to prioritize those segments that may be more susceptible to SCC. This procedure could form part of an operator's linewide threat assessment plan and/or ECDA process as such as defined in Non-mandatory Appendix B of ASME B31.8S. An example of an assessment procedure for high pH SCC is given in the report *Protocol to Prioritize Sites for High pH Stress-Corrosion Cracking on Gas Pipelines* (Eiber and Leis 1998). The minimum criteria for gas lines is presented in B31.8S, Appendix A3. Evidence of update procedures and the assurance of competent personnel who perform/evaluate the update should be included in the plan document.

Comment: There are a number of approaches that can be used to assess and/or prioritize pipeline susceptibility to SCC, and no single method is recommended above others. Rather, the important point is that a consistent approach is used that includes both the technical factors as well as other societal and environmental factors that contribute to the overall risk of a potential SCC incident. Also, it is important that this procedure is maintained and updated as new technical data is collected, new information regarding SCC is developed, and/or new information regarding the external consequences is received. The viewpoint must be that the procedure is really a methodology to continually refine understanding of the threat posed by SCC.

It is noted that this procedure is also used by the operator to demonstrate that a pipeline segment is not susceptible to SCC. The mere fact that no SCC-related incident has occurred on a pipeline segment should never be considered as evidence that the pipeline is not susceptible to SCC.

3. ***Examination Procedure for SCC:***

   Plan Document: A written procedure to be used during direct examination that addresses the identification and examination procedures relative to SCC. It should address factors that will trigger more detailed SCC-specific examination, such as evidence of a disbonded coating during a visual examination. The procedure should identify the data collection effort, as well as the specifics of the direct examination technique(s) applicable, e.g. surface preparation, types of magnetic particle or dye penetrant, etc. It should also address hydrostatic test procedures.

   Comments: See Chapter 6 of this report for additional information.

4. ***SCC Evaluation Procedure:***

   Plan Document: A written procedure should be evident that shows the steps to be followed when SCC is detected. This should include an FFS assessment of the pipeline segment containing the SCC, possible mitigation and/or preventative steps, as well as a procedural outline for continued monitoring and reassessment.

   Comments: Once SCC susceptibility is identified in a pipeline segment, it is prudent to establish a focused program to track SCC indications, establish and monitor growth and growth rates, develop a remedial and/or preventative program, and consider investigation techniques such as high-resolution ILI crack detection tools and/or increased hydrostatic testing. Such a program must be well documented, auditable, and consistent with best industry practice.

   Testing and/or inspection intervals depend on the growth rate of SCC. Ideally, the retest intervals should be set to detect cracks that will not grow to critical size before the next test. This depends on a clear understanding of the crack mechanism within the operational parameters of the system, as well as an understanding of the crack growth mechanism and its consequent growth rate. Crack growth is calculated using conservative methods so as to predict the fastest crack growth rate. The time to failure is then computed by dividing the difference between the critical defect at the operating pressure and the critical depth at the test pressure by the calculated crack growth rate. Since such a definitive understanding is not currently achievable for most operating pipelines, consideration of safety factors which account for the associated uncertainty is also recommended.

5. ***SCC Remedial Action:***

   Plan Document: A written plan that details actions to be taken when the evaluation procedure finds that pipeline integrity has deteriorated to non-maintainable levels. This would include field procedures (or references to such) for the safe implementation of repair and retrofit procedures, coating replacement, and associated safety considerations. The plan should also detail procedures (or references to such) for incident response.

   Comments: Repair and mitigation methods are discussed in Chapter 7. Each operator must prepare a plan for response to leaks and failure incidents, including those caused by SCC, according to 49 CFR 191 and 192 for gas pipelines and 194 and 195 for hazardous liquid pipelines. The response procedure identifies a qualified team who can recognize SCC failure and understand the information that should be recovered from the incident in order to expedite safe repair and extend the evaluation, as required, to adjacent pipeline segments. If a section of pipeline is removed, representative samples should be preserved for metallurgical analysis.

The following is not specifically required by the protocols but should be considered. It would be difficult to provide effective threat protection against SCC if such a program was not in place.

6. *SCC Education/Awareness:*

A written procedure addressing an education/awareness program, especially for field personnel discussing SCC, the threat posed, causal and incident factors, and identification during direct examination. The procedure should address operator qualification in this regard, specifically in-house trained personnel, or a key third-party contact working with the organization that can readily recognize SCC.

Items 1, 2 and 5 above should be in evidence for all IMP. To make any assessment of the threat posed by SCC, even when there is a presumption that the conditions for SCC do not exist for a pipeline, basic data collection and an initial assessment should be concluded. As a result of this initial exercise, and in the event that an operator concludes that the conditions for SCC are not identified, local site threat assessments (i.e. extension of item #2) would be obviated. Also, in this case, items 3 and 4 would not be required.

11.4 References

Eiber, R. J., and B.N Leis. 1998. *Protocol to Prioritize Sites for High pH Stress-Corrosion Cracking on Gas Pipelines*. PRCI. Project PR-3-9403, L51864.

This page intentionally left blank.

12 Response to SCC Incidents

12.1 Scope Statement

"Identify recommended actions to be taken by pipeline operators to facilitate response and assure appropriate remedial measures are implemented following an SCC-related incident.

12.2 Regulatory Oversight in Post-SCC Incident Response

There are two separate agencies involved in the oversight of a pipeline accident:

1) National Transportation Safety Board: The NTSB is an independent Federal agency charged by Congress with investigating significant accidents in pipelines, i.e. pipeline accidents involving a fatality or substantial property damage, and issuing safety recommendations aimed at preventing future accidents. It is not part of the U.S. Department of Transportation (DOT), nor organizationally affiliated with any of DOT's modal agencies. The Safety Board has no regulatory or enforcement powers. The Board derives its authority from 49 CFR.

2) Office of Pipeline Safety: In l968, Congress adopted the first comprehensive federal pipeline safety statute, the Natural Gas Pipeline Safety Act, in response to a tremendous increase in the nation's use of natural gas, the concurrent growth in population, and several well-publicized gas pipeline accidents. Eleven years later, in 1979, Congress passed a parallel regulatory program for hazardous liquid pipelines with passage of the Hazardous Liquid Pipeline Safety Act. Under both statutes ('the Acts'), the DOT was granted primary regulatory authority to establish reporting and record-keeping requirements for the industries, to set technical standards for the design, construction, testing, and maintenance of pipeline facilities, and to enforce safety standards. This authority was delegated, in turn, to RSPA/OPS. By 1970, OPS had adopted core requirements for the gas pipeline industry, with regulations for liquefied natural gas following in 1980, interstate hazardous liquid in 1981, and intrastate hazardous liquid in 1985.

Generally, in the event of a significant pipeline accident, it is understood that the NTSB will take primary charge of the incident and accident report itself, while the OPS will take primary charge of oversight of the return-to-service of the pipeline. Normally representatives from both agencies respond to the scene of a pipeline rupture as soon as practical to ensure data collection and dissemination to the various technical disciplines involved.

12.3 Initial Report

The Accident Report form for liquid lines is available on-line from the OPS. Form No. 7000-1 (01-2001) "Accident Report – Hazardous Liquid Pipeline Systems," which also has a companion document: "Instructions for Form RSPA F 7000-1 (01-2001). Accident Report – Hazardous Liquid Pipe Systems." Similarly, for gas lines there is Form 7100.2 (01-2002) "Incident Report-Gas

Transmission and Gathering Systems" with its companion document: "Instructions for Form RSPA F 7100.2 (01-2002) Incident Report – Gas Transmission and Gathering Systems."

These forms and companion instruction documents, compiled by the Operator, form the baseline evaluation for any incident. The intent of the initial notification, other than documentation for the records, is to gain adequate knowledge to determine the urgency for a regulatory representative or others to be dispatched to the incident site and to establish awareness level of the Operator. The on-line forms adequately cover the information requirements for this initial phase.

12.4 Site Security and Data Collection

The first priority is to ensure the site is totally secure and threats have been removed adequately to allow for special team investigations to proceed.

If SCC is suspected, the information and data examination should be broadened to ensure that all pertinent information about the incident is collected. In this case, the data collection efforts should be augmented to include relevant data to enable the evaluation of the particular problem, as well as to better enable oversight for return-to-service efforts. The following is recommended information to be gathered after the site is secure. This information is intended to be much more accurate and precise than initial report data, but still subject to change as a detailed evaluation continues. The operator should have qualified personnel to gather such data, especially if SCC is suspected, and regulatory oversight and collaboration is recommended at this stage. Explicit definitions for the data types, as well as collection procedures, discussed in below would be an appropriate area for further study and elaborating. If no cause is readily apparent, note that the data collection for SCC may be prudent, especially for line segments that are considered potentially susceptible to SCC.

1. Location of incident relative to nearest town.
2. Location of incident relative to the pipeline features.
3. Physical description of pipeline at Incident location:
• Diameter. • Wall thickness. • Grade of pipe. • Manufacturer of pipe. • Date of manufacture of pipe. • Type of Longitudinal weld. • Date of Construction of pipeline.
• Type of pipe coating. Include manufacturer/supplier, grade, original construction or replacement, date of installation.
• Type of coating joint system (if applicable). Include manufacturer/supplier, grade, original construction or replacement, date of installation.
4. Operating conditions of the pipeline at time of Incident:
• U/S Station discharge pressure immediately prior to Incident.

• D/S Station suction pressure immediately prior to Incident. • Estimated pipeline pressure at Incident site immediately prior to Incident. • Estimated throughput at Incident site immediately prior to Incident. • U/S Station discharge temperature immediately prior to Incident. • D/S Station suction temperature immediately prior to Incident. • Estimated pipeline temperature at Incident site immediately prior to Incident. • Describe any other operating parameters that may have affected the integrity of the pipeline. (Unusual pressure/temperature cycles, extreme demand situations, valve closures, station shut downs, major customer usage variances, etc.)
5. Environmental conditions near the pipeline at time of Incident:
• Temperature • General weather description. Photos required. (Clear, Rain, Snow, Ice storm, etc.) • Topography description: ⇒ Lay of land in General Area. Photos required. (Flat, rolling hills, mountainous, lakebed, etc.) ⇒ Lay of land at Incident site. Photos required. (Hill top, valley, creek bottom, side hill, etc.) ⇒ Depiction of Incident site relative to the public. Photos required. (Remote – no populace, remote – near a farm house, remote – near several homes and a community center, in small town, near a small town, in a large city, near a large city, etc.) ⇒ Depiction of Incident site relative to Environmental issues. Photos required. (No significant threat, nearest stream 3 miles away, near the Kenai River, in Galveston Bay, etc.) • Type of soil (general characterization, e.g. sand, silt…) • pH readings: ⇒ Take readings with litmus paper and extract lab samples in uncontaminated soil as close to the origin as possible. ⇒ Take readings with litmus paper and extract lab samples at all four quadrants around the pipe. ⇒ Take readings with litmus paper and extract lab samples (four-quadrant) U/S and D/S of the origin. ⇒ Take readings with litmus paper and extract lab samples at several intervals on both sides of the pipe down at a depth equal to the bottom of the pipe. ⇒ Take readings with litmus paper and extract lab samples any disbonded coating locations in the vicinity of, as well as immediately adjacent to, the origin. ⇒ Take steps to preserve the identity and integrity of the samples so that they may be further evaluated by a laboratory if deemed necessary. ⇒ Prepare sketch to show where all readings and samples were taken.
6. Physical description of the damage to human life.
7. Physical description of the damage to property. Photos required.
8. Physical description of the damage to the Environment. Photos required.
9. Physical description of the damage to the pipeline:
• Leak:

- ⇒ Location (Distance from an identified reference girth weld.)
- ⇒ Orientation (~ o'clock position looking D/S). Photos required.
- ⇒ Dimensions of leak feature including orientation. Sketch or rubbing desirable.
- ⇒ Caused from Internal corrosion/external corrosion?
- ⇒ Located in Girth weld/longitudinal seam?
- ⇒ Located in manufacturing defect?
- ⇒ Located In longitudinal/transverse crack?
- ⇒ Located in mechanical damage. Sketch or rubbing mandatory.
- ⇒ Other

- Rupture:
  - ⇒ Gaping Split (Major longitudinal opening in the pipe but still intact looking similar to a fish's mouth.) Photo required with a scaled reference attached.
    - o Orientation of split.
    - o Description of fracture surface.
    - o Estimate of percent of wall thickness remaining at the time of failure.
    - o Length of Split.
    - o Maximum width of split.
    - o Describe any physical anomalies present on the pipe surface or on the fracture surface at the origin of failure. Photos required.
      - Internal Corrosion
      - External corrosion
      - Mechanical damage – Gouge
      - Mechanical damage – Dent
      - Manufacturing defect
      - Girth welding defect
      - Longitudinal welding defect
      - Arc burn
      - Longitudinal crack
      - Longitudinal crack clusters
      - Transverse crack
      - Transverse crack clusters
    - o Actions taken to preserve the integrity of the ruptured pipe as required for future metallurgical testing. Include copy of Protocol. Photos required.
    - o Actions taken to preserve the "Chain of Custody". Include copy of Protocol. Photos required.
  - ⇒ Major pipeline failure:
    - o Length of pipe that failed.
    - o Length of pipe recovered.
    - o Number of pieces of pipe recovered
    - o Map of the fracture path. Include orientation (direction of flow, o'clock position)

- o Estimated length of pipe not recovered and a description of processes implemented to effect recovery.
- o Describe any physical anomalies present on the pipe surface or on the fracture surface at, or near the origin of failure. Photos required.
  - Internal Corrosion
  - External corrosion
  - Mechanical damage – Gouge
  - Mechanical damage – Dent
  - Manufacturing defect
  - Girth welding defect
  - Longitudinal welding defect
  - Arc burn
  - Longitudinal crack
  - Longitudinal crack clusters
  - Transverse crack
  - Transverse crack clusters
- o Actions taken to preserve the integrity of the ruptured pipe as required for future metallurgical testing. Include copy of Protocol. Photos required.
- o Actions taken to preserve the "Chain of Custody". Include copy of Protocol. Photos required.

10. Protective Coating:

- Describe condition of the coating at or near the origin. Photos required.
  - ⇒ Bonded
  - ⇒ Disbonded
  - ⇒ Damaged
  - ⇒ Porous
- Describe the conditions that exist under the coating in the event it is disbonded or damaged. Photos required.
  - ⇒ Dry and clean
  - ⇒ Presence of iron oxide
  - ⇒ Wet
  - ⇒ Dry with calcareous build-up.
  - ⇒ Wet with calcareous build-up.
- Extract samples of uncontaminated materials found under disbonded or damaged coating. (contamination is from the release) Photos required:
  - ⇒ Extract lab samples from under the coating U/S of and as close as possible to the origin.
  - ⇒ Extract lab samples from under the coating D/S of and as close as possible to the origin.
  - ⇒ Extract lab samples from under the coating at other locations in the vicinity of the incident that might be useful to obtain a full understanding of all activities that have taken place.
  - ⇒ Take steps to preserve the identity and integrity of the samples so that they may be further evaluated by a laboratory if deemed necessary.

⇒ Prepare a sketch to show where all samples were taken. • Extract samples of coating materials found near the origin of failure. Photos required: ⇒ Extract coating lab samples U/S of and as close as possible to the origin. ⇒ Extract coating lab samples D/S of and as close as possible to the origin. ⇒ Extract coating samples at other locations in the vicinity of the incident that might be useful to obtain a full understanding of all activities that have taken place. ⇒ Take steps to preserve the identity and integrity of the samples so that they may be further evaluated by a laboratory if deemed necessary. ⇒ Prepare a sketch to show where all samples were taken.
11. Cathodic Protection:
• Evaluate the cathodic protection elements in place at and near the origin of failure: ⇒ Measure pipe-to soil potentials as close as possible U/S of the origin of failure. ⇒ Measure pipe-to soil potentials as close as possible D/S of the origin of failure. ⇒ Measure pipe-to soil potentials at other locations in the vicinity of the incident that might be useful to obtain a full understanding of all activities that have taken place. ⇒ Measure soil resistivities as close as possible U/S of the origin of failure. ⇒ Measure soil resistivities as close as possible D/S of the origin of failure. ⇒ Measure soil resistivities at other locations in the vicinity of the incident that might be useful to obtain a full understanding of all activities that have taken place. ⇒ Prepare a sketch to show where all readings were taken. • Describe the functionality of the closest CP elements U/S and D/S of the origin of failure: ⇒ Ground beds ⇒ Rectifiers ⇒ Anodes ⇒ Foreign line crossings ⇒ Other ⇒ Prepare a sketch to show where all descriptors above are located relative to the origin of failure.

12.5 Procedural Development

After the initial data collection and site evaluation, a written procedure to address the following steps should be developed:

- Interim Measures: Repair procedure; interim operational plan; safety considerations; communication plan and protocol
- Return to Service Plan Development: Evaluation of line segment for additional SCC; required metallurgical/geotechnical investigations and reporting; conformance with IM plan and protocols; requirements for additional ILI, direct examination and/or direct assessment. This plan is summarized in a written report suitable for distribution to regulatory/public groups. Adjustments are made as required and the Return-to-Service Plan finalized.

- Incident Follow Through: Monitoring of performance and/or additional investigations as required; QA/QC plan and reporting requirements; review of all Engineering Evaluations.
- Incident Closeout: Final delivery of the incident evaluation report with associated Engineering and laboratory evaluations; adjustment to the Operations Manual as required; adjustment to linewide SCC threat assessment as required; long-term communications plan.

This page intentionally left blank.

13 Summary

13.1 Conclusions

The following conclusions are based on the findings of this study and should be considered "point in time" (i.e. based on the industry's current understanding, or lack of understanding, of the phenomena known collectively as SCC). Additional research and data compilation is expected in this area, and the study conclusions should be revised accordingly (see Section 9, and particularly Section 9.3.4 and Figure 9-1 for research priorities).

In general, the emphasis for dealing with SCC is on awareness, qualification of personnel, planning, and documentation. It is recognized that there are currently no plans or actions that can adequately address all situations, especially given the current state of data and knowledge concerning SCC.

13.1.1 Design

- Line pipe - Although significant research has been performed on line pipe steel, no specific conclusions relating to the effect of grade, chemical composition or microstructure on susceptibility to SCC are available. However, manufacturing processes that minimize residual tensile stresses in the line pipe should be considered.
- Coating – FBE, which is the modern coating of choice, appears to offer good resistance to SCC when coupled with an effective and complete specification for application. There are other coatings that potentially offer good resistance to disbondment that could also be considered, but have less experience industry wide. For new pipelines, tape coatings should not be used where there is a risk for SCC—and, at the least, tape coatings should be critically assessed to ensure against disbondment. For recoatings FBE is usually not practical, so the type of coating should be carefully considered to ensure that the recoated section achieves full protection, and perhaps some additional research is indicated in this area.

  Selection, application and inspection of field-applied coatings are at least as critical, if not more so, than those for plant-applied coating
- Alignment – the operator should consider completing an initial SCC threat assessment, using an internal evaluation technique (such as that described below) to prioritize segments, which have a high susceptibility to SCC. Where possible, consideration should be given to additional QA/QC oversight of coating installation for these segments, additional protection against holidays, and realignment where possible in high threat circumstances.

13.1.2 Construction

- Coating installation and repair specifications, citing surface preparation and application procedures to ensure bonding and quality coatings, should be considered for inclusion in the contract documents.

- QA/QC procedures for coating installation should be implemented by qualified personnel, trained in NACE or similar procedures.

13.1.3 Operations

- Procedures to ensure the operating temperature remains within design limits of the coating and bonding mechanism should be developed.
- Operational awareness of the detrimental effects of temperature excursions should be available in the operational procedures, with accompanying procedures for engineering evaluation in the event of temperature excursions.
- Per 49 CFR 192 and ASME B31.8S all indications of stress corrosion cracks on gas pipelines require an immediate response, typically with a corresponding reduction in pressure. In lieu of other information, the pressure reduction should be to a value not exceeding 80 percent of the pressure at the time the anomaly is discovered. Another immediate response would involve removal of the cracks by an approved technique (e.g., grinding, hot-tapping, etc.).

  In any case, and for both gas and liquid pipelines, the anomaly should be critically evaluated for determination of the safe operating limits based on the best available data. The daily pressure history should be available in a form conducive to engineering evaluation.

  Once the immediate integrity concern has been addressed, the implications of the finding on the integrity and SCC risk must be considered and a situation-appropriate course of action decided upon. This consideration should take into account the actual severity of the feature relative to failure at the operating conditions, as well as such other information as the past pipeline performance data, past condition monitoring information for the pipeline, operating conditions, and materials of construction. In all cases, the longer term integrity plan must be commensurate with the SCC findings, the risk exposure, and past operational and condition monitoring data.

13.1.4 SCC Awareness Program

- An operator education program, explaining the causes and identification of SCC to field personnel, should be developed and readily available.
- A core cadre of operator personnel should be NACE, or similar professional organization, qualified, and designated in operating plans as corporate resources for addressing SCC.
- To the extent possible and appropriate, operator engineering personnel should have continuing education in the areas of SCC and be encouraged to keep abreast of research in SCC.

13.1.5 SCC Detection through ILI

- A written document that identifies the practicality of ILI tools in detecting SCC for the operator lines should be completed for each major operating pipeline. Although, and as discussed in this report, SCC detection in gas pipelines using ILI may not be currently considered practical, at least by some operators and for some lines, the tool development is rapidly advancing and close attention should be focused on ILI capability in this regard.

- An internal database that tracks the effectiveness of an ILI tool in detecting SCC on the operator's lines should be developed and regularly updated. Error bands for detection should start with vendor data and be refined through the use of this database. The error bands should be included in SCC threat assessment techniques. As discussed in this report, this may currently be problematic for most gas pipelines since the tool capability is probably not compatible with a detailed effectiveness tracking procedure at this time, but the tool development is rapidly advancing and close attention should be focused on ILI capability in this regard.

13.1.6 SCC Detection through Direct Examination

- Anytime a pipeline is uncovered, the assessment should include consideration of the possibility of SCC.
- Direct Examination methods should be reviewed to ensure that SCC awareness is included in all direct examination techniques. "Triggers" for more detailed SCC techniques, such as coating disbondment, should be identified.
- Written procedures for examination of pipeline segments with potential SCC should be developed.
- Personnel with experience and/or detailed education of SCC should be included in all investigations when there is a possibility of SCC.
- Data collection forms should be developed, completed and stored for each SCC Direct Examination threat assessment.
- An engineering evaluation procedure should be developed and followed for determination of the SCC threat. It is recognized that there is no single formula or software code that will address this complicated technical evaluation. Further, different operators may find different approaches are more appropriate to their circumstances. The engineering procedure should acknowledge this and allow for different metallurgical, environmental, and mechanical factors as well as consideration for a change in approach as understanding progresses. This could be done as part of a more general corrosion engineering procedure. Nevertheless, the engineering approach should be documented and readily available throughout the organization to ensure a base level of consistency in all pipelines within the operator's purview.

13.1.7 SCC Remediation

- Specific repair techniques should be developed and updated as required for SCC. The repair techniques should clearly identify the threat assessment limits for which the repair is applicable.

- Operating procedures that mitigate the SCC threat until repairs are completed should be developed, again with clearly identified threat assessment limits for which the procedure is applicable.
- Engineering evaluation procedures that are adjusted based on the repair evaluation should be developed and followed.

13.1.8 IM Program – SCC

- The Protocols should be examined to ensure that the IM plan meets all minimum requirements.
- Historical evidence of SCC should trigger specific additional requirements for the applicable lines.

13.1.9 Response to In-Service Failure

- Any in-service failure investigation should consider the possibility that SCC is a primary or contributing factor.
- Qualified staff knowledgeable in the causes and identification of SCC should be detailed to respond to an incident that may include SCC.
- Data collection forms should be developed, completed and stored for each SCC failure investigation.
- SCC examinations should include plans for metallurgy examination, immediate reduction of pressure and/or other mitigative means, and a plan to return to service that includes not only an evaluation of the site but also consideration of additional areas which have similar threat indicators.

Appendix A

Stress Corrosion Cracking Research Gap Analysis

This page intentionally left blank.

A Research Gap Analysis

A.1 Mechanisms of SCC

A.1.1 Mechanism of High pH SCC

There is almost universal agreement that crack initiation and growth in the high pH environment occur by selective dissolution of the grain boundaries, while a passive film forms on the remainder of the surface and on the crack sides to prevent corrosion at those locations. When an unstressed, polished surface of line-pipe steel is exposed to the high pH carbonate/bicarbonate environment at the appropriate potential for SCC, etching of the grain boundaries occurs with no noticeable corrosion of the grain faces (Parkins 1994). A strong correlation has been found between the maximum rate of crack growth and the maximum corrosion rate that can be sustained in that environment (Parkins 1987). The reason for preferential attack at the grain boundaries is thought to be related to some kind of chemical segregation or precipitation at the grain boundaries, but no direct evidence of either has been found.

Additional basic research into the fundamental mechanism of high pH SCC probably would not be justified.

A.1.2 Mechanism of Near-neutral pH SCC

Some researchers have suggested that the mechanism of initiation of near-neutral pH SCC may be different from that of crack growth (Fessler and Krist 2000). Neither stage of the cracking process is as well understood as is the mechanism of high pH SCC.

Crack Initiation. The mechanism for stress corrosion crack initiation in the near-neutral pH environment is not completely understood, but evidence from field failures suggests that corrosion pits might be a common site for crack initiation. In some cases the cracks were found in broad, shallow corroded areas. More commonly, there was very little corrosion visible to the naked eye, but very small corrosion pits at each crack have been seen with microscopic examination. Thus, many researchers believe that a corrosion pit may act as a stress raiser to initiate the stress corrosion crack. Also, the environment at the bottom of a pit will become more acidic.

Initiating near-neutral pH SCC in the laboratory under stressing conditions that are representative of those on an operating gas pipeline has proven very difficult. In experiments with polished, smooth specimens, researchers at CANMET produced clusters of transgranular cracks that appear very similar to near-neutral pH stress-corrosion cracks that have occurred in the field (Elboujdainia, et al. 2000). The earliest cracks to appear initiated at corrosion pits that formed around nonmetallic inclusions, and later cracks grew from corrosion pits that formed randomly on the surface. However, cracks initiated only in tests that involved many thousands of high-amplitude (low-R) stress cycles, a situation that is not typical of gas pipelines. Tests with more realistic stressing conditions did not produce cracks. Therefore, there is a concern that the tests that produced cracks may have involved corrosion fatigue rather than SCC.

Several mechanisms for producing shallow crack-like features at the surface of a sample of line-pipe steel under more realistic loading conditions have been demonstrated by King, et al. (2001). Expanding upon previous work by Wang, et al. (2000), which showed that corrosion pits formed preferentially along the heavily deformed metal in scratches on the surface, it was then shown that the rows of corrosion pits would join and preferentially grow deeper if the scratches were perpendicular to the direction of the tensile stress. Chu, et al. (2004) showed that preferential corrosion occurs at the boundaries of pearlite colonies, and transgranular crack-like features can grow from such surface attack.

Another possible mechanism for initiation involves small cracks oriented approximately 45 degrees to the direction of the tensile stress that were produced on specimens that had been subjected to a series of cyclic stresses patterned after a typical 20-year service life. Presumably, the cracks formed where persistent slip bands intersected the surface of the specimen.

Crack Growth. Whereas a dissolution mechanism for high pH SCC was supported by the agreement between measured crack velocities and those that would be predicted from Faraday's Law and current densities measured in polarization experiments, the same did not appear to hold for near-neutral pH SCC. Anodic current densities measured near the open-circuit potential in near-neutral pH environments were on the order of 10 microamps per square centimeter, which would correspond to a crack velocity of about 10^{-8} mm/sec according to Faraday's Law (Parkins 1998). Whereas that crack velocity is considered to be a reasonable estimate for the maximum rate of crack growth in the field and also corresponds to typical velocities measured on laboratory specimens subjected to realistic stressing conditions, there were reports of measured crack velocities as high as 10^{-6} mm/sec. Therefore, researchers looked for other mechanisms that might explain a crack velocity that was 2 orders of magnitude larger than would be produced by dissolution according to Faraday's Law. Other mechanisms that are known to produce transgranular fractures in carbon steels include fatigue, corrosion fatigue, and hydrogen embrittlement, the latter mechanism being the one that has been embraced by most researchers.

The hydrogen theory was supported by the results of a variety of slow-strain-rate experiments. For example, Mao, et al. (1998) showed that precharging specimens with hydrogen prior to testing in the near-neutral pH environment caused a decrease in the final reduction in area, which was assumed to indicate more severe SCC. However, as is shown in Figure A-1, the precharged specimens did not exhibit lower ductility when tested in air, so some synergistic effect between the hydrogen and the corrosive environment may be indicated.

More evidence for synergy between corrosion and hydrogen was developed by Parkins (1999) when he used slow-strain-rate tests (SSRT) to measure reduction in area (RA) as a function of potential and compared those results with anodic current densities and hydrogen contents (as determined from permeation experiments) over the same range of potentials. As is shown in Figure A-2, the dip in RA, which presumably corresponds to the region of SCC, between –550 and –700 mV occurs where there are small but significant amounts of both corrosion and hydrogen. At less negative potentials, the hydrogen concentration drops to insignificant levels, and the RA rises to high values, indicating no more SCC. At potentials between –700 and –750 mV, the corrosion rate drops to insignificant levels and there is a local maximum in RA.

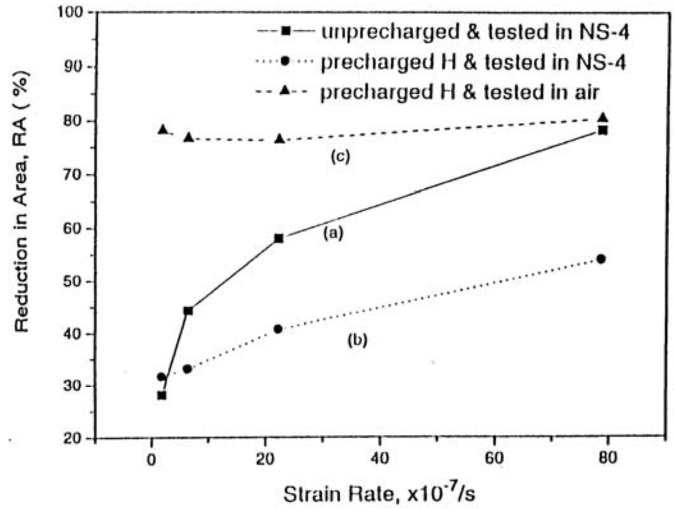


Figure A-1 Effect of Precharging with Hydrogen on Reduction in Area of SSRT Specimens Tested in NS4 and Air

The reason for the continual decline in RA at still more negative potentials is not clear. By analogy to the high pH SCC situation, one might believe that the decrease in RA at very negative potentials is due to some hydrogen effect that only occurs at very high levels of continuous plastic deformation and therefore is not relevant to an operating pipeline. Parkins (1998) has indicated that some SSRT specimens with RA values as low as 30 percent contained no detectable cracks, indicating that some embrittling, but not cracking, mechanism was operative. In fact, experience tells us that cathodically protected pipelines do not experience cracking problems where the potentials are adequate and the steel is not shielded from the cathodic-protection currents. An alternate point of view that is held by some researchers is that the SCC reaction continues to negative potentials in laboratory experiments because the stirring prevents the formation of an alkaline environment at the cathode, whereas that alkaline environment in the field will not support SCC at those potentials. Experiments that do not involve high amounts of plastic deformation (e.g. cyclic-load tests rather than SSRT) with stirred and stagnant environments will be required to clarify the significance of the low RA values at very negative potentials.

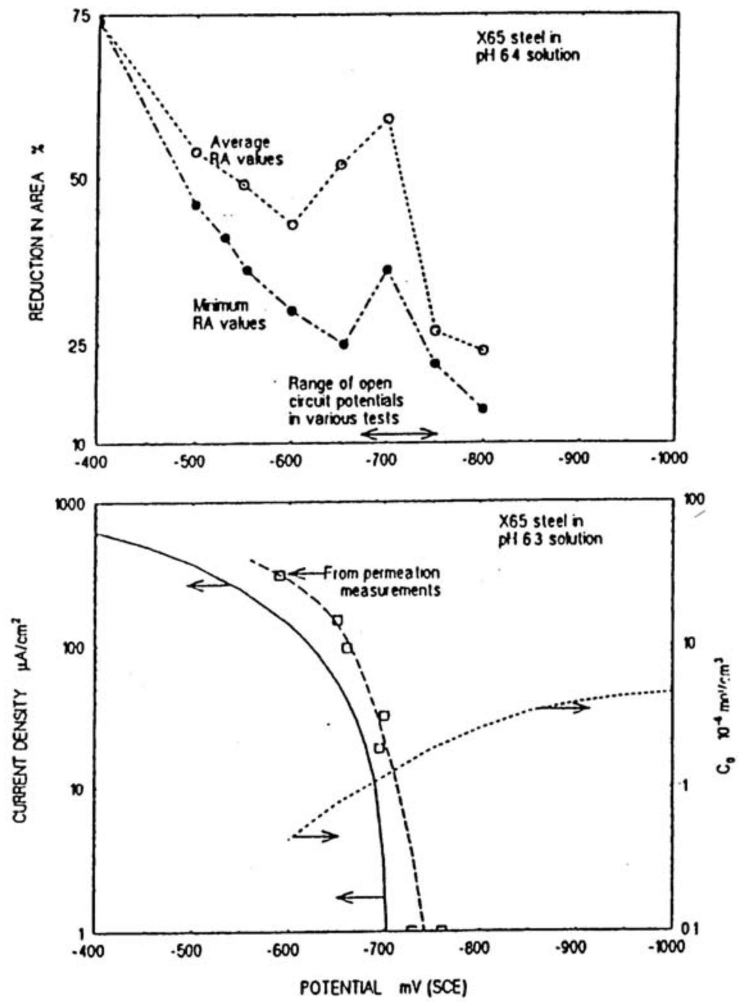


Figure A-2 Correlation Between Potential for Most Severe Near-neutral pH SCC and the Narrow Potential Range Where Both Dissolution and Hydrogen Entry Occur at Significant Levels

Even though a hydrogen-based theory is popular with most researchers in this field, there are several reasons that dissolution should not be ignored as possibly a significant part of the mechanism of near-neutral pH SCC:

1. Although hydrogen can cause delayed brittle fracture in very-high-strength steels at stresses below the yield strength, that phenomenon has not been observed in steels with yield strengths below 80 ksi (Fessler, et al. 1973). Hydrogen can reduce the ability of lower-strength steels to tolerate large amounts of plastic deformation, but pipelines do

not experience large amounts of plastic deformation in service. It might not be coincidence that all experiments that seem to demonstrate an effect of hydrogen on SCC have involved SSRT.

2. The high crack velocities on the order of 10^{-6} mm/sec have only been observed on specimens that have been subjected to low-R (typically about 0.5) stress fluctuations. ("R" is "…the ratio of the minimum to the maximum load for each cycle" (King, et al. 2001). As is described later in this report, there is reason to believe that the mechanism at low R may be corrosion fatigue rather than SCC. Laboratory experiments at R values of 0.85 and above, which are more typical of gas pipeline operation, usually produce crack velocities of 10^{-8} mm/sec or lower, which would not be inconsistent with Faraday's Law.
3. The anodic current densities that have been used with Faraday's Law were determined on undeformed coupons of steel. However, the steel at the tip of a crack (the plastic zone) is highly deformed. There are some reasons to believe that heavily deformed steel will corrode more rapidly than undeformed steel. It was mentioned previously that corrosion pits formed preferentially in the deformed metal in scratches on the surface of coupons. Foroulis and Uhlig (1964) determined that 50 percent cold work could increase the corrosion rate of carbon steels in 0.1N HCl by about 7 times, and subsequent aging at 100°C for a few hours could double the rate again. However, the effect of cold work on corrosion rate was not observed in neutral solutions. Whether there is an effect at the pH levels between 5 and 7 is not known. It also has been speculated that the pH inside the crack could be much lower than outside, which would tend to magnify the effect. Incidentally, Uhlig (1976) also showed that anodic dissolution enhances the room-temperature creep of cold worked iron and steel, and Oriani (Oriani and Josephic 1981) showed that hydrogen also enhances the room-temperature creep of steel, suggesting the possibility of several synergetic effects at the tip of the crack.
4. Another way that the corrosion rate at the crack tip might be accelerated is due to the fact that the hydrogen that is in the steel will preferentially move into the plastic zone. Mao, et al. (1998) have shown that charging X52 and X80 steels with hydrogen changes the shape of the polarization curves to suggest an increase in corrosion rate due to hydrogen in dilute bicarbonate solutions and NS4. However, while the effect was pronounced at positive potentials, it is difficult to tell from the published data whether the effects near the open-circuit potential, where near-neutral pH SCC occurs, were significant.
5. Near-neutral pH stress-corrosion cracks from the field or from laboratory tests invariably contain a considerable amount of corrosion product.

If hydrogen truly is an important factor in near-neutral pH SCC, a better understanding of the role of hydrogen might lead to better site-selection models if soil environments could be ranked with respect to their propensity to introduce hydrogen into the steel under free-corrosion conditions.

A.2 Causes of SCC in Pipelines

SCC is known to occur in many metallic alloys and polymers that are exposed to a wide variety of environments. However, for each material, there are a limited number of environments that can cause SCC, and certain levels of stress or stress fluctuations are required. Thus, it is a process that involves three interrelated factors: a susceptible *material* exposed to a specific *environment*, and subjected to specific ranges of *stress*. Significant alteration of any one of those factors is sufficient to prevent SCC.

A.2.1 Causes of High pH SCC

Environment. The effects of various environmental factors on high pH SCC are reasonably well understood. High pH SCC has been observed in solutions with various ratios of sodium carbonate to sodium bicarbonate ranging from almost pure sodium bicarbonate to almost pure sodium carbonate (Parkins and Fessler 1978). Those ratios correspond to a pH range from about 8 to 10. SCC is most severe in highly concentrated solutions, but it has been observed in less concentrated solutions having concentrations about one third those usually used in laboratory experiments (Parkins and Zhou 1997).

Although high pH SCC has been observed at temperatures ranging from 20°C to about 90°C, the crack velocity is much higher at the higher temperatures, and it decreases exponentially with decreasing temperature (Fessler 1979).

High pH SCC will occur only in a narrow range of potentials, the specific range depending upon solution composition and temperature. As is shown in Figure A-3, the width of the range decreases as the pH increases (Parkins and Fessler 1978). The width of the potential range for SCC also decreases with decreasing temperature, as is shown in Figure A-4 (Fletcher et al. 1982). In general, the critical potential range for high pH SCC is between the open-circuit potential and cathodic-protection potentials. Such potentials can be achieved on a pipeline with normal levels of cathodic protection due to partial shielding of the cathodic-protection current by a disbonded coating. However, laboratory experiments have shown that a heavy oxide, such as mill scale, on the steel surface is necessary to hold the potential in the critical range for appreciable times. If the surface is nearly free of oxides, the potential under the disbonded coating will rapidly move to more negative values in the highly conductive carbonate/bicarbonate environment (Parkins and Fessler 1986).

Stress. The role of stress, including stress fluctuations, is thought to be the promotion of creep deformation at the tip of the crack, which results in rupture of the comparatively brittle passive film, thus exposing bare metal to the corrosive action of the environment. The stress or stress intensity must be above a certain threshold level to produce a sufficient strain rate to exceed the passivation rate. The threshold stress can vary considerably from batch to batch of steel and even for different thermal and mechanical histories of a given batch (Fessler and Barlo 1984).

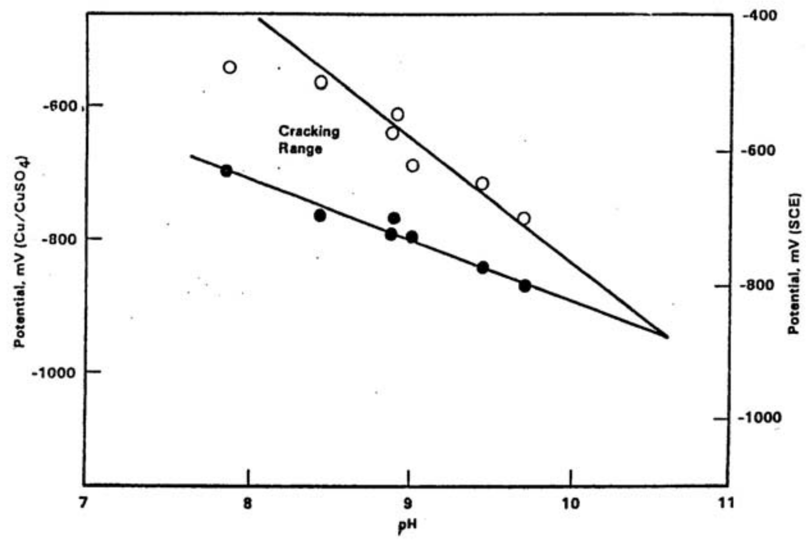


Figure A-3 Effect of pH on the Range of Potentials in Which Intergranular SCC can Occur in Line-Pipe Steels at 75°C

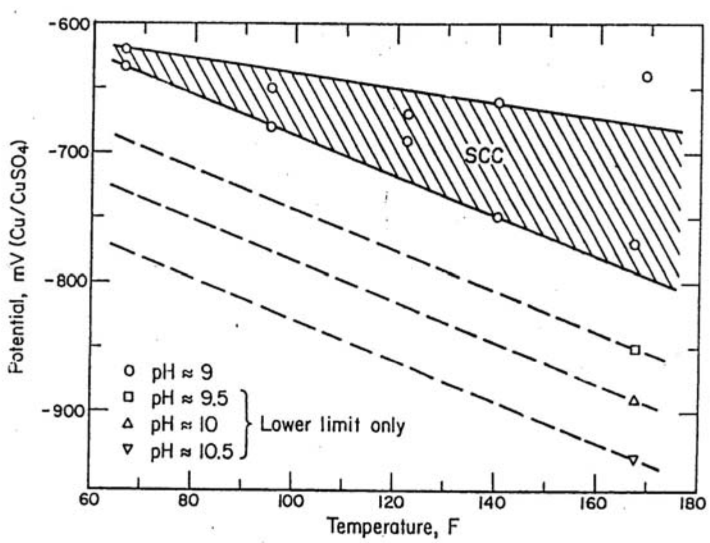


Figure A-4 Effect of Temperature on the Critical Potential Range for High pH SCC

The threshold stress can be reduced considerably if small-amplitude, low-frequency stress fluctuations are superimposed on the mean stress. The amount of reduction varies from steel to steel and varies with the amplitude and frequency of the fluctuations. One of the most dramatic effects, which is illustrated in Figure A-5, was a decrease of the threshold stress to 40 percent of the yield strength through the application of fluctuations as low as 1.5 percent of the mean stress twice a month (Fessler 1976).

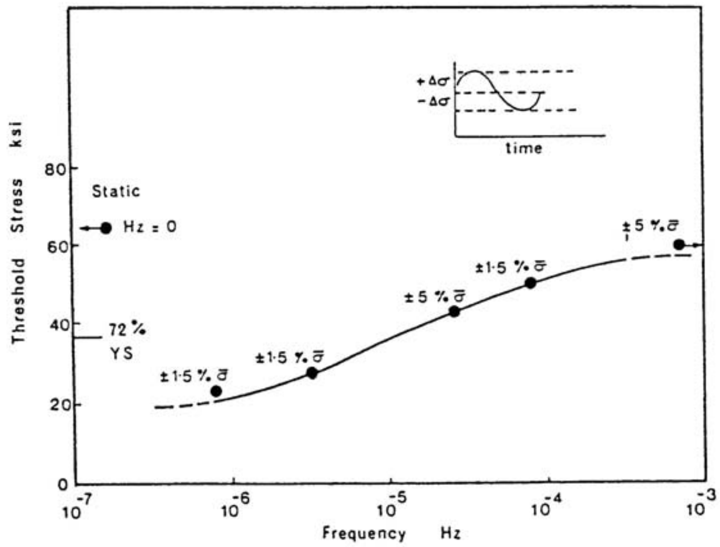


Figure A-5 Effect of Low-Amplitude (High-R) Stress Cycles on the Threshold Stress of an X52 Steel Exposed to a 1N Solution Carbonate + 1N Sodium Bicarbonate Solution at 75°C and –650 MV (SCE)

Steel. Although analyses of samples of line pipe that failed in service have not revealed any obvious correlations with steel composition, grade, or microstructure (Fessler 1976), there is direct evidence from laboratory studies that certain batches of steel are much more resistant to SCC than others. There are two important parameters associated with steel susceptibility: (1) crack growth rate and (2) threshold stress or stress intensity. Those parameters may be controlled by different mechanisms and, therefore, might not be directly related to each other. In other words, a given steel might have a relatively high threshold stress compared to that of another steel, but the crack growth rate above the threshold stress might not necessarily be lower. For example, in the case of high pH SCC, the crack growth rate probably is primarily controlled by the rate of dissolution, while the threshold stress may be more directly related to the creep resistance of the steel.

In a 1N sodium carbonate + 1N sodium bicarbonate solution at 75°C with a constant applied load, the threshold stresses of 10 different steels were found to be nearly equal to the yield strengths, the maximum differences being about 15 percent (Parkins, et al. 1993). The range of yield strengths was from about 30 to 70 ksi.

Parkins, et al. (1993) correlated the reduction in threshold stress with the strain-hardening behavior of the steel when subjected to cyclic stresses superimposed on a monotonically increasing stress. As is shown schematically in Figure A-6, the superimposed cyclic stress (typically on the order of 2 to 11 ksi) caused plastic deformation to start at much lower levels of mean stress, and the slope of the plastic portion of the stress-strain curve changed abruptly at a certain stress. That stress, where the slope became very low, correlated strongly with the threshold stress as measured under the same magnitude and frequency of superimposed fluctuating stress (see Figure A-7).

Thus, the susceptibility of a steel to high pH SCC appears to be controlled by its cyclic strain-hardening behavior or cyclic creep behavior and possibly by chemical segregation. Unfortunately, the relationships of cyclic strain hardening or cyclic creep or corrosion behavior to microstructure and impurity distribution are not known nor are the relationships of the critical microstructural features and impurity distribution to composition and processing. An understanding of those relationships will be needed to enable one to design steels that are highly resistant to SCC.

A.2.2 Causes of Near-neutral pH SCC

Environment. The chemical environments surrounding stress-corrosion cracks in the field have been studied far more extensively for near-neutral pH SCC than for high pH SCC. Hundreds of trapped water samples from under coatings and soil samples near the pipe have been analyzed. The results have been summarized by Jack, et al. (2000). The water samples have been very dilute, containing some bicarbonate ions plus lesser amounts of carbonate, chloride, and sulfate. The pH usually has been between 6 and 7. The major cations are sodium, calcium, potassium, and magnesium. Soils near SCC sites have been found to contain 4 to 23 percent CO_2 (Delanty and O'Beirne 1992).

The fact that the pH of the trapped water is slightly below 7 suggests that little if any cathodic-protection currents reach the pipeline where near-neutral pH SCC occurs. Thus, it occurs near the open-circuit potential, which is near –700 mV (SCE) or –770 mV ($Cu/CuSO_4$) for the environments in question.

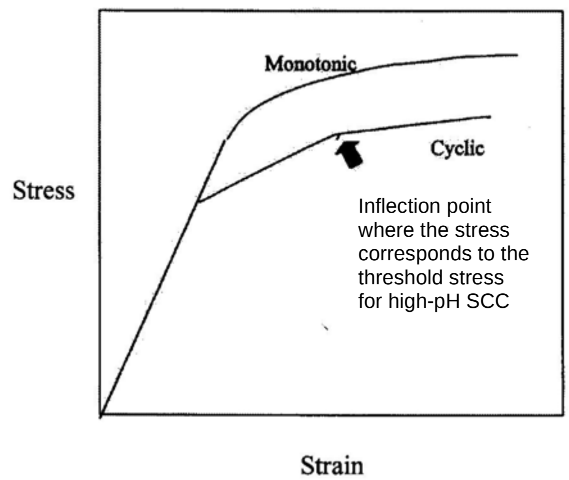


Figure A-6 Comparison of Typical Stress-Strain Curves Produced with Monotonic Loading and with Cyclic Loads Superimposed on the Steady Loads

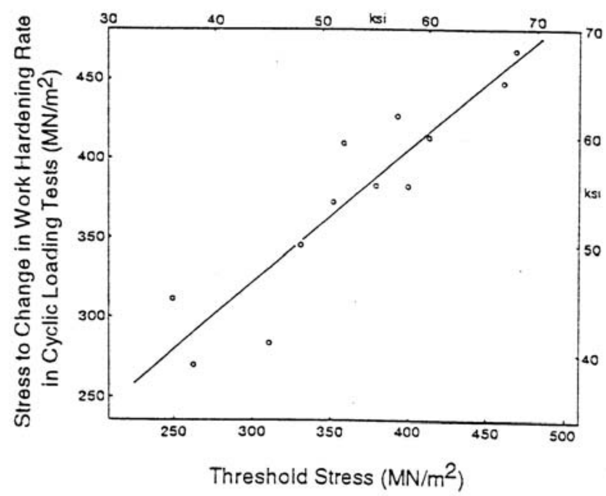


Figure A-7 Correlation of the Threshold Stress for High pH SCC and the Stress at which the Work-Hardening Rate in Cyclic-Loading Tests Suddenly Decreases

No pronounced effect of temperature on the kinetics of near-neutral pH SCC has been observed, but the research into temperature effects has been very limited. Parkins, et al. (1994) conducted a series of SSRTs at temperatures between 10 and 45°C. As is shown in Figure A-8, the considerable scatter in the data probably would mask any temperature effect that might exist. Based upon the fact that near-neutral pH stress-corrosion cracks frequently have been found far downstream from compressor stations, some researchers have concluded that temperature is not important. However, the fact that the most severe SCC (that leading to service failures) usually has been near the discharge of compressor stations (NEB 1996) raises some question about that conclusion.

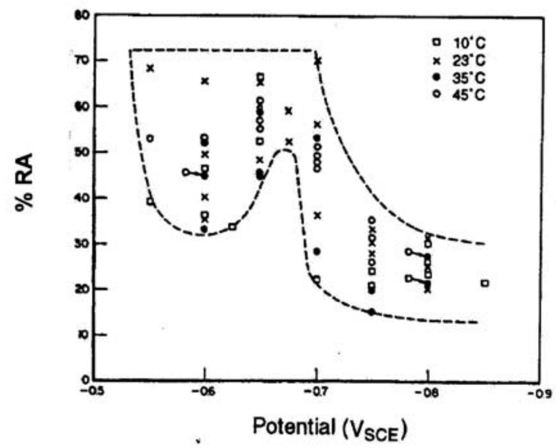


Figure A-8 Effect of Temperature on Reduction in Area for an X65 Steel Subjected to Slow-Strain-Rate Tests in NS4 Solution with pH about 6.4

From a mechanistic viewpoint, arguments could be made either way regarding an effect of temperature, depending upon the relative roles of dissolution and hydrogen. As with most chemical reactions, the rate of dissolution would be expected to increase exponentially with increasing temperature. However, the corrosivity of the environment is strongly affected by CO_2, the solubility of which decreases with increasing temperatures. The temperature dependence of hydrogen embrittlement for line-pipe steels is not known, but studies on QT steels (Tyson 1979) have shown a maximum effect around –100°C, the effect becoming very small above room temperature (see Figure A-9).

Stress. As is the case for high pH SCC, the role of stress appears to be to produce some continual plastic deformation at the crack tip, which also seems to be required for near-neutral pH SCC. Although Zhang, et al. (1999) reported near-neutral pH SCC under static loads, most researchers have found it useful, if not necessary, to vary the stress during the test to promote some continual deformation.

Steel. No obvious relationships between susceptibility to near-neutral pH SCC and the grade, composition, or microstructure of the steel have been apparent from analyses of pipe that developed SCC in service (Dupuis 1998). However, several recent laboratory studies of various batches of steel with different microstructures have suggested that steels with more uniform microstructures may be less susceptible to near-neutral pH SCC (Meyer, et al. 2003). Those results are based upon a very small sampling of steels, so more research in this area would be useful.

Recent studies showing a correlation between residual stresses and locations of SCC on a given joint of pipe (Beavers, et al. 2000) and between pipe manufacturers and probability of finding SCC in the field (Beavers and Harper 2004) suggest that residual stresses from the manufacturing process may be very important.

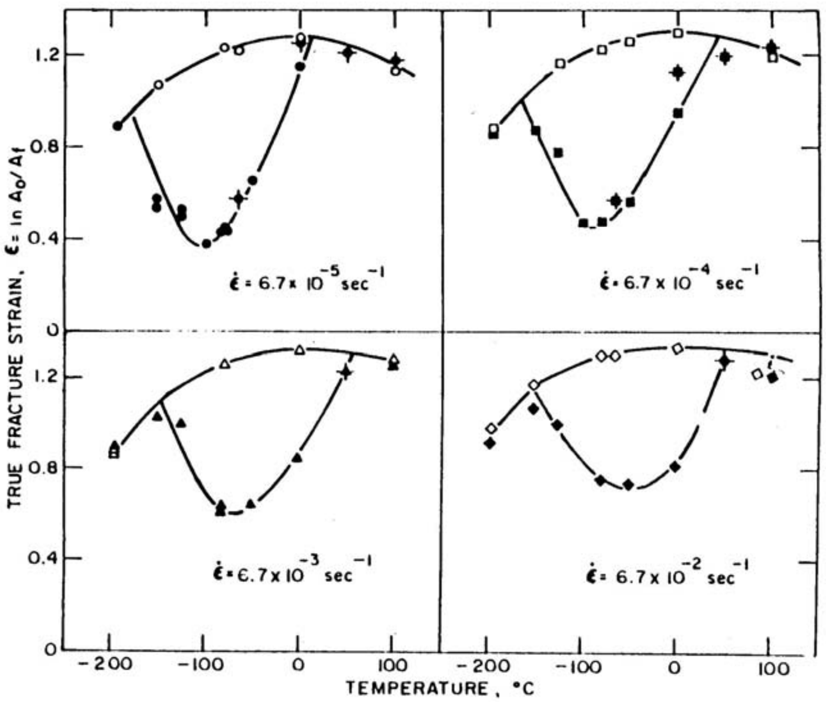


Figure A-9 Effect of Temperature on Hydrogen Embrittlement of a Quenched-and-Tempered Steel with a Yield Strength of About 100 Ksi

(Note: Solid points represent hydrogen-charged specimens.)

A.2.3 Summary of Gaps Related to Causes of SCC

Environment. Although the NS4 solution or something similar is being used by most researchers to simulate the environment that causes near-neutral pH SCC in the field, many researchers have experienced difficulties in initiating SCC in that environment under realistic loading conditions and in obtaining reproducible results in terms of crack growth rates. There have been several reports of unexpected and unexplained very high or very low growth rates. One possible explanation is that there are yet some undiscovered constituents in the field environment that may be critical in terms of SCC initiation and growth.

A fundamental understanding of how the environment at the steel surface under a disbonded coating relates to the surrounding soil and other external factors also has not been fully developed.

Stress. Many research projects have shown that low-amplitude pressure (stress) fluctuations and high-amplitude fluctuations can affect the growth of both high pH and near-neutral pH stress-corrosion cracks. However, it is not clear what kinds of pressure fluctuations (amplitude, frequency, and mean stress) are most harmful or how those factors might be related to the properties of the steel.

Steel. Although there can be large variations in susceptibility of different batches of steel to SCC, even within a single grade, it is not yet possible to predict the susceptibility from the composition and microstructure, nor is it possible to design a steel that will be resistant to SCC. Work completed by CEPA demonstrated that residual stresses in the pipe, probably as a result of the pipe manufacturing process, can have a significant impact on SCC susceptibility (Beavers, et al. 2000).

A.3 Methods for Managing SCC

It is highly unlikely that any single approach to managing SCC will be optimum for all pipeline companies. The choice of one or more approaches will depend on specific characteristics of a pipeline such as the following:

- Is it an existing line or a future one being designed
- Is the more likely threat from high pH SCC or near-neutral pH SCC
- Is the line piggable in its current condition
- What are the feasibility and cost of hydrostatic retesting (as affected by factors such as water supply or disposal, elevation differences, etc.)
- What are the economics of aftercooling gas prior to injection into a pipeline
- What is the ability to control cathodic protection (as affected by factors such as soil resistivity, accessibility, and coating condition)

Following is a list of options that a pipeline company might consider for managing SCC on its system:

Existing pipelines:

- Locate SCC and treat the pipe
  - ⇒ Locate
    - o Bell-hole inspections
    - o Hydrostatic testing
    - o ILI
  - ⇒ Evaluate/size the cracks
    - o Buffing/grinding
    - o Non-destructive evaluation (NDE)
  - ⇒ Treat
    - o Buffing/grinding
    - o Sleeving
    - o Remove the joint
    - o Leave cracks and establish safe re-inspection interval
- Change operating practices
  - ⇒ Lower temperature (for high pH SCC)
  - ⇒ Eliminate harmful pressure fluctuations
  - ⇒ Improve cathodic protection

Additional options for future pipelines:

- Select effective coating
- Consider steel susceptibility
- Optimize operating conditions
  - ⇒ Temperature
  - ⇒ Stress
  - ⇒ Pressure fluctuations
  - ⇒ Cathodic protection

Table A-1 and Table A-2 summarize some of the most important questions that remain regarding each of the options for managing SCC and the research areas that could be pursued to answer those questions.

Table A-1 Questions and Research Areas Relevant to Existing Pipelines

Management Technique	Question	Research Area
Locate and Treat SCC		
Locate SCC	How to increase the effectiveness and reduce the cost by identifying high-probability areas for focusing efforts	Develop improved site-selection models
	How to establish suitable inspection intervals	Develop improved crack-growth models
	How to reduce the cost of ILI for gas pipelines	Develop new ILI techniques that do not require a liquid couplant
Evaluate/size cracks in the ditch	How to obtain accurate measurements with portable equipment	Develop new in-the-ditch sizing technologies
Leave small cracks and establish safe re-inspection interval	How to ensure that interval is short enough to prevent unacceptable amount of growth but not too short as to be unnecessarily expensive	Develop improved crack-growth models
Change Operating Practices		
Lower temperature	Does temperature really have no significant effect on near-neutral pH SCC	Investigate effect of temperature on initiation and growth rates
Eliminate harmful pressure fluctuations	What kinds of pressure fluctuations are most harmful	Develop improved crack-growth models
Improve cathodic protection	Reasonably well understood	None needed

Table A-2 Additional Questions and Research Areas Relevant to Future Pipelines

Management Technique	Question	Research Area
Steel Susceptibility	How does SCC susceptibility depend upon composition, processing, and properties of steel	Empirical comparison of various batches of steel and regression analysis
		Fundamental study to relate susceptibility to properties, composition, and processing
Select effective coating	Are coatings with good service histories prone to failure after longer times	Monitor field-failure experience
Optimize operating conditions	Same as for existing pipelines	Same as for existing pipelines

The following sections describe the current level of understanding and possible future research approaches for each of the research areas listed in Table A-1 and Table A-2.

A.3.1 Site-Selection Models

Very soon after the initial discovery of near-neutral pH SCC on the TCPL system, data collected suggested that the locations of significant SCC were "…strongly related to terrain conditions surrounding the pipe where there was the potential for pipe coatings to have disbonded" (NEB 1996). If SCC is discovered in some location due to a failure, visual inspection, or non-destructive inspection, there is a high probability that SCC can be found in other joints of pipe in the same vicinity. This has led to a continued effort to find ways to predict locations where SCC may be highly likely or other locations where it may be highly unlikely or even impossible. The obvious benefits of such an ability would be to allow pipeline companies to focus their remedial efforts where they would be most effective and not waste time and money in areas where there is no significant threat of SCC.

It should be noted that site-selection models might take different forms from system to system since factors that may be highly significantly on one system might be completely absent from another. For example, while recent work reported in *"Stress Corrosion Cracking Prediction Model"* (Beavers and Harper 2004) demonstrated that the pipe manufacturer was highly statistically significant in the SCC prediction model for one pipeline company, pipe manufacturer might not be highly statistically significant for other companies.

Site-Selection Models for High pH SCC. Based upon statistics of reported incidents of high pH SCC, two models have been proposed to prioritize or rank areas in terms of relative probability of high pH SCC – one by Martinez and Stafford (1994) and the second by Eiber (1998).

Both models consider soil moisture level, coating condition, operating stress, cathodic-protection level, and gas temperature. The Martinez model also considers soil pH, coating age, pipeline age, history of SCC leaks and ruptures, and length of time since the most recent hydrostatic retest or bell-hole examination. The Eiber model also considers coating type, clay content of the soil, pipe surface preparation, and magnitude of stress fluctuations. The Eiber model requires less specific knowledge of the conditions at the surface of the pipe.

The Martinez model assigns either zero or one point for each condition and adds the points to get a relative probability. The Eiber model assigns weights to each factor to represent the estimated relative importance and then adds the values.

Both models represent thoughtful, prudent approaches to prioritizing areas for attention with respect to high pH SCC, especially in view of the limited amount of data upon which they could be based and against which they could be judged. Both give relatively high values for known locations of SCC.

However, as more data are collected from the field and a better understanding is gained in the laboratory, there may be several ways in which the models could be modified to make them more reliable:

- When reliable ILI information becomes available, the models could be tested against areas where SCC has not occurred in addition to more areas where it has.
- The weighting factors might then be refined to improve the reliability.
- When dealing with independent factors that affect the probability of an event, the probabilities of the individual factors usually are multiplied together, not added. Some system of multiplying ratings in the models should be considered.
- Although extensive early studies of the soils and geological features that were associated with high pH SCC failures revealed no correlation with chemistry (Mercer 1979), more recent work by Beavers suggests that soils with high amounts of sodium or potassium would favor high pH SCC because they would allow highly concentrated solutions of carbonates and bicarbonates to be produced (Beavers and Durr 2001). Conversely, high amounts of calcium or magnesium would lower the solubility of carbonates and bicarbonates to very low levels.

Site-Selection Models for Near-neutral pH SCC. In contrast with the site-selection models for high pH SCC, the models for near-neutral pH SCC have been based more on characteristics of the soil and terrain with less emphasis on operating history and other factors.

A limited survey of the industry indicated mixed experience with respect to success rate. As is shown in Table A-3, success rates in terms of correct positive indications for the tape-coated pipe ranged from 12 percent to 80 percent. For a coal-tar-coated line, there were no correct positives in a small number of digs.

Table A-3 Success Rates of Site-Selection Models for Near-Neutral pH SCC

Type Coating	No. of Digs	Correct Positive	Correct Negative	False Positive	False Negative	Comments
Tape	>800	80 percent	?	20%	?	A
Tape	85	12%	54%	18%	16%	
Tape	>100	40%	?	60%	?	B
Coal Tar	7	0	0	100%	0	

A. Tenting at longitudinal double-submerged arc weld.
B. Minor SCC; no significant cracks. Similar statistics for random digs.

A more recent study on a U.S. gas pipeline found a significant correlation between locations of SCC and a combination of coating type, soil type, and pipe manufacturer, the latter correlation speculated to be related to residual stresses (Beavers and Harper 2004).

There are a number of reasons why it is difficult to evaluate site-selection models for near-neutral pH SCC:

- They are based on correlating field experiences rather than a fundamental understanding of how the soil and geology contribute to the conditions that promote cracking. Thus, the models tend to improve over time because more data are accumulated, so the reliability this year might be much better than it was several years ago.
- They generally have been based on proprietary data and algorithms.
- They appear to be geographically specific. For example, the algorithms that work for Eastern Canada do not necessarily work for Western Canada.
- There are interdependent factors associated with locations of near-neutral pH SCC. For example, SCC on tape-coated pipelines has a tendency to occur more often in poorly drained soils, while SCC on asphalt-coated pipelines tends to occur in well-drained soils (CEPA 1998). However, there are exceptions to that rule of thumb as well; for one tape-coated liquid pipeline in Western Canada, the cracking was more frequent and deeper where the soil was well drained (Krishnamurthy et al. 2000). Not surprisingly, algorithms that work for tape-coated pipelines do not work well for asphalt-coated pipelines.

Research Gaps Related to Site-Selection Models. Although several important projects currently are being conducted to correlate various soil characteristics with the locations of SCC, there are several other opportunities to improve existing models:

- From the soil extracts that produced exceptionally high or low crack growth rates of near-neutral pH SCC, attempt to identify the critical constituents. Identifying the accelerating constituent would have the added benefit of allowing laboratory tests to be conducted in much shorter times, thus producing more data per dollar.
- As more ILI runs are completed, test the parameters of the pipeline and geology from places where SCC is not found against the models. It also may be useful to compare parameters related to large cracks versus shallow cracks.
- Broaden the range of parameters that are considered in site-selection models. For example, incorporate more operating data into models for near-neutral pH SCC and more soils/terrain data into models for high pH SCC. Consider factors such as proximity to a compressor or pump station and results of metal-loss ILI surveys if available.
- Since it is very difficult, if not impossible, to measure the environmental conditions at the pipe surface as a way of determining where SCC might occur, it would be useful to develop a fundamental mechanistic model for the relationship between the nature of the environment at the pipe and factors that are easier to measure such as soil chemistry, soil resistivity, cathodic-protection values, moisture levels, and coating conditions. Rather than relying solely on empirical correlations, such a fundamental model should be more reliable and more

broadly applicable for predicting different areas where either high pH SCC or near-neutral pH is more probable.

A.3.2 Crack-Growth Models

Ability to predict crack growth rates is important to predicting remaining life, assessing risk, determining what kinds of operating practices (such as pressure fluctuations) are harmful or beneficial, and establishing reasonable intervals for hydrostatic retesting or ILI. B31.8S states "When time-dependent anomalies such as...stress corrosion cracking are being evaluated, an analysis using appropriate assumptions about growth rates shall be used to assure that the defect will not attain critical dimensions prior to the scheduled repair or next inspection." It further states that, if an SCC failure has occurred, the pipeline company must have a documented hydrostatic retest program with a technically justified retest interval.

Models of High pH SCC Growth Kinetics. A four-stage model of high pH SCC that was proposed by Parkins (1988) is illustrated in Figure A-10. Stage 1 represents the time required to deteriorate the coating and build up the necessary environmental conditions for SCC. It probably is the least predictable stage, and it probably varies by several orders of magnitude from one pipeline to another depending upon the condition of the coating, the nature of the backfill, and many other factors. If a crack-growth model is used to estimate the remaining life of a pipeline that is known to contain stress-corrosion cracks, then knowledge of Stage 1 is irrelevant. However, if one is trying to predict the total life of a pipeline, then it will be necessary to make an arbitrary assumption about the length of Stage 1.

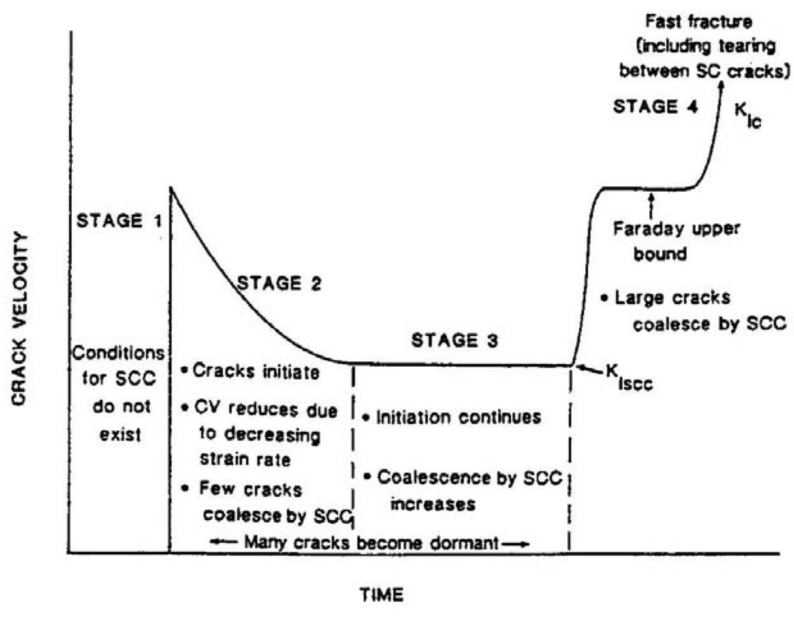


Figure A-10 Four-Stage Model of High pH SCC

The final event in Stage 1 is the initiation of a stress-corrosion crack. Parkins has shown evidence that the initiation mechanism is simply selective dissolution of the grain boundaries, which is the same mechanism as that for crack growth (Parkins 1994).

Stage 2 represents the exponential decrease in crack growth rate with time and may cover only a few days for an individual crack. The schematic illustration in Figure A-10 greatly exaggerates the length of Stage 2.

Stage 4 represents the final part of the growth process where the crack is so large that a small amount of growth reduces the remaining wall thickness enough to cause the driving force to increase fast enough to overcome the effect of work hardening. Parkins has shown that the growth rate in Stage 4 can be calculated from Faraday's Law and the corrosion rate as measured from a polarization curve (Leis and Parkins 1998). For the carbonate/bicarbonate environment at 75°C, it typically is around $2x10^{-6}$ mm/sec. Stage 4 is followed by rapid mechanical penetration of the pipe wall to produce a leak or rupture. Both Parkins (2000) and Leis (1995) have argued convincingly that the time spent in Stage 4 is a relatively small fraction of the total time to failure.

The key to predicting the remaining life of a pipeline with small stress-corrosion cracks lies with Stage 3, which probably involves sporadic crack growth due either to crack coalescence or cyclic softening or both.

In laboratory experiments, average crack growth rates typically are calculated by measuring the crack depth at the end of the test and dividing by the total test time. Since it is known that cracks initiate continuously during a test, (Parkins 1988) the deepest crack usually is used for reporting a maximum average growth rate.

Several investigators have found that the average crack growth rate decreases exponentially with time for initially plain specimens or fatigue-precracked specimens where the precrack does not extend to the edges of the specimen (Parkins 1987; Parkins and Zhou 1997; Parkins, et al. 1993; Baker, et al. 1986; Marshall 1984). A typical behavior pattern is illustrated in Figure A-11, where the slope of the line usually is between –0.8 and –1.0. A slope of –1.0 would indicate zero growth, and a crack characterized by a slope of –0.9 would be less than 0.1 mm deep in 100 years. Thus, the measured crack growth rates in the laboratory become negligibly small in a few days.

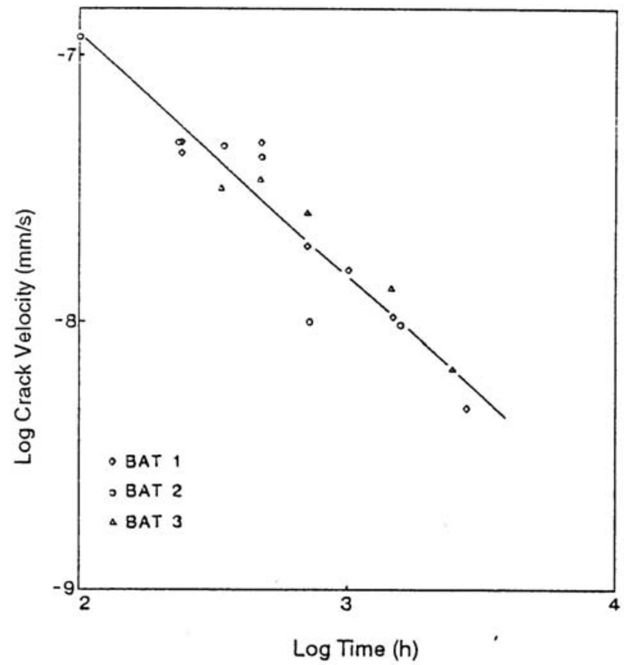


Figure A-11 Effect of Time on Average Velocity of a Single High pH Stress-Corrosion Crack

One possible explanation for how cracks that move so rapidly toward dormancy can eventually grow large enough to cause a service failure in a pipeline has been given by Leis (Leis and Parkins 1993) who monitored the lengths of cracks on the surface of a specimen exposed to the carbonate/bicarbonate solution. As is shown in Figure A-12, crack growth stopped and restarted a number of times during the experiment. The periodic halting of the crack was attributed to creep exhaustion, and the restarting was attributed to coalescence of a dormant crack with other cracks that had initiated near the ends of the first crack. It has been demonstrated that cracks continue to nucleate as time goes on (Parkins 1988). Computer simulations of crack growth were carried out for five different initial random distributions of cracks assuming the exponential decreases in growth rate and nucleation rate with time but allowing for crack coalescence whenever the separations were less than 14 percent of the average lengths (Leis and Parkins 1993). The results, shown in Figure A-13, compare remarkably well with the measurements shown in Figure A-12. The dashed line in Figure A-13 represents the crack growth that would be expected in the absence of coalescence.

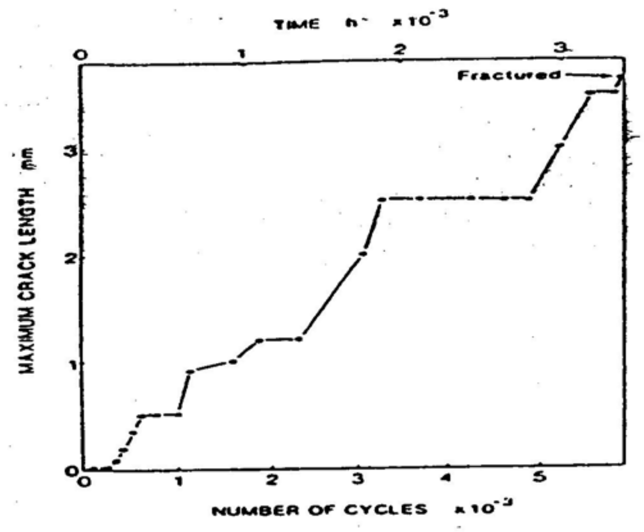


Figure A-12 Intermittent Growth of High pH Stress-Corrosion Cracks

Leis, et al. have developed a quantitative crack growth model for high pH SCC (Leis, et al. 1995) that reproduces the general features of Stages 2, 3, and 4 in Parkins' model. Called SCCLPM (stress-corrosion-cracking life-prediction model), it involves the following steps:

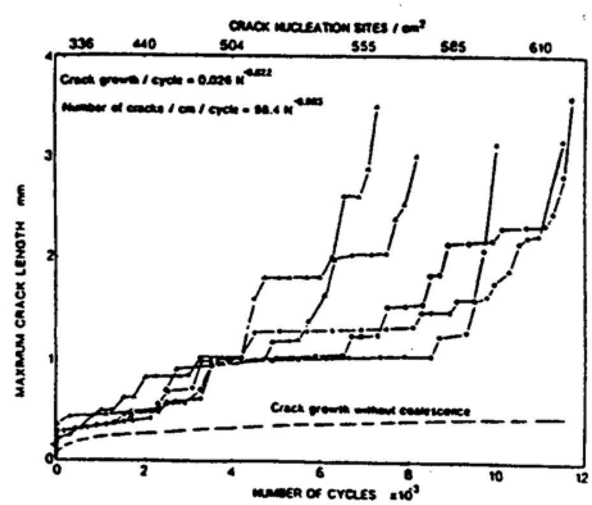


Figure A-13 Simulated Growth of High pH Stress-Corrosion Cracks Showing Intermittent Growth Due to Crack Coalescence

1. Generating a random array of cracks where the cracks depths and number of cracks per unit area are functions of the stress on the pipe, the yield strength of the steel, and the proportional limit of the steel, the relationships being determined from laboratory tests.
2. Updating the nucleated array of cracks to account for additional crack nucleation near the ends of the first cracks due to the increased stress concentration there.
3. Allowing the cracks to grow according to some kinetic relationship. This is the only part of the model that is specific to high pH SCC. It uses the crack growth rate predicted by Faraday's Law whenever the steel is experiencing a strain rate sufficient to support SCC. The strain rate depends upon the cyclic stresses and the mean stress, and it decreases over time due to work hardening. Continued crack growth depends upon crack coalescence. The effects of cyclic softening can be included in the model for a specific steel, but they have not been included in a generic sense. As Leis points out, it would be desirable to do so.
4. The cracks are allowed to grow until they, as a group within the cluster, reach a critical size for mechanical extension by tearing.

The model is pipeline specific with respect to size, grade, toughness, service conditions, and hydrostatic-test history.

Predictions from the model have been compared with the behavior of an actual operating pipeline that contained SCC. The predictions agreed well with the aspect ratio, time to failure, crack depth, and relative incidence of dense to sparse cracking (Leis 1997). The model also can predict dormancy and re-initiation of cracks. It predicted that reductions in pressure cycling and discharge temperature were the most important parameters to extend the service life of pipelines suffering high pH SCC.

A more complicated probabilistic model had been formulated based upon the deterministic model SCCLPM but considering random variations or uncertainties in mechanical properties of the pipe, gas pressure, temperature, and electrochemical potential (Leis and Kurth 1999). This model has been used to quantify the beneficial effects of lowering discharge temperatures and to develop guidelines for optimizing hydrostatic-retest procedures. Those results will be described in more detail later in this document.

Models of Near-neutral pH SCC Growth Kinetics. A variety of possible initiation mechanisms for near-neutral pH SCC have been proposed by several investigators. (Parkins and Delanty 1996; King, et al., 2001) For the most part, crack-like features that were produced at the surface failed to extend more than 0.02 mm below the surface and did not closely resemble typical deep stress-corrosion cracks. Currently, there is no well-accepted model for initiation of near-neutral pH SCC.

In laboratory bend tests with specimens from the field that contained service-induced stress-corrosion cracks, only 8.5 percent of the cracks could be activated, and 80 percent of the growing cracks were near the edges of the clusters (Jack et al. 1994).

Beavers and Jaske (2002) measured instantaneous crack growth rates with an electric-potential-drop technique and found that crack velocities decreased continuously after the start of a test with low-frequency, high-R stress fluctuations typical of those on a gas pipeline. As is shown in Figure A-14, higher-frequency, lower-R fluctuations, which probably caused corrosion fatigue, resulted in increasing crack velocities. Decreasing crack velocities with time also have been observed by Parkins, (2002) as is shown in Figure A-15, where the slopes of the lines are between -0.8 and -0.9, indicating that crack growth had almost stopped by the end of the tests.

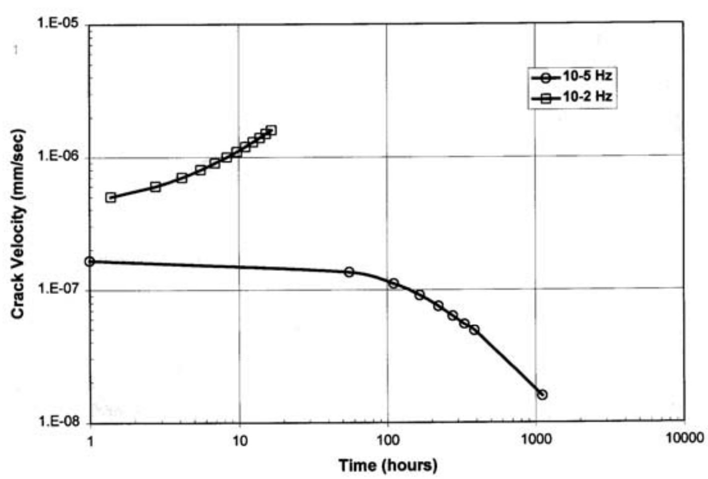


Figure A-14 Variations of Crack Velocity with Time for Near-Neutral pH SCC

Chudnovsky (Zhang et al. 2000) has attempted to develop a thermodynamic model for the growth of near-neutral pH stress-corrosion cracks. The approach starts with a sophisticated mathematical formalism that ultimately depends upon laboratory experiments to determine key parameters such as the electro-chemical driving force. Those parameters are in question because they were determined under conditions of high-frequency, low-R stress fluctuations and cathodic charging. Thus it is more likely that he was producing data for corrosion fatigue rather than stress-corrosion cracking. Other problems with his approach are that it does not consider decreasing crack velocity with time, the importance of plastic strain as opposed to stress intensity, and kinetic considerations such as diffusion in the liquid or in the steel.

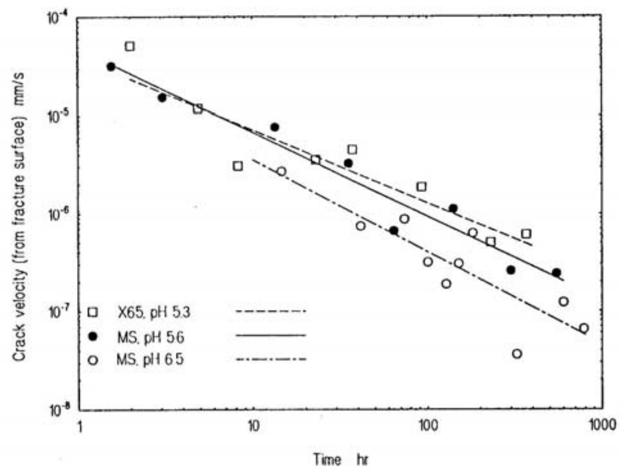
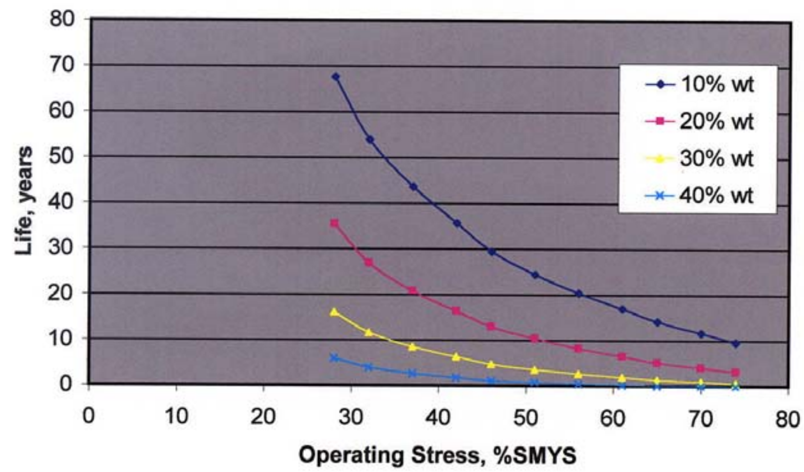


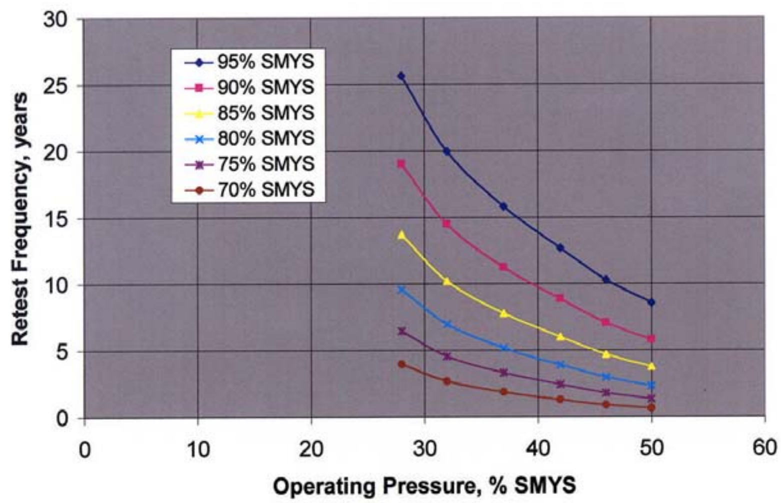
Figure A-15 Decrease in Average Crack Velocity with Time for Near-Neutral pH SCC

Krishnamurthy, et al. (1996) used an elastic-plastic (J-integral) analysis to calculate the safe remaining life of a pipeline segment with near-neutral pH stress-corrosion cracks of known depths. Results of their calculations are shown in Figure A-16 for predicted remaining life of a pipeline with different size cracks and recommended hydrostatic-retest frequency as a function of retest pressure and maximum operating pressure. The results probably are somewhat conservative because the calculations involved two conservative assumptions: (1) that the cracks were infinitely long, and (2) that crack velocity as a function of J could be extrapolated from some tests by Harle, et al., (1994) which were conducted with very aggressive stressing conditions, conditions that produced substantial crack growth even in the absence of a liquid environment. Nevertheless, the model allows the company to make justifiable decisions about operating the pipeline and scheduling remedial measures. It also provides an interesting framework that could be refined to make it less conservative.

For pipelines that experience both high-frequency, low-R stress fluctuations and low-frequency, high-R fluctuations, Lambert and others (Lambert et al. 2000) have proposed a superposition model, where the amount of corrosion-fatigue crack growth from the low-R fluctuations is simply added to the amount of stress-corrosion crack growth from the high-R fluctuations. While that approach seems reasonable, plots of the data, as shown in Figure A-17, contain so much scatter that it is difficult to judge the quality of agreement between experiment and theory. Part of the problem might stem from the fact that they do not consider variations of the rate of SCC with time.



a. Remaining life as a function of crack depth and operating stress



b. Retest frequency as a function of retest pressure and operating pressure

Figure A-16 Results of Elastic-Plastic Analysis for a Specific Liquid Pipeline with Near-Neutral pH SCC

(Note: These results are pipeline specific; they do not apply to any pipeline in general.)

In fact, none of the models for near-neutral pH SCC that have been proposed to date consider or predict the decrease in crack growth rate with time.

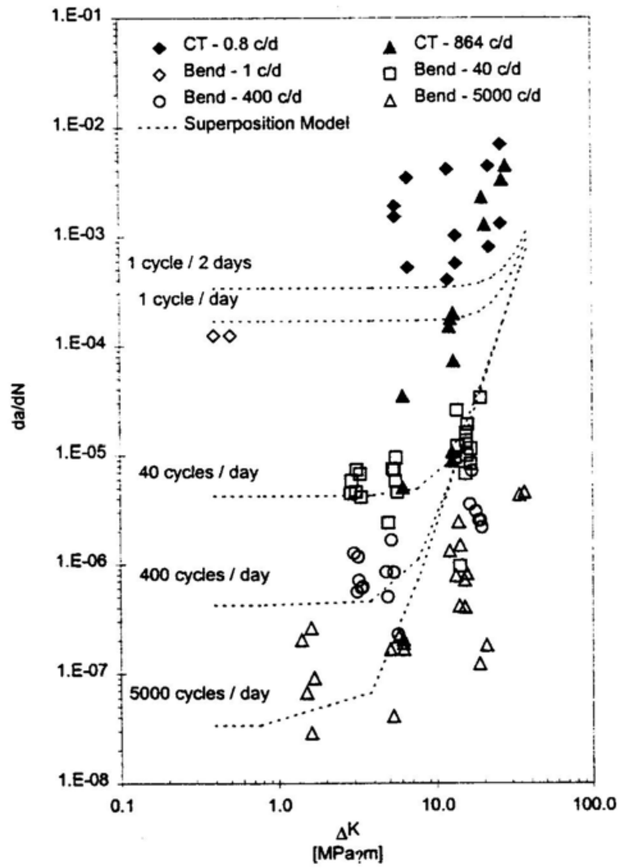


Figure A-17 Crack-Growth Data Generated in a Near-Neutral pH Environment

Gaps Related to Crack-Growth Models. Determining how frequently to test requires reliable crack growth models. The advantages and disadvantages of current models have been discussed above. Leis (Leis and Kurth 1999) used his probabilistic life-prediction model to calculate that the time to the first retest could vary from 10 to 70 years depending upon the aggressiveness of the environment and the operating conditions. Subsequent retest intervals could vary from 3 to 30 years depending upon those same parameters plus the previous retest pressure. The calculations must be customized to each pipeline. Refining the model to make it more user friendly would help in this matter. The above calculations were for high pH SCC, but a comparable interval for near-neutral pH SCC in "highly susceptible valve sections" of 2 to 3 years was determined from observations of crack growth following a hydrostatic retest (Delanty and O'Beirne 1992). A model to predict the effects of operating pressure and retest pressure on retest frequency has been discussed with reference to Figure A-16.

Crack-growth models also are useful for determining optimum pressures and hold times. Using his probabilistic life-prediction model, Leis showed that retesting to 95 percent of the SMYS or below produces almost no benefit in terms of increasing remaining life, but higher retest pressures can be very beneficial. Pressures between 105 and 110 percent SMYS for 1 hour followed by a longer, lower-pressure leak test appeared to be optimum. A totally independent model for near-neutral pH SCC also shows a pronounced effect of retest pressure and demonstrates the need to exceed 95 percent SMYS if future operating stresses are going to exceed 50 to 60 percent SMYS (see Figure A-16). It is difficult to see how additional research would add to our knowledge in this area.

There are a number of significant challenges to developing a quantitative model for the kinetics of crack growth for either high pH or near-neutral pH SCC. The first is the inability to calculate the length of Stage 1, the time required to establish the necessary environmental conditions at the surface of the steel. That is, in fact, just a subset of the larger problem of not having specific knowledge about the severity of the environmental conditions anywhere along the pipeline.

Another challenge is modeling the acceleration or re-initiation of a crack that is moving rapidly toward dormancy. Several possible mechanisms have been suggested:

1. Crack coalescence, which has been discussed above.
2. Re-initiation of creep strain due to softening as the result of continued cyclic loading. Figure A-18 shows an example of this, (Leis and Parkins 1993) where creep essentially stopped after about 400 cycles but then resumed after about 1000 cycles.
3. Re-initiation of creep due to a single large stress cycle, such as complete unloading and reloading. Figure A-19 shows an example of that phenomenon (Leis and Parkins 1993) and Figure A-20 shows how such unloading and reloading can result in bursts of additional crack growth (Beavers and Jaske 2002).

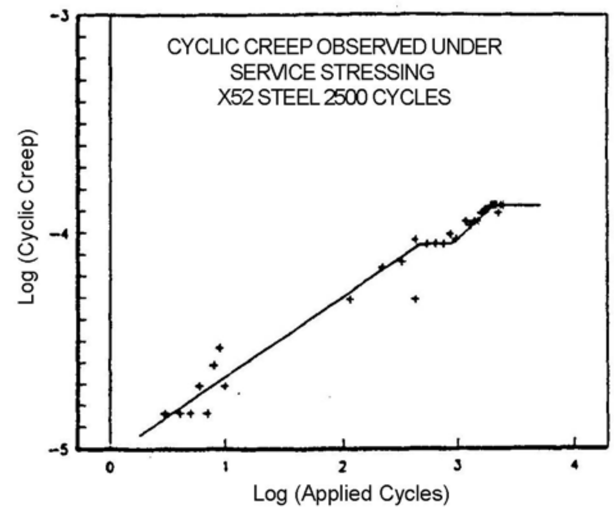


Figure A-18 Creep Exhaustion Followed by Re-Initiation of Creep Due to Additional Stress Cycles

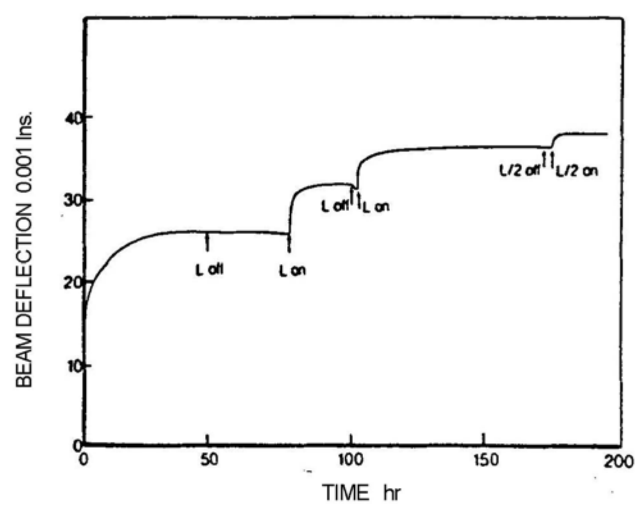


Figure A-19 Creep Exhaustion Followed by Re-Initiation of Creep Due to Loading and Unloading

The first of those mechanisms is considered in Leis's SCCLPM; all three may be important for operating pipelines.

Leis's probabilistic model for high pH SCC is the most sophisticated and complete, but its complexity is a discouragement to wide-spread use. It might be more useful if its results could be illustrated in charts or tables for typical operating conditions. Also, as the Leis has suggested, it should be expanded to include the effects of cyclic softening.

That same model might also be appropriate for near-neutral pH SCC if the appropriate growth mechanism for a single crack were better understood.

In spite of all the difficulties, by making reasonable but conservative estimates about some of the unknown parameters, existing models have provided useful insight and guidance to pipeline companies.

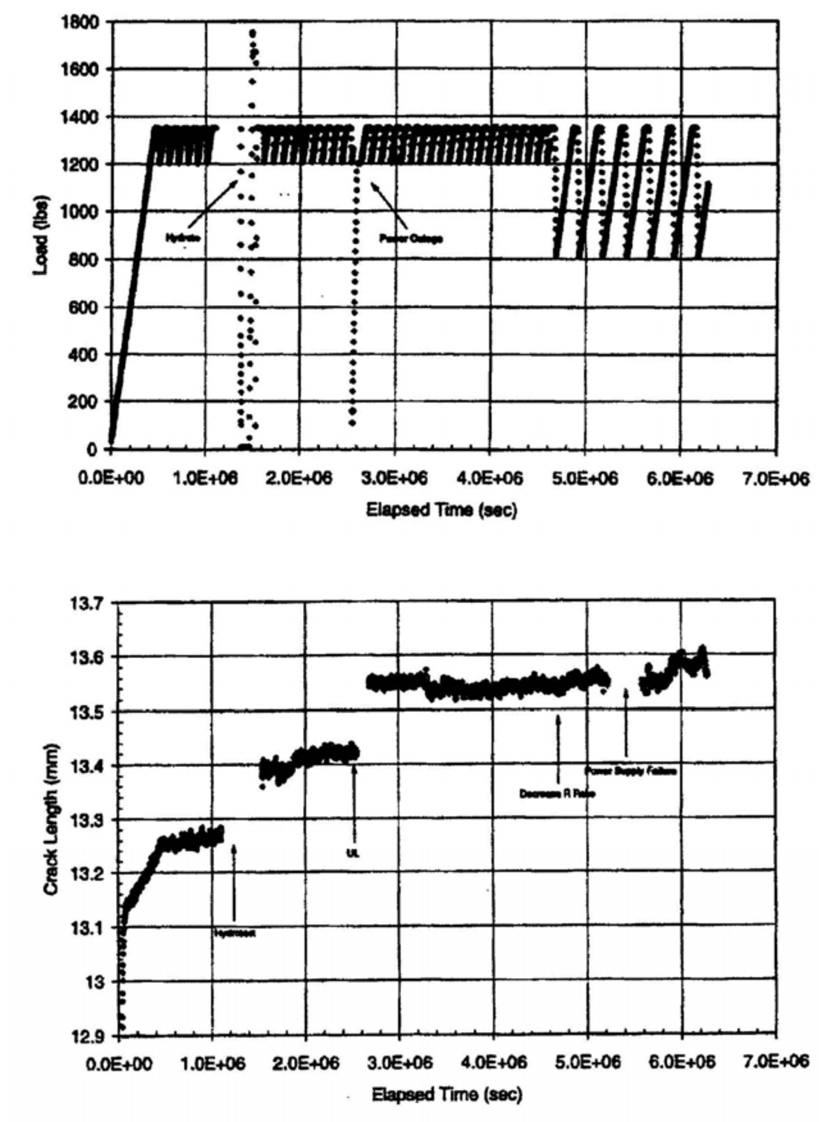


Figure A-20 Bursts of Crack Growth (Lower Graph) Due to Unloading and Reloading (Upper Graph)

Possible improvements to existing crack growth models include the following:

- Incorporate the effects of cyclic softening and high-amplitude stress cycles into SCCLPM and the probabilistic model for high pH SCC.
- Use the probabilistic model to investigate reasonable ranges of the important parameters and present the results in tables or charts that can provide the basis for at least "rule-of-thumb" guidelines to pipeline operators.
- Expand SCCLPM and the probabilistic model to cover near-neutral pH SCC.

- Incorporate more realistic crack growth rates into the elastic-plastic model for near-neutral pH SCC.
- Expand the elastic-plastic model to cover high pH SCC.
- Compare the predictions from SCCLPM and the probabilistic model with those from the elastic-plastic model.

A.3.3 ILI Technologies

ILI technologies for detecting, characterizing, and sizing stress-corrosion cracks in pipelines are described in Section 6.2.2 of this document. ILI obviously is important in locating SCC and offers an attractive substitute for hydrostatic retesting in some situations. In principle, ILI can provide much more information, especially about locations and sizes of cracks or crack clusters that are too small to cause a failure during a hydrostatic test. ILI also is important for risk assessment.

ILI crack-detection tools have been built based upon liquid-coupled ultrasonics, wheel-coupled ultrasonics, magnetic-flux leakage, and EMAT. The only technology that has been satisfactory in terms of locating, identifying, and sizing cracks is liquid-coupled ultrasonics. Unfortunately, it is very difficult (many would say impractical) to use in gas pipelines because it requires surrounding the tool with a slug of water. Procedures to do so may be more trouble than conducting a hydrostatic retest. Considerable hope has been placed on the development of a new technology based upon EMAT that does not require the pipeline to be filled with a liquid. At least two vendors are developing such a tool, and they will need pipeline companies to provide manpower, equipment, and pipelines to evaluate them in their final stages of development.

The highly competitive, proprietary nature of the ILI industry makes it difficult for public organizations to participate in developing new technologies or tools. The vendors seem willing to do so if the pipeline companies will commit to using the tools once they are developed and shown to be reliable and durable. The industry should stimulate the academic and/or basic-research community to suggest new technologies that might be overlooked by the ILI vendors.

A.3.4 In-the-Ditch Sizing

Current nondestructive approaches to measuring the sizes of stress-corrosion cracks in the ditch involve either electromagnetic or ultrasonic techniques. Ten such technologies were recently evaluated in a round-robin testing program (Francini et al. 2000). The electromagnetic methods included alternating-current potential drop, alternating-current frequency modulation, and eddy-current techniques. All of the electromagnetic methods underestimated the sizes of the stress-corrosion cracks. Making such techniques reliable probably will require improved technology, calibration methods, and cleaning procedures.

The ultrasonic methods included time-of-flight diffraction, phased array, and several proprietary technologies. Ultrasonic time-of-flight diffraction gave the most accurate measurements. An ultrasonic phased-array technique was the second most promising technology, but divergent results from two different companies using this technology indicated that refinement of the procedures is required. Perhaps the biggest concern about ultrasonic technology for work in the field is that current equipment is large and expensive, although vendors appear to be making progress at reducing both size and cost.

Because of the difficulties with nondestructive methods, most pipeline operators determine the size of cracks by grinding until magnetic powder inspection shows that the cracks have been removed. This destructive approach is much more time consuming and expensive than a nondestructive technique should be.

A.3.5 Effect of Temperature

The effect of temperature is a part of crack-growth modeling. The effect on high pH SCC is well known, and additional research in this area probably would have little benefit. The effect for near-neutral pH SCC is not so clearly established, but it does not appear to be a major factor.

A.3.6 Steel Susceptibility

Some are convinced that enough is known about the beneficial effects of surface treatments (shot or grit blasting) and certain types of coatings that future pipelines can be designed to be safe from SCC regardless of the inherent susceptibility of the steel. Others prefer a "belt-and-suspenders" approach for cases where the coating is damaged or deteriorates in service.

Susceptibility to High pH SCC. Because high pH SCC involves selective dissolution at grain boundaries, a number of researchers have looked for chemical segregation to the grain boundaries to explain why they are more susceptible to corrosion. Based upon past work with other kinds of steels in other environments, the principal suspects were sulfur, phosphorus, and carbon. Danielson, et al. (2000) tried to produce intergranular fractures in pipe-steel specimens while they were in an Auger spectrometer to analyze the compositions at grain boundaries, but they were unable to produce intergranular fractures, Wang, et al. (2001) used electron energy-loss spectroscopy in a high-resolution analytical electron microscope to look at cross-sections through grain boundaries, and they were unable to detect any segregation of S, P, or C in samples of X42, X52, and X65 steel. Hunt (1988) prepared a number of steels with various levels of P, S, Cu, Sn, and Ni and compared their susceptibilities to high pH SCC by comparing times to failure in slow-strain-rate tests. Although he was able to detect phosphorous segregation to some of the grain boundaries, he found longer failure times (implying lower susceptibilities) for all of the steels with added impurities.

Also using slow-strain-rate tests, Parkins, et al. (1981) studied the effects of Mo, Cr, Ni, and Ti additions. Under these test conditions, it required unacceptably large additions (e.g., 1 percent titanium) to impart high resistance to high pH SCC. However, any improvement to the creep resistance of the steels would not have been detected in those tests.

Using tapered-tensile-specimen tests with superimposed, high-R, cyclic loads to measure the threshold stresses of six line-pipe steels ranging from Grade X42 to X70, Wells (1993) found no correlation between susceptibility (as measured by the ratio of threshold stress to SMYS or actual yield strength) and pipe grade. Using a similar approach with two X70 steels and an X80 steel, Christman (1988a) measured threshold stresses between 42 and 60 ksi, and the susceptibility decreased somewhat with increasing yield strength and grade. The susceptibility was judged to be comparable to, or better than, that of many X52 steels.

In sharp contrast to those results, Danielson, et al., (2001) using precracked, compact-tension specimens, found the critical stress-intensity (K_{Iscc}) for three randomly selected heats of X65, X70, and X80 steels to be at least 20 percent lower than those of six heats of older X52 steel. The heats of X52 steel were selected to have as broad a range of compositions as possible so as to produce a range of susceptibilities, but all six had comparable critical stress-intensity factors and crack growth rates.

Asahi, et al., (1996) measured the threshold stress of five different steels that were processed differently to produce different microstructures. The steels included an X80 and X65 steel that were TMCP, an X65 steel that was QT, and an X65 steel and X52 steel that were controlled rolled. Results of threshold-stress measurements from four different laboratories are shown in Figure A-21. The authors concluded that the TMCP and QT steels, which had more uniform microstructures, were less susceptible to high pH SCC than were the other two steels. In view of the lack of large differences among the steels, lab-to-lab variations for a single steel, and the limited number of steels in the study, a general conclusion about the effect of microstructure would be questionable.

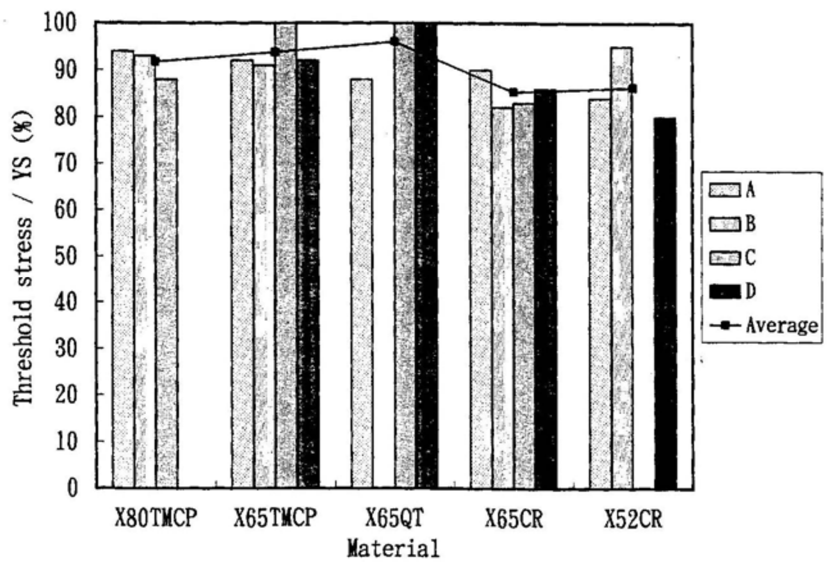


Figure A-21 Susceptibilities of Five Steels to High pH SCC as Measured in Four Laboratories (Designated A Through D in the legend)

For any given steel, small amounts of plastic strain, on the order of that which would be produced by forming and cold expanding a pipe, can have a large effect on the threshold stress. Examples for four steels are shown in Figure A-22, where it also can be seen that there is no consistent trend with grade (Fessler and Barlo 1984). Subsequent heating of the type that might be experienced in a coating operation also can affect the threshold stress, as is illustrated in Figure A-23 (Barlo 1979). It is interesting that the coating temperatures for FBE, which has not been associated with SCC, produces a much higher threshold stress than does the coating temperature for coal tar, with which most of the high pH SCC failures have been associated.

Parkins (1979) presented similar data on the effects of straining and aging, and he was able to show a strong correlation between the effects on creep resistance and the effects on threshold stress. That correlation also has been confirmed in a study of three X52 steels by Christman (1988b).

Susceptibility to Near-Neutral pH SCC. In a detailed study of 14 joints of pipe (from four pipeline companies) that contained patches of near-neutral pH stress corrosion cracks, no significant differences between the cracked areas and uncracked areas were found in terms of composition, microstructure, and inclusion size, inclusion shape, or inclusion composition. The SCC areas might have been about 3 percent harder on average (Beavers, et al. 2000). However, the most significant finding of this study was that the occurrence of SCC was highly correlated with residual stresses in the pipe.

A laboratory study of two X65 steels and an X80 steel indicated no measurable difference in crack growth rates among the three steels, as measured on compact-tension specimens in NS4 solution sparged with 10 percent CO_2/N_2 gas (Meyer and Pontremoli 2001).

A claim has been made that steels with a "more uniform" microstructure (e.g., bainite or bainite plus ferrite) are more resistant to near-neutral pH SCC than are steels with a non-uniform (ferrite plus pearlite) microstructure, (Kushida, et al. 2001) but the test conditions involving negative potentials (generally around –930 mV SCE or –1.0 volt $Cu/CuSO_4$) and low stress ratios (R values of 0.5 and 0.7) suggest that the fracture mechanism may have been hydrogen-assisted corrosion fatigue rather than SCC. However, another study found similar results for more realistic testing conditions (Meyer, et al. 2003).

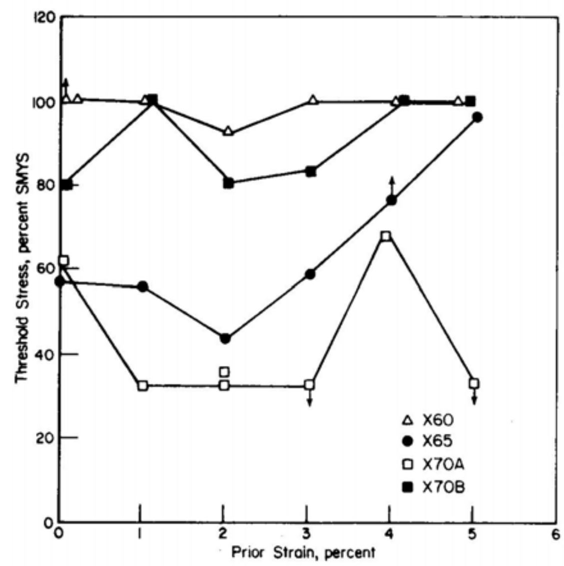


Figure A-22 Effect of Prior Strain on Threshold Stress for High pH SCC of Various Line-Pipe Steels

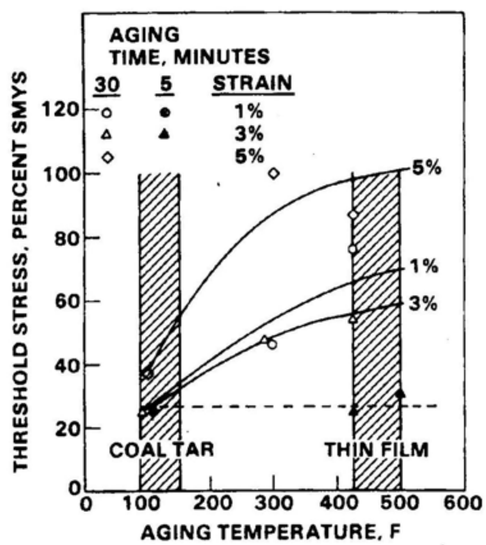


Figure A-23 Effects of Thermal Treatments on the Susceptibility of Cold-Worked X65 Steel to High pH SCC

Whereas the bulk microstructure appears to have little effect on SCC susceptibility, the same is not necessarily true for weld HAZ. In one study, the crack growth rate in a coarse-grained weld HAZ was found to be about 4 times higher than in the base metal (Beavers, Durr, and Shademan 1998).

Possible Research Approaches. The key to developing more resistant steels seems to be to increase the resistance to cyclic creep. However, that hypothesis is based on limited direct evidence and some scattered indirect evidence, almost entirely for high pH SCC. More experiments to directly test the hypothesis for both high pH and near-neutral pH SCC probably would be justified before embarking on a long effort to relate the cyclic-creep resistance under a variety of stressing conditions to the composition, processing, microstructure, and thermomechanical history. The latter effort probably would require a substantial amount of basic research followed by another significant effort in making and testing experimental steels.

An alternative approach, which is currently being used by researchers in Europe and Japan, is to prepare a number of steels with a variety of microstructures and properties by varying the composition and thermo-mechanical treatment, and then developing empirical correlations between measured susceptibility to SCC and the composition, mechanical properties, and microstructure.

In view of the recent evidence pointing to residual stresses as possible contributing factors to determining where SCC occurs in the field, research into ways to minimize such stresses through modifications of the manufacturing process might be beneficial.

A.4 References

Asahi, H., T. Kushida, M. Kimura, H. Fukai, and S. Okano. 1996. The Investigation on Stress Corrosion Cracking in a Carbonate-Bicarbonate Solution and Its Mechanism for Metallurgical Aspects. In *Proceedings from the Ninth Symposium on Pipeline Research*. PRCI. Catalogue No. L1746. pp.17-1 to 17-18.

Baker, T.R., G.G. Rochfort, and R.N. Parkins. 1986. Investigations Relating to Stress Corrosion Cracking on the Pipeline Authority's Moomba to Sydney Pipeline. In *Proceedings from the Seventh Symposium on Line Pipe Research*. PRCI. Catalogue No. L51495. pp. 27-1 to 27-25.

Barlo, T. 1979. Factors that Influence the Susceptibility of a Steel to Stress-Corrosion Cracking. In *Proceedings from the 6th Symposium on Line Pipe Research*. PRCI Catalogue No. L0175. pp. P-1 to P-17.

Beavers, J.A. and W.V. Harper. 2004. *Stress Corrosion Cracking Prediction Model*. NACE International CORROSION 2004. Paper 04189.

Beavers, J.A., and C.L. Durr. 2001. *Cathodic Protection Conditions Conducive to SCC*. Final Report to PRCI on Project PR 186-9807.

Beavers, J.A., and C. Jaske. 2002. *Effects of Pressure Fluctuations on SCC Propagation*. Final Report to PRCI on Project PR 186-9706. Catalogue No. L51872.

Beavers, J.A., C.L. Durr, and S.S. Shademan. 1998. Mechanistic Studies of Near-neutral pH SCC on Underground Pipelines. In *Materials for Resource Recovery and Transport*. L. Collins, ed. The Metallurgical Society of CIM. pp. 51-69.

Beavers, J.A., J.T. Johnson, and R.L. Sutherby. 2000. Materials Factors Influencing the Initiation of Near-Neutral pH SCC on Underground Pipelines. In *2000 Proceedings of International Pipeline Conference*. ASME. pp. 979-988.

Beavers, J.A., and W.V. Harper. 2004. *Stress Corrosion Cracking Prediction Model*. Corrosion 2004, Paper 04189.

CEPA. 1998. *CEPA Stress Corrosion Cracking Database: First Trending Report*. Submitted to Canadian National Energy Board. January 1998.

Christman, T.K. 1988a. *Evaluation of Stress-Corrosion Cracking Resistance of Newly Developed Grade X70 and X80 Line Pipe Steels*. NG-18 Report 173 to PRC. PRCI. Catalogue No. L51563.

Christman, T.K. 1988b. *Prediction of SCC Susceptibility Based on Mechanical Properties of Line Pipe Steels*. NG-18 Report 180. Catalogue No. L51577.

Chu, R., W. Chen, S.H. Wang, F. King, and R.R. Fessler. 2004. Microstructure Dependence of Stress Corrosion Cracking Initiation in X-65 Pipeline Steel Exposed to a Near-Neutral pH Soil Environment. *Corrosion*. 60. pp. 275-283.

Danielson, M.J., R.H. Jones, and P. Dusek. 2001. *Effect of Microstructure and Microchemistry on the SCC Behavior of Archival and Modern Pipeline Steels in a High pH Environment*. NACE International Corrosion 2001. Paper 01211.

Danielson, M.J., R.H. Jones, and K. Krist. 2000. *Effect of Microstructure and Microchemistry on the SCC Behavior of Pipeline Steels in a High pH Environment*. NACE International Corrosion 2000. Paper 00359.

Delanty, B., and J. O'Beirne. 1992. Major Field Study Compares Pipeline SCC with Coatings. *The Oil and Gas Journal*. June 15. pp. 39-44.

Dupuis, B.R. 1998. The Canadian Energy Pipeline Association Stress Corrosion Cracking Database. In *1998 Proceedings of International Pipeline Conference*. ASME. pp. 589-594.

Eiber, R.J. 1998. *Protocol to Prioritize Sites for High pH Stress-Corrosion Cracking on Gas Pipelines*. Report to PRCI on Project PR-3-9403.

Elboujdaini, M., Y. Z. Wang, R.W. Revie, R.N. Parkins, and M.T. Shehata. 2000. *Stress Corrosion Crack Initiation Processes: Pitting and Microcrack Coalescence.* NACE International Corrosion 2000. Paper No. 00379.

Fessler, R.R. 1976. Combination of Conditions Causes Stress-Corrosion Cracking. *The Oil and Gas Journal*. Vol. 74. No. 7. pp.81-83.

Fessler, R.R. 1979. Stress-Corrosion Cracking Temperature Effects. In *Proceedings from the 6th Symposium on Line Pipe Research*. PRCI. Catalogue No. L30175. pp. R-1 to R-10.

Fessler, R.R., and T.J. Barlo. 1984. *Threshold-Stress Determination Using Tapered Specimens and Cyclic Stresses. Environment-Sensitive Fracture: Evaluation and Comparison of Test Methods*. ASTM STP 821. pp. 368-382.

Fessler, R.R., and K. Krist. 2000. *Research Challenges Regarding Stress-Corrosion Cracking of Pipelines*. NACE International Corrosion 2000. Paper No. 00370.

Fessler, R.R., T. Groeneveld, and A. Elsea. 1973. Stress-Corrosion and Hydrogen-Stress Cracking in Buried Pipelines. International Conference on Stress Corrosion Cracking and Hydrogen Embrittlement of Iron Base Alloys. Unieux-Firminy. France. June. 1973. Published in *Stress Corrosion Cracking and Hydrogen Embrittlement of Iron Base Alloys*. NACE. 1977.

Fletcher, E.E., T.J. Barlo, A.J. Markworth, E.W. Brooman, W.E. Berry, R.N. Parkins, W.C. McGary, and R.R. Fessler. 1982. *A Study of Interrupted Cathodic Protection As It Relates to Stress-Corrosion Cracking and Corrosion of Buried Pipelines*. NG-18 Report No. 127. Catalogue No. L51425.

Foroulis, Z., and H. Uhlig. 1964. Effect of Cold-Work on Corrosion of Iron and Steel in Hydrochloric Acid. *Journal of Electrochemistry Society*. Vol. 111. pp. 522-528.

Francini, R.B., B.N. Leis, J.B. Nestleroth, and David W. Detly. 2000. *Stress Corrosion Crack Depth Measurement*. Final Report to PRCI on Project PR-3-8718.

Harle, B.A., J.A. Beavers, and C.E. Jaske. 1994. *Low-pH Stress Corrosion Cracking of Natural Gas Pipelines*. NACE International Corrosion 94. Paper No. 242.

Hunt, C.P. 1988. The Effect of Impurities on the Intergranular Stress Corrosion Cracking of a C/Mn Steel. *Corrosion Science*. 28. pp. 901-922.

Jack, T.R., B. Erno, K. Krist, and R.R. Fessler. 2000. *Generation of Near Neutral pH and High pH SCC Environments on Buried Pipelines*. NACE International Corrosion 2000. Paper No. 00362.

Jack, T.R., G. Van Boven, M. Wilmott, and R.L. Sutherby. 1994. Parameters Affecting the Growth of Low pH Stress Corrosion Cracking of Pipeline Steels. In *Proceedings of NACE Western Regional Conference*. Calgary. AB. pp. 504-526.

King, F., T. Jack, W. Chen, S.H. Wang, M. Elboujdaini, W. Revie, R. Worthingham, and P. Dusek. 2001. *Development of Predictive Model for the Initiation and Early-Stage Growth of Near-Neutral pH SCC of Pipeline Steels*. NACE International Corrosion 2001. Paper 01214.

Krishnamurthy, R.M., R.W. MacDonald, and P.M. Marreck. 1996. Stress Corrosion Cracking of a Liquid Transmission Line. In *1996 Proceedings of International Pipeline Conference*. ASME. pp. 495-506.

Krishnamurthy, R.M., B. Martens, S. Feser, P. Marreck, and R. MacDonald. 2000. Liquid Pipeline Stress Corrosion Cracking. In *2000 Proceedings of International Pipeline Conference*. ASME. pp. 1439-1449.

Kushida, T., K. Nose, H. Asahi, M. Kimura, Y. Yamane, S. Endo, and H. Kawano. 2001. *Effects of Metallurgical Factors and Test Conditions on Near Neutral pH SCC of Pipeline Steels*. NACE International Corrosion 2001. Paper No. 01213.

Lambert, S.B., J.A. Beavers, B. Delanty, R. Sutherby, and A. Plumtree. 2000. Mechanical Factors Affecting Stress Corrosion Crack Growth Rates in Buried Pipelines. In *2000 Proceedings of International Pipeline Conference*. ASME. pp. 961-966.

Leis, B.N. 1995. *Characterization of Axial Flaws in Pipelines, with a Focus on Stress-Corrosion Cracking. Volume I: Summary*. NG-18 Report No. 212.

Leis, B.N. 1997. *Validation of a High pH Stress-Corrosion Cracking Life Prediction Model (SCCLPM) for Gas-Transmission Pipelines*. Report to PRCI on Project PR-3-9531.

Leis, B.N., and R.E. Kurth. 1999. *Hydrotest Parameters to Help Control High pH SCC on Gas Transmission Pipelines*. Final Report to PRCI on Project PR-3-9404.

Leis, B.N., and R.N. Parkins. 1993. Modeling Stress-Corrosion Cracking of High-Pressure Gas Pipelines. In *Proceedings from the Eighth Symposium on Line Pipe Research*. PRCI. Catalogue No. L51680. pp. 19-1 to 19-24.

Leis, B.N., and R.N. Parkins. 1998. *Mechanics and Material Aspects in Predicting Serviceability Limited by Stress-Corrosion Cracking. Fatigue and Fracture of Eng. Materials and Structures*. 21. (1998) to be published.

Leis, B.N., T. Forte, and N.D. Ghadiali. 1995. *Stress-Corrosion Cracking Life Prediction Model – SCCLPM: Users Manual and Software. Version 1.0*. NG-18 Report No. 217. PRCI. Catalogue No. L51808.

Mao, S.X., J.L. Luo, B. Gu, and W. Yu. 1998. Hydrogen Facilitated Anodic Dissolution Type Stress Corrosion Cracking of Pipeline Steels in Coating Disbondment Chemistry. In *1998 Proceedings of International Pipeline Conference*. ASME. pp. 485-492.

Marshall, C.W. 1984. *Kinetics of Stress-Corrosion Cracking in Pipe Steels at 175F*. NG-18 Report No. 143. Catalogue No. L51464.

Martinez, F.H., and S.W. Stafford. 1994. EPNG Develops Model to Predict Potential Locations for SCC. *Pipeline Industry*. July 1994. pp. 29-33

Mercer, W.L. 1979. Stress Corrosion Cracking – Control Through Understanding. In *Proceedings from the 6th Symposium on Line Pipe Research*. PRCI. Catalogue No. L30175.

Meyer, M., and M. Pontremoli. 2001. *Comparing of Laboratory Behaviour of Different Pipeline Steels Regarding Their Near-Neutral SCC Susceptibility*. PRCI-EPRG Joint Technical Meeting. New Orleans. Paper 20. May 2001.

Meyer, M., L. Scoppio, B. Rudd, E. Lo Piccolo, S. Matthews, and J.P. Jansen. 2003. *Near-Neutral pH SCC Resistance of Pipeline Steels: Effect of Some Material and Mechanical Parameters* (EPRG-Report). EPRG/PRCI 14th Biennial Joint Technical Meeting on Pipeline Research. Berlin. pp. 5-1 to 5-21.

NEB. 1996. *Public Inquiry Concerning Stress Corrosion Cracking on Canadian Oil and Gas Pipelines*. by Canadian National Energy Board. November. 1996.

Oriani, R.A., and P.H. Josephic. 1981. The Effects of Hydrogen on the Room-Temperature Creep of Spheroidized 1040-Steel. *Acta Metallurgica*. Vol. 29. p. 669.

Parkins, R.N. 1979. Stress-Corrosion Cracking Strain Aging Effects. In *Proceedings from the 6th Symposium on Line Pipe Research*. PRCI. Catalogue No. L30175.

Parkins, R.N. 1987. Factors Influencing Stress Corrosion Crack Growth Kinetics. *Corrosion*. Vol. 43. pp. 130-138.

Parkins, R.N. 1988. Localized Corrosion and Crack Initiation. *Material Science Engineering A*. 103(1). pp. 143-156.

Parkins, R.N. 1994. *Overview of Intergranular Stress Corrosion Cracking Research Activities*. Report on PR-232-9401 to PRCI. Catalogue No. L51719.

Parkins, R.N. 1998. The Influence of Hydrogen on Crack Growth in Pipelines. In *Materials for Resource Recovery and Transport*. L. Collins, ed. The Metallurgical Society of CIM. pp. 35-49.

Parkins, R.N. 1999. *The Involvement of Hydrogen in Low pH Stress Corrosion Cracking of Pipeline Steels*. Presented at PRCI/EPRG Meeting. Groningen, The Netherlands. May 17-21, 1999.

Parkins, R.N. 2000. *A Review of Stress Corrosion Cracking of High Pressure Gas Pipelines*. NACE International Corrosion 2000. Paper No. 00363.

Parkins, R.N. 2002. *Some Effects of Strain Rate on the Transgranular Stress Corrosion Cracking of Ferritic Steels in Dilute Near-Neutral pH Solutions*. Topical Report submitted to PRCI.

Parkins, R.N., and B.S. Delanty. 1996. The Initiation and Early Stages of Growth of Stress Corrosion Cracks in Pipeline Steel Exposed to a Dilute Near-Neutral pH Solution. In *Proceedings from the Ninth Symposium on Pipeline Research*. PRCI. Catalogue No. L51746. pp. 19-1 to 19-14.

Parkins, R.N., and R.R. Fessler. 1978. Stress Corrosion Cracking of High-Pressure Gas Transmission Pipelines. In *Materials in Engineering Applications*. Vol. 1. No. 2. pp. 80-96.

Parkins, R.N., and R.R. Fessler. 1986. *Line Pipe Stress Corrosion Cracking – Mechanisms and Remedies*. NACE Corrosion 86. Paper No. 320.

Parkins, R.N., and S. Zhou. 1997. The Stress Corrosion Cracking of C-Mn Steel in CO_2-HCO_3^--CO_3^{2-} Solutions I: Stress Corrosion Data. *Corrosion Science*. Vol. 39. pp. 159-173.

Parkins, R.N., E. Belhimer, and W.K. Blanchard Jr. 1993. Stress Corrosion Cracking Characteristics of a Range of Pipeline Steels in Carbonate-Bicarbonate Solutions. *Corrosion*. Vol. 49. pp. 951-966.

Parkins, R.N., W.K. Blanchard Jr., and B.S. Delanty. 1994. Transgranular Stress Corrosion Cracking of High-Pressure Pipelines in Contact with Solutions of Near Neutral pH. *Corrosion*. Vol. 50. pp. 394-408.

Parkins, R.N., P.W. Slattery, and P.S. Poulson. 1981. The Effects of Alloying Additions to Ferritic Steels upon Stress Corrosion Cracking Resistance. *Corrosion*. 37. pp. 650-664.

Tyson, W. 1979. Hydrogen in Metals. *Canadian Metallurgical Quarterly*. Vol. 18. pp. 1-11.

Uhlig, H. 1976. Effect of Surface Dissolution on Plastic Deformation of Iron and Steel. *Journal of Electrochemistry Society*. Vol. 123. pp. 1699-1701.

Wang, J.Q., A. Atrens, and D.R.G. Mitchell. 2001. *Grain Boundary Characterization of X42 Pipeline Steel in Relation to IGSCC*. NACE International Corrosion 2001. Paper No. 01210.

Wang, S.H., W. Chen, T. Jack, F. King, R.R. Fessler, and K. Krist. 2000. Role of Prior Cyclic Loading in the Initiation of Stress-Corrosion Cracks in Pipeline Steels Exposed to Near-Neutral pH Environment. In *Proceedings of 2000 International Pipeline Conference*. ASME. pp. 1005-1009.

Wells, D.B. 1993. SCC Threshold Stress in Line Pipe Steels. In *Proceedings from the Eighth Symposium on Line Pipe Research*. PRCI. Catalogue No. L51680. pp. 18-1 to 18-15.

Zhang, B., J. Fan, Y. Gogotsi, A. Chudnovsky, and A. Teitsma. 2000. Theoretical and Experimental Study of Stress Corrosion Cracking of Pipeline Steel in Near Neutral pH Environments. In *Proceedings of 2000 International Pipeline Conference*. ASME. pp. 1013-1020.

Zhang, X.Y., S.B. Lambert, R. Sutherby, and A. Plumtree. 1999. Transgranular Stress Corrosion Cracking of X-60 Pipeline Steel in Simulated Ground Water. *Corrosion*. Vol. 55. pp. 297-305.

Attachment A – Operator Questionnaire

This page intentionally left blank.

Baker

Michael Baker Jr., Inc.
A Unit of Michael Baker Corporation

Airside Business Park
100 Airside Drive
Moon Township, PA 15108
(412) 269-6023
(412) 375-3996 (FAX)

February 13, 2004

Dear Pipeline Operator:

Michael Baker Jr., Inc., a full service engineering firm providing engineering and energy expertise for public and private clients worldwide, has been contracted by the U.S. Department of Transportation Research and Special Programs Administration's Office of Pipeline Safety (OPS) to provide expert technical assistance to them under their Integrity Management Initiative. Since 2002, Baker has supported OPS through technical studies and assessments on issues ranging from ecological effects of releases from HVL pipelines, evaluation of longitudinal seams of LF-ERW pipe and lap welded pipe, and an evaluation of wrinkle bends and buckles in pipelines.

In this current effort, Baker is assisting OPS with a study of Stress Corrosion Cracking (SCC) issues relating to pipeline integrity for both gas and liquid lines, including history of SCC, level of risk, indicators of potential for SCC, detection methods, mitigation measures, and assessment procedure. An initial step in the study process was the workshop on SCC held on December 2, 2003, in Houston, Texas, where Baker presented an outline of the study effort. OPS and the National Association of Pipeline Safety Representatives (NAPSR) cosponsored this workshop along with API, AOPL, INGAA, AGA and NACE.

Baker has prepared the attached survey document to assist in gathering information from pipeline operators on SCC occurrence history and operating company practices for SCC detection, management and mitigation. We are asking for your cooperation in supplying this information so that we can have as complete a picture as possible on the practices currently being employed to address SCC. It is our intent to selectively follow-up with more in-depth interviews with some operators to learn more about the effectiveness of measures taken by operators for dealing with SCC. OPS intends that the study be made public, which will be later in 2004.

Baker wishes to thank the industry trade organizations for their support of this study effort. The survey itself has been reviewed by a working group led by Dave Johnson of Enron and its final format has been developed with the cooperation of that group.

We are requesting that the survey be returned to Baker by March 3, 2004. It can be returned electronically to me at cmayernik@mbakercorp.com, mailed to me at the above address, or faxed to me at 412-375-3996

We appreciate your efforts in completing this survey. If you have any questions, please contact me at 412-269-6023.

Sincerely,

Christine S. Mayernik, P.E.
Project Manager

This page intentionally left blank.

PIPELINE OPERATOR RESPONSE

STRESS CORROSION CRACKING STUDY

Conducted by Michael Baker, Jr., Inc.
In support of

US DOT RSPA/Office of Pipeline Safety
Contract No. DTRS56-02-D-70036
Technical Task Order 8 – SCC Study

Baker has been tasked by OPS to conduct a study of Stress Corrosion Cracking (SCC). The study effort will include discussion of the current state of knowledge by operators regarding SCC. Through this survey instrument and follow-up select interviews, the study will attempt to address the following questions:

- *Are operators are being prudent in the detection, management and mitigation of SCC?*
- *How are operators addressing SCC in their Integrity Management Programs?*
- *How effective are measures taken by operators to mitigate SCC?*
- *What are best industry practices with regard to SCC?*
- *What gaps exist in operator knowledge, application and response that need to be addressed to improve SCC detection, management and mitigation?*

Baker appreciates the support of INGAA, AOPL and API in their assistance and endorsement of this survey effort and of their support of the study.

Operator Information

Company Name:

Address:

Contact Name:

Contact Title:

Phone Number

Fax Number:

Email Address:

SCC Occurrence Information

1. **Has SCC been detected on any of your pipelines in the past?** ☐ **Yes** ☐ **No**

   a. **If YES, when was SCC first detected on your pipeline system?** ____________

   b. **If YES, what was the system age at that time?** ____________

2. **Approximate number of SCC in-service failures:** ____________

3. **Approximate number of hydrostatic test failures:** ____________

4. **How prevalent is SCC on your system?**

   a. **Number of main line valve sections where SCC has been detected:** ____________

   b. **Percentage of total number of valve sections:** ______%

5. **If SCC occurrence was found during an inspection(s), what was the reason for the inspection(s)?**

   ☐ **Looking for SCC** ☐ **Other (please describe:)**

6. **Product in pipeline where SCC was found:**

   ☐ **Natural Gas** ☐ **Liquid** ☐ **Other:** ____________________

7. **Has an in-service failure or a hydrostatic test failure at or below the prior test pressure occurred on a line segment previously subjected to SCC mitigation activities?**

   ☐ **Yes** ☐ **No**

   a. **If YES, how many years elapsed from initial occurrence or discovery to the failure?**

SCC Occurrence Information (cont.)

8. Geographic region or state/province where SCC has been detected:

Please provide a range of pipeline characteristics where SCC has occurred:

OD:

Wall Thickness:

Grade:

Year Installed:

Coating Type:

Operating Pressure:

Operating Temperature:

Soil Type and Condition:

Other relevant information:

SCC Detection Methods

What NDE methods has your company used to identify SCC?
(check all that apply)

☐ **Visual**

(The pipe is exposed and the pipe coating is examined for soundness and performance. Some coating is removed at locations where disbonding is suspected. A technician examines the pipe after removing the coating. The technician then examines the pipe for evidence of cracks.)

☐ **Magnetic Particle**

(The pipe in question is examined visually with the assistance of magnetic particle imaging.)

☐ **Liquid Dye Penetrant**

(The use of dyes on the surface of the pipe to enhance the visualization of cracks.)

☐ **Eddy Current**

(The use of eddy currents to measure the occurrences of cracking.)

☐ **ILI Tool (type of tool used: ____)**

☐ **Other (please describe: ____)**

Does your company have written procedures that:

- **Describe reassessment intervals if SCC is detected?** ☐ **Yes** ☐ **No**
- **Describe physical field practices for SCC detection?** ☐ **Yes** ☐ **No**
- **Describe NDE evaluation procedures?** ☐ **Yes** ☐ **No**

Other information or comments:

SCC Management

Which of the following practices does your company use to manage SCC?
(check all that apply)

☐ **Failure History Characterization**

(Use information of past SCC failures as an indication of the specific conditions that may result in the future occurrence of SCC.)

☐ **Coating Type Characterization (Coal tar, tape, etc.)**

(Characterizes the condition and type of coating, and correlates the information with the occurrence of SCC.)

☐ **Pipe Material Characterization (API Grades, Pipe Mill, etc.)**

(Characterizes the type of pipe and correlates it to the occurrence of SCC.)

☐ **Operation Characterization (Pressure, Temperature, etc.)**

(Correlates the specific operating conditions of the pipeline with the occurrence of SCC.)

☐ **Location Characterization**

(Correlates the environmental conditions near the pipe with the occurrence of SCC.)

☐ **Age Characterization**

(Correlates the age of the facilities with the occurrence of SCC.)

☐ **Bell Hole Characterization**

(Results of buried pipe inspection reports are utilized to determine if there are common characteristics in pipe with SCC compared to pipe with no SCC utilizing trending analysis.)

☐ **Magnetic Flux Leakage ILI Characterization**

(Utilization of MFL pigs to detect wall loss primarily due to corrosion.)

☐ **Other ILI Characterization**

(Utilization of other pigs to detect SCC.)

☐ **Cathodic Protection Level Characterization (Voltage Levels)**

(Monitoring of CP voltage levels at locations with and without active SCC for use as a predictive tool.)

☐ **Hydrostatic Retest Program**

(Destructively testing pipe to determine presence of SCC.)

☐ **External Corrosion Direct Assessment**

☐ **Risk Assessment Ranking (Segment by Segment Comparison)**

Does your company have written procedures for SCC management? ☐ **Yes** ☐ **No**

If YES, how long have you had written procedures?

SCC Management (cont.)
Describe any SCC predictive models used by your company

SCC Mitigation

What actions does your company use to mitigate SCC (or SCC failures)?

(check all that apply)

☐ **Operating Condition Modification (Pressure or temperature reduction, etc.)**

☐ **Selective Sleeve Installation**

☐ **Clean Pipe and Recoat**

☐ **Grind Pipe and Recoat**

☐ **Soil Condition Modification (Drainage pattern change, replacement or chemical treatment of soil, etc.)**

☐ **Other (please describe below:)**

Does your company have written procedures for SCC mitigation? ☐ **Yes** ☐ **No**

Please return form (preferably in electronic format) by March 1, 2004, and address any questions to:

Christine S. Mayernik, P.E.
Michael Baker Jr., Inc.
Airside Business Park
100 Airside Drive
Moon Township, PA 15108
(412) 269-6023 (direct)

This page intentionally left blank.

Attachment B – Operator Interview

This page intentionally left blank.

Department of Transportation
Research and Special Programs Administration
Office of Pipeline Safety

Integrity Management Program
Delivery Order DTRS56-02-D-70036

Stress Corrosion Cracking Study

Agenda for Operator Interview

Michael Baker Jr., Inc.
2004

Operator Interview Regarding SCC Procedures

General Guidelines

Instructions for Interviewer:

What follows is a suggested agenda for the Operator Interviews regarding SCC. Although the agenda is formal in nature, the interviewers are encouraged to have informal discussions on any area of interest germane to the general topic that the operator wants to discuss.

The general topics listed have a number of suggested sub-topics suggested. It is well recognized that not all, and perhaps few, of the subtopics are expected to be addressed by any individual operator and they are largely meant as reminders of areas of interest. On the other hand, the subtopics are not meant to be exhaustive and additional information is welcomed.

Operator Written Information:

Written information (reports, forms, publications, records…) of any kind can only be received from the operator with the understanding that the information may be referenced within a public document. Although Baker's report will not reference operators information by name, unless specifically authorized to do so, receipt of written information cannot be guaranteed to be kept confidential.

The report would, however, like to simply list those operator companies (with no personnel contact names) who were interviewed and the interviewer should notify the operator of this intent.

Interview Notes:

The notes from the interview should be recorded in a timely manner and transmitted back to the operator for editing, clarification, additions by the operator. The operator should be notified that a timely response (within 3 business days) is desired. Report information will be based on these notes, but the notes will not be included in the report.

Suggested Agenda

1. General Background Information
   - General Contact Information
   - Pipeline Characteristics – commodity, miles, diameter, throughput…
   - IM Organization

- IM Contact Information
- SCC Technical Resources

2. SCC Historical Information
   - SCC Discovery
   - SCC Incidents
   - Followup
3. General Approach to SCC
   - Plans
   - Education, Training
   - Tracking Database/records
   - Maintenance Procedures (e.g. SCC awareness during excavations)
   - Participation in Research
   - Ongoing Activities
   - Future Plans
4. SCC Prevention Specifics
   - Considerations for New Construction
     - Line Pipe Considerations
     - Coatings
     - Specifications
     - Approved Materials
     - Surface Preparation
     - Corrosion Allowance
     - Design Practices
   - Construction Practices
   - Operations & Maintenance
     - CP
     - Recoating existing lines
     - Monitoring/Controlling cyclic pressure fluctuations
     - Other?
5. SCC Detection

- Predictive models
- Hydrostatic testing
- Field excavations
- ILI
- Other?

6. SCC Assessment
    - Direct assessment
    - Direct examination
    - Analytical techniques
    - Prioritization for mitigation/remediation
7. Mitigation of SCC
    - Pressure reduction
    - Field repair techniques
8. Post-Incident Response
    - Lower operating pressure
    - Lower operating temperature
    - Hydrostatic testing
9. Industry Views
    - Lead Organizations
    - Ongoing studies being followed/participated
    - Suggested studies
    - Regulation and oversight
10. SCC Study Evaluation
    - Critique of interview
    - Ways to improve interview