COPY

The Honorable Barbara Jacobs Rothstein

UNITED STATES DISTRICT COURT
WESTERN DISTRICT OF WASHINGTON

UNITED STATES OF AMERICA, **Plaintiff** **v.** **SHELL PIPELINE COMPANY LP fka EQUILON PIPELINE COMPANY LLC and OLYMPIC PIPE LINE COMPANY,** **Defendants.**	)	**Civil Action No. CV02-1178R** **CONSENT DECREE BETWEEN THE UNITED STATES OF AMERICA AND SHELL PIPELINE COMPANY LP fka EQUILON PIPELINE COMPANY LLC**

I. BACKGROUND

A. Plaintiff, the United States of America (United States), through the Attorney General, at the request of the Administrator of the United States Environmental Protection Agency (EPA), filed a civil complaint (Complaint) against Shell Pipeline Company LP, fka Equilon Pipeline Company LLC (Shell), pursuant to the Clean Water Act (CWA), 33 U.S.C. §§ 1251-1387, seeking civil penalties for the discharge of gasoline into or upon navigable waters of the United States or adjoining shorelines. The Complaint alleges that Shell is liable for the discharge

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of gasoline into Hanna and Whatcom Creeks, navigable waters of the United States, and their adjoining shorelines, beginning on June 10, 1999, in violation of Sections 301(a) and 311(b)(3) of the CWA, 33 U.S.C. §§ 1311(a) and 1321(b)(3).

B. The State of Washington (State), through its Attorney General, at the request of the Washington Department of Ecology, served a Notice of Penalty (Notice) against Shell, seeking civil penalties pursuant to Wash. Rev. Code Chapters 90.48 and 90.56. The Notice alleges that Shell is liable for the discharge of gasoline into ground and surface waters of the State, including Whatcom and Hannah Creeks, beginning on June 10, 1999, in violation of Wash. Rev. Code Chapters 90.48 and 90.56.

C. The Parties agree that it is desirable to resolve these matters without resort to litigation.

D. Shell has entered into this Consent Decree solely for the purposes of settlement and compromise of disputed claims. By entering into this Consent Decree, Shell does not admit any, and hereby denies all, of the factual allegations or legal claims in the Complaint except as otherwise specified in Section II (Jurisdiction and Venue) of this Consent Decree, nor does Shell admit any, and hereby denies all, liability to the United States or any third party arising out of the Incident (as that term is defined herein) or out of the transactions or occurrences alleged in the Complaint. This Decree may not be used in any civil proceeding of any type as evidence or proof of any fact or as evidence of the violation of any law, rule, regulation, or Court decision, except in a proceeding to enforce this Consent Decree.

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E. Cooperative negotiation efforts of the United States, the State, and Shell resulted in settlements resolving Shell's civil liability both to the United States pursuant to the CWA and to the State pursuant to Wash. Rev. Code Chapters 90.48 and 90.56.

F. To resolve Shell's civil liability for the claims asserted in the Complaint, Shell will pay a civil penalty of $5 million to the United States, comply with the other relief in Appendix A, and satisfy all other terms of this Consent Decree.

G. To resolve civil penalty liability to the State pursuant to Wash. Rev. Code Chapters 90.48 and 90.56, Shell will enter into a settlement agreement with the State (State Agreement) requiring Shell to pay a total of $5 million in civil penalties to the State which may include, in whole or in part, expenditures agreed to by the State and Shell.

H. The Parties agree, and this Court by entering this Consent Decree finds, that this Consent Decree and these civil penalties address only the allegations and claims against Shell related to the Incident and not any allegations and claims against any other person or entity.

I. The Parties agree, and this Court by entering this Consent Decree finds, that the Parties have negotiated this Consent Decree in good faith, that settlement of this matter will avoid further litigation between the Parties related to the claims in the Complaint, and that the settlement embodied by this Consent Decree is fair, reasonable, and in the public interest.

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THEREFORE, with the consent of the Parties to this Consent Decree, it is ORDERED, ADJUDGED AND DECREED:

II. JURISDICTION AND VENUE

1. This Court has jurisdiction over the subject matter of this action and the Parties pursuant to 28 U.S.C. §§ 1331, 1345, 1355, and 33 U.S.C. §§ 1319(b), 1321(b)(7)(E).

2. Venue is proper in this Court pursuant to 28 U.S.C. §§ 1391(b), 1395(a), and 33 U.S.C. §§ 1319(b), 1321(b)(7)(E).

3. For the purposes of this Consent Decree and the underlying claims of the United States, Shell waives all objections and defenses that it may have to jurisdiction of the Court or to venue in this District. Shell consents to and shall not challenge entry of this Consent Decree or this Court's jurisdiction to enter and enforce this Consent Decree.

III. DEFINITIONS

4. Whenever terms listed below are used in this Consent Decree or Appendix A, the following definitions shall apply:

   a. "Affiliate" shall mean a person or entity directly, or indirectly through one or more intermediaries, in control of, or controlled by, or under common control with another entity. For the purposes of this Consent Decree, an entity that results from a name change by Shell or merger by Shell with another entity during the pendency of this Decree shall be considered an Affiliate.

   b. "Appendix A" or "Appendix" shall mean Appendix A (Other Relief) attached to this Consent Decree, and all Exhibits attached to Appendix A.

   c. "Chase Pipeline System" shall mean those elements of the Shell Pipeline Systems known as the Chase Kansas Products Pipeline and the Chase Colorado Products

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Pipeline, including approximately 731 miles of pipeline running in the states of Kansas and Colorado.

d. "Complaint" shall mean the Complaint filed by the United States in this case.

e. "Consent Decree" or "Decree" shall mean this document and the Appendix, and any modifications of this document or Appendix in accordance with Section XVIII (Modifications) of this document. In the event of conflict between this document and the Appendix, this document shall control.

f. "CWA" shall mean the Clean Water Act (CWA), 33 U.S.C. §§ 1251-1387.

g. "Day" shall mean a calendar day unless expressly stated to be a working day. "Working Day" shall mean a day other than a Saturday, Sunday, or Federal holiday. In computing any period of time pursuant to this Consent Decree, where the last Day would fall on a Saturday, Sunday, or Federal holiday, the period shall run until the close of business of the next Working Day.

h. "DOJ" shall mean the United States Department of Justice.

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

j. "Engineering Judgment" shall mean judgment based on the application of scientific and mathematical principles to the design, construction, operation, and maintenance of pipeline systems, with such judgment exercised by a suitably qualified person.

k. "Incident" shall mean the discharge of gasoline into or upon Whatcom and Hanna Creeks and their adjoining shorelines in Bellingham, Washington, beginning on June 10, 1999, as described with particularity in the Complaint filed by the United States in this case.

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l. "Independent Monitoring Contractor" shall mean the independent monitoring contractor selected pursuant to Section XIV of the Appendix.

m. "National Pipeline Mapping System" shall mean the National Pipeline Mapping System referred to in 49 C.F.R. § 195.452, Appendix C, § I.A.

n. "OPA" shall mean the Oil Pollution Act of 1990 (OPA), 33 U.S.C. §§ 2701-2761.

o. "Other Relief" shall mean the other relief described in Section VII (Other Relief) and Appendix A.

p. "Paragraph" shall mean a portion of this Consent Decree or Appendix A identified by an Arabic numeral.

q. "Parallel Criminal Proceedings" shall mean the criminal proceedings initiated in this Court under the caption: *United States of America v. Olympic Pipe Line Company*, et al., No. CR01-338, and any subsequent related proceedings.

r. "Parties" shall mean the United States and Shell. Olympic Pipe Line Company is not a party to this Decree.

s. "PSA" shall mean the Pipeline Safety Act, 49 U.S.C. Chapter 601.

t. "RCRA" shall mean the Solid Waste Disposal Act as amended by the Resource Conservation and Recovery Act, 42 U.S.C. §§ 6921-6992.

u. "Responsible Corporate Official" shall mean the person or persons designated by Shell to perform relevant decision-making functions, and who has authority to sign documents on behalf of Shell with respect to the Decree.

v. "Section" shall mean a portion of this Consent Decree identified by a capitalized Roman numeral.

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w. "Semester" shall mean either the period from January 1 through June 30 of any calendar year, or the period from July 1 through December 31 of any calendar year.

x. "Shell" shall mean Shell Pipeline Company LP, fka Equilon Pipeline Company LLC, one of the defendants in this action, and its officers, employees, Affiliates, successors and assigns. For the purpose of this definition, a purchaser of assets shall not be considered a successor or assign.

y. "Shell Pipeline Systems" shall mean the pipeline systems commonly referred to as the East Line Products, North Line Products, Chase Kansas Products, Chase Colorado Products, and Orion Products pipeline systems that are used for transporting petroleum products, and include approximately 2139 miles of pipeline running in the States of Texas, Oklahoma, Colorado, Kansas, Ohio, Illinois, and Indiana and associated structures and buildings used for operations and administration, control equipment, pumps, valves, breakout storage tanks, and other equipment used in the operation of the pipeline systems, and any like associated equipment added to the Shell Pipeline Systems during the pendency of this Consent Decree. The term does not include marine terminals or facilities such as refineries, lube plants, and marine and distribution terminals, that are connected to, or associated with the pipelines but which perform separate functions such as storage or blending.

z. "State" shall mean the State of Washington.

aa. "State Agreement" shall mean all documents constituting or describing the agreement between Shell and the State resolving the State's civil penalty claims

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pursuant to Wash. Rev. Code Chapters 90.48 and 90.56 against Shell related to the Incident.

bb. "Submit" shall mean any of the following: (1) place in certified mail in a properly addressed envelope with sufficient postage for first class delivery; (2) tender to an overnight courier in a properly addressed envelope, and prepay the delivery fees; or (3) hand deliver and obtain signature of recipient.

cc. "Subparagraph" shall mean a portion of this Consent Decree and Appendix A identified by an upper or lower case letter, except that a portion of the Appendix identified by an uppercase letter shall be designated as a Subsection.

dd. "United States" shall mean the United States of America, including its departments, agencies, and instrumentalities.

IV. PARTIES BOUND

5. This Consent Decree applies to and is binding on Shell except as otherwise provided in this Paragraph. If Shell transfers ownership of any portion of the Shell Pipeline Systems, Shell nevertheless shall fulfill all requirements of this Consent Decree regarding the portions of the Shell Pipeline Systems that Shell continues to operate for as long as Shell continues to operate those portions. If Shell transfers any portion of the Chase Pipeline System to any other entity, Shell nevertheless shall fulfill all requirements of this Consent Decree for the portion of the Chase Pipeline System so transferred, with the exception of record retention requirements under Section XVI of this Decree.

V. GENERAL PROVISIONS

6. Compliance with Applicable Law. This Consent Decree in no way affects or relieves Shell of its responsibility to comply with applicable federal, state, and local laws, regulations, and permits. Shell shall perform all work required by this Consent Decree in

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compliance with the requirements of all applicable federal, state, and local laws, regulations, and permits. Except as expressly provided herein, compliance with this Consent Decree shall be no defense to any actions commenced pursuant to federal, state, and local laws, regulations, and permits. This Consent Decree is not, and shall not be construed as, a permit issued pursuant to any federal, state, or local statute or regulation.

7. Construction for Purposes of Parallel Criminal Proceedings. For the purposes of the Parallel Criminal Proceedings only, Shell shall be deemed to be in compliance with this Consent Decree if Shell has paid all civil penalties and stipulated penalties, when and if required pursuant to this Decree, and is making a reasonable and diligent good faith effort to comply with all requirements of this Decree.

8. Permits. Shell shall submit timely and complete applications for, and otherwise diligently seek to obtain, any and all permits or approvals from federal, state, or other governmental entities necessary to perform work that this Consent Decree requires.

VI. PAYMENT OF CIVIL PENALTIES

9. Within 45 Days of entry of this Consent Decree, Shell shall pay the United States a civil penalty of $5,000,000.

10. Shell shall make the payment described in the preceding Paragraph in the manner specified in Section XI (Payment and Related Matters) of this Consent Decree.

11. If the civil penalty required by Paragraph 9 is not paid within 45 Days after entry of the Consent Decree, Shell shall pay stipulated penalties in accordance with Section X (Stipulated Penalties), and interest in accordance with Section XI (Payment and Related Matters).

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VII. OTHER RELIEF

12. Shell shall perform the Other Relief described in, and in accordance with the requirements contained or referenced in, Appendix A.

VIII. REPORTING REQUIREMENTS

13. Semiannual Progress Reports. Beginning on the Effective Date of this Decree and through and including the Semester in which this Consent Decree is terminated pursuant to Section XXII (Termination Date), Shell shall submit certified Semiannual Progress Reports to EPA and the Independent Monitoring Contractor. The first Semiannual Progress Report shall be due within 45 Days of the close of the first Semester ending more than 90 Days after entry of this Consent Decree, with subsequent reports due within 30 Days of the close of each Semester thereafter. Additionally, if requested by EPA, Shell shall meet with EPA at a reasonable location after reasonable notice, to discuss Shell's compliance with the terms of this Decree. Each Semiannual Progress Report shall include all information required by Section XV of the Appendix.

14. Certifications. Whenever this Consent Decree or Appendix A requires Shell to certify a report or any other submission of information, Shell shall submit the following written statement with the submission, signed by a Responsible Corporate Official:

> I certify under penalty of law that this submission was prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. I further certify under penalty of law that, to the best of my knowledge, based on my reasonable inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is 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.

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IX. SITE ACCESS

15. From the date of entry of this Consent Decree until its termination date as described in Section XXII (Termination), Shell agrees to provide EPA and its authorized representatives, including contractors, prompt access at all reasonable times to the Shell Pipeline Systems and all property on which the Shell Pipeline Systems are located for the purposes of assessing, monitoring, or verifying compliance with the terms of this Consent Decree, and verifying any data or information submitted by Shell pursuant to this Consent Decree.

16. Notwithstanding any provisions of this Consent Decree, the United States retains all of its access authorities and rights, including enforcement authorities related thereto, pursuant to the CWA and any other applicable statutes or regulations.

X. STIPULATED PENALTIES

17. Shell shall be liable to the United States for stipulated penalties in the amounts set forth in Paragraphs 18 and 19 for failure to comply with the requirements of this Consent Decree, unless excused pursuant to Section XII (*Force Majeure*). "Noncompliance" by Shell shall include failure to complete the requirements of this Consent Decree within the time allowed in the Decree in accordance with all applicable requirements of law.

18. The following stipulated penalties shall accrue per violation per Day for any noncompliance identified in Subparagraphs a-b below:

Penalty Per Noncompliance	Period of Noncompliance
$500 per Day or portion thereof	1st through 15th Day
$1,250 per Day or portion thereof	16th through 30th Day
$2,500 per Day or portion thereof	31st Day and beyond

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a. Failure to timely pay civil penalties in accordance with the terms of Section VI (Payment of Civil Penalties).

b. Failure to comply with the requirements in the Appendix other than reporting requirements.

19. The following stipulated penalties shall accrue per violation per Day for any failure to comply with the reporting requirements specified in Section VIII (Reporting Requirements) and in the Appendix:

Penalty Per Noncompliance	Period of Noncompliance
$250 per Day or portion thereof	1st through 15th Day
$500 per Day or portion thereof	16th through 30th Day
$1,250 per Day or portion thereof	31st Day and beyond

20. All stipulated penalties shall begin to accrue on the Day after complete performance is due or the Day a violation occurs, and shall continue to accrue through the final Day of the correction of the noncompliance or completion of the activity except as otherwise provided in this Paragraph. Nothing herein shall prevent the simultaneous accrual of separate penalties for separate violations of this Consent Decree.

a. If Shell demonstrates that, based on exercise of reasonable Engineering Judgment, after diligent inquiry, Shell believed it fully complied with a requirement of this Decree, stipulated penalties for any violation of this Decree shall begin to accrue on the Day that Shell receives notice from EPA of such violation and shall continue to accrue through the final Day of the correction of the noncompliance or completion of the activity.

b. All stipulated penalties for violations of Paragraphs 18 through 25 of the Appendix shall begin to accrue on the date that a preliminary Notice of Dispute,

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issued pursuant to Paragraph 26 of the Appendix, becomes final or, if Shell files with the Court a petition to resolve the dispute within the time required by Paragraph 26 of the Appendix and the United States prevails in whole or in part, on the date of the District Court's decision, and shall continue to accrue through the final Day of the correction of the noncompliance or completion of the activity.

21. If EPA determines that Shell has failed to comply with a requirement of this Consent Decree, EPA may give Shell written notification of the same and describe the noncompliance. EPA may send Shell a written demand for the payment of penalties. Stipulated penalties shall accrue as provided in Paragraph 20 of this Consent Decree. Shell shall pay the stipulated penalties specified in EPA's written demand within 30 Days from the date of EPA's demand for payment unless:

a. Shell has submitted a written request for discretionary waiver of stipulated penalties pursuant to Paragraph 25 of this Consent Decree and EPA has not responded to the written request;

b. Shell has submitted to EPA pursuant to Paragraph 31 of this Consent Decree a written claim that a delay in compliance is caused by a *force majeure* event regarding which EPA has not issued a decision pursuant to Paragraph 32 of this Consent Decree; or

c. Shell has submitted to EPA a written Notice of Dispute pursuant to Paragraph 35 of this Consent Decree, in which case the date that payment of any stipulated penalties is due shall be governed by Paragraph 22 of this Consent Decree.

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22. Penalties shall continue to accrue, as provided in Paragraph 20 of this Consent Decree, during any dispute resolution period, but need not be paid until the following:

a. If the dispute is resolved by agreement or by a decision of EPA that is not appealed to the Court, accrued penalties determined to be owing shall be paid to EPA within 20 Days of the date of the agreement or EPA's decision;

b. If the dispute is appealed to the Court, and the United States prevails in whole or in part, Shell shall pay all accrued penalties determined by the Court to be owed to EPA within 60 Days of the date of the Court's decision or order, except as provided in Subparagraph c below;

c. If the District Court's decision is appealed by either Party, Shell shall pay all accrued penalties determined by the District Court to be owing to the United States into an interest-bearing escrow account within 60 Days of the date of the Court's decision or order. Penalties shall be paid into this account as they continue to accrue, at least every 30 Days. Within 20 Days of the date of the issuance of the mandate by the Court of Appeals, the escrow agent shall pay the balance of the account to EPA or to Shell to the extent that they prevail.

23. The payment of stipulated penalties shall not affect Shell's obligation to satisfy all of the requirements of this Consent Decree.

24. Subject to the provisions of Section XIV of this Consent Decree (Effect of Settlement/Reservation of Rights), the stipulated penalties provided for in this Consent Decree shall be in addition to any other non-monetary rights, remedies, or sanctions available to the United States for Shell's violation of this Consent Decree or any rights, remedies, penalties, or sanctions for Shell's violation of applicable law. If a violation of this Consent Decree also is a violation of the Clean Water Act, Shell shall be allowed a

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credit, for any stipulated penalties paid, against any statutory penalties imposed for such violation.

25. Notwithstanding any other provision of this Section, the United States may, in its unreviewable discretion, waive payment of any portion of the stipulated penalties that have accrued pursuant to this Consent Decree.

XI. PAYMENT AND RELATED MATTERS

26. Shell shall make the payments described in Section VI (Payment of Civil Penalties) by Fedwire Electronic Funds Transfer (EFT) to the United States Department of Justice, in accordance with current EFT procedures and instructions provided to Shell by the Office of the United States Attorney for the Western District of Washington. The payments shall reference the Civil Action Number assigned to this case and DOJ Number 90-5-1-1-06967, and shall specify that the payments are made toward CWA civil penalties to be deposited into the Oil Spill Liability Trust Fund pursuant to 31 U.S.C. § 1321(s), § 4304 of Pub. L. No. 101-380, and 26 U.S.C. § 9509(b)(8). Any funds received after 11:00 a.m. Eastern Time shall be credited on the next Working Day. Shell shall submit to the United States, as provided in Section XV (Notices and Submissions), notice of all payments made pursuant to this Paragraph within 10 Days of the date of the payment.

27. Shell shall make the payments described in Section X (Stipulated Penalties) by EFT to the United States Department of Justice, in accordance with current EFT procedures and instructions provided to Shell by the Office of the United States Attorney for the Western District of Washington. The payments shall reference the Civil Action Number assigned to this case and DOJ Number 90-5-1-1-06967, and shall specify that the payments are for stipulated penalties to be deposited into the United States Treasury pursuant to 31 U.S.C.

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§ 3302. Any funds received after 11:00 a.m. Eastern Time shall be credited on the next Working Day. Shell shall submit to the United States, as provided in Section XV (Notices and Submissions), notice of all payments made pursuant to this Paragraph within 10 Days of the date of the payment.

28. If Shell fails to timely make any payment required pursuant to Section VI (Payment of Civil Penalties) or Section X (Stipulated Penalties), then, commencing on the Day after payment is due, Shell shall be liable to the United States for interest on the unpaid balance at the composite prime rate computed by, and published in the Wall Street Journal on the date that payment was due, and any costs of enforcement and collection incurred pursuant to the Federal Debt Collection Procedure Act, 28 U.S.C. § 3001 *et seq.*

29. The United States shall be deemed a judgment creditor for purposes of collection of any penalties, interest, and expenses of enforcement and collection pursuant to this Consent Decree. Shell specifically acknowledges that, pursuant to 26 U.S.C. § 162(f), penalty payments made pursuant to Sections VI (Payment of Civil Penalties) and X (Stipulated Penalties) of this Consent Decree shall not be deductible for federal tax purposes.

XII. *FORCE MAJEURE*

30. Shell's obligation to comply with the requirements of this Decree shall only be deferred to the extent and for the duration that the delay is caused by *force majeure*. "*Force majeure*," for purposes of this Consent Decree, is defined as any event arising from causes beyond the control of Shell, or of any entity controlled by Shell, that delays or prevents the performance of any obligation pursuant to this Consent Decree despite Shell's best efforts to fulfill the obligation. The requirement that Shell exercise "best efforts to fulfill the obligation" includes using best efforts to anticipate any potential force majeure event and best efforts to anticipate and address the effects of any potential force

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majeure event (1) as it is occurring: and (2) following the potential force majeure event, such that any delay is avoided or minimized to the greatest extent practicable. "*Force Majeure*" does not include financial inability to perform an obligation required by this Consent Decree or the Appendix. Notwithstanding any other provision of this Consent Decree, *force majeure* is not, except as otherwise provided by law, a defense to compliance with obligations imposed pursuant to the Clean Water Act, or any other statute, regulation, or permit.

31. Within 7 Days of any event that may delay the performance of any obligation pursuant to this Consent Decree, whether or not caused by a *force majeure* event, Shell shall provide a written notice to EPA explaining the reasons for the delay, the anticipated duration of the delay, all actions taken or planned to prevent or minimize the delay, a proposed schedule for implementation of any measures planned to prevent or mitigate the delay or the effect of the delay, and Shell's rationale for attributing such delay to a *force majeure* event if Shell intends to assert such a claim. If Shell is claiming a *force majeure* cause, the notice specifically shall reference this Section of the Consent Decree. Shell shall include with any notice all available documentation supporting its claim that the delay was attributable to a *force majeure* event. Failure to comply with the above requirements shall preclude Shell from asserting any claim of *force majeure* for that event. Shell shall be deemed to know of any circumstance of which Shell, or any entity controlled by Shell, knew or should have known.

32. If EPA agrees that the delay or anticipated delay is attributable to a *force majeure* event, EPA will extend the time for performance of the obligations pursuant to this Consent Decree that are affected by the *force majeure* event for such time as EPA deems necessary to complete those obligations. An extension of the time for performance of the

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obligations affected by the *force majeure* event shall not, of itself, extend the time for performance of any other obligation. Within 14 Days after receiving a written *force majeure* claim from Shell pursuant to the preceding Paragraph, EPA will exercise best efforts to notify Shell in writing of (1) EPA's decision regarding Shell's *force majeure* claim; (2) the amount of any demand for the payment of stipulated penalties related to any rejected *force majeure* claim; and (3) the length of the extension, if any, for performance of the obligations affected by the *force majeure* event; provided, however, that any delay by EPA in notifying Shell of EPA's decision regarding a *force majeure* claim does not excuse Shell's noncompliance based on an event that is not *force majeure*. Any extension of time pursuant to this Section shall not be valid unless the extension of time is confirmed in writing as provided in this Paragraph. Stipulated penalties shall not apply to a delay resulting from a *force majeure* event, as determined by EPA or the Court.

33. The dispute resolution procedures in Section XIII (Dispute Resolution) shall apply to any dispute regarding EPA's decision regarding a *force majeure* claim that Shell asserts pursuant to Paragraph 31 of this Consent Decree. If Shell elects to invoke the dispute resolution procedures set forth in Section XIII (Dispute Resolution), Shell shall do so no later than 15 Days from the date of EPA's written decision regarding a *force majeure* claim pursuant to Paragraph 32 of this Consent Decree. In any proceeding, Shell shall have the burden of proving 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 Shell complied with the requirements of Paragraphs 30 and 31, above. If EPA or the Court determines that a violation was caused by a *force majeure* event, then Shell shall be excused from that violation, including

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stipulated penalties for that violation, but only for the period of time the violation continues because of circumstances that qualify as *force majeure*.

XIII. DISPUTE RESOLUTION

34. Except as otherwise provided in this Paragraph or in Paragraph 26 of the Appendix, the dispute resolution procedures of this Section shall be the exclusive mechanism for Shell to resolve disputes arising under or with respect to this Consent Decree. Once Shell submits a Notice of Dispute to EPA pursuant to Paragraph 35 of this Decree, the dispute resolution procedures of this Section shall govern the resolution of the dispute. If Shell has not invoked the dispute resolution procedures of this Section, however, the United States may invoke either the dispute resolution procedures of this Section or any other available procedure to resolve any issue related to Shell's compliance with this Consent Decree.

35. Any dispute that arises under, or with respect to, this Consent Decree shall in the first instance be the subject of good faith, informal negotiations between EPA and Shell and, if either of the parties requests, in consultation with the Independent Monitoring Contractor. The period for informal negotiations shall not exceed 21 Days from the time the dispute arises, unless extended by written agreement of EPA and Shell. The dispute shall be considered to have arisen when one party sends the other party a written Notice of Dispute. EPA, in its unreviewable discretion, may agree in writing to suspend accrual of stipulated penalties for a specified time period to facilitate negotiations pursuant to this Paragraph.

36. If informal negotiations do not resolve the dispute, EPA's position shall control unless Shell files with the Court a petition to resolve the dispute within 10 Working Days after the conclusion of the informal negotiation period. This 10 Working Day period may be

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extended by written agreement of the Parties to the dispute. Within 30 Days after receiving a petition filed with the Court pursuant to this Paragraph, EPA may file a response. During the Court proceeding, Shell shall have the burden of proving that Shell's proposed resolution of the issues in dispute better meets the requirements of this Consent Decree and the CWA.

37. The invocation of dispute resolution procedures pursuant to this Section shall not extend, postpone or affect in any way any obligation of Shell pursuant to this Consent Decree, not directly in dispute, unless EPA agrees or the Court determines otherwise. Unless waived pursuant to Paragraph 25 of this Decree or suspended pursuant to Paragraph 35 of this Decree, stipulated penalties with respect to the disputed matter shall continue to accrue as provided in Paragraph 20 of this Decree, but payment shall be stayed pending resolution of the dispute as provided in Paragraph 22 of this Decree. If Shell does not prevail on the disputed issue, stipulated penalties shall be assessed and paid as provided in Section X (Stipulated Penalties).

XIV. EFFECT OF SETTLEMENT/RESERVATION OF RIGHTS

38. Performance of all of Shell's obligations pursuant to this Consent Decree, and Shell's obligations pursuant to the State Agreement discussed in Subparagraph I.G of this Consent Decree resolves any civil claims of the United States against Shell:

a. pursuant to Sections 301, 309, and 311 of the CWA, 33 U.S.C. §§ 1311, 1319, and 1321, as specifically alleged in the Complaint;

b. arising from the Incident for civil penalties pursuant to Section 3008(a) of RCRA, 42 U.S.C. § 6928(a), for violations of Section 3004 of RCRA, 42 U.S.C. § 6924, of which the United States had knowledge on or before the date this Decree is lodged; and

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c. arising from the Incident for claims received by the Oil Spill Liability Trust Fund pursuant to Subchapter I of OPA, 33 U.S.C. §§ 2701-2719, on or before December 20, 2002.

39. Nothing in this Decree shall be construed to create any rights in, or grant any cause of action to, any person not a Party to this Consent Decree. The United States and Shell expressly reserve any and all rights, defenses, claims, demands, and causes of action that they may have with respect to any matter, transaction, or occurrence relating in any way to the Incident against any person not a Party to this Consent Decree. The United States and Shell further expressly reserve any and all rights, defenses, claims, demands, and causes of action that the United States or Shell may have with respect to any matter, transaction or occurrence not related to the Incident.

40. Notwithstanding any other provision of this Consent Decree, the United States retains all authority and reserves all rights to take any and all response actions authorized by law.

41. This Consent Decree does not resolve, and the United States expressly reserves claims against Shell related to all other matters including, but not limited to, the following:

a. claims based on a failure by Shell to meet a requirement of this Consent Decree;

b. liability for damages for injury to, destruction of, or loss of natural resources, and for the costs of any natural resource damage assessments;

c. criminal liability;

d. liability pursuant to regulations of the United States Department of Transportation, Research and Special Programs Administration, Office of Pipeline Safety or pursuant to the Pipeline Safety Act, 49 U.S.C. §§ 60101, *et seq.*;

e. liability pursuant to Subchapter I of OPA, 33 U.S.C. §§ 2701-2719, for claims submitted to the Oil Spill Liability Trust Fund after December 20, 2002; and

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f. liability for any past, current, or future violation of federal or state law not resolved pursuant to Paragraph 38 of this Consent Decree.

42. In any subsequent administrative or judicial proceeding initiated by the United States for civil penalties or injunctive relief, Shell shall not assert, and may not maintain, any defense or claim based upon the principles of waiver, *res judicata*, collateral estoppel, claim preclusion, issue preclusion, claim-splitting, or other defenses based upon any contention that the claims raised by the United States in the subsequent proceeding should have been brought in the instant case; provided, however, that nothing in this Paragraph affects the resolution of the civil claims resolved pursuant to Paragraph 38 of this Consent Decree.

43. Shell hereby covenants not to sue and agrees not to assert any claims related to the Incident, or response activities in connection with the Incident, against the United States pursuant to the CWA, OPA, or any other federal law, State law, or regulation including, but not limited to, any direct or indirect claim for reimbursement from the Oil Spill Liability Trust Fund, or pursuant to any other provision of law.

44. This Decree does not limit or otherwise adversely affect any rights of Shell to proceed against any person or entity other than the United States for contribution or any other cause of action arising from the Incident.

45. The United States, by consenting to the entry of this Consent Decree, does not warrant or aver in any manner that Shell's complete and satisfactory compliance with this Consent Decree will constitute or result in compliance with the CWA or any other federal law or regulation.

46. Nothing in this Consent Decree shall limit or modify the authority of the United States Department of Transportation pursuant to the Pipeline Safety Act, 49 U.S.C.

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§ 60101, *et seq.*, and the regulations promulgated thereunder including 49 C.F.R. §§ 190, 195. Nor shall anything in this Consent Decree limit or modify the provisions of such statute and regulations or orders issued thereunder.

XV. NOTICES AND SUBMISSIONS

47. Whenever, pursuant to the terms of this Consent Decree and Appendix, written notice is required to be given or a report or other document is required to be sent by one party to another, it shall be directed to the individuals at the addresses specified below, unless those individuals or their successors give written notice of a change. All notices and submissions shall be considered effective on receipt, unless otherwise provided.

AS TO THE UNITED STATES:

As to the United States Department of Justice:

Chief, Environmental Enforcement Section
Environment and Natural Resources Division
United States Department of Justice
Post Office Box 7611
Washington, D.C. 20044-7611
DOJ #90-5-1-1-06967

As to the United States Environmental Protection Agency:

Regional Counsel
United States Environmental Protection Agency
Region X
1200 Sixth Avenue
Seattle, Washington 98101

Manager, Emergency Response Unit
Office of Environmental Cleanup
Region X
United States Environmental Protection Agency
1200 Sixth Avenue
Mail Stop ECL-116
Seattle, Washington 98101

AS TO SHELL PIPELINE COMPANY, LP:

Lance Tolson - Senior Counsel
Shell Oil Company - Legal Services/US
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Houston, Texas 77002

J. Gordon Arbuckle
Patton Boggs LLP
2550 M Street, N.W.
Washington, D.C. 20037-1350

Richard W. Elliott
Davis Wright Tremaine LLP
10500 N.E. 8th Street
1800 Bellevue Place
Bellevue, Washington 98004-4300

XVI. RECORD RETENTION/ACCESS TO INFORMATION

48. In addition to complying with any record-keeping requirements pursuant to applicable law and regulations, regardless of any contrary corporate retention policy, Shell shall preserve and retain, during the pendency of this Consent Decree and for a minimum of three years after termination of this Consent Decree, all records, documents and information in the possession, custody, or control of Shell, or which come into their possession, custody, or control, that relate in any manner to compliance with this Consent Decree, including without limitation, documents and information from the National Pipeline Mapping System, final reports and correspondence, and data related to the work performed pursuant to Section VII (Other Relief) and the Appendix. Shell may at its election keep such documents on computer disks if Shell provides EPA or the Independent Monitoring Contractor, on request and free of charge, a copy of any computer software needed to review or print the documents.

49. At any time prior to termination of this Consent Decree, and for three years thereafter, Shell shall provide to the United States, within 30 Days of the date of a request, all

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documents and information responsive to the request, within the possession, custody, or control of Shell or its contractors or agents, described in the preceding Paragraph.

50. Shell may assert business confidentiality claims covering part or all of the documents or information provided to the United States pursuant to this Consent Decree to the extent authorized by, and in accordance with, 40 C.F.R. Part 2. Documents or information that EPA determines to be confidential will be afforded the protection specified in 40 C.F.R. Part 2, Subpart B. If no claim of confidentiality accompanies documents or information when they are submitted to EPA, or if EPA has notified Shell that the documents or information are not confidential pursuant to applicable law, the public may be given access to such documents or information without further notice to Shell.

51. Shell may assert security-related claims covering part or all of the documents or information provided to the United States pursuant to this Consent Decree to the extent authorized by any applicable law or regulation. Documents or information that EPA determines to be security-related will be afforded the protection provided by applicable law or regulation. If no claim of security accompanies documents or information when they are submitted to EPA, or if EPA has notified Shell that the documents or information are not security-related pursuant to applicable law, the public may be given access to such documents or information without further notice to Shell. Nevertheless, no documents, reports, or other information specifically required to be created or generated pursuant to the requirements of the Consent Decree shall be withheld on the grounds that they are security-related.

52. Shell may assert that certain documents, records and other information are privileged pursuant to the attorney-client privilege or any other privilege recognized by federal law. Nevertheless, no documents, reports, or other information specifically required to be

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created or generated pursuant to the requirements of the Consent Decree shall be withheld on the grounds that they are privileged. If a claim of privilege applies only to a portion of a document, the document shall be provided to the United States in redacted form to mask the privileged information only. If Shell asserts a privilege instead of providing documents, it shall provide the United States with 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 the author of the document, record, or information;

d. the name and title of each addressee and recipient;

e. a description of the contents of the document, record, or information; and

f. the privilege asserted by Shell.

53. Nothing in this Consent Decree shall limit the access and information-gathering authorities and rights of the United States pursuant to any federal law or regulation, including without limitation, related enforcement authorities pursuant to the CWA and OPA.

XVII. RETENTION OF JURISDICTION

54. This Consent Decree shall be considered an enforceable judgment for purposes of post-judgment collection in accordance with the provisions of the Consent Decree, Rule 69 of the Federal Rules of Civil Procedure, and other applicable federal statutory authority.

55. This Court retains jurisdiction over both the subject matter of this Consent Decree and the Parties for the duration of the performance of the terms and provisions of this Consent Decree for the purpose of enabling either of the Parties to apply to this Court at any time for such further order, direction, and relief as may be necessary or appropriate for the

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construction or modification of this Consent Decree, or to effectuate or enforce compliance with its terms, or to resolve disputes in accordance with Section XIII (Dispute Resolution).

XVIII. MODIFICATION

56. Modifications to the schedules for completion of the requirements pursuant to Appendix A may be made without consent of the Court by written agreement between Shell and EPA. Except as provided in the preceding sentence, no material modifications shall be made to this Consent Decree without written notification to, and written approval by, the United States, Shell, and the Court. Minor modifications that do not materially alter Shell's obligations pursuant to this Consent Decree may be made without consent of the Court by written agreement between the Parties. Shell may consult with EPA regarding advances in knowledge or technology; and EPA and Shell may agree to modifications to this Decree to efficiently achieve the objectives of the Decree. Modifications to which EPA and Shell agree in accordance with the preceding sentence shall be deemed to be minor modifications.

XIX. LODGING AND OPPORTUNITY FOR PUBLIC COMMENT

57. This Consent Decree shall be lodged with the Court for a period of at least 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 to the Consent Decree if the United States becomes aware of facts or considerations that indicate to the United States that the Consent Decree is inappropriate, improper, or inadequate. Shell agrees not to oppose entry of this Consent Decree or to challenge any provision of this Consent Decree unless the United States has notified Shell in writing that it no longer supports entry of the Consent Decree. Shell consents to entry of this Consent Decree without further notice.

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58. If for any reason the Court declines to approve this Consent Decree in the form presented, this agreement is voidable at the sole discretion of any Party and the terms of the agreement shall not be used as evidence in any litigation.

XX. EFFECTIVE DATE

59. The effective date of this Consent Decree is that date upon which it is entered by the Court.

XXI. INTEGRATION/APPENDIX

60. This Consent Decree, Appendix A (Other Relief), and Exhibits 1-6 to Appendix A, constitute the final, complete and exclusive Consent Decree and understanding between the Parties regarding the settlement embodied in this Consent Decree. 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 Appendix and Exhibits are attached to and incorporated into this Consent Decree:

"Appendix A" is the Other Relief referenced in Paragraph 12 of this Consent Decree.

"Exhibit 1 to Appendix A" is AGA Project PR-3-805 as defined in Subparagraph 1.b of Appendix A.

"Exhibit 2 to Appendix A" is API RP 1110 as defined in Subparagraph 1.e of Appendix A.

"Exhibit 3 to Appendix A" is API 1161 as defined in Subparagraph 1.f of Appendix A.

"Exhibit 4 to Appendix A" is API RP 1130 as defined in Subparagraph 1.g of Appendix A.

"Exhibit 5 to Appendix A" is ASME B31.4-2002 as defined in Subparagraph 1.i of Appendix A.

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"Exhibit 6 to Appendix A" is ASME B31G-1991 as defined in Subparagraph 1.j of Appendix A.

"Exhibit 7 to Appendix A" is NACE RP0169-2002 as defined in Subparagraph 1.x of Appendix A.

XXII. TERMINATION

61. Not earlier than 5 years after entry of this Consent Decree, this Decree shall be subject to termination upon motion by either Party after Shell fully satisfies all requirements of this Consent Decree, except those obligations required pursuant to Section XVI (Record Retention/Access to Information). At such time as Shell believes it has fulfilled all such requirements, Shell shall so certify to the United States. Not earlier than 30 Days after such certification, either Party may apply to the Court for termination of the Consent Decree. The obligations set forth in Section XIV (Effect of Settlement/Reservation of Rights) and Section XVI (Record Retention/Access to Information) shall survive termination of the Consent Decree as contractual obligations.

XXIII. SIGNATORIES/SERVICE

62. The Parties' undersigned representatives certify that they are fully authorized to enter into the terms and conditions of this Consent Decree and to execute and legally bind such Party to this document.

63. Shell shall identify, on the attached signature page, the name, address, and telephone number of an agent who is authorized to accept service by mail on behalf of Shell with respect to all matters arising under or relating to this Consent Decree.

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XXIV. COSTS

64. Each Party shall bear its own costs and attorneys' fees in the action resolved by this Consent Decree.

Dated this _____ day of _____, 2003.

COPY

_____
UNITED STATES DISTRICT JUDGE

THE UNDERSIGNED PARTIES enter into this Consent Decree relating to the Incident.

FOR THE UNITED STATES OF AMERICA

Date: 1.13.03

Tom Sansonetti
THOMAS L. SANSONETTI
Assistant Attorney General
Environment and Natural Resources Division
United States Department of Justice

Wayne T. Ault
WAYNE T. AULT
Trial Attorney
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FOR THE UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

JOHN PETER SUAREZ
Assistant Administrator for
Enforcement and Compliance Assurance
United States Environmental Protection Agency

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L. JOHN IANI
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Agent Authorized to Accept Service on Behalf of Shell Pipeline Company LP:

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Telephone: 202-457-6090

Counsel for Shell Pipeline Company LP

A

The Honorable Barbara Jacobs Rothstein

UNITED STATES DISTRICT COURT
WESTERN DISTRICT OF WASHINGTON

UNITED STATES OF AMERICA, **Plaintiff** **v.** **SHELL PIPELINE COMPANY LP fka EQUILON PIPELINE COMPANY LLC and OLYMPIC PIPE LINE COMPANY,** **Defendants.**	**Civil Action No. CV02-1178R** **APPENDIX A TO THE CONSENT DECREE BETWEEN THE UNITED STATES OF AMERICA AND SHELL PIPELINE COMPANY LP fka EQUILON PIPELINE COMPANY LLC (OTHER RELIEF)**

I. DEFINITIONS

1. The terms used in this Appendix shall have the meaning assigned to them in Paragraph 4 of the Consent Decree to which this Appendix is attached. Whenever terms listed below are used in this Appendix or in the Exhibits attached to this Appendix, the following definitions shall apply:

   a. "AGA" shall mean the American Gas Association.

   b. "AGA Project PR-3-805" shall mean an AGA publication entitled "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe," December, 1989, a copy of which is attached to, and incorporated into this Appendix as Exhibit 1.

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c. "Analyzed ILI Data" shall mean a final written report from an ILI Vendor or other qualified employee or agent of Shell analyzing raw data from an ILI to identify suspected or predicted defects and anomalies.

d. "API" shall mean American Petroleum Institute.

e. "API RP 1110" shall mean a document entitled "Pressure Testing of Liquid Petroleum Pipelines," API Recommended Practice 1110, 4th Edition, March, 1997, a copy of which is attached to, and incorporated into this Appendix as Exhibit 2.

f. "API 1161" shall mean a document entitled "Guidance Document for the Qualification of Liquid Pipeline Operations and Maintenance Personnel," API Publication 1161, 1st Edition, August, 2000, a copy of which is attached to, and incorporated into this Appendix as Exhibit 3.

g. "API 1130" shall mean a document entitled "Computational Pipeline Monitoring," API 1130, First Edition, October, 1995, a copy of which is attached to, and incorporated into this Appendix as Exhibit 4.

h. "ASME" shall mean the American Society of Mechanical Engineers.

i. "ASME B31.4-2002" shall mean a document entitled "Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids, ASME Code for Pressure Piping," 2002 edition, a copy of which is attached to, and incorporated into this Appendix as Exhibit 5.

j. "ASME B31G-1991" shall mean a document entitled "Manual for Determining the Remaining Strength of Corroded Pipelines, A Supplement to ASME B31 Code for Pressure Piping," 1991 edition, a copy of which is attached to, and incorporated into this Appendix as Exhibit 6.

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k. "Cathodic Protection System" shall mean a system to prevent the corrosion of a metal surface by making that surface the cathode of an electrochemical cell with the use of impressed current or galvanic anodes.

l. "Commercially Navigable Waterway" shall mean a commercially navigable waterway as defined and identified pursuant to 49 C.F.R. §§ 195.450, 195.452.

m. "EFRD" shall mean an emergency flow restricting device that either is a check valve (a type of valve that permits fluid flow in one direction only), or a valve that can be remotely operated from another monitoring or control location, including an existing valve that will be converted to a remotely operated valve that can be operated from another monitoring or control location.

n. "Engineering Judgment" shall mean judgment based on the application of scientific and mathematical principles to the design, construction, operation, and maintenance of pipeline systems, with such judgment exercised by a suitably qualified person.

o. "Excavation Activity" shall mean digging, deep plowing, blasting, boring, directional drilling, other trench-less excavation methods, clearing, grading, ditching, tunneling, dredging, back-filling, the removal of above-ground structures by either explosive or mechanical means, and other earth moving operations.

p. "Excavator" shall mean any person or entity engaging in Excavation Activity.

q. "Exposed Pipe" shall mean any pipe at or above any body of water or at or above ground level, unless (1) the pipe was intentionally designed and intentionally installed above ground (a) to traverse land; (b) as an overhead crossing of a body of water, a highway, a railroad, or similar structure; (c) as a span over a ditch or gully; (d) as part of a scraper trap or block valve; or (e) within a fenced area owned, leased, or maintained by Shell constituting a pump station, tank farm,

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metering facility, delivery facility, or junction; and (2) the pipe is protected from the forces exerted by the anticipated loads.

r. "High Consequence Area" shall mean a high consequence area as defined and identified pursuant to 49 C.F.R. §§ 195.450, 195.452.

s. "ILI" shall mean in-line inspection.

t. "ILI Vendor" shall mean a vendor in the business of performing ILIs of hazardous liquid pipelines using ILI tools that generate data regarding suspected defects on hazardous liquid pipelines and providing analysis of the data.

u. "Independent Monitoring Contractor" or "IMC" shall mean the Independent Monitoring Contractor selected pursuant to Section XIV of this Appendix.

v. "Metal Loss Tool" shall mean a high resolution magnetic flux leakage tool or an alternative tool selected pursuant to Paragraph 5 of this Appendix.

w. "MOP" shall mean maximum operating pressure.

x. "NACE" shall mean National Association of Corrosion Engineers.

y. "NACE RP0169-2002" shall mean a document entitled "Standard Recommended Practice: Control of External Corrosion on Underground or Submerged Metallic Piping Systems," NACE RP0169-2002, originally approved in 1969, reaffirmed in 2002, a copy of which is attached to, and incorporated into this Appendix as Exhibit 7.

z. "One-Call System" shall mean a notification system through which a person can notify owners and operators of underground lines or facilities of proposed excavations.

aa. "Pipeline" shall mean all main transmission line portions of Shell Pipeline Systems comprising line pipe.

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bb. "Responsible Corporate Officer" shall mean the person or persons designated by Shell to perform relevant decision-making functions, and who has authority to sign documents on behalf of Shell with respect to the Decree.

cc. "Supervisory Control and Data Acquisition (SCADA) System" shall mean a computer-based communications system that gathers, processes, and displays data from field instrumentation and allows an operations controller to execute control functions;

dd. "Semester" shall mean either the period from January 1 through June 30 of any calendar year, or the period from July 1 through December 31 of any calendar year.

ee. "Shallow Cover Pipe" shall mean any portion of the Pipeline that crosses under a Commercially Navigable Waterway and which has a depth of cover of less than 24 inches.

ff. "Shell Pipeline Systems" shall mean the pipeline systems commonly referred to as the East Line Products, North Line Products, Chase Kansas Products, Chase Colorado Products, and Orion Products pipeline systems that are used for transporting petroleum products, and include approximately 2139 miles of pipeline running in the States of Texas, Oklahoma, Colorado, Kansas, Ohio, Illinois, and Indiana and associated structures and buildings used for operations and administration, control equipment, pumps, valves, breakout storage tanks, and other equipment used in the operation of the pipeline systems, and any like additions to the Shell Pipeline Systems made during the pendency of this Consent Decree. The term does not include facilities such as refineries, lube plants, and marine and distribution terminals that are connected to, or associated with the pipelines but which perform separate functions such as storage or blending.

gg. "SMYS" shall mean the specified minimum yield strength.

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hh. "Top-Side of the Pipeline" shall mean the portion of the Pipeline above the 8:00 o'clock and 4:00 o'clock positions on any part of the Pipeline.

II. CONSTRUCTION OF THIS APPENDIX

2. If compliance with applicable provisions of ASME, NACE, AGA, or API publications would prevent compliance with this Consent Decree, Shell shall comply with this Consent Decree. If compliance with this Consent Decree or with applicable provisions of ASME, NACE, AGA, or API publications would prevent compliance with applicable laws and regulations, Shell shall comply with applicable laws and regulations. All references to ASME, NACE, AGA, or API publications in this Appendix shall be construed to be specific to the documents incorporated by reference herein and attached as Exhibits to this Appendix, and no such references shall be interpreted to include, or require compliance with, any modifications or amendments to any such documents subsequent to the versions attached as Exhibits to this Appendix.

III. ILIs, EVALUATIONS, EXCAVATIONS, AND RESPONSE REQUIREMENTS

A. Pipelines Covered

3. The Pipeline consists of the segments described in the table below.

Pipeline System	Segment	Nominal Pipe Size	Length (miles)
Chase Kansas Products	Sunset-Eldorado	8"	2.0
Chase Kansas Products	Eldorado-Hudson	10"	107.0
Chase Kansas Products	Hudson-Scott City	10"	146.0
Chase Colorado Products	Scott City-Aurora	10"	228.0
Chase Colorado Products	Aurora to DIA	10"	17.7
Chase Colorado Products	Sunset to Eldorado	16"	2.0
Chase Colorado Products	Eldorado to MP44	10"	44.0
Chase Colorado Products	MP44 to Scott City	12"	185.0
East Line Products	Wood River to Zionsville	12"	225.0
East Line Products	Zionsville to Lima	12"	127.0
North Line Products	Wood River to Peotone	14"	220.0

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North Line Products	Peotone to Argo	14"	32.0
North Line Products	Peotone to East Chicago	14"	28.0
North Line Products	Argo to Des Plaines	14"	27.0
Orion Products	East Houston to	16"	174.8
Orion Products	Corsicana to Frost	20"	23.0
Orion Products	Frost to Clyde	16"	163.0
Orion Products	Clyde to Abilene	14"	10.0
Orion Products	Abilene to Tye	16"	8.0
Orion Products	Tye to Stanton	16"	116.0
Orion Products	Stanton to Midland	14"	16.0
Orion Products	Midland to Odessa	12"	25.0
Orion Products	Frost to Underwood	12"	69.5
Orion Products	Underwood to Henrietta	12"	89.1
Orion Products	Henrietta to Duncan	12"	48.5
Orion Products	Underwood to Pride	12"	3.0
Orion Products	Pride to Aledo	6"	2.0

B. ILIs Using Both Deformation and Metal Loss Tools

1. General Requirements

4. For each ILI required by this Appendix, Shell shall ensure that each ILI Vendor calibrates the inspection tool in accordance with applicable ILI Vendor standards and that each ILI Vendor provides verification of the calibration to Shell.

5. Whenever Shell uses a magnetic flux leakage tool for an ILI required by this Appendix, Shell shall use a high resolution magnetic flux leakage tool. Shell may use a Metal Loss Tool other than a magnetic flux leakage tool if:

   a. The alternative Metal Loss Tool is more appropriate, in the exercise of reasonable Engineering Judgment, considering the circumstances; and

   b. Shell informs EPA of the technical basis for selecting the alternative Metal Loss Tool before conducting the ILI.

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2. ILI Schedule

6. Shell shall complete ILIs during 2003 using both a Metal Loss Tool and a deformation ILI tool on the following segments of the North Line Products Pipeline System within Shell Pipeline Systems: Peotone to East Chicago 14" and Argo to Des Plaines 14". For the 2003 ILIs, Shell may utilize any Analyzed ILI Data or other information from ILIs conducted on or after January 1, 2002.

7. Shell shall complete ILIs during 2003 using both a Metal Loss Tool and a deformation ILI tool on the following segments of the Orion Products Pipeline System within Shell Pipeline Systems: Walnut Springs to Clyde 16" (sub-segment), and Frost to Underwood 12". For the 2003 ILIs, Shell may utilize any Analyzed ILI Data or other information from ILIs conducted on or after January 1, 2002.

8. Shell shall complete ILIs during 2007 using both a Metal Loss Tool and a deformation ILI tool on the following segments of the Orion Products Pipeline System within Shell Pipeline Systems: Abilene to Tye 16", Clyde to Abilene 14" and Frost to Walnut Springs 16"(sub-segment).

9. Shell shall complete ILIs during 2003 using both a Metal Loss Tool and a deformation ILI tool on the following segments of the Chase Colorado Products Pipeline System within Shell Pipeline Systems: Scott City to Aurora 10", Eldorado to MP44 10", and MP44 to Scott City 12". For the 2003 ILIs, Shell may utilize any Analyzed ILI Data or other information from ILIs conducted on or after January 1, 2002.

10. Shell shall complete ILIs during 2003 using both a Metal Loss Tool and a deformation ILI tool on the following segments of the East Line Products Pipeline System within Shell Pipeline Systems: Wood River to Zionsville 12" and Zionsville to Lima 12". For the 2003 ILIs, Shell may utilize any Analyzed ILI Data or other information from ILIs conducted on or after January 1, 2002.

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11. Shell shall complete an ILI during 2003 using both a Metal Loss Tool and a deformation ILI tool on the Wood River to Peotone 14" segment of the North Line Products Pipeline System within Shell Pipeline Systems. For the 2003 ILI, Shell may utilize any Analyzed ILI Data or other information from ILIs conducted on or after January 1, 2002.

12. Shell shall complete ILIs during 2003 using both a Metal Loss Tool and a deformation ILI tool on the following segments of the Orion Products Pipeline System within Shell Pipeline Systems: Tye to Stanton 16", Stanton to Midland 14", Underwood to Henrietta 12", and Henrietta to Duncan 12". For the 2003 ILIs, Shell may utilize any Analyzed ILI Data or other information from ILIs conducted on or after January 1, 2002.

13. Shell shall perform an ILI during 2004 using both a Metal Loss Tool and a deformation ILI tool on the Aurora to DIA 10" segment of the Chase Colorado Products Pipeline System within Shell Pipeline Systems.

14. Shell shall perform an ILI during 2004 using both a Metal Loss Tool and a deformation ILI tool on the Midland to Odessa 12" segment of the Orion Products Pipeline System within Shell Pipeline Systems.

15. Shell shall perform an ILI during 2005 using both a Metal Loss Tool and a deformation ILI tool on the East Houston to Corsicana 16" segment of the Orion Products Pipeline System within Shell Pipeline Systems.

16. Shell shall perform ILIs during 2006 using both a Metal Loss Tool and a deformation ILI tool on the following segments of the Chase Kansas Products Pipeline System within Shell Pipeline Systems: Eldorado to Hudson 10" and Hudson to Scott City 10".

17. Shell shall perform an ILI during 2006 using both a Metal Loss Tool and a deformation ILI tool on the Corsicana to Frost 20" segment of the Orion Products Pipeline System within Shell Pipeline Systems.

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C. Evaluation Requirements

18. Within 1 year after completing any ILI required by this Appendix, Shell shall obtain Analyzed ILI Data and shall use reasonable Engineering Judgment to complete an evaluation of that data and other appropriate and adequate information to identify predicted or suspected defects or anomalies described in Paragraph 24 of this Appendix. The date of completion of the evaluation required by this Paragraph shall be deemed the Date of Discovery of the predicted or suspected defects or anomalies identified in the evaluation.

D. Excavation and Response Requirements

19. After Shell completes any evaluation required by Paragraph 18 of this Appendix, and within the time required by Paragraphs 20-22 of this Appendix, Shell shall:

a. excavate and perform a visual inspection and further evaluation to confirm the existence of any defects or anomalies described in Paragraph 24 of this Appendix at each location where such defects or anomalies were predicted or suspected as a result of the evaluation performed pursuant to Paragraph 18 of this Appendix; and

b. repair, remove, or replace, any portion of the Pipeline for which visual inspection and further evaluation confirms the existence of any of the defects or anomalies described in Paragraph 24 of this Appendix.

20. Excavation and Response Schedule for Pipeline Within a High Consequence Area. For all Pipeline covered by an ILI required by this Appendix and within a High Consequence Area, Shell shall complete all excavation and response requirements in the preceding Paragraph within 9 months from the Date of Discovery as defined in Paragraph 18 of this Appendix, unless Shell has reasonably determined, pursuant to Paragraph 25 of this Appendix, that a reinterpretation of the Analyzed ILI Data is required or that a new ILI must be performed.

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21. Excavation and Response Schedule for Pipeline Not Within a High Consequence Area. For all Pipeline covered by an ILI required by this Appendix and not located within a High Consequence Area, Shell shall complete all excavation and response requirements in Paragraph 19 of this Appendix within 18 months from the Date of Discovery as defined in Paragraph 18 of this Appendix, unless Shell has reasonably determined, pursuant to Paragraph 25 of this Appendix, that a reinterpretation of the Analyzed ILI Data is required or that a new ILI must be performed.

22. Immediate Excavation and Response Requirements. Notwithstanding the schedule for excavation and repairs in Paragraphs 20 and 21 of this Appendix and pursuant to Paragraph 19 of this Appendix, as soon as safely possible after the Date of Discovery of predicted or suspected defects or anomalies that would meet the description in Subparagraphs a-d of this Paragraph, Shell shall temporarily reduce the operating pressure at the location of the predicted or suspected defect or anomaly (1) to 80% of the MOP; or (2) in the case of a defect or anomaly described in Subparagraph b of this Paragraph, based on the predicted burst pressure calculated in accordance with ASME B31G-1991 or AGA Project PR-3-805, until Shell has further evaluated the suspected defect or anomaly and completed any required responses. After reducing the operating pressure in accordance with the requirements of the preceding sentence, within 120 Days after the Date of Discovery, Shell shall excavate the predicted or suspected defect or anomaly and repair, remove, or replace any defect or anomaly, as defined in this Paragraph , confirmed by visual examination and further evaluation following excavation, after which the temporary pressure reduction required by the preceding sentence shall no longer be required. The defects or anomalies subject to these requirements are:

a. metal loss greater than or equal to 80% of the nominal wall thickness regardless of pipe dimension;

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b. any defect or anomaly for which a calculation of the remaining strength of the pipe shows a predicted burst pressure less than the established MOP at the location of the defect or anomaly as determined by the calculation methods in:

i. ASME B31G-1991;

ii. AGA Project PR-3-805; or

iii. upon approval by EPA, which approval may not unreasonably be withheld, any other suitable calculation method;

c. a dent on the Top-Side of the Pipeline that has an indication of metal loss, cracking, or a stress riser; and

d. a dent on the Top-Side of the Pipeline with a depth exceeding 6% of the nominal pipe diameter.

23. Shell shall perform the repair, removal, or replacement of any portion of the Pipeline pursuant to Paragraphs 19-22 of this Appendix in accordance with the standards in ASME B31.4-2002 Parts 451.6.2 and 451.6.3.

E. Response Standards

24. In accordance with the schedule in Paragraphs 20-22 of this Appendix, Shell shall repair, remove, or replace any portion of the Pipeline that has any of the following defects or anomalies:

a. dents of any size containing a scratch, crack, gouge, or groove;

b. dents of any size that have an indication of metal loss, cracking, or a stress riser;

c. dents of any size that affect pipe curvature at the pipe seam or at any girth weld;

d. dents exceeding a depth of 6% of the nominal pipe diameter;

e. corrosion of, or along, seam welds;

f. any defect or anomaly for which a calculation of the remaining strength of the pipe using the criterion in ASME B31G-1991 or AGA Project PR-3-805 shows a

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predicted burst pressure less than or equal to 100% of the SMYS of the affected pipe;

g. metal loss greater than 50% of the nominal wall thickness in areas of general corrosion;

h. metal loss greater than 50% of the nominal wall thickness that is located at the crossing of another pipeline, or is in an area with widespread circumferential corrosion, or is in an area that could affect a girth weld;

i. metal loss greater than or equal to 80% of the nominal wall thickness regardless of pipe dimension;

j. weld anomalies with metal loss greater than 50% of nominal wall thickness;

k. cracks of any size;

l. gouges, and grooves of any size;

m. arc burns of any size;

n. localized corrosion pitting as defined by ASME B31.4 § 451.6.2(a)(7); or

o. any defect or anomaly for which a calculation of the remaining strength of the pipe shows a predicted burst pressure less than the established MOP at the location of the defect or anomaly as determined by the calculation methods in:

i. ASME B31G-1991;

ii. AGA Project PR-3-805; or

iii. upon approval by EPA, which approval may not unreasonably be withheld, any other suitable calculation method.

Nothing in this Appendix shall be or is intended to be an admission or concession by Shell that any of the conditions set forth in this Paragraph or in Paragraph 22 of this Appendix, if not immediately corrected, would likely result in a failure of the Pipeline or a release of petroleum products from that Pipeline.

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F. Reinterpretation of ILI Data or Performance of New ILI

25. If during excavation or visual inspection and further evaluation of the predicted or suspected defects or anomalies identified pursuant to Paragraph 18 of this Appendix, Shell has a reasonable basis to determine that the anomalies described in the Analyzed ILI Data are characterized incorrectly or otherwise do not allow a reasonably accurate identification of defects or anomalies described in Paragraph 24 of this Appendix, Shell may, based on reasonable Engineering Judgment, elect to cease excavation and evaluation activities and consult with the ILI Vendor to determine whether to require a reinterpretation of the Analyzed ILI Data or to perform a new ILI. If Shell elects to cease excavation and evaluation activities, Shell shall notify EPA and the Independent Monitoring Contractor of the election no later than 60 Days before the original deadline for completing the excavation and response.

a. Within 60 Days after the date that Shell notifies EPA and the Independent Monitoring Contractor of its election to cease excavation and response activities, Shell shall either:

i. submit to EPA and the Independent Monitoring Contractor a written commitment to complete a reinterpretation and new evaluation of the Analyzed ILI Data and report to EPA and the Independent Monitoring Contractor the results of the new evaluation, including the Date of Discovery of any defects or anomalies pursuant to the new evaluation, within 90 Days of the date of the written commitment; or

ii. submit to EPA and the Independent Monitoring Contractor a written commitment to conduct a replacement ILI within 270 Days of the date of the written commitment.

b. If Shell elects to complete a reinterpretation and new evaluation of the Analyzed ILI Data in accordance with the Subparagraph a.i of this Paragraph, and

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recommences excavation and response activities and reasonably determines that the reinterpretation and new evaluation of the Analyzed ILI Data still improperly characterizes the defects or anomalies or otherwise does not allow a reasonably accurate identification of defects or anomalies described in Paragraph 24 of this Appendix, Shell shall submit to EPA and the Independent Monitoring Contractor a written commitment to conduct a replacement ILI within one year of the date of the commitment pursuant to Subparagraph a.i of this Paragraph to complete a reinterpretation and new evaluation of the Analyzed ILI Data.

c. Whenever Shell proceeds with a replacement ILI pursuant to this Paragraph, Shell shall complete a new evaluation of the Analyzed ILI Data from the replacement ILI, and other appropriate and adequate information, within the time required by Paragraph 18 of this Appendix, and shall complete any required excavations, repairs, removals, or replacements within the time required by Paragraphs 20-22 of this Appendix.

G. Dispute Resolution Regarding Shell's Obligations Pursuant to Paragraphs 18 through 25 of this Appendix

26. Shell shall include a written Notice of Completion in the Semiannual Progress Report for the Semester in which Shell completes all evaluation, excavation, and response actions required by Subsections III.C and III.D of this Appendix for a particular Pipeline segment.

a. Within 120 Days of the date of any Semiannual Progress Report containing a Notice of Completion described in the preceding sentence, or at any time before receiving the Notice of Completion, EPA may submit to Shell a written Notice of Review stating that EPA seeks further review of all or part of Shell's evaluation, excavation, and response actions for a Pipeline segment.

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b. Within 30 Days of the date of any Notice of Review, or such longer period to which EPA and Shell agree in writing, Shell shall meet with EPA and, at EPA's option, any authorized representatives or EPA contractors, to discuss EPA's concerns.

c. Within 30 Days after the conclusion of any meeting required by the preceding sentence, EPA may issue to Shell a written preliminary Notice of Dispute briefly describing the elements of the dispute.

d. Within 20 Days after the date of any preliminary Notice of Dispute, Shell may submit to EPA a written response.

e. If EPA does not rescind a preliminary Notice of Dispute in writing within 45 Days of such notice, or such longer period to which EPA and Shell agree in writing, the preliminary Notice of Dispute shall become final.

f. Within 10 Working Days after a Notice of Dispute becomes final, a petition for review may be filed with the Court to resolve the dispute. In any such proceeding, the Court will determine whether Shell's evaluation or response actions meet the requirements of Paragraphs 18-25 of this Appendix.

g. Notwithstanding any other provisions of this Appendix or the Consent Decree, the dispute resolution procedures described in this Paragraph shall be the exclusive mechanism for resolving disputes arising under Paragraphs 18 through 25 of this Appendix except as otherwise provided in this Subparagraph. If the United States has not invoked the dispute resolution procedures in this Paragraph, however, the United States may invoke any available procedure other than the dispute resolution procedures in Section XIII (Dispute Resolution) of the Consent Decree to resolve any issue arising under Paragraphs 18 through 25 of the Appendix.

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H. Extensions of Time to Complete Evaluation and Response Actions

27. If Shell cannot complete the evaluation or response actions in the time required by Paragraphs 18, 20-22 and 25 of this Appendix despite reasonable and diligent efforts to do so, Shell may submit a written request for an extension of time to EPA, specifying the number of Days of the requested extension, at least 45 Days before the expiration of the relevant deadline. After receiving a written request for an extension of time from Shell pursuant to this Paragraph, EPA shall provide Shell with a written response in which EPA may, in its discretion, either grant or deny, in whole or in part, the requested extension of time. EPA shall not unreasonably deny a request for extension of time pursuant to this Paragraph. If EPA provides Shell with a written response denying Shell's request for an extension of time, the original deadline will remain in effect unless the date that Shell receives EPA's letter denying the extension of time is less than 30 Days before, or at any time after, the original deadline, in which case Shell shall be required to complete the evaluation or response actions within 30 Days of the date that Shell receives EPA's denial.

I. Data Submission and Record Retention Requirements

28. Within 10 Days after receiving any request from EPA for a copy of any ILI data or Analyzed ILI Data, Shell shall submit the requested ILI data or Analyzed ILI Data to EPA.

29. Record Retention. Shell shall retain all ILI data and Analyzed ILI Data in accordance with the record retention provisions of Section XVI of the Consent Decree.

IV. PRESSURE TESTING

30. Shell shall perform either an ILI pursuant to the requirements of Section III of this Appendix, or a hydrostatic test during 2003 in accordance with the standards and requirements of ASME B31.4-2002, Paragraph 437.4.1 and API RP 1110, on the Sunset

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to Eldorado 8" segment of the Chase Kansas Products Pipeline System within Shell Pipeline Systems.

31. Shell shall perform either an ILI pursuant to the requirements of Section III of this Appendix, or a hydrostatic test during 2003 in accordance with the standards and requirements of ASME B31.4-2002, Paragraph 437.4.1 and API RP 1110, on the Sunset to Eldorado 16" segment of the Chase Colorado Products Pipeline System within Shell Pipeline Systems.

32. Shell shall perform either an ILI pursuant to the requirements of Section III of this Appendix, or a hydrostatic test during 2003 and in accordance with the standards and requirements of ASME B31.4-2002, Paragraph 437.4.1 and API RP 1110, on the following segments of the Orion Products Pipeline System within the Shell Pipeline Systems: Underwood to Pride 12" and Pride to Aledo 6".

33. Shell shall complete either an ILI pursuant to the requirements of Section III of this Appendix, or a hydrostatic test during 2007 in accordance with the standards and requirements of ASME B31.4-2002, Paragraph 437.4.1 and API RP 1110, on the Peotone to Argo 14" segment of the North Line Products Pipeline System within Shell Pipeline Systems.

34. Response Requirements. If a pressure test reveals a Pipeline leak, Shell shall:

a. repair or replace the portion of the Pipeline segment where the leak occurred in accordance with the standards in ASME B31.4-2002 Parts 451.6.2 and 451.6.3; and

b. retest the affected portion of the Pipeline segment in accordance with the applicable standards of 49 C.F.R. Part 195, if required.

35. Record Retention. Shell shall retain all records related to pressure testing of segments of Pipeline within Shell Pipeline Systems in accordance with the record retention provisions of Section XVI of the Consent Decree.

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V. CLOSE INTERVAL SURVEYS

36. Performance Standard for Cathodic Protection. Shell shall maintain a Cathodic Protection System on all Pipeline within Shell Pipeline Systems in accordance with NACE RP0169-2002. Shell shall follow corrosion control criteria in NACE RP0169-2002 including one or more of the criteria and other conditions for cathodic protection in section 6 of NACE RP0169-2002.

37. Close Interval Surveys. Shell shall complete one close interval survey on all Pipeline within Shell Pipeline Systems within 4 years of the Effective Date of the Consent Decree. Shell shall perform the close interval survey in accordance with NACE RP0169-2002 at maximum intervals of four feet (maintaining an overall system-wide average no greater than three feet) excluding areas in which such an interval is impracticable such as paved areas and railroads. Shell shall perform the close interval survey in a manner sufficient to determine whether or not the Cathodic Protection System conforms with the criteria referenced in the preceding Paragraph for all locations surveyed. Shell may utilize any data or other information from the close interval survey conducted during 2002 to meet the requirements of this Paragraph.

38. Corrective Action. If any portion of the Pipeline within Shell Pipeline Systems does not meet the performance standard referenced in Paragraph 36 of this Appendix, Shell shall perform all corrective action necessary to comply with that standard within 2 years after completing the close interval survey required by the preceding Paragraph.

39. Rotating Disk Visual Indicator Requirements. Within 3 years after the Effective Date of the Consent Decree, Shell shall install rotating disc visual indicators on all rectifiers within Shell Pipeline Systems. Within 1 year after installing the rotating disk visual indicators, and annually thereafter until the Consent Decree is terminated, Shell shall complete an on the ground survey to check the rotating disk visual indicator on each

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rectifier to determine whether or not the Cathodic Protection System is operating properly.

40. Rectifier Inspections. Beginning 6 months after the Effective Date of the Consent Decree until it is terminated, at intervals not exceeding 2½ months, but at least six times each calendar year after the initial year, Shell shall inspect each of its cathodic protection rectifiers to determine whether or not the Cathodic Protection System is operating properly.

VI. PIPELINE RIGHT-OF-WAY SURVEYS

41. On the Ground Surveys. Within one year of the Effective Date of the Consent Decree, and once every two years thereafter until the Consent Decree is terminated, Shell shall complete an on-the-ground survey of the entire Pipeline right-of-way within Shell Pipeline Systems to:

a. identify all Exposed Pipe;

b. assess the visibility and accessibility of the right-of-way;

c. assess the condition and spacing of pipeline signs; and

d. discover any third party Excavation Activity on, or within 50 feet of, the right-of-way.

42. Waterway Shallow Cover Inspection. Within six years of the Effective Date of the Consent Decree, Shell shall inspect each portion of the Pipeline crossing under any Commercially Navigable Waterway to identify any Shallow Cover Pipe.

43. Aerial Surveys. Beginning 9 months after the Effective Date of the Consent Decree, and until the Consent Decree is terminated, Shell shall complete weekly aerial surveys of the entire Pipeline right-of-way within Shell Pipeline Systems if weather, security, and flight conditions permit. To the extent possible and pursuant to industry standards, the aerial surveyors shall identify and assess the conditions and activities described in Paragraph 41 of this Appendix.

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44. Exposed Pipe. Shell shall, within 180 Days after completing the survey required by Paragraph 41 of this Appendix, conduct an inspection of any Exposed Pipe discovered during the survey to determine whether or not the Exposed Pipe has any of the defects or anomalies described in Paragraph 24 of this Appendix unless Shell needs to obtain a permit or access before conducting the inspection. If Shell needs to obtain a permit or access before conducting the inspection, Shell shall (1) apply for the permit within 90 Days after completing the survey in which the Exposed Pipe was discovered; and (2) conduct the inspection within 180 Days after obtaining the necessary permit or access. If an inspection confirms the existence of any such defect or anomaly, Shell shall repair, remove, or replace the Exposed Pipe in accordance with the standards referenced in Paragraph 23 of this Appendix and in accordance with the applicable schedule required by Paragraphs 20-22 of this Appendix, using the date of inspection as the Date of Discovery. Shell shall, at the time of any such repair, removal, or replacement, evaluate the risk of outside force damage to the Exposed Pipe, and in areas susceptible to outside force damage shall either (1) restore the cover to the standards in ASME B31.4-2002, Table 434.6(a); or (2) install physical protective measures necessary to provide reasonable assurance of safety and integrity of the Pipeline. For all other Exposed Pipe locations, Shell shall annually inspect such locations in accordance with this Paragraph.

45. Shallow Cover Pipe. Within 18 months after Shell discovers Shallow Cover Pipe during the inspection required by Paragraph 42 of this Appendix, Shell shall either:

a. restore the cover to the standards in ASME B31.4-2002, Table 434.6(a); or

b. with EPA's prior written approval, mitigate the Shallow Cover Pipe in a manner sufficient to provide reasonable assurance of safety and integrity of the Pipeline.

46. Pipeline Visibility and Accessibility. Within one year after completing the initial survey required by Paragraph 41 of this Appendix, and once every two years thereafter until the Consent Decree is terminated, to the extent practicable, Shell shall mow, clear brush, and

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perform all other actions necessary to ensure that the entire Pipeline right-of-way is visible and accessible for effective emergency response, Pipeline maintenance, inspection, and survey activities.

47. Pipeline Signs. Within two years of the Effective Date of the Consent Decree, and once every two years thereafter, Shell shall, as practicable, install, repair, clear vegetation obscuring, or replace, as necessary, pipeline signs directly above or in close proximity to the buried Pipeline so that, to the extent practicable, at least one pipeline sign is visible from any point along the Pipeline right-of-way.

VII. EMERGENCY FLOW RESTRICTIVE DEVICES

48. Shell EFRD Analysis. Within one year after the Effective Date of this Consent Decree, using its proprietary spill model, surge analysis, and other appropriate information or data, Shell shall complete an analysis to determine appropriate locations for installation of EFRDs that will provide additional protection to the public or the environment.

49. EFRD Installation. Within 4 years of the Effective Date of the Consent Decree, Shell shall install 8 EFRDs within Shell Pipeline Systems that will provide additional protection to the public or the environment.

VIII. COMPUTATIONAL PIPELINE MONITORING SYSTEM LEAK DETECTION TESTING

50. Testing Requirement. Within 180 Days after the Effective Date of the Consent Decree, Shell shall conduct a computational pipeline monitoring (CPM) system test on at least two of the Pipelines within Shell Pipeline Systems to determine whether or not the leak detection capability of the CPM software meets the performance standards and requirements of applicable regulatory requirements and API 1130. Within one year after Shell performs the CPM tests described in the preceding sentence, Shell shall perform one CPM test on each of the Pipelines that have not yet been tested. Following the completion of the initial CPM tests described in the first two sentences of this Paragraph,

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Shell shall repeat those CPM tests on all of the pipelines within Shell Pipeline Systems at least once every two years.

51. Corrective Action. If the testing required by the preceding Paragraph reveals that the leak detection capability of the CPM software does not meet the performance standards and requirements of applicable regulatory requirements and API 1130, Shell shall, within 6 months after completing the testing, perform all corrective action necessary to meet those performance standards and requirements.

IX. DAMAGE PREVENTION PROGRAM

52. Within 180 Days of the Effective Date of this Consent Decree, Shell shall submit to EPA and the Independent Monitoring Contractor a written Damage Prevention Program, which Shell shall implement within the time required by Paragraph 61 of this Appendix. The Damage Prevention Program shall require Shell to conduct the activities described below:

a. Shell shall continuously participate in a One-Call System covering each area in which a Pipeline operated by Shell Pipeline Systems is located.

b. For all Excavation Activity within 50 feet of the Pipeline right-of-way that has any potential to affect the integrity of the Pipeline of which Shell or its contractors either knows or should know through a One-Call System, patrolling, or observation, Shell shall:

1. obtain, if available, daily from the Excavator information regarding the construction schedule and any changes to the schedule;

2. obtain, if available, daily from the Excavator information regarding the type of excavation and equipment the Excavator plans to use and any changes to those plans;

3. obtain, if available, from the Excavator and retain drawings, plans, and any other documents necessary or helpful to monitor the Excavation

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Activity, including any documents reflecting any change in the Excavator's planned Excavation Activity;

4. ensure that a qualified Shell employee or contractor is physically present at the construction site to monitor Excavation Activity during the entire time that Excavation Activity occurs within 50 feet of the Pipeline; and

5. ensure that all Shell employees and contractors that monitor Excavation Activity prepare a daily written report of the monitored Excavation Activity, and that such daily reports are retained in Shell's files in accordance with the record retention provisions of Section XVI of the Consent Decree.

c. When portions of the Pipeline are excavated for maintenance or inspection, Shell shall install warning mesh above the Pipeline at the time that the Pipeline is reburied.

d. Shell shall ensure that the provisions of the Damage Prevention Program are incorporated or cross referenced, as appropriate, into Shell's written procedures and plans for training, operations, maintenance, and emergencies.

X. MANAGEMENT OF CHANGE PROGRAM

53. Within 180 Days of the Effective Date of this Consent Decree, Shell shall submit to EPA and the Independent Monitoring Contractor a written Management of Change Program, which Shell shall implement within the time required by Paragraph 61 of this Appendix. The Management of Change Program shall require Shell to conduct the activities described below:

a. develop procedures to manage and review all pressure, flow, and control settings on existing protective devices, and changes to any such devices or their components within Shell Pipeline Systems;

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b. address the following considerations prior to any change:

1. the technical basis for the proposed change including the methodology or analysis utilized to determine the appropriate settings;
2. the impact of the change on the integrity of the Pipeline;
3. potential modifications to operating procedures in response to the change;
4. necessary time period for the change;
5. authorization requirements for the proposed change; and
6. position, education, and level of experience required for the Shell employee or officer authorizing the change;

c. inform and train employees whose job duties are affected by the change in pressure, flow, and control settings of existing or newly installed protective and control devices;

d. ensure that the provisions of the Management of Change Program, and any revisions, are incorporated or cross referenced, as appropriate, in Shell's written procedures and plans for training, operations, maintenance, and emergencies; and

e. revise applicable engineering drawings and documents, as appropriate, to reflect each change to pressure, flow, and control settings for existing or newly installed protective and control devices and maintain records related to each change for the life of the equipment or facility.

XI. TRAINING PROGRAM

54. Within 180 Days of the Effective Date of this Consent Decree, Shell shall submit to EPA and the Independent Monitoring Contractor a written Training Program covering SCADA controllers of Shell Pipeline Systems, which Shell shall implement within the

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time required by Paragraph 61 of this Appendix. The Training Program shall require the activities described below:

a. Shell shall appoint one or more SCADA Controller Training Coordinator(s) responsible for training, maintaining training documentation, and ensuring that Shell complies with all provisions of this Paragraph.

b. For all new SCADA controllers of Shell Pipeline Systems hired on or after the Effective Date of this Consent Decree, Shell shall:

1. include in the training required by this Subparagraph classroom and practical exercises and the use of a pipeline simulator;

2. provide training and qualification testing pursuant to API 1161, specific to the SCADA system in use that includes responding to abnormal operations and starting up and shutting down any part of the Shell Pipeline Systems;

3. test each new SCADA controller's knowledge of the SCADA system to ensure that the SCADA controller is capable of exercising sound judgment to perform the functions needed during both normal and abnormal operations; and

4. require the new SCADA controller to work daylight shift for a minimum of the first two weeks of performing SCADA functions.

c. For all SCADA controllers of Shell Pipeline Systems hired before the Effective Date of this Consent Decree, Shell shall:

1. review the training and qualification records of each SCADA controller to determine whether or not each SCADA controller is capable of exercising sound judgment to perform the functions needed during both normal and abnormal conditions; and

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2. perform remedial training and review for each SCADA controller, if necessary.

d. Shell shall ensure that the provisions of the Training Program are cross referenced in Shell's written procedures and plans for training, operations, maintenance, and emergencies, as applicable.

55. Audit of the Training Program. Between two and three years after the Effective Date of the Consent Decree, Shell shall conduct, and prepare a written report of, an audit of Shell's SCADA Controller Training Program in accordance with the requirements of Paragraphs 56 and 57 of this Appendix. Within 15 Days of the date of the written audit report, Shell shall submit the written audit report to EPA and the Independent Monitoring Contractor.

56. Scope of Audit. At a minimum, the audit required by the preceding Paragraph shall include SCADA controller interviews and a review of all relevant documents including, but not limited to:

a. the written SCADA Controller Training Program;

b. SCADA controller training records;

c. SCADA controller training manuals;

d. Shell's written procedures and plans for SCADA controller training; and

e. Semiannual Progress Reports.

57. Contents of Audit Report. The written audit report required pursuant to Paragraph 55 of this Appendix shall include a description of the audit methodology, and also shall include:

a. a description of the documents reviewed;

b. a list of SCADA controllers interviewed and their titles, and a summary of each interview; and

c. a description of the audit findings.

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XII. PROCEDURE FOR INDEPENDENT REVIEW AND IMPLEMENTATION OF WRITTEN PROGRAMS REQUIRED PURSUANT TO SECTIONS IX-XI OF THIS APPENDIX

58. Independent Review. After receiving from Shell a written program required by Sections IX, X, or XI of this Appendix, or a revised written program pursuant to Paragraph 59.a or Paragraph 60 of this Appendix, EPA and the Independent Monitoring Contractor shall review the written program and EPA shall provide Shell with a written response that either:

a. states that the written program or revised written program meets the requirements of the Appendix to the best of EPA's knowledge and that EPA has no objection to the written program or revised written program; or

b. requires revisions to the written program or revised written program necessary to ensure compliance with the Consent Decree and this Appendix.

59. Shell's Response. If EPA requires revisions to a written program submitted by Shell pursuant to Paragraph 58.b of this Appendix, within 30 Days of the date of EPA's written response, Shell shall either:

a. make the required revisions and submit a revised written program to EPA; or

b. submit to EPA a written Notice of Dispute pursuant to Paragraph 35 of the Consent Decree that states Shell's grounds for disputing any or all of EPA's required revisions.

60. Submission of Revised Written Programs Following Resolution of Disputes. Within 30 Days after resolving any disputes, asserted pursuant to Paragraph 59.b of this Appendix, regarding any of EPA's required revisions to any written program; Shell shall submit a revised written program to EPA that reflects the resolution of the dispute.

61. Implementation of Written Programs. Within 30 Days after the date of a written EPA response pursuant to Paragraph 58.a of this Appendix, Shell shall implement the written program or revised written program.

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XIII. INDEPENDENT MONITORING CONTRACTOR

62. Shell shall follow the procedure in Section XIV of this Appendix to select, and contract with, an Independent Monitoring Contractor (IMC) to perform the duties described in Paragraph 65 of this Appendix. The IMC shall assign no more than 4 qualified employees to perform these duties.

63. Shell shall cooperate fully with the IMC and shall facilitate the IMC's execution of duties described in Paragraph 65 of this Appendix by providing the IMC with reasonable access to all relevant records, employees, and the physical Shell Pipeline Systems.

64. Qualifications. The IMC shall have one or more employees with demonstrated qualifications and experience in the technical areas relevant to the duties of the Independent Monitoring Contractor in Paragraph 65 of this Appendix. With the prior expressed approval of both EPA and Shell, the Independent Monitoring Contractor may also contract, as appropriate, with other outside individuals or entities that are qualified to perform the assigned tasks and satisfy the background requirements of Paragraph 67 of this Appendix.

65. Duties of the Independent Monitoring Contractor. The Independent Monitoring Contractor shall perform the following duties:

a. review each Semiannual Report submitted by Shell pursuant to Paragraph 13 of the Consent Decree, and any other documents that the Independent Monitoring Contractor or EPA deems necessary, to determine whether or not Shell has complied with all provisions of the Consent Decree and this Appendix and report any determinations of non-compliance to Shell and EPA within 30 Days of the date of each Semiannual Report; provided, however, that the IMC's duties within the scope of this Appendix or the Consent Decree shall not include reviewing ILI data or Analyzed ILI Data;

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b. Review the programs submitted by Shell pursuant to Sections IX-XI of this Appendix to recommend any revisions necessary to ensure compliance with the Consent Decree and this Appendix and submit those recommendations to both EPA and Shell within 30 Days after the date that Shell submits each proposed program;

c. review and analyze the written audit report of the Training Program that Shell submits pursuant to Section XI of this Appendix and notify EPA and Shell of any determinations of non-compliance with this Appendix revealed by the Independent Monitoring Contractor's analysis of the written audit report;

d. on each of the following pipeline systems within Shell Pipeline Systems: East Line Products, North Line Products, Chase Kansas Products, Chase Colorado Products, and Orion Products, each calendar year conduct up to one physical site visit, with up to 4 persons, lasting up to 3 Days for each visit, including employee or contractor interviews, record review, and inspections and observations of any activities if deemed appropriate, to assess whether or not Shell is complying with this Appendix. Absent emergency, any such site visit shall be made at reasonable times and after reasonable notice to Shell;

e. each calendar year conduct up to one additional physical site visit, with up to 4 persons, lasting up to 3 Days, other than the site visits in the preceding Subparagraph, on any one of the pipeline systems within Shell Pipeline Systems, in the unreviewable discretion of the Independent Monitoring Contractor or at the request of EPA, including employee or contractor interviews, record review, and inspections and observations of any activities if deemed appropriate, to assess whether or not Shell is complying with this Appendix;

f. confer on request by either Shell or EPA, separately or jointly, to discuss implementation of this Appendix and to assist in dispute resolution;

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g. investigate concerns regarding potential noncompliance with this Appendix as requested by EPA;

h. immediately notify Shell of problems that may affect compliance with this Appendix, and if the problems are not resolved within 15 Days after the Independent Monitoring Contractor notifies Shell, notify EPA of the problems, and summarize those problems in a report to EPA that includes recommendations regarding how Shell can resolve those problems;

i. immediately notify Shell and EPA of any circumstance that may constitute noncompliance with this Appendix and summarize those circumstances in a report to both Shell and EPA that includes recommendations regarding how Shell can resolve the circumstance;

j. submit an annual report to Shell and EPA within 30 Days after the end of each calendar year summarizing:

1. site visits that the Independent Monitoring Contractor conducted during the year pursuant to Subparagraphs d and e of this Paragraph;

2. any problems that may affect compliance with this Appendix;

3. any circumstances that may constitute noncompliance with this Appendix; and

4. the status of Shell's compliance with this Appendix during the year; and

k. any other duties or responsibilities specifically required of the Independent Monitoring Contractor in the Consent Decree or in this Appendix.

66. Neither Shell nor EPA shall be bound by the recommendations of the Independent Monitoring Contractor.

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XIV. PROCEDURE FOR SELECTING, CONTRACTING WITH, AND REPLACING THE INDEPENDENT MONITORING CONTRACTOR

67. Qualifications and Background. The Independent Monitoring Contractor shall have the qualifications and experience required by Paragraph 64 of this Appendix. The Independent Monitoring Contractor shall not:

a. be a present employee of Shell, or of any owner, parent corporation, subsidiary, or predecessor corporation of Shell;

b. have a current financial or ownership interest in any of Shell's businesses or operations; or

c. be a Shell contractor, or employee of such contractor, hired to implement any provision of this Appendix other than the provisions of Section XIII (Independent Monitoring Contractor).

68. Selection Procedure. The Independent Monitoring Contractor shall be selected pursuant to the procedures described below.

a. Within 30 Days from the Effective Date of this Consent Decree or 30 Days from the date that the parties agree on the need for a replacement consultant pursuant to Paragraph 70 of this Appendix, or a final decision affirming the need for a replacement consultant is rendered pursuant to the dispute resolution procedures in Section XIII (Dispute Resolution) of the Consent Decree, Shell shall submit to EPA (1) a letter providing the name of a proposed independent consultant that is willing to serve as the Independent Monitoring Contractor; (2) a resume or curriculum vitae of each individual who would perform the required work; (3) the terms of payment for the consultant's services; and (4) a description of any current or past financial relationship between the proposed consultant, and the consultant's employees who will perform the required work, and Shell or the related entities specified in the preceding Paragraph, which Shell shall certify as

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accurate. After receiving such information, EPA shall submit a letter to Shell that either accepts or rejects the proposed consultant. EPA shall not unreasonably withhold approval of a proposed consultant. If the letter from EPA accepts the proposed consultant, Shell shall contract with the consultant to perform the required work in accordance with the procedure in Paragraph 69 of this Appendix. If EPA rejects the proposed consultant, Shell shall repeat the procedure in this Paragraph up to two additional times by recommending another proposed consultant.

b. If EPA rejects three of Shell's proposed consultants, EPA shall then submit to Shell a letter providing (1) the names of at least three proposed independent consultants who are willing to serve; (2) a resume or curriculum vitae of each of consultants' personnel who would perform the required work; and (3) a description of any current or past financial relationship related to this case between each proposed consultant and the United States. Shell then shall have 30 Days from the date of such letter to submit to EPA a letter accepting one of the three proposed consultants or rejecting all of them. If Shell accepts one of the three consultants proposed by EPA, Shell shall contract with the consultant to perform the required work in accordance with the procedure in Paragraph 69 of this Appendix. If Shell rejects all of the consultants proposed by EPA, either EPA or Shell may invoke the dispute resolution procedures in Section XIII (Dispute Resolution) of the Consent Decree.

69. Contracting Procedure. Within 30 Days of the date of a letter from EPA or Shell accepting a proposed Independent Monitoring Contractor, or a final decision pursuant to the dispute resolution procedures in Section XIII (Dispute Resolution) of the Consent Decree designating an Independent Monitoring Contractor, Shell shall draft, and submit to EPA for approval, a proposed contract obligating the Independent Monitoring

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Contractor to perform the duties described in Paragraph 65 of this Appendix. Within 15 Days after the date of any letter from EPA notifying Shell of any needed revisions to the contract with the Independent Monitoring Contractor, Shell shall incorporate, modify, or reject the revisions and submit the revised contract to EPA for approval. Within 30 Days of the date of EPA's written approval of the contract, Shell shall enter into the contract with the Independent Monitoring Contractor, and submit a copy of the executed contract to EPA.

70. Replacement Procedure. If the Independent Monitoring Contractor becomes unable or unwilling to perform or complete the required work, or for other good cause, Shell and EPA shall confer in good faith regarding whether or not Shell and EPA need to select a replacement Independent Monitoring Contractor. If Shell and EPA agree on the need to select a replacement Independent Monitoring Contractor, Shell and EPA shall select the replacement Independent Monitoring Contractor in accordance with the selection procedures in Paragraph 68 of this Appendix. If Shell and EPA do not agree on the need to select a replacement Independent Monitoring Contractor, either Shell or EPA may invoke the dispute resolution procedures in Section XIII (Dispute Resolution) of the Consent Decree.

XV. SEMIANNUAL PROGRESS REPORTS

71. Semiannual Progress Reports. Beginning on the Effective Date of this Decree and through and including the Semester in which this Consent Decree is terminated pursuant to Section XXII (Termination Date), Shell shall submit certified Semiannual Progress Reports to EPA and the Independent Monitoring Contractor. The first Semiannual Progress Report shall be due within 45 Days of the close of the first Semester ending more than 90 Days after entry of this Consent Decree, with subsequent reports due within 30 Days of the close of each Semester thereafter.

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72. Certification Requirement. Shell shall submit the following written certification with each Semiannual Progress Report, signed by a Responsible Corporate Official:

> I certify under penalty of law that this submission was prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. I further certify under penalty of law that, to the best of my knowledge, based on my reasonable inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is 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.

73. Contents of Semiannual Progress Reports. Shell shall include in each Semiannual Progress Report a statement regarding Shell's activities during the Semester for each of the categories described below. If no information exists for a particular category during the Semester, Shell nevertheless shall include that category in the report with an affirmative statement that no information exists for that category and a brief explanation why no such information exists. Each Semiannual Progress Report shall describe:

a. A summary of all actions Shell has taken to comply with Section III of this Appendix including (1) ILIs conducted; (2) Analyzed ILI Data received; and (3) excavations and responses conducted. Additionally, for each defect or anomaly that Shell excavates or investigates in any way pursuant to Section III of this Appendix, Shell shall describe:

1. the location of the defect or anomaly including, as applicable, state, county, city, latitude and longitude, pipeline milepost segment, and any other information necessary or helpful to precisely identify the location of the anomaly;

2. a pipe description including outside diameter, wall thickness, grade, manufacturer, if known, depth of cover, type of coating, and date of construction;

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3. the date of completion of the ILI that identified the location of the defect or anomaly;

4. the identity of the ILI Vendor and a description of the ILI tool used;

5. ILI details such as the inspection chart number or other comparable identifier, odometer number, and defect or anomaly number;

6. a description of the defect or anomaly as represented in the Analyzed ILI Data report;

7. the Date of Discovery of the defect or anomaly identified Pursuant to Paragraph 18 of this Appendix;

8. the date that Shell or its agents excavated and further evaluated the defect or anomaly;

9. a summary of Shell's findings of the evaluation for the defect or anomaly including:

   i. the depth of gouges and grooves as a percentage of nominal wall thickness;

   ii. the depth of dents as a percentage of nominal pipe diameter;

   iii. whether or not each dent affected pipe curvature or a seam, girth, or repair weld and, if so, how;

   iv. whether or not each dent contained a scratch, gouge, or groove; and

      (a) the length of each scratch, gouge, and groove; and

      (b) the depth of each scratch, gouge, and groove at its deepest point;

   v. measurements and other field observations regarding crack indications; and

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vi. the extent of corrosion including its length, its circumferential extent around the pipe, and the percentage of wall thickness loss at the deepest point of corrosion; and

10. a statement regarding whether or not the defect or anomaly was repaired, removed, or replaced, and the reason for any decision not to repair, remove, or replace the defect or anomaly;

11. a description of any repair, removal, or replacement, of the defect or anomaly; and

12. a statement regarding whether or not the evaluation and disposition of each defect or anomaly complied with this Appendix;

b. a summary of all actions that Shell has taken to comply with Section IV of the Appendix including:

1. hydrostatic tests conducted;

2. anomalies, leaks, or Pipeline failures discovered during, or resulting from, any hydrostatic tests conducted; and

3. Pipeline repairs or replacements conducted of anomalies, leaks, or Pipeline failures discovered as a result of any hydrostatic tests;

c. a summary of all actions that Shell has taken to comply with Section V of the Appendix regarding close interval surveys including:

1. a summary of the pipeline segments surveyed including location, miles inspected, and the average lengths of the intervals;

2. the date of the survey;

3. the identity of any contractor used;

4. the results of the survey;

5. whether or not the survey was conducted in accordance with NACE RP0169-2002;

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6. a description of all corrective measures taken as a result of the survey; and

7. a report of any malfunctioning rectifiers discovered and/or repaired;

d. a summary of all actions that Shell has taken to comply with Section VI of the Appendix including:

1. on-the-ground surveys of the Pipeline right-of-way;

2. aerial surveys of the Pipeline right-of-way;

3. Exposed Pipe discovered, remediated, repaired, replaced, or reburied including:

i. the location of the Exposed Pipe;

ii. the existence of any defects or anomalies described in Paragraph 24 of this Appendix;

iii. repairs, removals, or replacements, if any, made; and

iv. any actions taken to increase the depth of cover or install physical protective devices;

4. all mowing, brush clearing, and similar activities;

5. activities undertaken to comply with Paragraph 47 of this Appendix and the date of installation of all Pipeline signs installed, repaired, or replaced after the Effective Date of the Consent Decree; and

6. third party Excavation Activity discovered and monitored as a result of the on-the-ground surveys required by Paragraph 41 of this Appendix; aerial surveys required by Paragraph 43 of this Appendix; or notifications through a One-Call System;

e. a summary of all actions that Shell has taken to comply with Section VII of the Appendix including:

1. the location of each EFRD installation;

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2. the type or specification of the EFRD installed, including remote operator; and

3. Shell's analysis for installing the EFRD at the location selected;

f. a summary of all actions that Shell has taken to comply with Section VIII of the Appendix regarding testing of, and corrective action for the computational pipeline monitoring system including:

1. all tests conducted; and

2. corrective action conducted;

g. a summary of all actions that Shell has taken to comply with Section IX of the Appendix including:

1. revisions of Shell's written procedures and plans for training, operations, maintenance, and emergencies as such revisions relate to the Damage Prevention Program, and as appropriate; and

2. third party Excavation Activity that Shell monitored and damage to the Pipeline that Shell identified during such monitoring;

h. a summary of all actions that Shell has taken to comply with Section X of the Appendix including:

1. a brief description of the program and procedures to manage and review all Shell Pipeline Systems pressure, flow, and control setting changes on existing or newly installed protective and control devices; and

2. the date of any revision to Shell's written procedures and plans for Shell Pipeline Systems to reflect each change, if any, to adjust pressure, flow, and control settings for existing and newly installed protective and control devices;

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i. a summary of all actions that Shell has taken to comply with Section XI of the Appendix including:

1. revisions of Shell's written procedures and plans for SCADA controller training;

2. the specific training, training review, and testing conducted for each of Shell's SCADA controllers; and

3. the name and job description of the SCADA Controller Training Coordinator, the date that the SCADA Controller Training Coordinator commenced and ended his or her duties, and the name, job description, and the date duties commenced and ended, of any replacement SCADA Controller Training Coordinator; and

j. a Schedule Exception List of all actions that Shell was required to complete during the Semester but which Shell did not complete within the time period required by this Appendix. For each action identified in the Schedule Exception List, Shell shall:

1. briefly explain why the action was not timely completed, including whether or not Shell claims that a *force majeure* event as defined in Section XII of the Consent Decree prevented timely completion;

2. state an anticipated completion date for the action; and

3. state whether or not an extension of the compliance date was requested from EPA and, if so, any disposition of that request.

XVI. EXHIBITS

74. The following exhibits are attached to, and incorporated into this Appendix:

"Exhibit 1" is AGA Project PR-3-805.

"Exhibit 2" is API RP 1110.

"Exhibit 3" is API 1161.

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"Exhibit 4" is API RP 1130.

"Exhibit 5" is ASME B31.4-2002.

"Exhibit 6" is ASME B31G-1991.

"Exhibit 7" is NACE RP0169-2002.

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A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe

Contract PR-3-805

Prepared for the
Pipeline Corrosion Supervisory Committee
Pipeline Research Committee

of
Pipeline Research Council International, Inc.

Prepared by the following Research Agencies:

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***PR-3-805 Ad Hoc Group Member

EXECUTIVE SUMMARY

Described herein is an improved method for evaluating the remaining strength of corroded pipe. The pipeline industry currently uses the "B31G" criterion to evaluate corroded pipe for removal or repair or for leaving it in service if the metal loss is within safe size limits as defined in the B31G criterion. A new and improved criterion was desired because of the known excess conservatism in the original B31G method. Even though the use of the B31G criterion has undoubtedly helped pipeline operators to avoid many unnecessary cut outs, the excess conservatism continues to cause some unnecessary cut outs that could be avoided without compromising safety. Thus, this project was undertaken to devise a modified criterion that, while still assuring adequate pipeline integrity, would eliminate as much as possible the excess conservatism embodied in the existing criterion.

The proposed modified criterion presented herein is less conservative than the existing B31G criterion. It will permit metal-loss anomalies of greater size to remain in service at the current maximum operating pressure. And, for anomalies which exceed the newly recommended allowable size, the modified criterion will require less pressure reduction to maintain an adequate margin of safety for all cases in which the reduced pressure level exceeds 55 percent of SMYS.

The new criterion was made less conservative by means of a change in the manner in which the flow stress of the material is considered and by means of a change in the format of the stress-intensifying effect of the metal loss.

The original body of data on burst tests of corroded pipe that was used to validate the original B31G criterion was expanded considerably by data obtained from companies who have performed their own burst tests. The expanded data base shows that the proposed modified criterion embodies an adequate margin of safety.

The proposed modified criterion can be used with detailed measurements of the metal loss and successive trial calculations to predict a minimum failure pressure for an area of metal loss based upon its "effective" area. Used in this mode, it tends to further reduce the

excess conservatism embodied in the existing criterion. This more complex analysis approach can be carried out by means of a PC-based program called RSTRENG.

The new criterion can also be applied via tables or curves or a long-hand equation with knowledge of only the maximum depth and overall length of the metal loss for cases in which a simplified analysis is preferred. In such cases, the area of metal missing is approximated as 0.85 times the overall axial length of corrosion times the maximum depth of the corrosion. The new area representation replaces the old "parabolic" area representation (2/3 times the axial length times the depth of the corrosion). The new area representation by itself is actually a more conservative representation than the old area representation, but as used with the improved definition of flow stress and the more accurate stress intensity representation, the new area representation method offers the following advantages. It is less conservative than the existing B31G method when used to assess the allowable length of a corroded area and when used to calculate a reduced operating stress level for all stress levels exceeding 55 percent of SMYS. It is more conservative than the existing B31G criterion when used to calculate a reduced operating stress level for stress levels below 55 percent of SMYS. In addition, the proposed new area representation permits more accurate (less conservative) assessments of long defects. A restrictive limit is placed on the length of defect that can be considered under the existing B31G criterion. Beyond this limit, the user is required to revert to a reduction in operating stress in proportion to the depth of the anomaly. With the proposed new area representation, the user is permitted to analyze much longer defects. The result is that many flaws which would require removal, repair, or pressure reduction under the existing criterion can be tolerated under the proposed new criterion with either no pressure reduction or less pressure reduction.

The limit on corrosion depth to not more than 80 percent of the wall thickness for purposes of using the old criterion is retained in the new criterion. However, unlike the old criterion, corroded areas of not more than 20 percent through the wall thickness may be left in

service regardless of length (for pipelines operating at stress levels not exceeding 72 percent of SMYS as long as the remaining thickness is not less than 80 percent of that required by the design stress level).

While the factor of safety of 1.39 embodied in the old criterion is retained for cases of pipelines operating at 72 percent of SMYS, provisions are made for use of the criterion with other factors of safety and for pipelines with design factors other than 0.72. Finally, a rationale is provided for applying the modified criterion to corrosion in submerged-arc seam welds. Such corrosion may be treated in the same manner as if it were in the body of the pipe.

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A MODIFIED CRITERION FOR EVALUATING THE REMAINING STRENGTH OF CORRODED PIPE

by

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INTRODUCTION

In the late 1960s and early 1970s, a criterion was developed through research sponsored by Texas Eastern Transmission Corporation and the Pipeline Research Committee of A.G.A. to evaluate the serviceability of corroded pipe. This criterion has been embodied in both the B31.4 and B31.8 pipeline design codes-and is described in detail in a separate document: "ABSI/ASME B31G - 1984 Manual for Determining the Remaining Strength of Corroded Pipelines". The criterion, commonly referred to as the B31G criterion", can be used by a pipeline operator to assess corroded pipe for rehabilitation purposes. The remaining pressure-carrying capacity of a pipe segment is calculated on the basis of the amount and distribution of metal lost to corrosion and the yield strength of the material. If the calculated remaining pressure-carrying capacity exceeds the maximum allowable operating pressure of the pipeline by a sufficient margin of safety, the corroded segment can remain in service. If not, it must be repaired or replaced. Applying this criterion, pipeline operators have saved millions of dollars by not removing corroded pipe which is still fit for service in spite of having sustained some loss of metal.

From its inception, the B31G criterion was intended to embody a large factor of safety to protect pipelines from failure. Experience has shown that the amount of conservatism embodied in the criterion is excessive, resulting in the removal or repair of more pipe than is necessary to maintain adequate integrity. Therefore, it is desirable to have a modified criterion which will still preserve adequate pipeline

integrity but will result in less removal of pipe. A modified criterion which meets this requirement is described in this report.

BACKGROUND

The B31G criterion is based upon a semiempirical fracture mechanics relationship referred to as the "NG-18 surface flaw equation" because of its origin in work sponsored by the NG-18 Line Pipe Research Committee of the American Gas Association. The original equation was conceived by Maxey[1]* and is described in detail in Reference 2. It was based upon a "Dugdale" plastic-zone-size model, a "Folias" analysis[3] of an axial crack in a pressurized cylinder, and an empirically established flaw-depth-to-pipe-thickness relationship. The extensive data base of flawed-pipe burst tests presented in Reference 2 demonstrated its usefulness and validity for axial flaws in line pipe. Subsequently, Kiefner[4] conducted a series of burst tests of corroded pipes which demonstrated the applicability of the NG-18 surface flaw equation to predicting the remaining strengths of such pipes. The applicability of this approach to the analysis of corroded pipe was further substantiated in a program of research conducted by British Gas (Shannon, Reference 5). From the work of Reference 4, the B31G criterion was derived.

Basis of the B31G Criterion

Basic Equation

The B31G criterion is based upon Equation (1) which is explained in Reference 2.

$$S = \bar{S} \left[\frac{1 - A/A_o}{1 - (A/A_o)(M^{-1})} \right] \qquad (1)$$

*Numbers in parenthesis refer to References on Page 48.

where

- M is the "Folias" factor, a function of L, D, and t
- S is the hoop stress level at failure, psi
- $\overline{S}$ is the flow stress of the material, a material property related to its yield strength, psi
- A is the area of crack or defect in the longitudinal plane through the wall thickness, in^2
- A_o is Lt, in^2
- L is the axial extent of the defect, inches
- t is the wall thickness of the pipe, inch
- D is the diameter of the pipe, inches..

Equation (1) is used to calculate the failure stress level of a pressurized pipe containing a longitudinally oriented crack or defect. It is also used to predict the remaining strength of corroded pipe where the parameters of the metal loss are handled as shown in Figure 1. The overall axial length of the corrosion is taken as L even if the corrosion is an array of pitting not necessarily lined up along an axial line. The projection of the pitted profile onto the axially oriented plane through the wall thickness as shown in Figure 1 yields the area, A, to be used in Equation (1). The maximum depth of a corroded area, d, as shown in Figure 1 does not appear in Equation (1) but is used in the analysis of corroded pipe as will be shown.

The *use* of L and A as defined in Figure 1 for an array of pits tends to result in a conservative assessment of the remaining strength for several reasons. First, corrosion pits are seldom lined up along an axial line as assumed in the use of Equation (1). When they are not so lined up, Equation (1) will tend to underestimate the remaining strength. If a reliable method to account for this misalignment existed, it could be used to reduce this aspect of the conservatism of Equation (1) with respect to the analysis of corroded pipe. So far, however, none has been developed. Thus, in the present effort to modify the B31G criterion, no attempt was made to change this aspect of the analysis.

Secondly, corrosion pits are blunt defects compared to cracks and many other kinds of flaws found in line pipe. It has been demonstrated that blunt surface flaws have appreciably higher failure stress levels than sharp surface flaws. Thus, Equation (1) which was developed on the basis of burst tests involving relatively sharp flaws will tend to give conservative predictions for the effects of blunt flaws. This aspect of the conservatism is built into the B31G method and has not been changed in the modified approach described herein.

Factors influencing the conservatism of Equation (1) which have been addressed in this project are the flow stress, $\bar{S}$, and the "Folias" factor, M. First, however, the assumptions which resulted in the original B31G criterion are discussed.

Assumptions Embodied in the B31G Criterion

In adapting Equation (1) to predicting the remaining strength of corroded pipe, the following assumptions were made. First, the Folias factor M was represented as follows

$$M = \left[1 + \frac{0.8L^2}{Dt} \right]^{1/2} \tag{2}$$

Secondly, the flow stress of the material, $\bar{S}$, was taken as 1.1 SMYS where SMYS is the specified minimum yield strength of the material. As noted above, both of these assumptions resulted in built-in conservatism.

To simplify the evaluation of corroded pipe, the area of metal loss, A, was represented by a parabola as shown in Figure 2. This permits one to calculate A on the basis of two simple parameters of the metal loss, its overall length, L, and its maximum depth, d. The resulting area, A, is equal to (2/3)Ld. A_o, of course, is Lt.

The format of Equation (1) as used in the B31G criterion is

$$S_f = 1.1\ \text{SMYS} \left[\frac{1 - (2/3)(Ld/Lt)}{1 - (2/3)(Ld/Lt)M^{-1}} \right]$$

$$= 1.1\ \text{SMYS} \left[\frac{1 - (2/3)(d/t)}{1 - (2/3)(d/t)(M^{-1})} \right] \tag{3}$$

$$M = \left[1 + \frac{0.8L^2}{Dt} \right]^{1/2} \tag{2}$$

Factor of Safety

Equation (3) predicts the hoop stress level which will cause the failure of a corroded pipe with diameter, D, wall thickness, t, and minimum yield strength, SMYS, where the metal loss has an axial length L and a maximum depth of d. Sound engineering judgement requires that corrosion should not be allowed to reach a size (L and d) so large that the predicted failure stress level is at or below the maximum operating stress level. Therefore, a factor of safety must be applied to Equation (3). The basis for the factor of safety consists of the reasonable requirement that the failure stress level, S_f, not be less than 100 percent of SMYS. In that manner, the acceptance or rejection of corroded areas by the criterion would embody the same factor of safety as a hydrostatic test of the pipeline to 100 percent of SMYS. For those pipelines in which the maximum operating stress level does not exceed 72 percent of SMYS, the factor of safety embodied in the B31G criterion (not considering any other built-in conservatism of which there is some) is 100/72 = 1.39.

Formats and Limitations of the B31G Criterion

Evaluating a Corroded Region

A given corroded region in a pipeline is evaluated on the basis of its maximum length, L, and maximum depth, d, via a transformation and combination of Equations (2) and (3). Letting

S_f = 1.0 SMYS in accord with the requirement for a factor of safety as discussed above, one can solve Equation (3) for M in terms of d/t because the SMYS terms on both sides of the equation cancel one another.

$$M = \frac{d/t}{1.1(d/t) - 0.15} \tag{4}$$

Next, observing that the right hand side of Equation (4) can be set equal to the right hand side of Equation (2), one can solve for L in terms of d, t, and D.

$$L = 1.12 \left[\left(\frac{d/t}{1.1\ d/t - 0.15}\right)^2 - 1\right]^{1/2} [Dt]^{1/2} \tag{5}$$

The corroded area L is acceptable if L is less than or equal to the value given by Equation (5).

The B31G document provides tables of acceptable lengths of corroded areas. Alternatively, the B31G document provides the relationship shown in Figure 3 and the equation

$$L \leq 1.12\ B\sqrt{Dt} \tag{6}$$

as a means of evaluating a given anomaly.

Pits with depths greater than 0.8 of the wall thickness are not permitted because of the chances that very deep pits would develop leaks even though the criterion predicts that they will not cause ruptures. Because the parabolic representation becomes less and less an accurate representation of the actual area of metal loss as the length increases, the use of B values greater than 4.0 is not permitted. A value of B equal to 4.0 corresponds to a d/t of 0.175. Anomalies with depths in terms of d/t greater than 0.125 but less than 0.175 are not allowed to have lengths exceeding $4.0\sqrt{Dt}$. Anomalies of depths in terms of d/t less than or equal to 0.125* may be of unlimited length since

*This is permitted only for cases in which the remaining wall thickness is 0.875 times the nominal wall thickness, t, used in the design of the pipeline. If the remaining thickness is less than 0.875 t, the anomaly should be treated as if its depth were the measured depth plus the amount of metal not present because the pipe was under thickness to begin with.

such cases would be expected to have the same remaining strength as a pipe which just meets the minimum wall thickness requirement (for some grades of API line pipe).

Calculating a Reduced Operating Pressure Level

The B31G criterion provides that if L exceeds the allowable length, an acceptable reduced operating pressure may be calculated by keeping the factor of safety equal to 1.39. The reduced operating pressure is defined as follows on the basis of Equation (3)

$$SMYS = 1.1\ SMYS \left[\frac{1 - (2/3)(d/t)}{1 - (2/3)(d/t)(M^{-1})} \right] \quad (3)$$

For the left hand side of the equation, it is desired that the new (reduced) operating pressure, P', shall be related to SMYS by a factor of safety, F_s. Thus,

$$SMYS = \frac{P'DF_s}{2t} \quad . \quad (7)$$

For the right hand side of the equation, it is convenient to express the SMYS term in terms of the original design pressure, P,

$$SMYS = \frac{PD}{2tF} \quad (8)$$

where F is the design factor as defined for the appropriate class location in the B31.8 code.

Making appropriate substitutions into Equation (3) one gets

$$\frac{P'DF_s}{2t} = \frac{1.1\ PD}{2tF} \left[\frac{1 - (2/3)(d/t)}{1 - (2/3)(d/t)(M^{-1})} \right] \quad (9)$$

If one further requires that F_s = 1.39 (the desired factor of safety) and observes that F = 1/1.39 for a Class 1 location, one gets

$$P' = 1.1\ P \left[\frac{1 - (2/3)(d/t)}{1 - (2/3)(d/t)(M^{-1})} \right] \quad (10)$$

This equation is embodied in a set of curves in the B31G document*. It permits the calculation of reduced pressure levels in the event that the length of the corroded area is found to be unacceptable via Equation (6) Because of the previously mentioned inadequacy of the parabolic approximation of a long corroded area, Equation (10) is used only for B values less than or equal to 4.0. When B is greater than 4.0 the 2/3 factor on Ld is converted to 1.0 (a rectangular rather than a parabolic representation) and M is assumed to approach infinity. The result is that P' is calculated as follows for such cases.

$$P' = 1.1\ P\ [1 - d/t] \qquad (11)$$

except that P must be less than or equal to P

Limitations of the B31G Criterion

A number of limitations on the use of the B31G criterion are stated in the B31G document. One limitation which is reconsidered in this report is that the criterion is not to be applied to anomalies in welds of any kind. As will be discussed, the modified approach presented in this report can be applied to corrosion anomalies in submerged-arc seam welds. In addition, no provision is included for the consideration of interaction of corroded areas which do not touch but are separated by small islands of full or near full wall thickness pipe.

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*In the B31G document, the M value is shown as $(1 + Q^2)^{1/2}$ because one must calculate $Q = 0.893L/\sqrt{Dt}$ use the curves.

DEVELOPMENT OF A MODIFIED CRITERION

The rationale for developing a modified criterion for evaluating corroded pipe is that as a result of excess conservatism embodied in the original B31G criterion, too much serviceable pipe is being removed during rehabilitation efforts. For the sake of optimizing safety, it is better to concentrate rehabilitation efforts on the portions of the systems which truly need repair as soon as possible rather than stretch out rehabilitation efforts to meet a criterion known to contain an unnecessarily large margin of safety. To obtain the desired improvement in the criterion; the sources of excess conservatism and the serious limitations of the original approach were reconsidered as described below.

Sources of Excess Conservatism

The sources of excess conservatism in the original B31G criterion are

- The expression for flow stress
- The approximation used for the Folias factor
- The parabolic representation of the metal loss (as used within the B31G limitations)
- The inability to consider the strengthening effect of islands of full thickness or near full thickness pipe at the ends of or between arrays of corrosion pits.

Modified Flow Stress

It was known even when the original B31G criterion was developed that 1.1 SMYS substantially underestimates the flow stress of a line-pipe material. In Reference 2. it was clearly demonstrated that

yield strength + 10,000 psi closely approximates the flow stress. Even if one takes yield strength to be SMYS, this latter value would exceed the 1.1 SMYS value for all available grades of line pipe.

The effect of this difference is illustrated as follows for three common grades of line pipe.

Grade	1.1 SMYS	SMYS + 10,000	Percent Difference (based upon 1.1 SMYS)
B	38,500	45,000	16.9
X52	57,200	62,000	8.4
X60	66,000	70,000	6.2

The effect diminishes with increasing yield strength but is significant for the lower strength grades which are the ones most likely to be rehabilitated at the present time. Incidently, the effect on remaining strength is direct. That is, in Equation (1), the predicted failure stress level (or remaining strength) is a linear function of the flow stress. For the modified criterion, then, the value of flow stress will be taken as SMYS + 10,000 psi.

Modified Folias Factor

The two-term approximation for M, the Folias factor, used in the original B31G criterion has been presented herein in Equation (2). A more exact and less conservative approximation of MT is as follows. For values of $(L^2/Dt) \leq 50$:

$$M_T = \left[1 + 0.6275 \frac{L^2}{Dt} - 0.003375 \frac{L^4}{D^2 t^2}\right]^{1/2} . \qquad (12)$$

For values of $(L^2/Dt) > 50$

$$M_T = 0.032(L^2/Dt) + 3.3. \qquad (12a)$$

The alternate form of MT is illustrated in Figure 4. It is needed for very long anomalies because the negative term of the three-term series starts to dominate and the three-term approximation is no longer valid

beyond the stated limit. It is derived by extrapolating the MT versus L^2/Dt relationship by means of a straight line tangent to the curve Of Equation (12) at $L^2/Dt = 50$.

A comparison of the three-term M to the old two-term M for 30-inch O.D. by 0.375-inch wall pipe is as follows.

Flaw Length, inches	Two-Term M	Three-Term M_T	Percent Difference (based on two-term M)
2	1.1333	1.1058	2.5
5	1.6670	1.5420	7.7
10	2.8480	2.5122	12.0

Because the remaining strength of the pipe is not a linear function of M, the effect of changing M is smaller than these differences imply. For example, the remaining strengths for the same pipe geometry and flaw lengths for 50 percent through-the-wall rectangular defects in a material having a flow *stress* of 62,000 psi are as follows.

Flaw Length, inches	Two-Tens M	Three-Term M	Percent Difference (based upon two-term M value)
2	55,444	56,586	2.1
5	44,248	45,875	3.7
10	37,580	38,703	3.0

Thus, the three-term M gives higher (less conservative) predictions of remaining strength but only on the order of 3 percent higher.

Modified Representation of Metal-Loss Area

Parabolic Area (Original B31G Criterion). The exact area Of metal loss as portrayed in Figure 1 is difficult to represent in terms of simple geometric shapes definable by maximum length and depth. Two shapes which were considered in the development of the original B31G criterion were the rectangle (A = Ld) and the parabola (A = 2/3Ld). On

the basis of the 47 burst tests of corroded pipe presented in Reference 4, it was easily shown that the parabolic method was preferable. Predictions of remaining strength using the rectangular method were too conservative, but those made using the parabolic method as described in the form of Equation (3) consistently underestimated the actual failure stress levels as shown in Reference 4 (Table 4). The ratios of actual-to-predicted failure stress levels range from 1.07 to 3.07. It is apparent that even with the parabolic method, many of the predictions greatly underestimated the strengths of the pipes.

In reality, the parabolic method has significant limitations. Obviously, if the corroded area were very long, the effect of the metal loss would be underestimated and the remaining strength would be over estimated. The fact that the method of Equation (3) underestimated the strengths in all 47 cases is probably the result of circumstances such as the pits not being lined up axially and the deepest areas being separated by islands of greater remaining wall thickness. To prevent misuse of the criterion in cases where long, deep corroded areas might actually have lower strengths than the criterion would predict, the method was limited as described earlier to defects where the B values obtained from Figure 3 are less than or equal to 4.0.

Exact Area. More realistic representations of the metal loss are available if more detailed measurements of the pit depth profile are made. For example, a contour map of pit depths can be made as shown in Figure 5. Then, the "exact" profile can be made by plotting points along the "river bottom" path of the contour map. The profile corresponding to the dashed (river bottom) path in Figure 5 is shown in Figure 6.

Figure 6 presents 16 L values to illustrate the possible methods of predicting the remaining strength of a corroded region based upon detailed profile measurements. First, one could consider the total area within the entire length, L_{16} of the corroded region. The area is calculable by means of summing up all of the areas of the trapezoids formed by the discrete depth measurement points. If the discrete

points, d_i, are evenly spaced with an interval of x as shown in Figure 6, the total area is defined as

$$A = 1/2\ (d_0x + d_1x) + 1/2\ (d_1x + d_2x) + \ldots + 1/2\ (d_{n-1}x + d_nx) \quad (13)$$

If the end values d_0 and d_n, are zero,

$$A = x \sum_{i=1}^{i=n-1} d_i = n \times d_{avg} = L_{total}\ d_{avg} \quad (14)$$

Thus, the exact area is being represented by a rectangular area which is the product of the total length times the average depth. With the parameters L_{total} and d_{avg} thus defined, one can use Equation (12) to calculate MT based upon L_{total} and Equation (1) to calculate S_f. Note that A/A_o in Equation (1) becomes d_{avg}/t.

Equivalent Area. A second method (more accurate than the parabolic method) of analyzing the remaining strength on the basis of the profile shown in Figure 6 is called the equivalent length method. In this method, the metal-loss area, A, is defined as

$$A = L_{eq}d = L_{total}\ d_{avg} \quad (15)$$

where d is the maximum depth. In this method, the area is identical to that of the total length method but L_{eq} is used as the length instead of L_{total}.

$$L_{eq} = L_{total}\ (d_{avg}/d)\ . \quad (16)$$

In this case, the area of the defect is being represented by a rectangle $L_{eq}d$. L_{eq} is used in Equation (12) to calculate MT and Equation (1) is used to calculate S_f. Note that A/A_o in Equation (1) becomes d/t.

Effective Area. A third more accurate method to predict the remaining strength involves calculations based upon various subsections of the total area of metal loss. For example, one could calculate 16 different predicted failure pressures based upon the profile shown in Figure 6. Each calculation involves the length, L_i where i varies from

1 to 16. The area of each individual flaw is calculated as the sum of the areas of the trapezoids made up by the discrete depth points within L_i. The area of each is slightly more than $L_i d_{avg}$ because the end-point d values are nonzero. The procedure usually, though not always, results in a minimum predicted failure stress that is less than the value corresponding to the exact-area total-length method. This method is referred to as the "effective area" method. It is based upon the effective area and effective length of the defect and is embodied in the software developed as a part of this project.

The calculation of remaining strength via one or more of these more exact methods tends to give predictions that are in better agreement with actual burst-test results than those made using the parabolic representation of metal loss. However, there is no fixed relationship between the results predicted by the various methods. Furthermore, as will be shown, there is merit to retaining a representation of a corroded region based solely upon its overall length and maximum depth in the criterion while permitting the use of more exact methods. As a result, the excess conservatism that may be associated in some cases with the use of the parabolic method or any other method based solely on overall length and maximum depth cannot be arbitrarily eliminated.

A final point that must be made with regard to any type of profile representation of metal loss is that some excess conservatism will always be present when the deepest parts of the corrosion are not lined up along the axis of the pipe and when deeper portions of the pitting are separated by islands of greater remaining wall thickness. Within the present state of technology, it is not practical to deal analytically with these variables.

Appendix A provides a guide for making more exact measurements of metal loss in the typical case where the deepest portions of the corrosion do not all lie on the same axial line.

Format of the Modified Criterion

Equation for Allowable Length of Corrosion

Development of the modified criterion begins as the original criterion begins, namely, with Equation (1) which, for convenience, we restate here as Equation (17).

$$S_f = \bar{S} \left[\frac{1 - A/A_o}{1 - (A/A_o)(M_T^{-1})} \right] \tag{17}$$

In the new criterion, MT is the three-term Folias factor as defined in Equation (12) for $L^2/Dt \leq 50$.

$$M_T = \left[1 + 0.6275 \frac{L^2}{Dt} - 0.003375 \frac{L^4}{D^2t^2} \right]^{1/2} \tag{12}$$

and Equation (12a) for $L^2/Dt > 50$

$$M_T = 0.032(L^2/Dt) + 3.3. \tag{12a}$$

To arrive at a format for determining allowable values of L, some substitutions and transformations of Equations (12) and (17) are necessary. First, we let S_f = SMYS and $\bar{S}$ = SMYS + 10,000. Then, if we define q as

$$q = \frac{\text{SMYS} + 10000^*}{\text{SMYS}} \tag{18}$$

we can solve Equation (17) for MT

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*Note that this assumption means that we are defining the allowable axial length of a corroded area such that for a given A/A_o ratio, all anomalies as short as or shorter than the allowable value would be expected fail at stress levels of 100 percent of SMYS or more. The implications of this assumption are discussed in more detail starting on Page 18.

$$M_T = \frac{(-1/q)(A/A_o)}{1 - A/A_o - 1/q} \tag{19}$$

Next we can set the right side of Equation (12) equal to the right side of Equation (19) and solve for L. The fourth order equation yields four roots, of which only one is the valid solution for L we are seeking, namely

$$L = \sqrt{Dt}\left[92.963 - \left[(92.963)^2 + 296.296\left(1 - \frac{(1/q)^2(A/A_o)^2}{(1 - A/A_o - 1/q)^2}\right)\right]^{1/2}\right]^{1/2} \tag{20}$$

for values of $L \leq \sqrt{50Dt}$ For values of $L \geq \sqrt{50\ Dt}$, use

$$L = \sqrt{Dt}\left[\frac{31.25(-1/q)(A/A_o)}{1 - A/A_o - 1/q} - 103.125\right]^{1/2} \tag{20a}$$

Allowable lengths of corrosion are those which are less than or equal to L as defined in Equation (20) or (20a). It is recalled that with the parabolic representation of area $A = 2/3\ Ld$, A/A_o becomes $2/3(d/t)$ in the original criterion. As will become apparent in subsequent sections of the report, it is not prudent to use the parabolic representation in the new criterion The most appropriate area representation is the effective area arrived at by iteration as defined on Page 13. To define the effective area, however, one must calculate the minimum failure pressure and define the effective length. Hence, there would be no need for Equation (20) in such a case However, one can also use exact area and total length as described previously or a geometric representation of the anomaly For single long-hand calculations and for the purposes of tables and curves it becomes appropriate to use a geometric shape approximation in which A is $0.85dL$ and A/A_o is $0.85d/t$. The choice of

0.85 dL for A is arbitrary as was the choice of 2/3 dL in the original criterion. Without the other changes (i.e., flow stress and to the Folias factor) this new area representation would be more conservative than the parabolic representation. However, the 0.85 dL value becomes a reasonable choice because it has wider applicability than the parabolic representation. In particular it can be used safely to analyze much longer flaws than the parabolic representation. As a result, the restrictive limits associated with the existing B31G criterion which require reverting to remaining thickness to determine a reduced pressure level are extended significantly.

The new area representation satisfactorily fits the data from corroded pipe burst tests (as will be shown starting on Page 34) and it provides a better estimate of one particular test result involving a compound machined flaw consisting of a short, deep defect within a long, shallow defect, as will be shown starting on Page 35. Finally, when used with the new value of flow stress and the three-term Folias factor, it is shown to be less conservative than the 2/3dL representation (used with the old value of flow stress and the two-term Folias factor) with respect to limiting the allowable length of corrosion at a 72 percent SMYS operating stress and with respect to calculating reduced allowable operating pressures above 55 percent SMYS. Unlike the 2/3 dL area for which the geometric shape is defined by a parabola, the 0.85 dL area does not correspond to a unique shape. Instead, as will be shown, it is possible to define an arbitrary but reasonable shape.

As with the case of the original criterion, Equation (20) or (20a) should not be used for certain values of A/A_o. A similar situation occurred in the old criterion for a d/t value of 0.136. These values exist because Equation (20) is based upon a failure stress of 100 percent SMYS excluding from consideration the family of small flaws which would fail at stress levels between 100 percent of SMYS and flow stress (SMYS + 10,000). The range of values of A/A_o not allowed for this reason varies with SMYS. For example, it is clear that in dealing with X52 pipe (q = 1.193), a value of A/A_o = 0.1613 would result in the term $(1 - A/A_o - 1/q)$ being zero. For Grade B pipe, the limiting value

of A/A_o in Equation (20), is 0.222. For X60, it is 0.1429. Defects with lower A/A_o values are undefined because they would have failure stress levels in excess of 100 percent of SMYS. As in the original B31G criterion, the cutoff value of d/t at the high end remains 0.8. Defects deeper than 80 percent of the wall thickness should be repaired or removed to prevent leakage.

It is imediately obvious that the new criterion is very difficult to handle in the form shown above. As will be shown, revised curves, tables, and a PC (personal computer)-based format are practically a necessity. Before those options are presented, however, let us consider how one would use the new criterion to calculate a reduced operating pressure.

Equation for Reduced Operating Pressure Level

The format of Equation (17) used to calculate a reduced operating pressure level under the new criterion is derived by letting $S = P'DF_s/2t$ and $\check{S} = PD/2tF + 10{,}000$ where

F_s is 1.39, the factor of safety

F is 0.72, the design factor for a Class 1 location.

Thus

$$\frac{P'DF_s}{2t} = \left[\frac{PD}{2tF} + 10{,}000\right]\left[\frac{1 - A/A_o}{1 - (A/A_o)M_T^{-1}}\right] \tag{21}$$

When Equation (20) is solved for M_T^{-1} (in the form of Equation (19) the new equation for reduced operating pressure becomes

$$P_1' = \frac{P_1\left[1 + \frac{14400t}{P_1 D}\right]\left[1 - A/A_o\right]}{1 - (A/A_o)\left[1 - \frac{(92.963 - L^2/Dt)^2 - (92.963)^2}{296.296}\right]^{-1/2}} \tag{22}$$

For clarity, the variables are defined again here as

P_1' is the reduced operating pressure which would be expected to exceed the failure pressure of the anomaly by a margin of 1.39 to 1: (Values of P_1' which calculate to be larger than P_1 are not valid), psig

P_1 is the operating pressure which corresponds to a stress level of 72 percent of SMYS, psig

D is the outside diameter of the pipe, inches

t is the nominal wall thickness of the pipe (or actual wall thickness, if known), inch

L is the axial extent of the corroded area, inch

A is the area of metal missing in the longitudinal plane through the wall thickness, $inch^2$

A_o is Lt, $inch^2$.

The safe operating pressure, P_1', for values of L which are too large to satisfy Equation (20) are calculated via Equation (22).

One may elect to use the exact area A determined from detailed measurements, or instead one may use the representation of A = 0.85 dL based only upon the maximum depth of the corrosion. In using Equation (22) please note that P_1' must be less than or equal to P_1.

As in the calculation of allowable length, the new criterion for reduced operating pressure is difficult to handle from a long-hand calculation standpoint. Thus, the curves, tables, and PC program presented below become almost a necessity.

Options for Pipelines Designed to Operate at Stress Levels Other Than 72 Percent of SMYS

Equation (22) strictly applies only to pipelines designed to operate at a stress level of 72 percent of SMYS because the value of F in Equation (21) was set at 0.72. One can derive appropriate analogous equations dealing with pipelines operating at other stress levels in one

of two ways*. One may either retain the factor of safety, F_s, of 1.39 or one may elect to let the factor of safety "float" resulting in increased conservatism for operating stress levels below 72 percent of SMYS and a lower margin of safety for operating stress levels above 72 percent. Examples are as follows.

Suppose one chooses to retain a factor of safety of 1.39 and let defect failure pressures vary with the operating stress levels. This means that F_s in Equation (21) remains as 1.39 while F varies. For a Class 2 location, for example, F_2 would be 0.60 and Equation (21) would become

$$\frac{P_2'D\,(1.39)}{2t} = \left[\frac{P_2D}{2t(.60)} + 10{,}000\right]\left[\frac{1 - A/A_o}{1 - (A/A_o)\,M_T^{-1}}\right] \qquad (23)$$

Equation (22) then becomes

(60 percent SMYS operation) $F_s = 1.39$; $F = 0.60$

$$P_2' = \frac{P_2\left[1.2 + \frac{14400t}{P_2D}\right]\left[1 - A/A_o\right]}{1 - (A/A_o)\left[1 - \frac{(92.963 - L^2/Dt)^2 - (92.963)^2}{296.296}\right]^{-1/2}} \qquad (24)$$

For other operating stress levels such as $F_3 = 0.50$, $F_4 = 0.40$, and $F_0 = 0.80$ the corresponding equations for reduced pressure are

(50 percent SMYS operation) $F_s = 1.39$; $F = 0.50$

$$P_3' = \frac{P_3\left[1.44 + \frac{14400\,t}{P_3D}\right]\left[1 - A/A_o\right]}{1 - (A/A_o)\left[1 - \frac{(92.963 - L^2/Dt)^2 - (92.963)^2}{296.296}\right]^{-1/2}} \qquad (25)$$

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*Note: It is not necessary to have equations such as Equation (22) or those which follow if one elects to use the effective-area method to calculate failure pressure. This will be explained later in the report.

(40 percent SMYS operation) F_s = 1.39; F = 0.40

$$P_4' = \frac{P_4 \left[1.8 + \frac{14400\ t}{P_4 D} \right] \left[1 - A/A_0 \right]}{1 - (A/A_0) \left[1 - \frac{(92.963 - L^2/Dt)^2 - (92.963)^2}{296.296} \right]^{-1/2}} \tag{26}$$

(80 percent SMYS operation) F_s = 1.39; F = 0.80

$$P_0' = \frac{P_0 \left[0.9 + \frac{14400\ t}{P_0 D} \right] \left[1 - A/A_0 \right]}{1 - (A/A_0) \left[1 - \frac{(92.963 - L^2/Dt)^2 - (92.963)^2}{296.296} \right]^{-1/2}} \tag{27}$$

Considering the other option where one chooses to let the factor of safety float and to hold the failure stress level of the anomalies constant at 100 percent of SMYS, one arrives at the following equations.

(60 percent SMYS operation) F_s = 1.67; F = 0.60

$$P_2'' = \frac{P_2 \left[1 + \frac{12000\ t}{P_2 D} \right] \left[1 - A/A_0 \right]}{1 - (A/A_0) \left[1 - \frac{(92.963 - L^2/Dt)^2 - (92.963)^2}{296.296} \right]^{-1/2}} \tag{28}$$

(50 percent operation) F_s = 2.00; F = 0.50

$$P_3'' = \frac{P_3 \left[1 + \frac{10000\ t}{P_3 D} \right] \left[1 - A/A_0 \right]}{1 - (A/A_0) \left[1 - \frac{(92.963 - L^2/Dt)^2 - (92.963)^2}{296.296} \right]^{-1/2}} \tag{29}$$

(40 percent SMYS operation) F_s = 2.50; F = 0.40

$$P_4'' = \frac{P_4 \left[1 + \frac{8000\ t}{P_4 D} \right] \left[1 - A/A_0 \right]}{1 - (A/A_0) \left[1 - \frac{(92.963 - L^2/Dt)^2 - (92.963)^2}{296.296} \right]^{-1/2}} \tag{30}$$

(80 percent SMYS operation) F = 1.25; F = 0.80

$$P_0^* = \frac{P_0 \left[1 + \frac{16000\ t}{P_0 D} \right] \left[1 - A/A_0 \right]}{1 - (A/A_0) \left[1 - \frac{(92.963 - L^2/Dt)^2 - (92.963)^2}{296.296} \right]^{-1/2}} \qquad (31)$$

PC Format

A software package has been developed for pipeline operators to use in order to simplify the necessary calculations embodied in the modified B31G criterion. Repetitive calculations using the long-hand solutions of Equation (17) could be done to define the effective area but this would prove to be very time consuming. The PC program makes the calculations quickly, defines the effective area, and provides documentation of the anomaly.

As mentioned above, the PC program uses the three-term Folias factor (or the extended version of Equation (12a)), a flow stress of SMYS + 10,000* psi, detailed measurements, and an iterative calculation method to determine the minimum predicted failure pressure based on an effective area (CASE 1). The PC program also performs two additional calculations. One uses the three-term Folias factor (or the extended version of Equation (20a), a flow stress of SMYS + 10,000 and the 0.85 dL area representation (CASE 2). The other uses the two-term Folias factor, a flow stress of 1.1 SMYS and the parabolic area representation (CASE 3). This case corresponds to the previous B31G analysis method.

Because the PC format calculates the above-mentioned three cases of failure pressure with no factor of safety included, the user has a great deal of flexibility regarding how the answer is used. All one has to do is define the desired factor of safety, F_s to determine the "safe" operating pressure, P_{allow}. If P_{allow} is greater than or equal to the MAOP (maximum allowable operating pressure), the corroded

*An option of using flow stress as actual yield plus 10,000 psi is available. This option is useful for comparing predictions with burst-test results as is done herein for the 80 burst tests

region is acceptable. If P_{allow} is less than the MAOP, the pressure should be reduced to P_{allow} or the corroded region should be repaired or replaced. The pipeline operator must decide what constitutes an acceptable F_s. Also, since an alternate MT for $L^2/Dt > 50$ exists in the CASE 1 and CASE 2 formats, there is no limit on the L value with which one can make the CASE 1 and CASE 2 calculations*.

A disk containing this PC program called "RSTRENG" can be found in the back cover of this report. A manual for using RSTRENG can be found in Appendix B. Example calculations will be covered in a subsequent section of the report.

Revised Curves and Tables

The existing B31G document contains a B versus d/t curve as shown in Figure 3 based upon a parabolic representation for the corroded area. The analogous curve for the new criterion along with the old criterion is shown in Figure 7 for a 30-inch O.D. by 0.375-inch X52 material. Note that the old allowable length L is given by

$$L \leq 1.12\ B_1 \sqrt{Dt}$$

where B_1 is the B value from the old curve in Figure 7 and that the new allowable length L is given by

$$L \leq B_2 \sqrt{Dt}$$

where B_2 is the B value from the new curve in Figure 7. Also, note that with the new criterion, unlike with the old criterion, it is necessary to have a separate curve for each grade of material. This is because of the fact that the new definition of flow stress is not simply proportional to SMYS. A table of allowable lengths for the same pipe material under the new criterion is shown as Table 1. This table is for Grade X52 only; the new criterion necessitates a table for each grade. A set of curves and tables for the new criterion is presented in

*CASE 3 calculations are automatically flagged to the user's attention when L^2/Dt exceeds 20. In such instances, the calculation is based upon the assumption that the flaw is infinitely long and everywhere as deep as the maximum depth.

Appendix C for Grades B, X52, and X60 and pipe diameters of 24, 30, and 36 inches

Analysis of Corroded Areas Having Depths Not More Than 20 Percent Through the Wall

Shannon[5] of British Gas proposed a "no-failure" boundary for corroded pipe which can be used to define the depth of pitting below which failure is not a concern in a pipeline operating at a given maximum stress level. The "no-failure" boundary was developed from Equation (1) and was validated by British Gas using their own and early A.G.A. corroded pipe burst tests. It is in fact derived from Equation (1) by letting A/A_0 equal d/t (true for a rectangular flaw), MT approach ∞, and Š be 1.15 SMYS. Hence,

$$S = 1.15\ SMYS\ (1 - d/t) \tag{32}$$

The failure stresses of all corroded pipe tested up to that time exceeded S regardless of the length of the corrosion. As shown *in* Figure D-I of Appendix D (a plot of S/SMYS versus 1-d/t), the results of all 86 burst tests in A.G.A. data base satisfy Equation (32) also.

For pipelines operating at stress levels not exceeding 72 percent of SMYS, it would seem acceptable to say that S should not be less than 90 percent of SMYS. Setting S = 0.9 SMYS in Equation (32) and solving for d/t, one finds that d/t = 0.217. Therefore, it is reasonable to state that a pipeline containing corrosion not exceeding 20 percent of the wall thickness can be safely left in service regardless of the length of the corrosion as long as the operating stress level does not exceed 72 percent of SMYS and as long as the remaining wall thickness is at least 80 percent of that required by the design stress level.

Comparison of the Old and the New Criteria

Comparisons of the old and the new criteria are made in several ways as illustrated below. These examples also provide

information on the advantages and limitations of both criteria. The example problems all involve 30-inch O.D. by 0.375-inch wall X52 pipe. Nine cases are considered as described below.

Case	Flaw Shape	Flaw Length	Maximum Depth (percent of wall)
1	Rectangular	10	50
2	Rectangular	3	50
3	Rectangular	2	50
4	Parabolic	10	50
5	Parabolic	3	50
6	Parabolic	2	50
7	0.85dL	10	50
8	0.85dL	3	50
9	0.85dL	2	50

The maximum flaw depth in every case in 187 mils. For the rectangular flaws, the depth is uniform. For the parabolic flaws, the depth is 187 mils at the center (0.51) and zero at the ends. The depths of the intermediate points are defined as follows: 67 mils at 0.1L and 0.9L, 120 mils at 0.2L and 0.8L, 157 mils at 0.3L and 0.7L, and 180 mils at 0.4L and 0.6L. For the new area representation, the maximum depth is 187 mils at the center (0.5L) and zero at the ends. The depths at the intermediate points are defined as follows:

83 percent of maximum depth at 0.1L and 0.9L

95 percent of maximum depth at 0.2L and 0.8L

98 percent of maximum depth at 0.3L and 0.7L

99 percent of maximum depth at 0.4L and 0.6L.

The resulting depths are 155 mils at 0.1L and 0.9L, 178 mils at 0.2L and 0.8L, 184 mils at 0.3L and 0.7L, and 185 mils at 0.4L and 0.6L.

Evaluating Allowable Lengths

First we will treat these samples cases as if we only know the maximum lengths and maximum depth. In this situation, all three shapes will be considered based on the parabolic shape in the old criterion and

based on the new area representation in the new criterion. Using Figure 7 one follows the vertical line at d/t = 0.5 until it intersects both curves. The corresponding B_1 value via the old criterion is 0.75. This results in an allowable length of 2.82 inches (allowable L = 1.12 $B_1\sqrt{Dt}$). By the old criterion, then, only the 9-inch flaws of Cases 3, 6, and 9 would be permitted. The B_2 value via the new criterion is 1.152* This results in an allowable length of 3.86 inches (allowable L = $B_2\sqrt{Dt}$) Thus, by the new criterion not only would Cases 3, 6, and 9 be acceptable, but Cases 2, 5, and 8, the 5-inch flaws, would also be acceptable. Only Cases 1, 4, and 7 fail to pass both criteria.

Evaluating Safe Operating Pressures

Next, we will calculate safe operating pressures for the 3-inch flaws via the old criterion and for the 10-inch flaws via both criteria. In each case, the flaws were too long to allow the pipeline to continue to operate at 72 percent of SMYS. For this we turn to Figure 8, a plot of Q versus d/t for both the new and the old criteria. Note that we must deal with a specific curve for Grade X52 pipe because of the definition of flow stress in the new criterion. This was not necessary for the old criterion. To use the old criterion, we calculate $Q_1 = 0.893\ L/\sqrt{Dt}$. $Q_1 = 0.799$ for Cases 2, 5, and 8 and $Q_2 = 2.662$ for Cases 1, 4, and 7. Since both Q_1 and Q_2 are less than 4, one can use

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*Note that when the arbitrary 0.85 dL representation is used the upper limit on B_2 is not 4 as in the old criterion. The limit on B_2 is for practical purposes set at 10 because as mentioned earlier, Equations (20) and (20a) become undefined for the families of small flaws which have failure stress levels above 100 percent of SMYS. In using the new criterion, one must use a value of 10 if the calculated B exceeds this amount. This corresponds to a d/t level of about 0.30 for Grade B, 0.22 for Grade X52, and 0.20 for Grade X60. However, it is clear from the previous analysis involving Equation (32) that corrosion pits which are not more than 20 percent through the wall can be safely left in service regardless of their length for pipelines operating at stress levels not exceeding 72 percent of SMYS. Therefore, for those few cases in which d/t lies between 0.20 and 0.30 for Grade B and 0.20 and 0.22 for Grade X52, it is recommended that B_2 be set at 10 when one is using the 0.85dL calculation.

the $(P'/P)_{old}$ curves of Figure 8. If this had not been the case, one would have had to revert to Equation (11). Using Figure 8, one follows the vertical line at d/t = 0.5 until it reaches the horizontal lines at $Q_1 = 0.799$ and $Q_2 = 2.662$. The intersection of Q_1 and d/t = 0.5 lies between the old $(P'/P)_{old}$ curves of 0.9 and 1.0. This results in an estimated $(P'/P)_1 = .99$. Therefore, $P_1' = 927$ psig. The intersection of $Q_2 = 2.662$ and d/t = 0.5 lies between the old 0.8 and 0.9 curves. $(p'/p)_{old}$ is about 0.83 which corresponds to a safe operating pressure of 777 psig based upon $P \doteq 936$ psig.

To perform a similar operation for Cases 1, 4, and 7 under the new criterion, one must calculate a value of $Q_3 = L/\sqrt{Dt} = 2.981$ and use the $(P'/P)_{new}$ curve of Figure 8. Using Figure 8, one follows the vertical line at d/t = 0.5 until it intersects a value of $Q_3 = 2.981$. This point lies between the new curves of 0.8 and 0.9. One can then extrapolate a value of $(P'/P)_{new} = 0.83$ which corresponds to an allowable pressure of 777 psig based upon P = 936 psig.

The fact that the calculated safe pressure for the lo-inch flaws is the same for both criteria is more than a coincidence. As one can see from Figure 8, the safe pressure levels for the new criterion start out higher for a given flaw size at the relatively high pressure levels (i.e., P'/P > 0.8) but end up lower for a given flaw size at relatively low pressure levels (i.e., P'/P c 0.8). At P'/P = 0.8, the safe pressures are about the same for a given flaw size. The old criterion is excessively conservative at failure stress levels of about 90 percent of SMYS, about right at failure stress levels of 80 percent of SMYS and inadequately conservative at low failure stress levels. Since it is generally applied to exclude corrosion which will fail at or below 100 percent of SMYS, this situation has not created any problems. The new criterion is more adequate over the entire range of evaluation and certainly adequately conservative in the 100 percent of SMYS range where it will be used the most.

Note that with both the old and the new criteria, the actual flaw shape is immaterial. For both sets of curves, the calculations utilize only the maximum length andmaximum depth.

Analysis of the Examples Using RSTRENG

Using Equation (17) repetitively, one could determine the effective area of a corrosion anomaly and calculate an allowable length or, alternatively, a safe operating pressure. Given the complexity of iteration by hand, however, it is much easier to use Equation (17) via RSTRENG to calculate the effective area that gives the minimum failure pressure level of the flaw and then see whether or not it exceeds the maximum operating pressure level by the pipeline operator's designated factor of safety.

As an example of how one uses RSTRENG, let us consider the 10-inch rectangular flaw (Case 1) covered in the previous comparisons of the old and the new criteria. The output format for the calculation is shown in Figure 9. After calling up RSTRENG, entering the file name, choosing the 'INPUT" option (see Appendix B for the detailed "user's manual"), and selecting either the "PIT DEPTH" or the "REMAINING WALL THICKNESS" option, one inputs 'SPECIMEN IDENTIFICATIONS (Rectangular - 10") and a "COMMENT" (if desired). Next, the particulars of the pipe material are entered when indicated by the cursor: DIAMETER = 30.00 in., THICKNESS = 0.375 in., YIELD STRENGTH = 52,000 psi, and SMYS 52,000 psi*.

Next, enter the overall LENGTH of the anomaly (10 inches in this case) and the INCREMENT over which pit depth measurements have been made (1.00 inch in this case). Note that it is not necessary that the measurements be made on any exact grid. One can make pit depth or wall thickness measurements as required by the corroded geometry so as to reflect the worst-case corrosion even if the locations are not exactly at an even spacing. There is very little loss of accuracy when one then

*Note that both yield strength and SMYS are included and may not be the same. The actual yield strength is useful in checking the method against burst-test results, however, since RSTRENG CASE 1 uses actual yield strength, the user should specify the actual yield strength as SMYS to evaluate anomalies in pipelines.

enters the data as if they had been taken on a uniform spacing. The interval of measurement, however, should be chosen judiciously. In our example, a 10-inch flaw, measurements on a 1-inch spacing, even if the actual measurements may be located 1/2 inch off of the uniform grid, will be adequate. If the flaw had been only 2 inches in length, an adequate measurement spacing might have been 1/4 or 1/2 inch. Similarly, in highly irregular areas, it may be desirable to use a finer spacing.

The pit depth measurements in mils are entered as prompted by the cursor and will appear on the screen as entered. After the last measurements have been entered, the data will be written to the designated file. The user can then EDIT the data, INPUT another case, perform ANALYSIS, or QUIT. If ANALYSIS is selected, a screen will appear with the file names of all stored examples. If one moves the cursor to the desired case and evokes a carriage return, the example will be analyzed and CALCULATING will flash on the screen. When the calculation is complete, Screen 1 of Figure 9 will appear. This screen identifies the example, presents some of the inputs to the problem, shows the corroded profile (length versus depth indicated by asterisks), and gives the minimum predicted hoop stress level at failure and the failure pressure. In our example, the depth portrayed on the screen is uniform at 0.180 (the nearest 0.02 inch increment to the actual depth of 0.187 inch) over the 10-inch length. The actual value of 0.187 inch is used in the calculations, however. The predicted failure pressure is 970 psig. The arrows over the 0 and the 10 joined by a dashed line indicate the position of the flaw constituting the "effective" length which gives the minimum predicted failure pressure. In this example, the effective length was the total length, 10 inches.

One uses the CASE 1* minimum pressure of 970 psig as follows. Suppose that a factor of safety of 1.39 is desired. This means that a "safe" operating pressure for this anomaly is 970/1.39 =-698 psig. If

*NOTE: CASE 1 (all uppercase letters) refers to the minimum pressure prediction as opposed to Case 1 (our example calculation).

the MAOP of the pipeline is 698 or less, this anomaly is acceptable. If the MAOP is higher than 698, the operator must lower the pressure to 698 to maintain a factor of safety of 1.39. Similarly, if a factor of safety of 1.67 had been used, the safe pressure would be 970/1.67 = 581 psig.

The user can view Screen 2 (as shown in Figure 9) by evoking PAGE DOWN. This screen shows the original pit depth measurements and presents two additional calculations. CASE 2 is the minimum failure pressure based upon the modified method (three-tern Folias, flow stress of SMYS + 10 000 psi and Area = 0.85 dL). Note that this is not the safe pressure calculable via Equation (22). The safe pressure 1074/1.39 = 773 psig (factor of safety of 1.39). This example shows an extreme case of the weakness in approximate representation of a corroded area. The consideration of the actual area via RSTRENG as opposed to 0.85 dL results in a 10 percent lower value of safe pressure (698 as opposed to 773). In actual practice, however, corrosion does not occur as a uniform depth phenomenon, and the 0.85 dL representation will be adequate.

CASE 3 calculated by RSTRENG represents the failure pressure calculable by the existing B31G criterion (two-tens Folias, flow stress of 1.1 SMYS and Area = (2/3) dL). This is not the safe pressure calculable via Equation (10) or (11). The safe pressure is 1081/1.39 = 773 psig. As with the CASE 2 calculation, the existing B31G method tends to overestimate the strength of a "rectangular" flaw. This has been recognized from the outset of the development of the B31G criterion in 1970. Adequate safeguards have always been present, however, to prevent misuse of the criterion.

Additional examples of the use of RSTRENG are provided in Figures 10 and 11. These represent the 10-inch-long parabolic and 0.85 dL areas of previously discussed examples. In both cases, the "effective" lengths indicated by the arrows are 8 inches instead of the full 10 inches. The CASE 1 minimum predicted failure pressures are 1,160 psig and 1,045 psig, respectively. Also, in both cases the CASE 2

and CASE 3 calculated minimum failure pressures are 1,074 psig and 1,081 psig, the same as for the rectangular example.

Failure pressure levels for all nine cases calculated via RSTRENG on the basis of a 1.39 factor of safety are presented in Table 2. Note that the RSTRENG outputs are the P_f values in Table 2. For rectangular flaws, the effective area is the same as the exact area and the minimum level based on the effective area is the same as that based-on the full length of the flaw. For the cases of the new area representations and the parabolic flaws, however, the effective areas which give the minimum failure pressures are in some cases less than the exact areas.

VALIDATION OF THE METHODOLOGY

The original B31G criterion was validated by means of 47 burst tests of corroded pipe as described in Reference 4. Failure pressures for the 47 test results calculated via Equation (1) using (2/3)dL as the area of the anomaly, the two-term M of Equation (2) and the flow stress equal to 1.1 SMYS ranged from 1.07 to 3.07 times the observed failure pressure. Thus, when used with the factor of safety of 1.39, the original criterion provides more than adequate assurance that anomalies accepted by the criterion will not fail in service. Because the goal of this project is to reduce excess conservatism without creating an unsafe condition, it is necessary to revisit these 47 burst test results and to assess whether or not the modified criterion provides an adequate means of predicting the effects of metal loss on the remaining strength of the corroded pipe. In addition, through efforts of individual companies 39 additional burst test results have been made available for this validation effort.

Predictions of Failure Pressure Via RSTRENG Compared to Burst Test Results

A detailed list of all 86 burst test results including the associated predictions of failure pressure is presented in Appendix D. All predictions of failure pressure used in these comparisons are the minimum values predicted from CASE 1 calculations via RSTRENG. The list contains two groups of tests, tests which resulted in ruptures and tests which resulted in leaks. The distinction is necessary because the method of prediction based upon Equation (1) appears to do a better job of predicting ruptures than it does in predicting leaks. As will be discussed, however, this results from probable experimental measurements errors in the first 4 experiments.

The comparisons of actual to predicted failure pressures for the 41 ruptures are shown in Figure 12. The diagonal line indicates the point of exact agreement between actual and predicted failure pressure. Points which lie above the line represent cases in which the actual failure pressure observed in the burst test exceeded the predicted level indicating that the pipe had greater remaining strength than the methodology based on Equation (1) predicts.

As shown in Figure 12, the burst pressures exceeded the predicted pressures in 38 out of the 41 cases. The three cases in which the predicted levels exceeded the actual levels were Cases 48, 49, and 86 listed in Appendix D. In Case 48 the predicted failure pressure was 785 psig, 6 percent greater than the actual burst pressure of 742 psig. In Case 49, the predicted failure pressure was 813 psig, 3 percent greater than the actual burst pressure of 788 psig. In Case 86, the predicted failure pressure was 844, two percent greater than the actual burst pressure of 828 psig.

The comparisons of Figure 12 provide a high degree of confidence that the RSTRENG methodology used for predicting rupture pressures of corroded pipe can be used to predict safe operating pressure levels for corroded pipe

The comparisons of actual to predicted failure pressures for the 45 leaks are shown in Figure 13. Again, the diagonal line represents exact agreement between actual and predicted failure pressure. In the case of leaks, the predicted failure pressures do not seem to provide a reliably conservative estimate of the actual failure pressures as in the case of ruptures. This situation is thought to be attributable to two circumstances. One is that Equation (1) does not work as well for deep defects as it does for less deep defects. Defects which are more than 80 percent through the wall are prone to develop leakage from local stress conditions in the remaining thickness that are not well described in Equation (1). In addition, it is known that several of the leaks in the original 47 burst tests developed after several cycles of pressurizations indicating that low-cycle fatigue effects may have been a factor*. Also, it is felt that the early data were prone to errors in wall thickness as a result of the pipe being seamless (highly variable thickness) and the fact that because of weld-over repairs of each leak, plaster casts were used to make measurements rather than the pipe itself. In fact, as will be seen in Figure 15 and as discussed below, the predictions of Equation (1) were in much better agreement with the results of leaks in the 39 new burst tests where thickness measurements were taken directly and cyclic pressurizations were avoided. In any case, the method embodied in Equation (1) cannot be expected to reliably predict the development of a leak at a very deep pit (greater than 80 percent of the wall thickness). As a result, the original B31G criterion was not intended to be applied to anomalies having depths greater than 80 percent of the wall thickness. This same limitation should be retained in any modified criterion.

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*In Table D-I of Appendix D, Tests 9 through 24 occurred on successive cycles of pressurization of one sample. Repairs were made after each cycle to close prior leaks. This made it virtually impossible to check final wall thickness after the test. The cyclic pressurizations and the poor documentation of actual thickness are believed to have led to previous misinterpretation of the ability of Equation (1) to predict leaks. Note that except for Tests 37 and 41 which involved flaws exceeding 80 percent of the wall thickness, almost all of the "poor-fit" data in Figure 15 are attributable to the multiple tests on one specimen.

Predictions of Failure Pressures Via Approximate Methods Compared to Exact Area Methods

Recognizing that some pipeline operators will choose to use the approximate methods rather than RSTRENG to evaluate corrosion, we made additional comparisons as shown in Figures 14 and 15. These figures compare failure pressures predicted by RSTRENG (CASE 1) and by two approximate methods, CASE 2 (0.85 dL) and CASE 3 (2/3 dL) to the actual failure pressures in the 86 burst tests. Both the CASE 2 and CASE 3 predictions are based upon the full length, L, of the corroded area and its maximum depth, d. CASE 2 utilizes the new area representation (0.85dL), the flow stress equal to SMYS plus 10,000 psi, and the three-term M. CASE 3 utilizes the parabolic representation (2/3dL), the flow stress equal to 1.1 times SMYS, and the two-term M. Note that in making these predictions of failure pressure, the safety factor has been eliminated so that if perfect agreement existed the points would lie on the line at a value of 1 on the Y-axis of Figures 14 and 15. The format of Figures 14 and 15 differs from that of Figures 12 and 13 because it is desirable to compare the predictions of three methods instead of only one to the actual burst pressures. Also, note that the RSTRENG predictions (CASE 1) in Figures 14 and 15 (as in Figures 12 and 13) are based upon the use of actual yield rather than SMYS.

Figures 14 and 15 reveal that the approximate methods gave consistently conservative estimates of the actual failure pressures. For both CASE 2 and CASE 3, the predictions are consistently more conservative than those of RSTRENG.

The comparison of Figures 14 and 15 show that the approximate methods, one embodied in the current B31G criterion and one proposed for a modified criterion, consistently underestimate the remaining strengths of the corroded pipes. Also, it is noted that the predictions of leaks in Figure 15 tended to overestimate the actual failure pressures most often for the early data where, as mentioned above, the data on wall

thicknesses were less accurate. Predictions for later data, except for two very deep flaws (37 and 41), tended to underestimate remaining strength.

Further Justification for using the Effective-Area Method and 0.85 dL

To examine further the rationale for using the effective area and 0.85 dL as a "modified" B31G approach, let us compare several calculation methods on the basis of a flaw of nonuniform depth. The flaw of interest consists of a defect within a defect as shown in Figure 16. In this situation, the existing B31G criterion requires the use of the maximum length (L_1) and the maximum depth (within the relatively short L_2 region) to determine allowable length or reduced operating pressure. In some cases, this results in an overconservative assessment; in other cases, it results in an underconservative assessment. The point is, the existing criterion of A = 2/3 dL is not adequate for dealing with this kind of defect.

Defect Parameters and Failure Stress Prediction Methods

The geometric parameters of the defect are shown in Figure 16. Also shown are the lengths and areas related to eight candidate types of analysis with respect to predicting the failure stress of the defect. These methods are described below. All are based upon Equation (1). Note that nothing in the analysis requires the deep defect to be centered within the shallow defect. Hence, two defects of unequal depths touching end-to-end may be treated in this manner.

Method 1 - Exact Area. In this method as shown in Figure 16, the length is taken as L_1, and the area is taken as $A = L_1 d_1 + L_2 (d_2 - d_1)$. A_0 is $L_1 t$.

Method 2 - Short, Deep Defect Only. In this case, the long defect is ignored. The defect length is taken as L_2 and the area is taken as $A = L_2 d_2$. A_0 is $L_2 t$.

Method 3 - Short, Deep Defect in a Reduced Thickness Pipe. For this method, the short, deep defect is considered to exist in a pipe the thickness of which is equal to the net thickness beneath the long defect $(t - d_1)$. The length of the defect is L_2 and the area A is $L_2(d_2 - d_1)$. A_0 is $L_2 (t - d_1)$. Because the pipe is assumed to be $(t - d_1)$ in thickness, the hoop stress must be calculated from the Barlow formula using $(t - d_1)$. Hence,

$$s = \frac{P \times R}{(t - d_1)}$$

Method 4 - Equivalent Length, Total (Equivalent) Area. In this method, the entire defect area is considered. That is $A = L_1 d_1 + L_2 (d_2 - d_1)$ as in Method 1, but the length is defined as $L = A/d_2$ or the total area divided by the maximum depth d_2. This method creates for analysis purposes, a single rectangular defect with an area and maximum depth equal to that of the actual defect. A_0 is Lt.

Method 5 - Long, Shallow Defect Only. In this case, the existence of the deep defect is ignored. Length is taken as L_1 and area is $A = L_1 d_1$. A_0 is $L_1 t$.

Method 6 - Effective Area (RSTRENG). In this case, RSTRENG is used to find the minimum failure pressure based on the effective area and length.

Method 7 - Parabolic Area. This is the method currently embodied in the B31G criterion.

Method 8 - 0.86 dL. This is the method recommended to replace the parabolic area when only the maximum length and depth of the defect are known.

Comparisons of the Eight Methods

Comparisons of six of the eight methods for predicting the behavior of a specific case of this type of defect are shown in Figure 17. The figure represents a sensitivity study using the variations on length and area and Equation (1). The pipe material is 36-inch O.D. by 0.400-inch wall X60 (actual flow stress = 73,100 psi). Methods 2 and 5 are not included in these comparisons because upon brief consideration it becomes obvious that neither of these methods is appropriate. In the case of Method 2, the predicted failure pressures would become unrealistically high as the length, L_2, becomes very short. In the case of Method 5, the failure pressure is independent of L_2 and d_2, clearly not a realistic situation. Hence, the following comparisons involve only Methods 1, 3, 4, 6, 7, and 8.

The analyses are summarized in Figure 17. The flaw parameters are as follows. The overall flaw is 13 inches in length. In one region its depth, d_1, is 0.120 inch. Its depth in the other region, d_2, is 0.300 inch. The length of the deeper region, L_2, varies from 0 to 6.5 inches. For the trivial case, $L_2 = 0$, the failure pressure level of the 13-inch-long rectangular flaw with a uniform depth of 0.120 inch is 1,203 psig as predicted by both the exact area method and RSTRENG. As L_2 becomes nonzero, the failure pressures predicted by both Method 1, the exact-area method and Method 6, the effective-area method, decrease. For L_2 values in excess of 2 inches, the effective-area predictions fall below those of the exact area method. The RSTRENG predictions at higher values of L_2 reflect the observable fact that the behavior of the flaw becomes controlled to an increasing extent by the shorter flaw. It is seen that the failure pressure predicted by the effective-area method (RSTRENG) for the situation in which $L_2 = 6.5$ is 735 psig. This result merely reflects the fact that RSTRENG found the minimum failure pressure to be based on the 6.5-inch-long 0.300-inch-deep effective area, independent of the longer defect.

The one available test result for this type of flaw was obtained on a 36-inch-diameter 0.400-inch wall pipe material with a flow stress level of 73,100 psi. The defect in the specimen was 13 inches in length overall with a centrally located shorter flaw of 6.5 inches in length. The depths, respectively, were 0.120 inch and 0.300 inch. Its failure pressure level was 749 psig. The failure pressure predicted by RSTRENG was 735 psig. Thus, the failure pressure of the test flaw was adequately predicted by the effective-area method but was overestimated by the exact-area method which gave a predicted failure pressure of 910 psig.

Note that the failure pressures predicted by Methods 3 and 4 fall considerably below those predicted by RSTRENG, indicating that they are considerably more conservative than RSTRENG.

Lastly, consider the predictions via Method 7 (parabolic or existing B31G method) and Method 8 (0.85 dL method proposed to replace the parabolic representation). Neither method is capable of considering the fact that L_2 varies and both are based on L_1 = 13 and d_2 = 0.300. However, the difference between the two is significant. Method 7 yields a predicted failure pressure (with no factor of safety) of 982 psig, 1.31 times the actual failure pressure of test specimen with the compound flaw of 6.5 inches at 0.300-inch depth within the 13-inch-long, 0.120-inch-deep flaw. In contrast, Method 8 yields a predicted failure pressure (with no factor of safety) of 756 psig. The latter compares favorably with the one test result and is in fact part of the reason why 0.85 was chosen as opposed to some other factor.

The use of either the effective-area method or the 0.85 dL area representation is clearly preferable to the handling of this type of defect by means of the old B31G criterion. If considered on the maximum-length-maximum-depth basis, the whole family of anomalies discussed (except for the trivial L_2 = 0 case) could be viewed as a 13-inch-long 0.300-inch-deep flaw in a 36-inch 0.390-inch nominal wall thickness X60 material (flow stress = 70,000 psi). In such a case, the existing B31G criterion allows a defect of 0.300-inch depth to be no more than 1.97 inches in length or the 13-inch-long flaw to be operated

at no more than 595 psig. The new criterion would allow only a slightly longer 2.13-inch-long flaw, but it would allow the 13-inch-long flaw to be operated at a pressure of only 491 psig. This illustrates a case in which the 0.85 dL representation is less conservative than the parabolic method as it should be at a 72 percent SMYS operating stress but more conservative than the parabolic method in the case of a greatly reduced operating pressure, as anticipated and as it should be. Note that the safe pressure level under the existing B31G approach is not sufficiently low to assure a factor of safety of 1.39 while that of the new area representation is (the actual failure pressure of the one test result was 749 psig).

Statistical Analysis of the Predictive Methods

The accuracies of the-predictive methods can be assessed statistically by considering ratios of predicted-to-actual failure pressures. Such ratios are listed in Appendix D for predictions via RSTRENG (CASE 1), the 0.85 dL representation (CASE 2), and the existing 2/3 dL representation (CASE 3). The mean values and standard deviations of these ratios are as follows. It is assumed that the data correspond to a "normal" distribution.

	CASE 1 (RSTRENG)	CASE2 (0.85 dL)	CASE 3[a] (2/3 dL)
		Ruptures	
Mean	0.850	0.622	0.537
Std. Dev.	0.150	0.138	0.178
Quantity	41	41	41
		Leaks	
Mean	0.992	0.675	0.630
Std. Dev.	0.180	0.221	0.209
Quanity	45	45	49

(a) Includes results for L^2/Dt >20. In such cases, the existing criterion reverts to the remaining thickness approach embodied in Equation (11), an overconservative approach.

The meanings of these results are discussed below.

First, consider the ruptures. The mean value for the RSTRENG predictions is 0.850 reflecting the fact that most of the time RSTRENG underestimates the remaining strength. The standard deviation of 0.150 means that 95 percent of the data can be expected to lie within 0.850 + 2(0.150) of the mean. This means that only 2-1/2 percent of the data would be expected to have ratios above 1.15. Similarly, only 0.5 percent of the data would be expected to have ratios above 1.30 (three standard deviations from the mean). By using a factor of safety of 1.39 on the failure pressure calculated by RSTRENG, then, one can expect that corrosion anomalies left in a pipeline via this screening analysis would be extremely unlikely to rupture in service.

From the standpoint of the 0.85 dL representation, the mean for the 41 ruptures is 0.622, the standard deviation is 0.138 and the two and three standard deviation upper bounds on the predictions are 0.622 + 2(0.138) = 0.898 and 0.622 + 3(0.138) = 1.036, respectively. Utilizing a factor of safety of 1.39 with the new area representation, one can have a very high degree of confidence that no "acceptable" corroded area will rupture in service.

From the standpoint of the existing B31G method (2/3 dL), the mean for the 41 ruptures is 0.537 and the standard deviation is 0.178, and the two and three standard deviation upper bounds on the predictions are 0.893 and 1.071, respectively.

Now, consider the 45 leaks. The mean value for the RSTRENG predictions is 0.992 and the standard deviation is 0.180. The two and three standard deviation upper bounds are 1.352 and 1.532. Clearly, a 1.39 factor of safety is not adequate. It is recalled, however, that the use of the criterion is limited to anomalies not greater than 80 percent of the wall thickness in depth. If one can overlook the suspect early corroded pipe tests in which leaks occurred at unexpectedly low pressures, this limit would be expected to eliminate most, if not all, circumstances wherein "acceptable" pits would leak in service.

The mean value for the 0.85 dL representation is 0.675 and the standard deviation is 0.221. This results in two and three standard deviation upper bounds of 1.117 and 1.338, respectively. These predictions are clearly more conservative than those of RSTRENG, but again, one must retain a limit on depth 0.80 d/t to avoid leaks in service.

The mean value for the existing B31G method (2/3 dL) is 0.630 and the standard deviation is 0.205. This results in two and three standard deviation upper bounds of 1.040 and 1.215, respectively. These predictions are also more conservative than those of RSTRENG.

It is reasonably clear that with an adequate factor of safety and a limit on maximum pit depth, the new methods can be used prudently to assess the remaining strength of corroded pipe.

Summary of the Validation Effort

The foregoing comparisons strongly suggest that the methodology embodied in both the existing B31G criterion and the proposed modified criterion can be used safely to assess corroded line pipe and to predict safe operating pressure levels.

CORROSION IN VARIOUS TYPE OF LONGITUDINAL SEAMS

The existing B31G criterion does not apply to corrosion in any type of seam weld. This situation can and should be changed as follows. Corrosion in submerged-arc welds should be treated exactly as corrosion in the body of the pipe. Corrosion (i.e., selective corrosion) in ERW or flash-welded seams should not be evaluated on the basis of either the existing B31G criterion or the proposed modified criterion. The rationale for these recommendations is presented below.

The justification for treating corrosion in a submerged-arc seam in the same manner as corrosion in the body of the pipe is that both operating experience and test data show that such seams tend to be at least as resistant to defects as the pipe material itself. Evidence

of this was gathered over 20 years ago as shown in Table 3. This table is taken from Reference 6. It involves pairs of tests in which identical through-wall flaws* were fabricated into two samples of the same length of pipe. In one sample, the defect was located in the heat-affected zone of the submerged-arc seam or in the fusion line on the ERW seam or flash-welded seam, while in the other sample the defect was located in the body of the pipe. The burst pressures of the flawed specimens were compared as shown in Table 3. In every instance the failure stress levels of defects in the submerged-arc welded seams were higher than those of the defects in the body of the pipe. In contrast, defects located in ERW and flash-welded pipe exhibited failures at stress levels below those of the defects in the body of the pipe.

Besides the evidence from these tests, experience has shown that hydrostatic test ruptures and service failures which originate in or near submerged-arc welds seldom propagate preferentially in the weld or heat-affected zone. More commonly, such fractures tend to move farther from the weld as they propagate. In contrast, experience in relation to hydrostatic test failures and service failures originating in or near ERW or flash-welded seams reveals many cases in which the fracture propagated end-to-end in the weld often at obviously higher speeds judging by the lack of fracture arrest. While this experience may not be typical of currently fabricated ERW pipe, it is a major consideration for the vast majority of ERW pipe that has been in service for some time and will be likely to be involved in inspection or revalidation projects.

One other factor which serves to discourage the consideration of corrosion in ERW or flash-welded seams by these methods is the fact that such corrosion is generally "selective" in nature, progressing more deeply and narrowly at the fusion line of the seam that into the surrounding pipe. Thus, a situation is created in which a relatively sharp defect exists in a material with less than optimum toughness. In

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*Through-wall flaws were evaluated by means of patches glued to the inside of the pipe to prevent leakage. Failure pressure is defined as the pressure level at which such a flaw causes a rupture.

addition, its crevice-like nature makes it difficult to obtain the critical depth dimensions for the analysis. Given these situations, it is not prudent to use the flow-stress dependent analysis methods of both the existing B31G and the proposed modified criterion to evaluate corrosion in ERW or flash-welded seams.

RESULTS, CONCLUSIONS, AND RECOMMENDATIONS

The results of this project are as follows.

- A modified method involving two calculation techniques has been developed to predict the failure pressure of corroded pipe.
- The modified method utilizes SMYS plus 10,000 psi *as* the flow stress of the material and a three-term "Folias" factor to describe the stress-intensity effect of a metal-loss anomaly.
- One embodiment of the modified method utilizes detailed measurements of metal loss and successive trial calculations to obtain a minimum value of predicted failure pressure corresponding to the "effective" area of the metal loss. In this embodiment there is no limit to the length of anomaly that may be analyzed.
- A PC-based program called RSTRENG has been created to facilitate the calculation of the minimum failure pressure via the effective-area technique.
- Another embodiment of the modified method utilizes only the maximum depth and overall length of the corroded region, approximating the metal-loss area as

0.85dL to predict the failure pressure of the pipe.

- Provisions have been included for evaluation of corrosion in pipelines with design factors of 72 percent of SMYS and for other design factors as well (i.e., 0.40, 0.50, 0.60, and 0.80). Also, although the safety factor of 1.39 has been retained for primary use of the new methods in any future B31G document, the optional formulas are given for use with other factors of safety.
- Results of 39 additional burst tests of corroded pipe have been compiled as the result of tests by various pipeline operators. These were added to the data base of 47 burst tests used to validate the original B31G criterion. All 86 results were then used to evaluate the modified criterion. The new data, more so than the old data, strongly suggest that the basic equation embodied in the B31G criterion and the proposed modified criterion is applicable to leaks as well as ruptures.
- The modified criterion underestimated the remaining strengths of 38 of the 41 burst test which terminated in rupture. In the remaining three cases, it overestimated the strengths by amounts ranging from 2 to 5 percent.
- While the existing criterion and the proposed new criterion are applicable to leaks as well as ruptures, the application

of the method should still be limited to pits no more than 80 percent through the wall thickness.

- The burst-test data support the position that any corrosion not greater than 20 percent through the wall thickness can safely be left in service in lines operating at 72 percent of SMYS or less regardless of the length of the corrosion as long as the remaining wall thickness is at least 80 percent of that required by the design stress level.
- Example tables of acceptable lengths and curves for predicting safe pressures have been generated for the modified criterion that can be used to replace those of the existing B31G criterion.
- A review of data presented in Reference 6 on the behavior of defects in longitudinal seams of various types (submerged-arc, ERW, and flash weld) revealed that flaws in submerged-arc seams tend to fail at higher pressures than identical flaws in the body of the pipe and that flaws in ERW and flash-weld seams tend to fail at lower pressures than identical flaws in the body of the pipe.

From these findings, it is concluded that

(1) The modified method as used in either of the two embodiments represents an improved method for evaluating corroded pipe compared to the existing B31G criterion because it eliminates two known sources of

excess conservatism embodied in the existing criterion.

(2) When used with a factor of safety of 1.39 (equivalent to a hydrostatic test to 100 percent of SMYS for a pipeline operating at 72 percent of SMYS), the modified criterion provides an adequately safe indication of the integrity of a corroded pipe

(3) The modified criterion would allow corroded regions on the order of 50 percent greater length than the existing B31G criterion and would predict higher safe operating pressures in cases where the safe operating pressures exceed 55 percent of SMYS.

(4) Corrosion in submerged-arc seams should be handled in the same manner as corrosion in the body of the pipe. Neither the existing B31G criterion nor the proposed modified criterion should be applied to selective corrosion in ERW or flash-welded seams

Recommendations

It is recommended that the modified criterion be substituted for the existing B31G criterion and that the criterion be made applicable to corrosion in submerged-arc seams. The new criterion should also permit areas of corrosion pits that are not more than 20 percent through the wall to remain in service regardless of length in pipelines that operate at 72 percent of SMYS or less as long as the remaining wall thickness is at least 60 percent of that required by the

design stress level. However, the current limitation on accepting pits no more than 80 percent through the wall should be retained.

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3. Folias, E. S., "The Stresses in a Cylindrical Shell Containing an Axial Crack", AFL 64-174 Aerospace Research Laboratories (October 1964)

4. Kiefner, J. F., and Duffy, A. R., Summary of Research to Determine the Strength of Corroded Areas in Line Pipe, presented at a Public hearing at the U.S. Department of transportation (July 20, 1971).

5. Shannon, R. W. E., "The Failure Behavior of Line Pipe Defects" International Journal of Pressure Vessels and Piping (2) (1974) - Applied Science Publishers, Ltd., England, Printed in Great Britain (1974)

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TABLE 1. EXAMPLE OF TABLE TO BE USED IN A MODIFIED VERSION OF B31G

Allowable Lengths of Corrosion Pitting
SMYS = 52,000 psi.
Diameter = 30.000 inches

Depth of corrosion, inches	Wall Thickness; inch						
	0.250	0.312	0.375	0.438	0.500	0.625	0.688
0.02	(a)	(a)	(a)	(a)	(a)	(a)	(a)
0.03	(a)	(a)	(a)	(a)	(a)	(a)	(a)
0.04	(a)	(a)	(a)	(a)	(a)	(a)	(a)
0.05	27.39	(a)	(a)	(a)	(a)	(a)	(a)
0.06	14.56	(a)	(a)	(a)	(a)	(a)	(a)
0.07	8.53	25.00	(a)	(a)	(a)	(a)	(a)
0.08	6.32	12.41	33.54	(a)	(a)	(a)	(a)
0.09	5.11	8.84	17.84	36.25	(a)	(a)	(a)
0.10	4.33	7.04	11.98	26.16	38.73	(a)	(a)
0.11	3.77	5.92	9.32	15.86	36.23	(a)	(a)
0.12	3.34	5.13	7.74	11.97	20.60	(a)	(a)
0.13	2.99	4.55	6.68	9.80	14.98	43.30	(a)
0.14	2.71	4.09	5.90	8.38	12.06	35.79	45.43
0.15	2.46	3.72	5.30	7.37	10.22	23.03	45.21
0.16	2.25	3.41	4.82	6.60	8.94	17.66	28.80
0.17	2.06	3.14	4.42	6.00	7.98	14.60	21.20
0.18	1.89	2.90	4.09	5.50	7.23	12.57	17.22
0.19	1.73	2.69	3.80	5.09	6.62	11.10	14.68
0.20	1.58	2.51	3.54	4.73	6.12	9.99	12.89
0.21	(b)	2.33	3.31	4.42	5.69	9.11	11.55
0.22	(b)	2.18	3.11	4.15	5.33	8.40	10.50
0.23	(b)	2.03	2.92	3.91	5.00	7.80	9.65
0.24	(b)	1.89	2.75	3.69	4.72	7.28	8.95
0.25	(b)	(b)	2.60	3.49	4.46	6.84	8.35
0.26	(b)	(b)	2.45	3.31	4.23	6.46	7.84
0.27	(b)	(b)	2.31	3.14	4.02	6.11	7.39
0.28	(b)	(b)	2.18	2.98	3.83	5.81	7.00
0.29	(b)	(b)	2.06	2.83	3.65	5.53	6.64
0.30	(b)	(b)	1.94	2.70	3.48	5.28	6.33
0.31	(b)	(b)	(b)	2.56	3.33	5.04	6.04
0.32	(b)	(b)	(b)	2.44	3.18	4.83	5.78
0.33	(b)	(b)	(b)	2.32	3.04	4.63	5.54
0.34	(b)	(b)	04	2.21	2.91	4.45	5.32
0.35	(b)	(b)	(b)	2.10	2.79	4.28	5.11
0.36	(b)	(b)	(b)	(b)	2.67	4.12	4.92
0.37	(b)	(b)	(b)	(b)	2.55	3.96	4.74
0.38	(b)	(b)	(b)	(b)	2.44	3.82	4.57
0.39	(b)	(b)	(b)	(b)	2.34	3.68	4.41
0.40	(b)	(b)	(b)	(b)	2.24	3.55	4.26
0.41	(b)	(b)	(b)	(b)	(b)	3.43	4.12
0.42	(b)	(b)	(b)	(b)	(b)	3.31	3.99
0.43	(b)	(b)	(b)	(b)	(b)	3.20	3.86
0.44	(b)	(b)	(b)	(b)	(b)	3.09	3.73
0.45	(b)	(b)	(b)	(b)	(b)	2.98	3.61
0.46	(b)	(b)	(b)	(b)	(b)	2.88	3.50
0.47	(b)	(b)	(b)	(b)	(b)	2.78	3.39
0.48	(b)	(b)	(b)	(b)	(b)	2.69	3.29
0.49	(b)	(b)	(b)	(b)	(b)	2.59	3.18
0.50	(b)	(b)	(b)	(b)	(b)	2.50	3.08
0.51	(b)	(b)	(b)	(b)	(b)	(b)	2.99

(a) Depth of Pitting <= 20% of Wall Thickness - No Length Limit
(b) Depth of Pitting > 80% of Wall Thickness - Not Allowed

TABLE 2. PREDICTED FAILURE PRESSURE LEVEL FOR CASES 1 THROUGH 9 USING RSTRENG
(All 30-inch O.D. by 0.375-inch wall, X52 material)

Case Number	Shape	Length L_f, inches	Maximum Depth d_f, inch	Failure Pressure[1] P_f, Psig	Safe pressure $P_f/1.39$	MAOP with no Defect	Status
1	Rectangle	10	0.1875	970	698	936	Repair or reduce pressure to 698 psig
2	Rectangle	3	0.1875	1309	942	936	Continue to operate at 936 psig
3	Rectangle	2	0.1875	1415	1018	936	Continue to operate at at 936 psig
4	Parabolic	10	0.1875	1160	835	936	Repair or reduce pressure to 835 psig
5	Parabolic	3	0.1875	1421	1022	936	Continue to operate at 936 psig
6	Parabolic	2	0.1875	1479	1064	936	Continue to operate at 936 psig

TABLE 2. (Cont'd)

Case Number	Shape	Length, L, inches	Maximum Depth, d, inch	Failure Pressure[a] P_f, psig	Safe Pressure, $P_f/1.39$	MAOP with no Defect	Status
7	New area (0.85dL)	10	0.1875	1045	752	936	repair or reduce pressure to 752 psig
8	New area (0.85dL)	3	0.1875	1365	982	936	Continue to operate at 936 psig
9	New area (0.85dL)	2	0.1875	1448	1042	936	Continue to operate at 936 psig

(a) P_f calculated via Equation (1) using MT based on Equation (12) and the "effective" area as determined by RSTRENG.

TABLE 1 COMPARISONS OF THE BEHAVIORS OF THROUGH WALL FLAWS IN LONGITUDINAL WELDS WITH IDENTICAL DEFECTS IN THE PIPE MATERIAL (FROM REFERENCE 6)

Material	Type of Longitudinal Weld	Flaw Length, inches	Failure Pressure, psig	Ratio of Failure Pressure of Weld Flaw to That of Flaw in Pipe Material, percent
30 x 0.328 inch X60				
Pipe		7.00	705	---
Weld	DSA	7.00	870	123
30 x 0.360-inch X60				
Pipe	---	6.00	925	---
Weld	DSA	6.00	995	108
36 x 0.390-inch X60				
Pipe	---	3.00	1265	---
Weld HAZ[a]	DSA	3.00	1334	106
30 x 0.375-inch X52				
Pipe	---	7.00	785	---
Weld	FW	7.00	695	89
30 x 0.360-inch X60				
Pipe	---	5.30	950	---
Weld	FW[b]	5.30	830	88
20 x 0.250-inch X52				
Pipe	---	3.00	1193	---
Weld	ERW	3.00	1102	92

(a) Flaw was located approximately in the heat-affected zone at mid thickness of the pipe wall. Both inside and outside reinforcements were ground off.

(b) Normalized flash welds

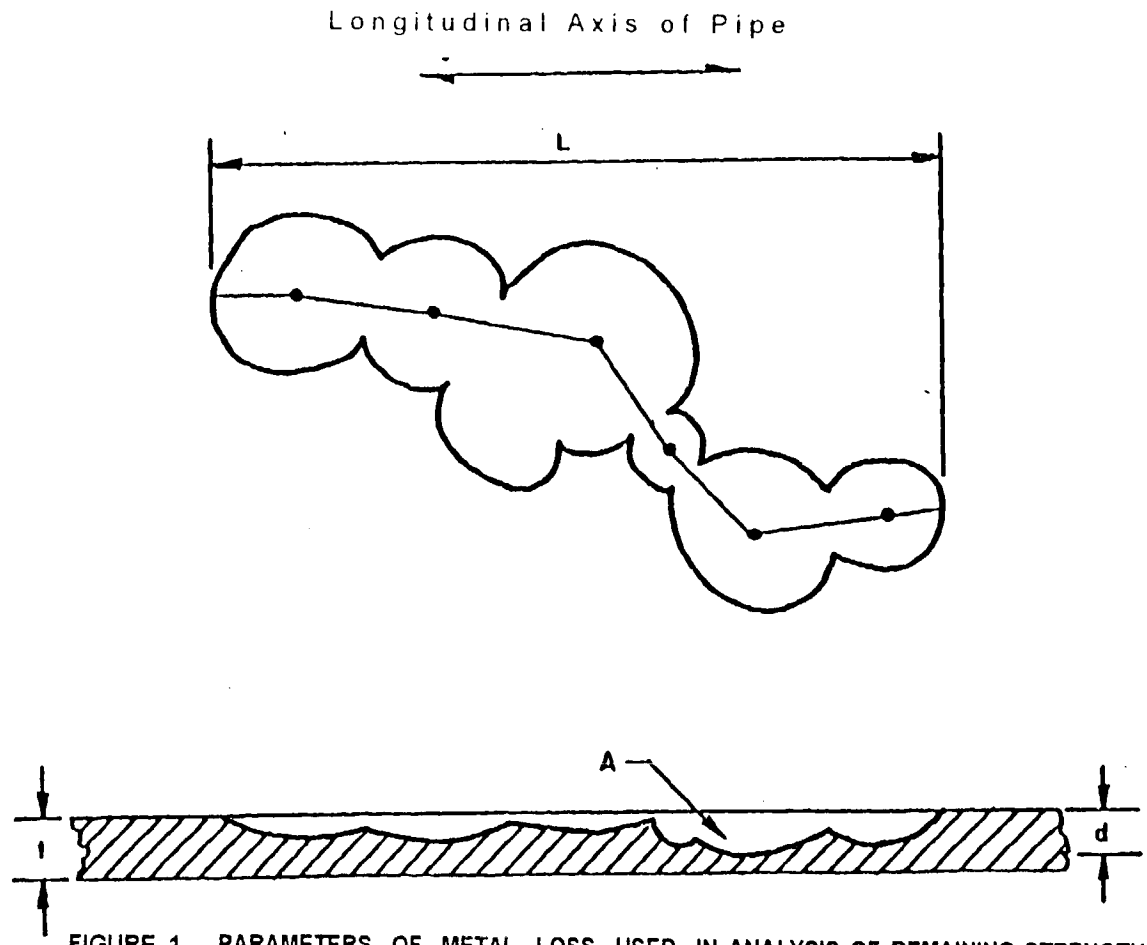


FIGURE 1. PARAMETERS OF METAL LOSS USED IN ANALYSIS OF REMAINING STRENGTH

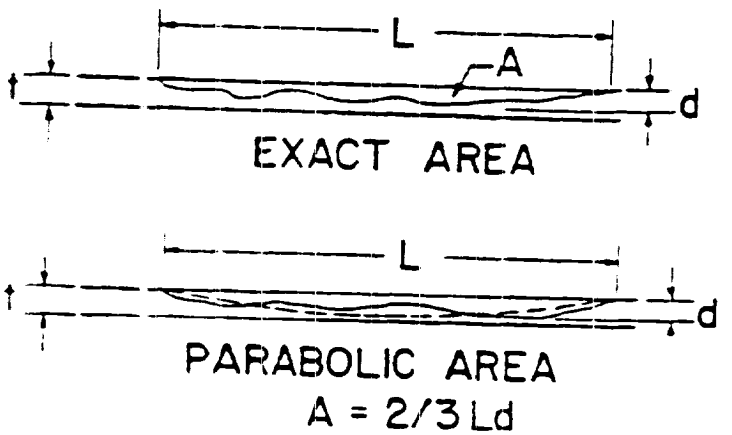
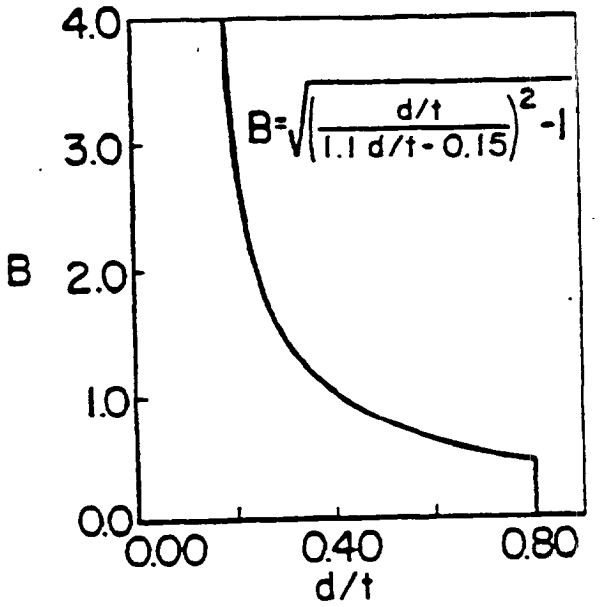


FIGURE 2 PARABOLIC REPRESENTATION OF METAL LOSS AS USED IN THE B31G CRITERION



$$L \leq 1.12\ B\sqrt{Dt}$$

FIGURE 3. THE B31G CRITERION FOR ACCEPTABLE LENGTH OF A CORRODED REGION

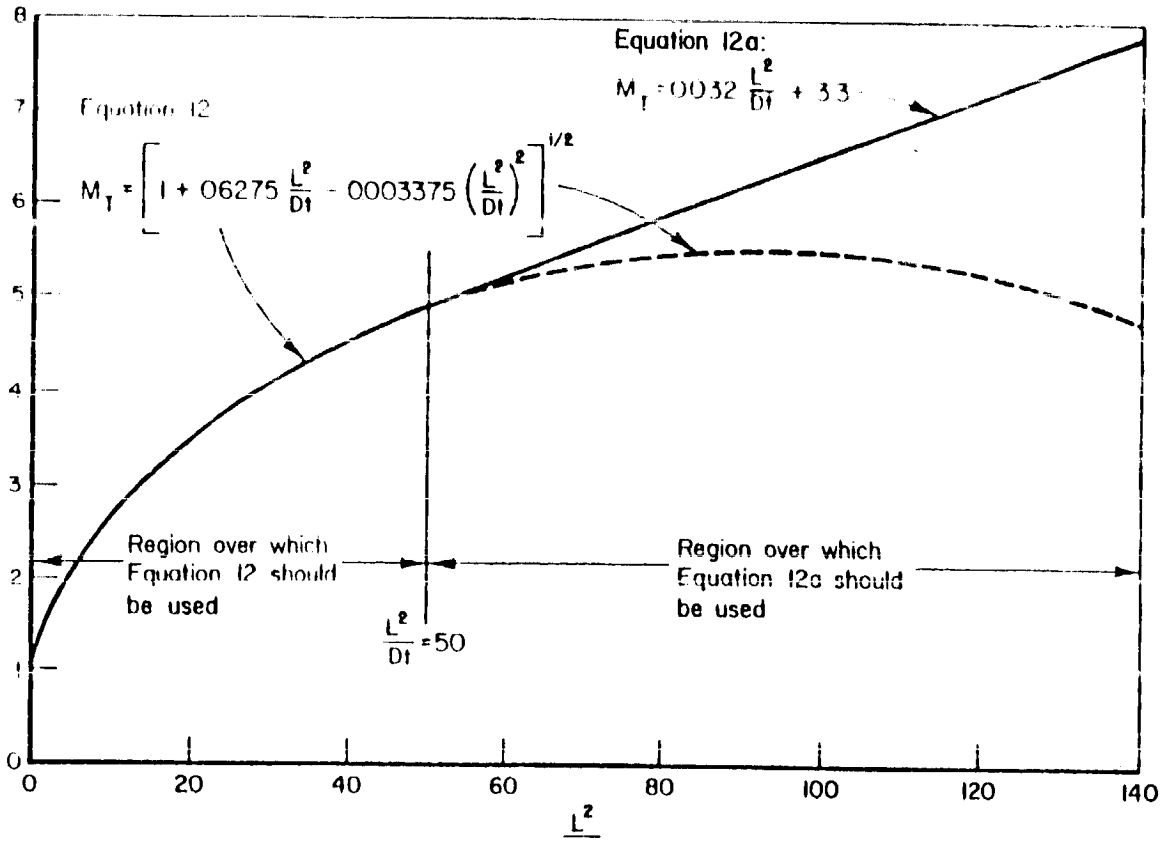


FIGURE 4. GRAPHICAL REPRESENTATION OF FOLIAS FACTORS USED IN THE MODIFIED CRITERION

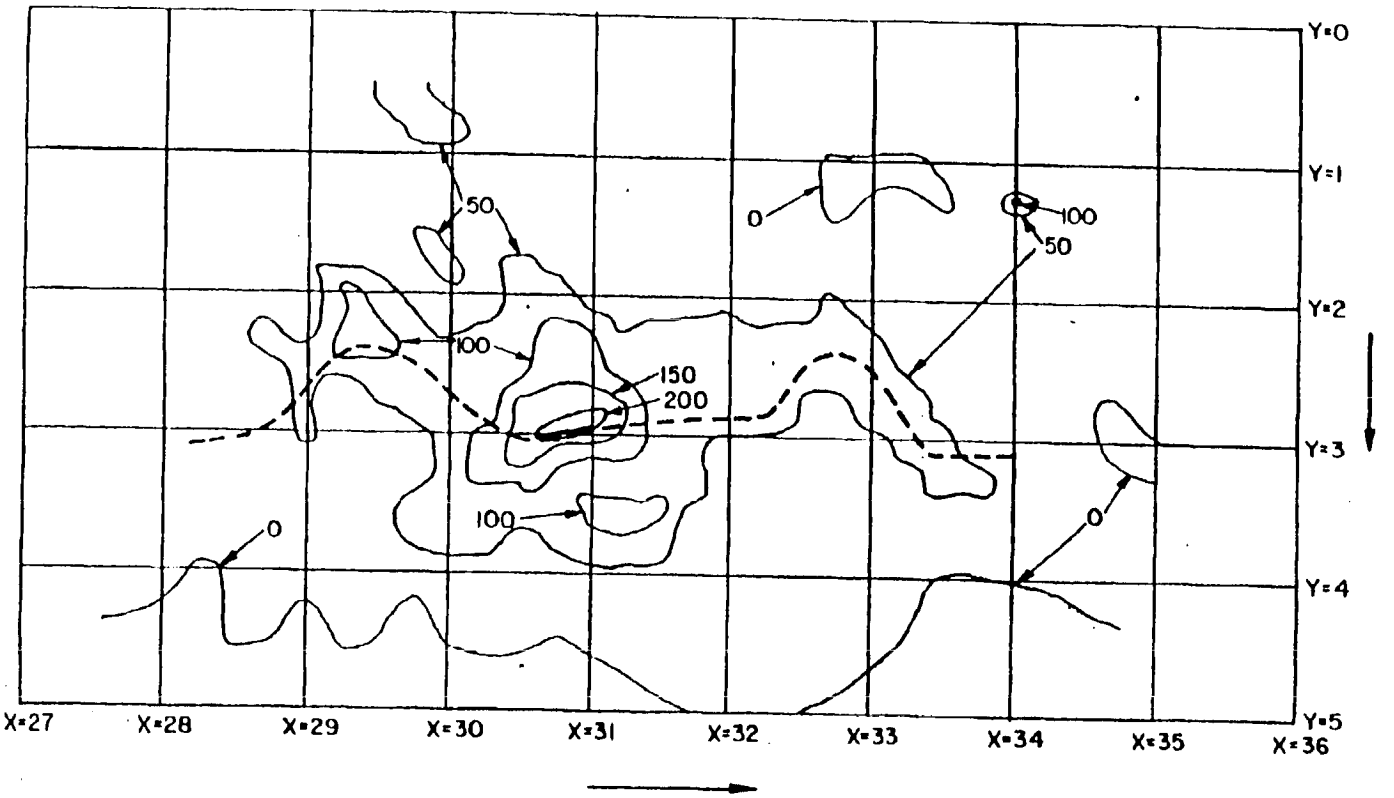


FIGURE 5. CONTOUR MAP OF PIT DEPTHS

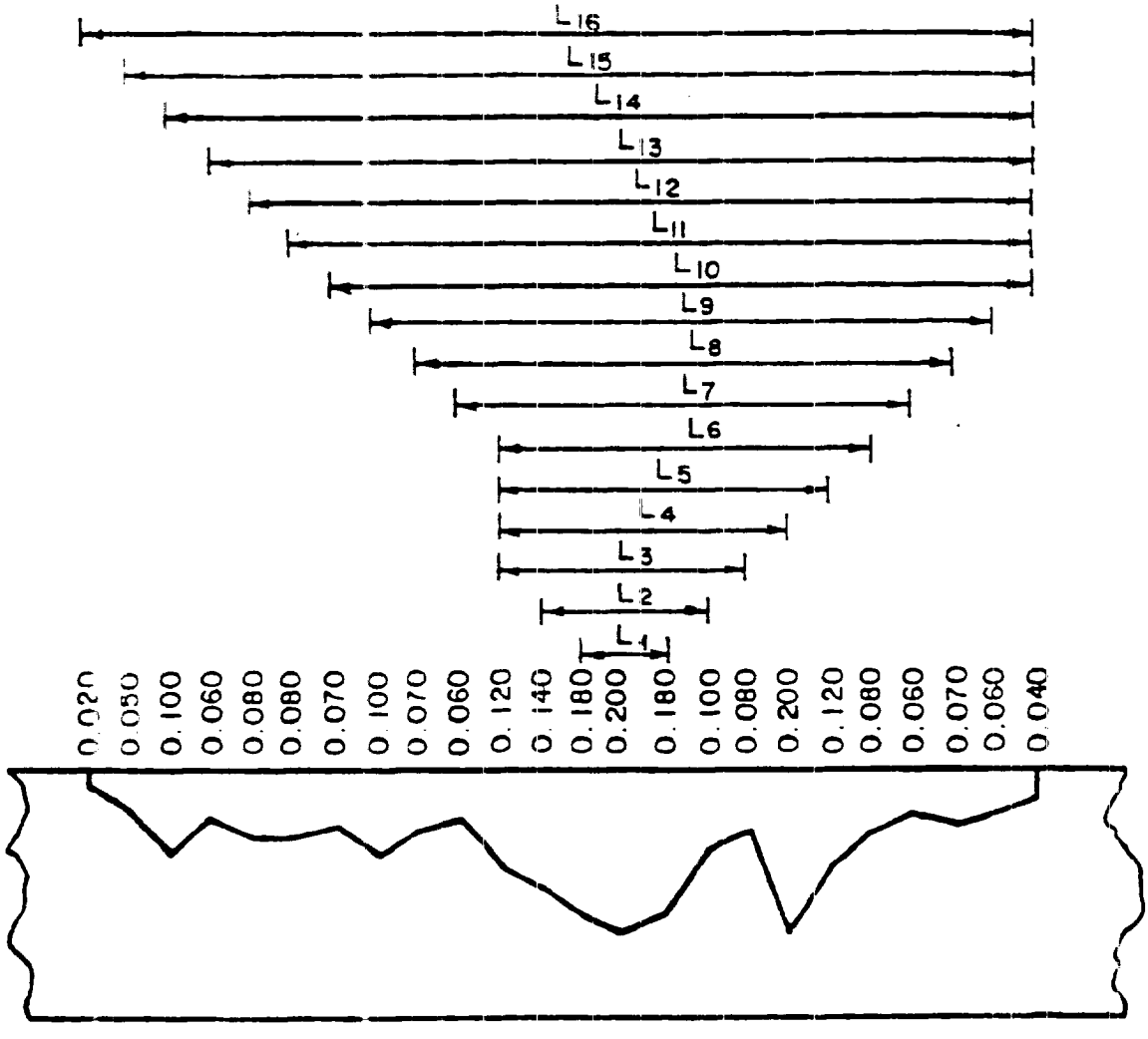


FIGURE 6 PROFILE OF PIT DEPTHS ALONG "RIVER-BOTTOM" PATH IN FIGURE 4

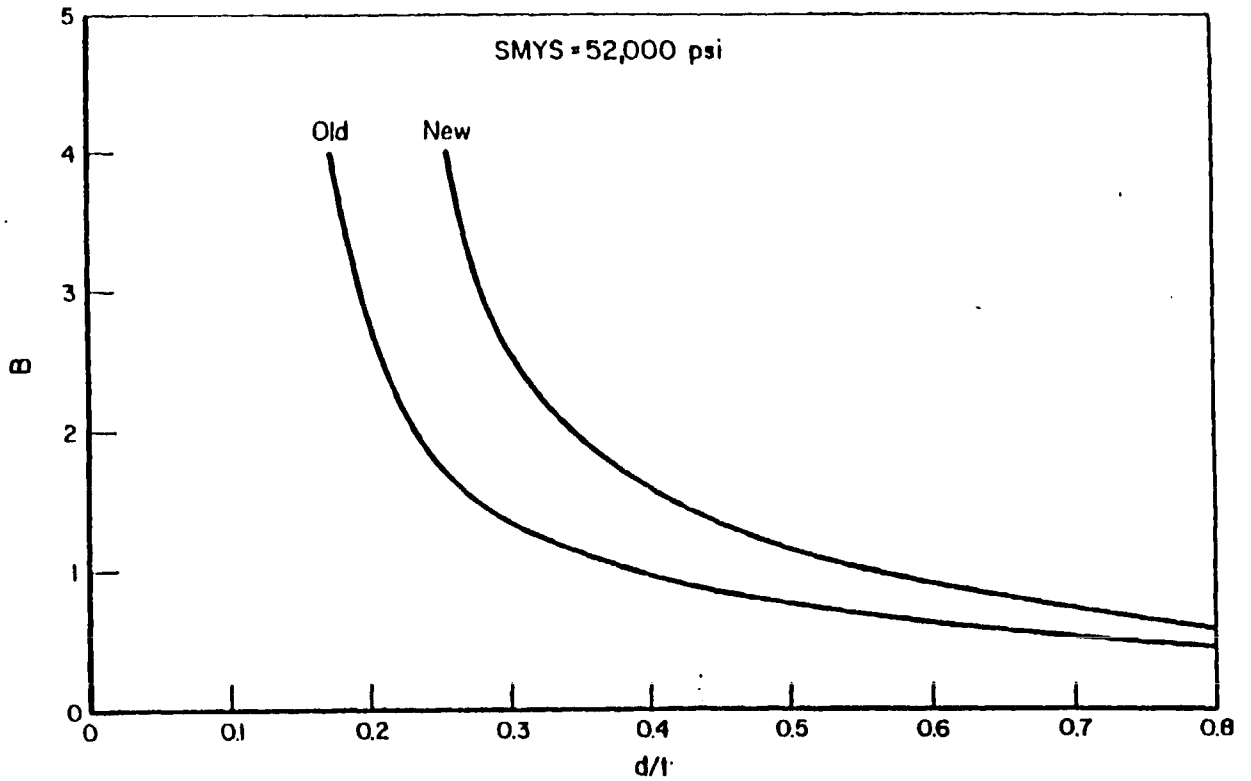


FIGURE 7 COMPARISON OF ALLOWABLE LENGTHS UNDER THE OLD AND THE NEW CRITERIA

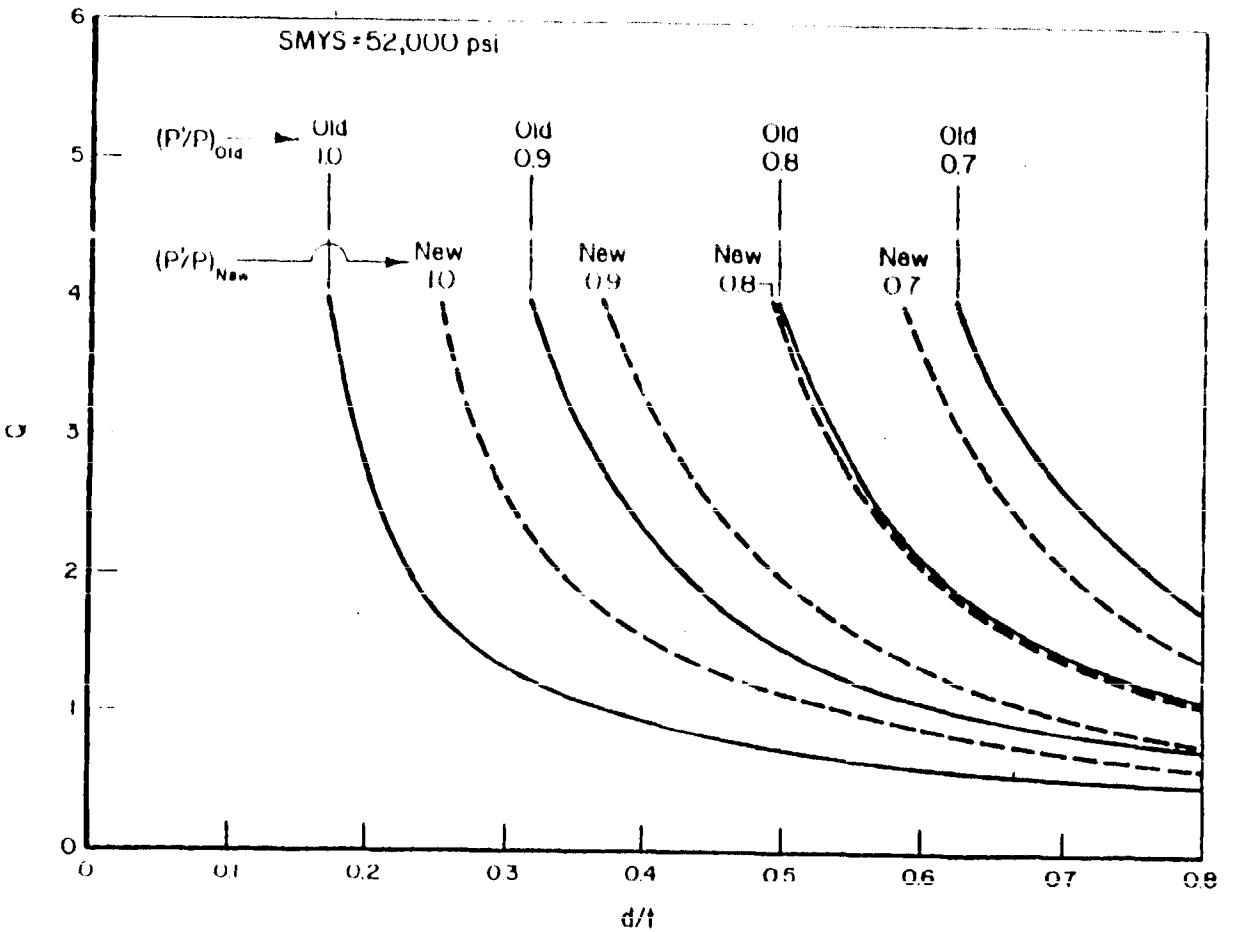
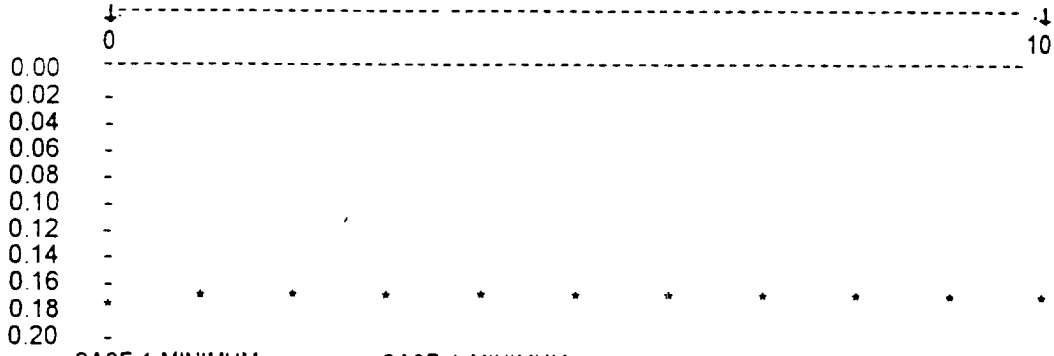


FIGURE 8. COMPARISON OF PREDICTED SAFE OPERATING PRESSURES UNDER THE OLD AND THE NEW CRITERIA

SCREEN 1

Specimen = RECT - 10 INCH Date = 10-19-1989
Diameter = 30.00 in. Thickness = 0.375 in.
Yield Str. = 52,000 psi. Comment =



CASE 1 MINIMUM Failure Stress psi. 38,781

CASE 1 MINIMUM Failure Pressure (NOTE: No Safety Factor Applied) psi. 970

SCREEN 2

SMYS = 52,000 psi. (NOTE: No Safety Factors Applied to CASE 1, 2 or 3)
CASE 2 MODIFIED METHOD USING AREA = 0.85 dL :
CASE 3 EXISTING B31G METHOD USING AREA = 2/3 dL : 1,081 psi:

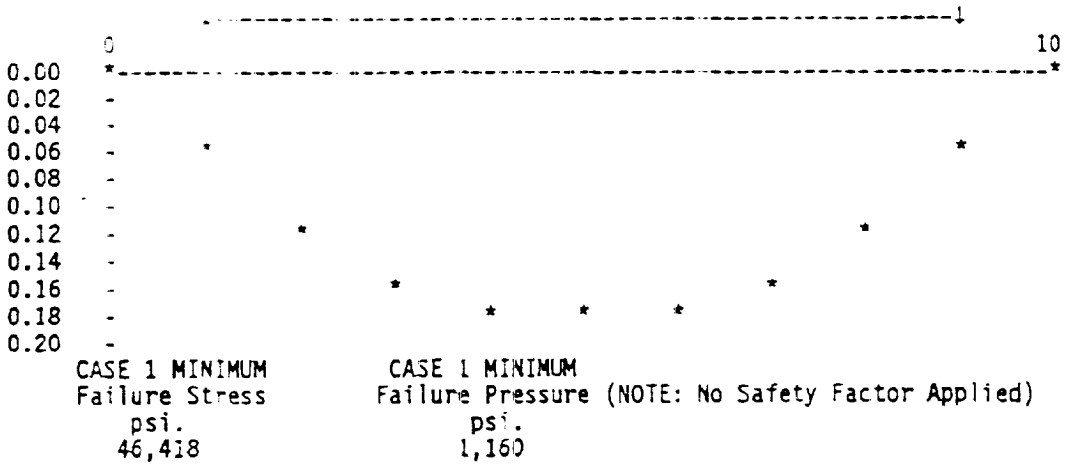
— PIT DEPTH MEASUREMENTS (MILS) —— (MAX. Pit Depth = 0.187 inch) ——

0.00	187
1.00	187
2.00	187
3.00	187
4.00	187
5.00	187
6.00	187
7.00	187
8.00	187
9.00	187
10.00	187

FIGURE 9. EXAMPLE CASE 1

SCREEN 1

Specimen = PARAB - 10 INCH Date = 10-19-1989
Diameter = 30.00 in Thickness = 0.375 in.
Yield Str = 52 000 psi Comment =



CASE 1 MINIMUM Failure Stress psi. 46,418

CASE 1 MINIMUM Failure Pressure (NOTE: No Safety Factor Applied) psi. 1,160

SCREEN 2

SMYS = 52,000 psi (NOTE No Safety Factors Applied to CASE 1 2 or 3)
CASE 2 MODIFIED METHOD USING AREA = 0.85 dL
CASE 3 EXISTING BIIG METHOD USING AREA = 2/3 dL 1,081 psi

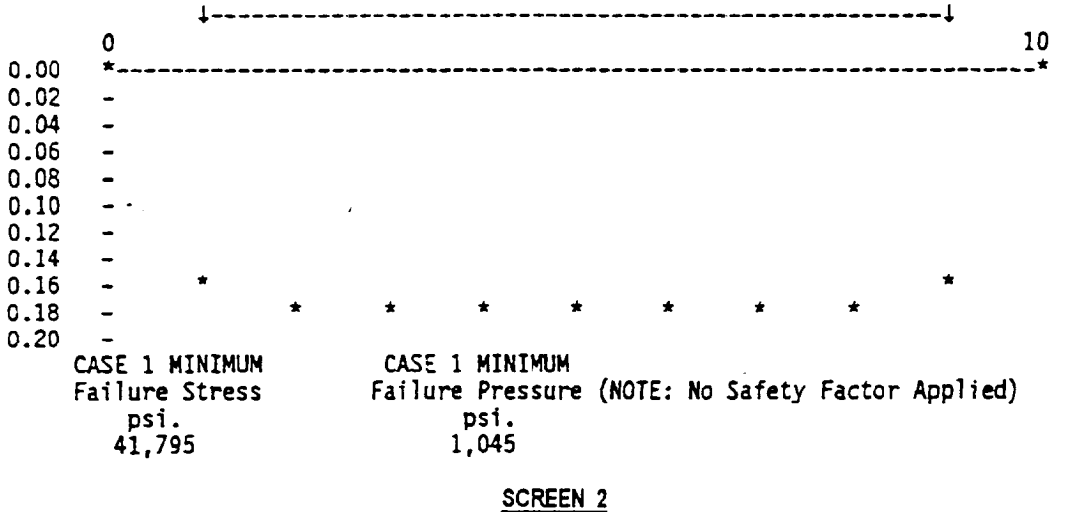
— PIT DEPTH MEASUREMENTS (MILS) --- (MAX Pit Depth = 0.187 inch) ----

0.00	0
1.00	67
2.00	120
3.00	157
4.00	180
5.00	187
6.00	180
7.00	157
8.00	120
9.00	67
10.00	0

FIGURE 10 EXAMPLE CASE 4

SCREEN 1

Specimen = 0.85 dL - 10 INCH Date = 10-19-1989
Diameter = 30.00 in. Thickness = 0.375 in.
Yield Str. = 52,000 psi. Comment =



CASE 1 MINIMUM Failure Stress psi. 41,795

CASE 1 MINIMUM Failure Pressure (NOTE: No Safety Factor Applied) psi. 1,045

SCREEN 2

SMYS = 52,000 psi. (NOTE: No Safety Factors Applied to CASE 1, 2 or 3)
CASE 2 MODIFIED METHOD USING AREA = 0.85 dL : 1,074 psi.
CASE 3 EXISTING B31G METHOD USING AREA = 2/3 dL : 1,081 psi.

--- PIT DEPTH MEASUREMENTS (MILS) --- (MAX. Pit Depth = 0.187 inch) -------

0.00	0
1.00	155
2.00	178
3.00	184
4.00	185
5.00	187
6.00	185
7.00	184
8.00	178
9.00	155
10.00	0

FIGURE 11. EXAMPLE CASE 7

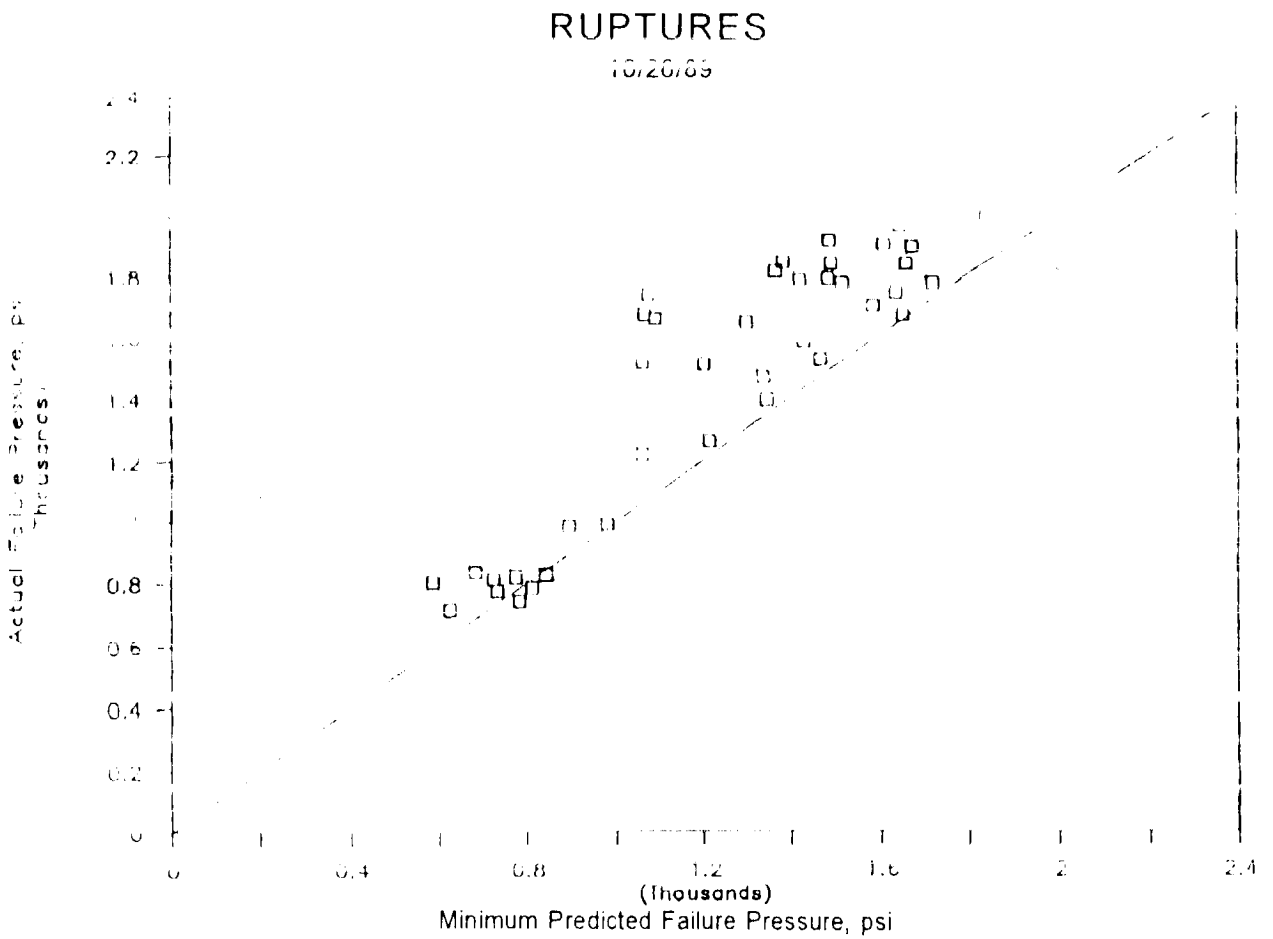


FIGURE 12. COMPARISON OF RSTRENG MINIMUM FAILURE PRESSURES TO BURST TEST RESULTS FOR CASES OF RUPTURES

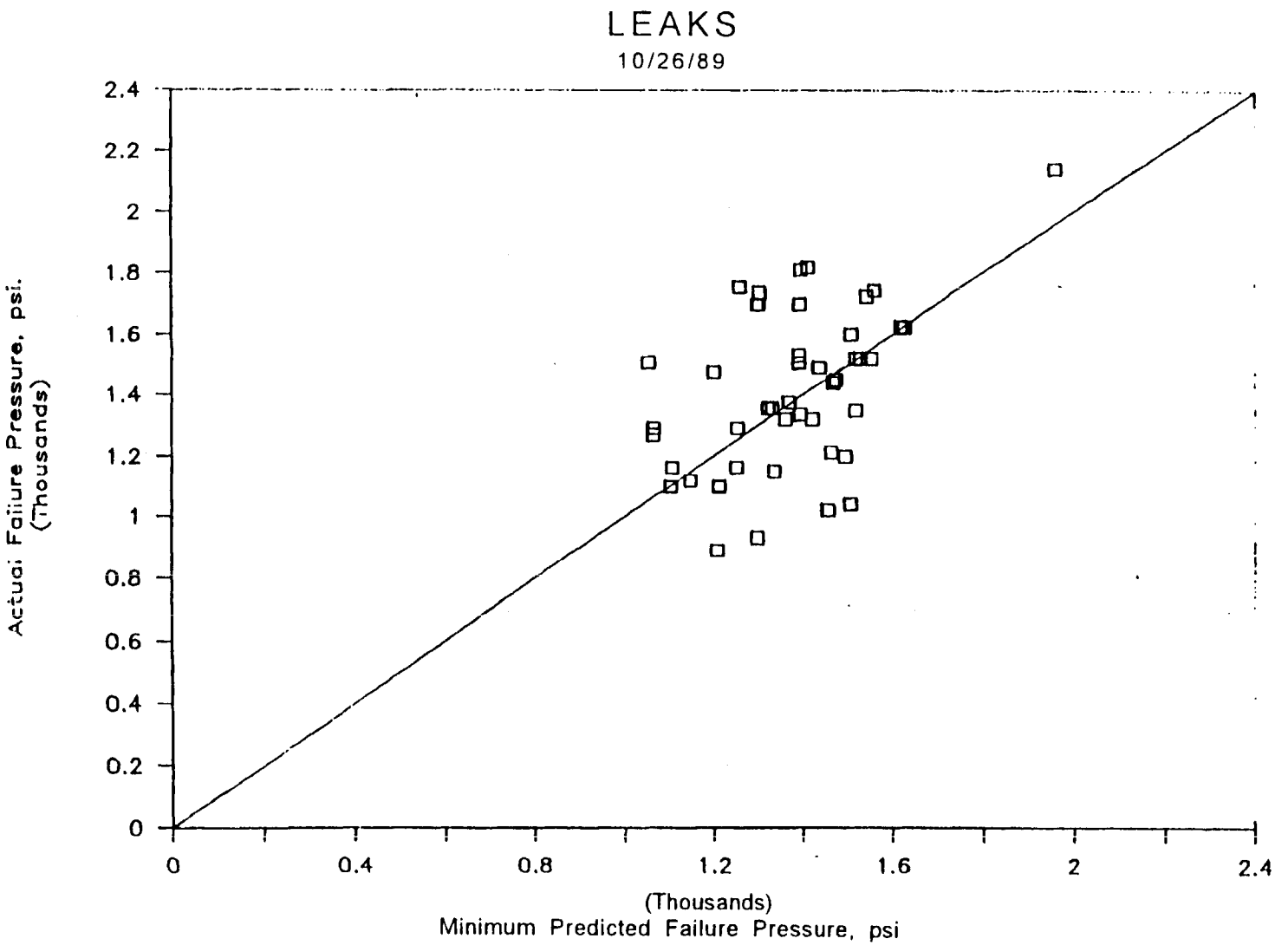


FIGURE 13. COMPARISON OF RSTRENG MINIMUM FAILURE PRESSURES TO BURST TEST RESULTS FOR CASES OF LEAKS

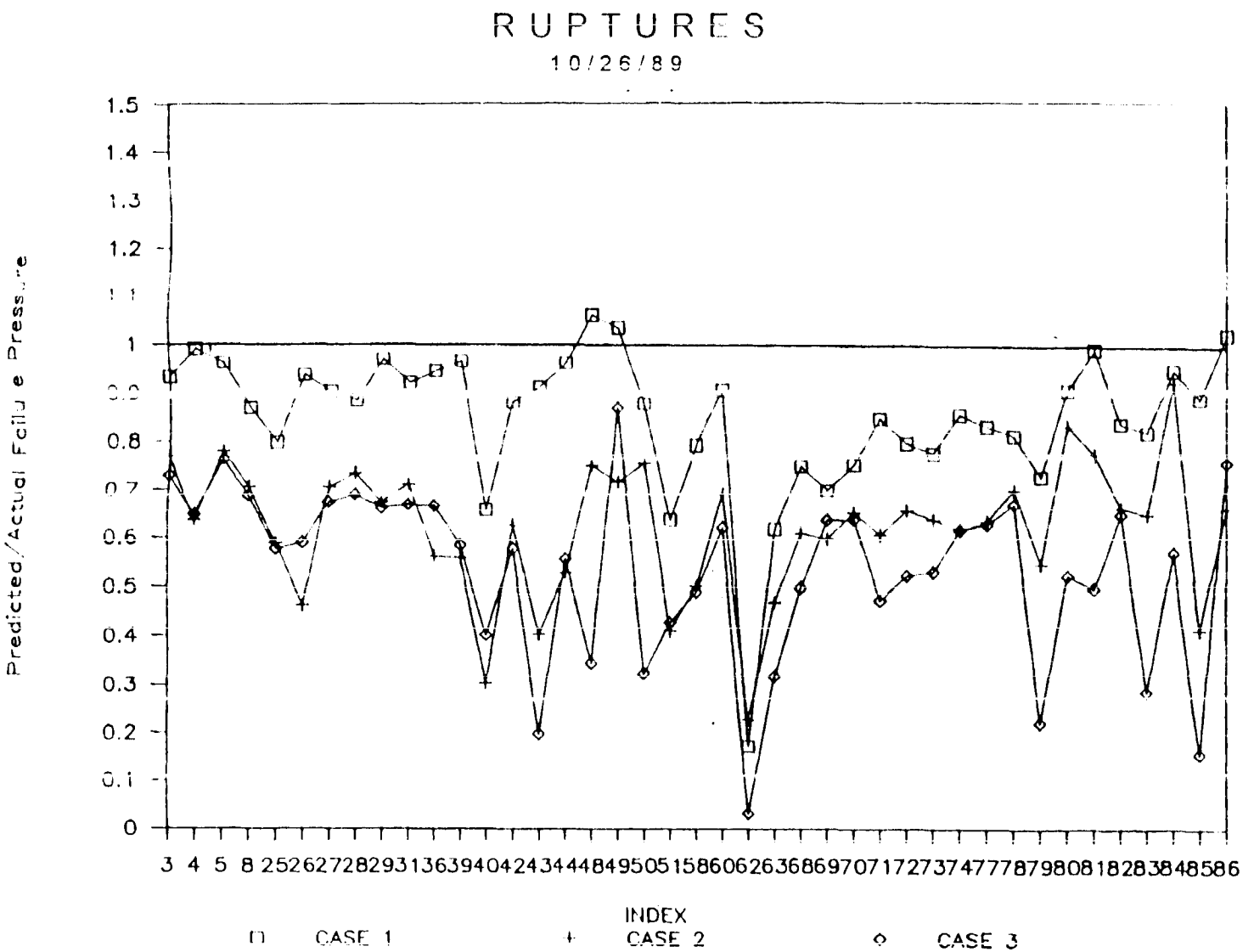


FIGURE 14. COMPARISON OF PREDICTIONS BY VARIOUS METHODS TO BURST TEST RESULTS FOR CASES OF RUPTURES

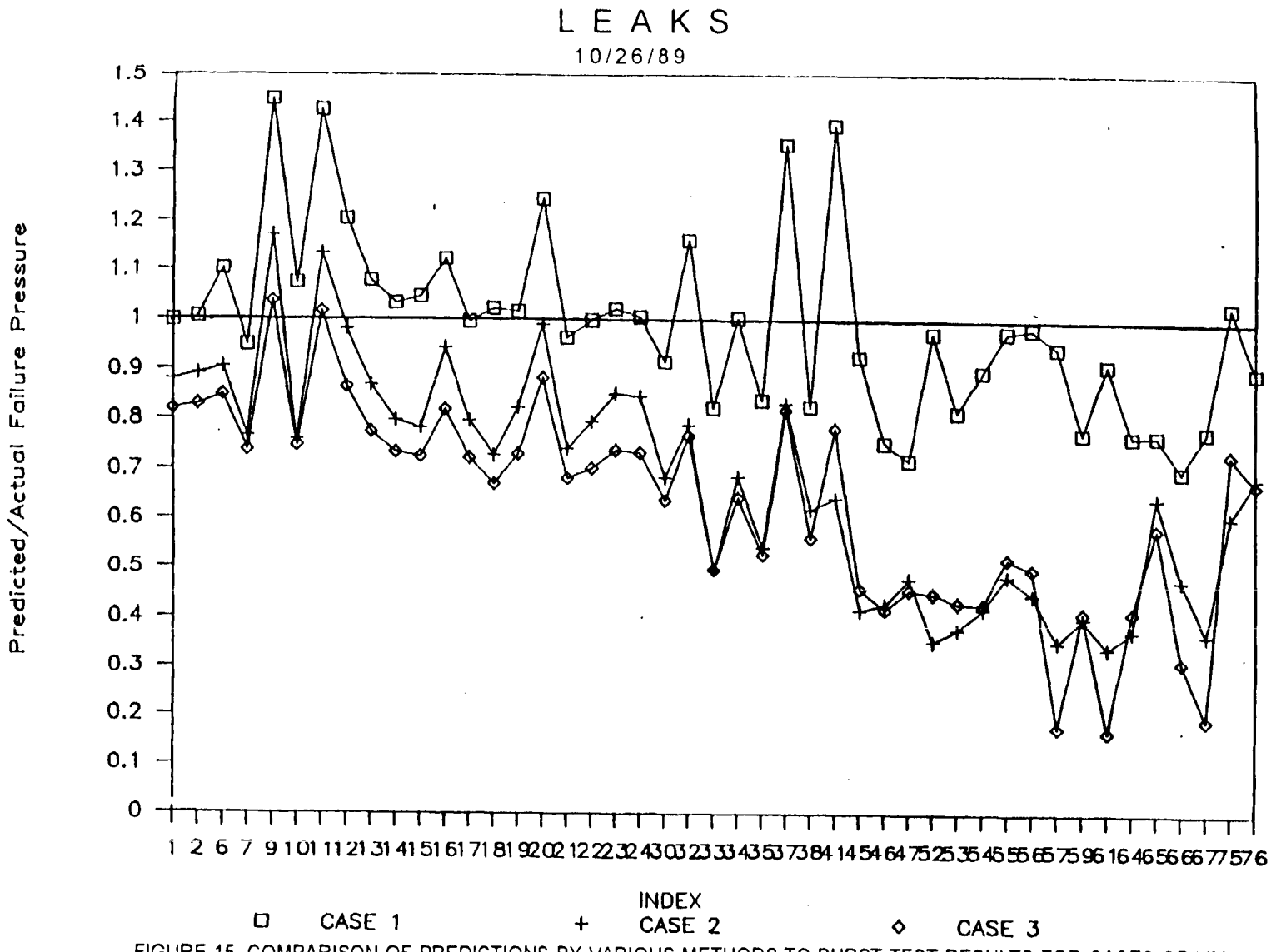
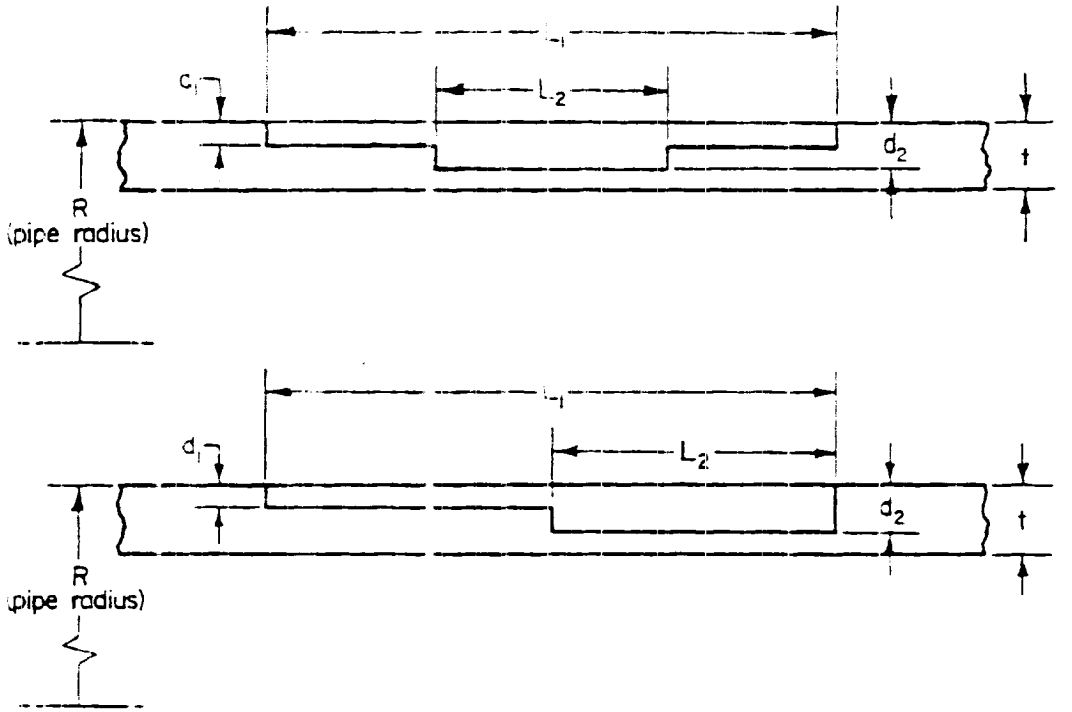


FIGURE 15. COMPARISON OF PREDICTIONS BY VARIOUS METHODS TO BURST TEST RESULTS FOR CASES OF LEAKS



	Method	Defect Length	Defect Area
1.	Exact area	L_1	$A = L_1c_1 + L_2(c_2 - d_1)$ $A_0 = L_1t$
2.	Considering only the deeper flaw	L_2	$A = L_2d_2$ $A_0 = L_2t$
3.	Considering deeper flaw in pipe of reduced wall thickness	L_2	$A = L_2(d_2 - d_1)$ $A_0 = L_2(t - d_1)$ Hoop Stress $= P \times R/(t - d_1)$
4.	Equivalent area	A/d_2	$A = L_1c_1 + L_2(c_2 - d_1)$ $A_0 = (A/d_2)t$
5.	Ignoring deeper flaw	L_1	$A = L_1c_1$ $A_0 = L_1t$
6.	Effective area	Effective	Effective Area
7.	Parabolic area	L_1	$A = 2/3\ (L_1d_2)$ $A_0 = L_1t$
8.	0.85 dL	L_1	$A = 0.85\ L_1d_2$ $A_0 = L_1t$

FIGURE 16 BASES FOR CALCULATIONS OF FAILURE PRESSURE FOR A FLAW HAVING NONUNIFORM DEPTH

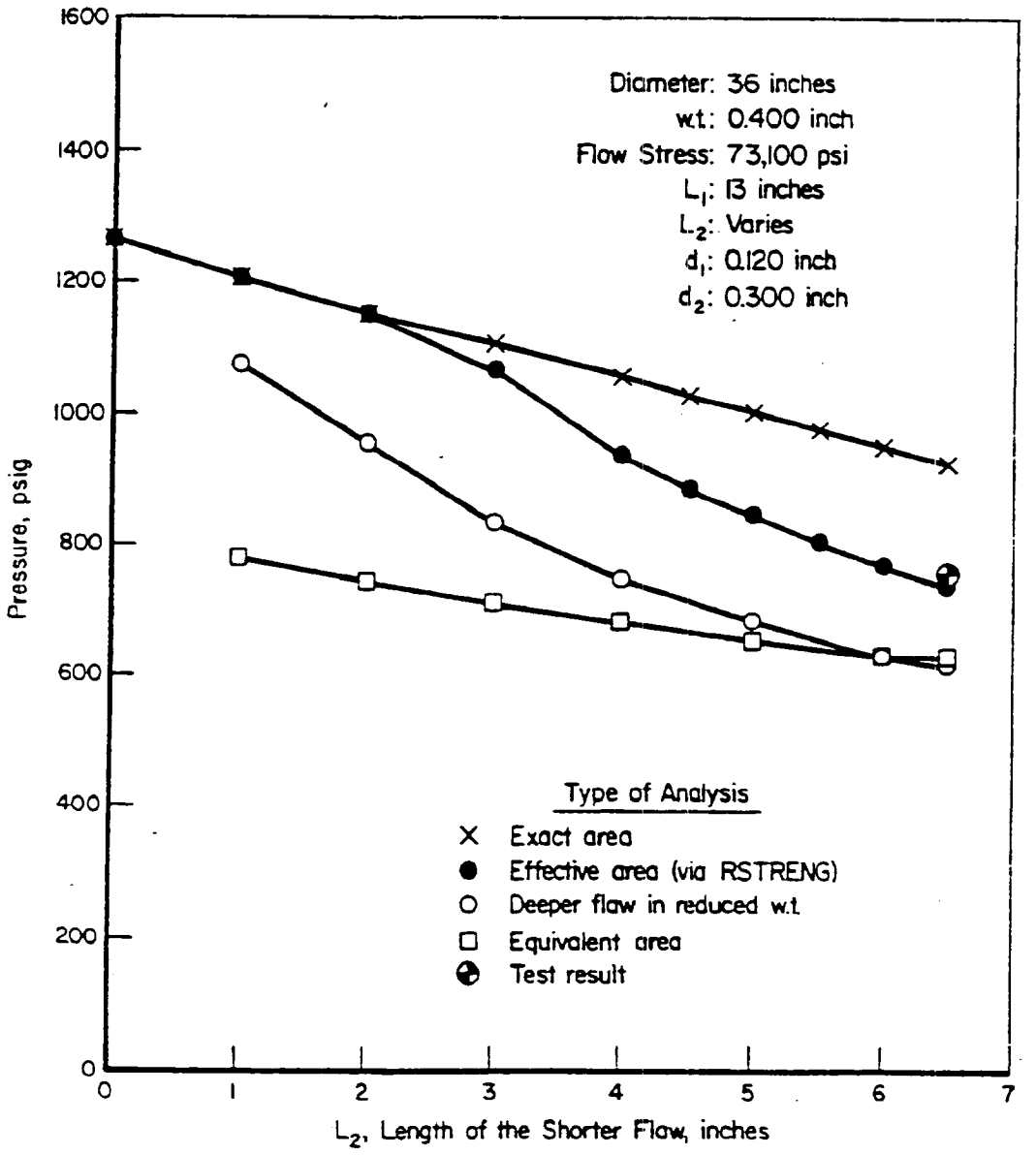


FIGURE 17. COMPARISONS OF CALCULATIONS OF FAILURE PRESSURE BY VARIOUS METHODS FOR A FLAW OF NONUNIFORM DEPTH

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APPENDIX A

MORE EXACT CALCULATIONS OF REMAINING STRENGTH FROM DETAILED MEASUREMENTS OF CORRODED AREAS

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More Exact Calculations of Remaining Strength from Detailed Measurements of Corroded Areas

It is possible and often useful to make more detailed analyses of corroded areas than those based on overall length and maximum depth. More exact evaluations of the remaining strength of corroded pipe may be made if more detailed information on the metal loss is gathered than the simple overall length and maximum depth needed to apply the B31G method. Such data would be useful, for example, to thoroughly evaluate the magnetic flux leakage tool log grading system. In the event that it becomes desirable to gather such information in large quantities in the future, the following procedures are suggested.

Type of Information Needed

The type of detailed information needed to determine a more exact value of remaining strength of a corroded pipe segment than is possible with only maximum depth and overall length is illustrated in Figures A-I and A-2. The boundaries of these two corroded regions are shown along with several longitudinal profiles of the missing metal. The boundaries 'have been defined by placing a sheet of paper over the corroded region and tracing the edges of the metal-loss areas.

The profiles of metal loss shown in Figures A-I and A-2 were recorded by means of a "contour" gage which may be purchased in most hardware stores. A contour gage is a set of parallel wires clamped together so that the wires can be slide by one another to conform to and duplicate any irregular curve. Another effective means of measurement consists of using a long straight edge to span the area of metal loss and a narrow or sharpened scale to measure from the straight edge to the bottom of the pits at intervals along the corrosion.

As seen in Figures A-1 and A-2, several profiles of the metal loss are measured parallel (or nearly parallel) to the axis of the Pipe. In some cases (Figure A-2, for example), it may be preferable to select profiles that are slightly at an angle to the axis of the pipe to

minimize the number of profiles taken. However, the deviation from the axial direction must not exceed 5 degrees or so; otherwise, the profile will be significantly affected by the curvature of the pipe. The main idea in selecting profiles is to record the deepest areas of metal loss within the boundaries of the corroded area.

The next step in calculating the remaining strength consists of compiling the "worst case" composite of all of the profiles within a given metal-loss area. For example, as shown in Figure A-1, 4.5 inches of Profile C and 1.5 inches of Profile B located as shown seemed to constitute a worst-case composite profile. Combining profiles in this manner is necessary because it has been observed in tests of corroded pipe that the origin of failure encompasses the thinnest regions as one might logically expect. Obviously, there are limits beyond which widely separated profiles need not be combined if they cannot possibly interact. Thus, combining profiles requires some judgement based upon experience. When experienced personnel are not available, the most conservative procedure is to combine the worst-case profile from all of the individual profiles regardless of their circumferential separation.

Calculating Remaining Strength

Calculations of remaining strength are made on the basis of the area of missing metal in the composite profile. A convenient means of quantifying the area is illustrated in Figure A-3. The depths of metal loss at regular intervals are recorded (every 1/4 inch in the case of Figure A-3). The area is calculated from the resulting trapezoids as follows.

$$A = \ell\left(\frac{h_0 + h_1}{2}\right) + \ell\left(\frac{h_1 + h_2}{2}\right) + \ldots + \ell\left(\frac{h_{n-1} + h_n}{2}\right)$$

$$= \ell\left[h_0/2 + h_n/2 + \sum_{i=2}^{n-1} h_i\right] \qquad (1)$$

where

A is the area of the missing metal, $inch^2$

ℓ is the uniform interval between depth measurements, inch

hi is the depth measurement at a given interval

h_o and h_n are the depths at the edge of the corroded area (Note: Ideally, h_o and h_n should be zero indicating a return to full wall thickness. This may not always be the case, however).

The area of missing metal, A, is used to calculate remaining strength via the following equations.

$$S_f = \bar{S} \left[\frac{1 - A/A_o}{1 - (A/A_o)(M_T^{-1})} \right] \tag{2}$$

$$M_T = \left[1 + 0.6275 \frac{L^2}{Dt} - 0.003375 \frac{L^4}{D^2 t^2} \right]^{1/2} . \tag{3}$$

when $(L^2/Dt) \leq 50$

$$M_T = 0.032(L^2/Dt) + 3.3. \tag{4}$$

when $(L^2/Dt > 50$

where

S is the hoop stress at failure, psi

Š is the flow stress of the material, (yield strength + 10,000 psi)

D is the diameter of the pipe, inches

t is the wall thickness of the pipe, inch

L is the axial length of the corroded region, inches.

For irregular defects such as corrosion, calculating remaining strength on the basis of the total area and total length of the defect does not always lead to the minimum value of remaining strength. The

minimum remaining strength can be found by trial and error on the basis of portions of the whole defect. For example, as shown in Figure A-3 one can compare the calculated strengths for the twelve partial defects L_1 through L_{12} to find the minimum value. Thus, the following calculations can be made via Equations 1 through 5. On a conservative bases, $\overline{S}$ is taken to be SMYS + 10,000 = 70,000 psi (D = 36 and t = 0.390).

Corroded Area A

Trial Length	Value of L, inches	Value of A_L, inch^2	Resulting Value of S_L, psi
L_1	5	0.05000	69,867
L_2	10	0.09875	69,491
L_3	15	0.14625	68,926
L_4	20	0.19500	68,208
L_5	25	0.24250	67,419
L_6	30	0.28750	66,633
L_7	35	0.33500	65,816
L_8	40	0.38500	64,987
L_9	45	0.43250	64,241
L_{10}	50	0.47500	63,627
L_{11}	55	0.51000	63,185
L_{12}	60	0.54000	63,096

In this case, the calculation based on Defect L_{12} (the entire defect) does lead to the minimum value of remaining strength. This level of hoop stress corresponds to 105 percent of SMYS and a safe operating pressure level of 984 psig (failure pressure divided by 1.4).

A similar trial and error procedure can be used to evaluate the minimum remaining strength of the defect shown in Figure A-4. In this case, the shape of the defect is quite irregular. Consequently, the minimum value of remaining strength appears to correspond to less than the full length (i.e., to Defect L_7). Notice that the choice of trial defects is somewhat arbitrary. Defects L_{10}, L_{11}, and L_{12} could

have been chosen in numerous ways. Also, in this case the interval between depth measurements is 1/2 inch. Finally, the starting defect, Defect L_1 was centered on the deepest point and not on the physical center of the defect. In any case, Defect L_7, in which L = 7 inches and A = 0.755 inch^2, results in a predicted failure stress level, S, of 59,900 psi. This is based upon $\bar{S}$ = 70,000, D = 36, and t = 0.390. The resulting hoop stress level is 100 percent of SMYS and the safe operating pressure level is 936 psig. The calculated stress levels for each of the trial defects are shown below.

Corroded Area B

Trial Length	Value of L, inches	Value of A, inch^2	Resulting Value of S, psi
L_1	1.0	0.1650	68,908
L_2	2.0	0.2800	67,040
L_3	3.0	0.3825	65,096
L_4	4.0	0.4875	63,233
L_5	5.0	0.5925	61,633
L_6	6.0	0.6900	60,440
L_7	7.0	0.7550	59,990
L_8	8.0	0.7825	60,199
L_9	8.5	0.7875	60,426
L_{10}	7.5	0.7500	60,374
L_{11}	8.0	0.7775	60,271
L_{12}	8.5	0.8125	60,081

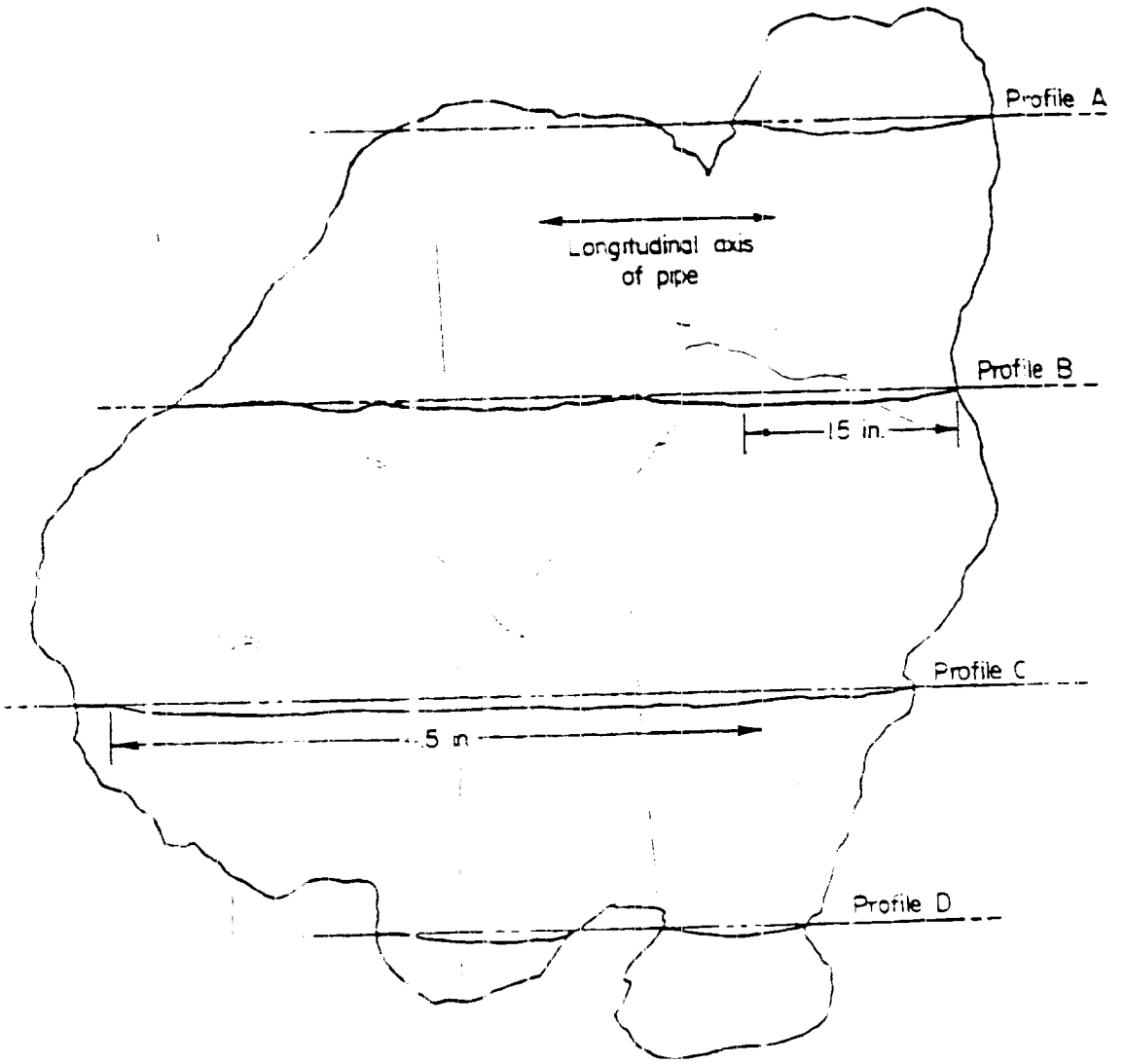

FIGURE A PLAN VIEW AND SELECTED PROFILES OF CORRODED AREA A'

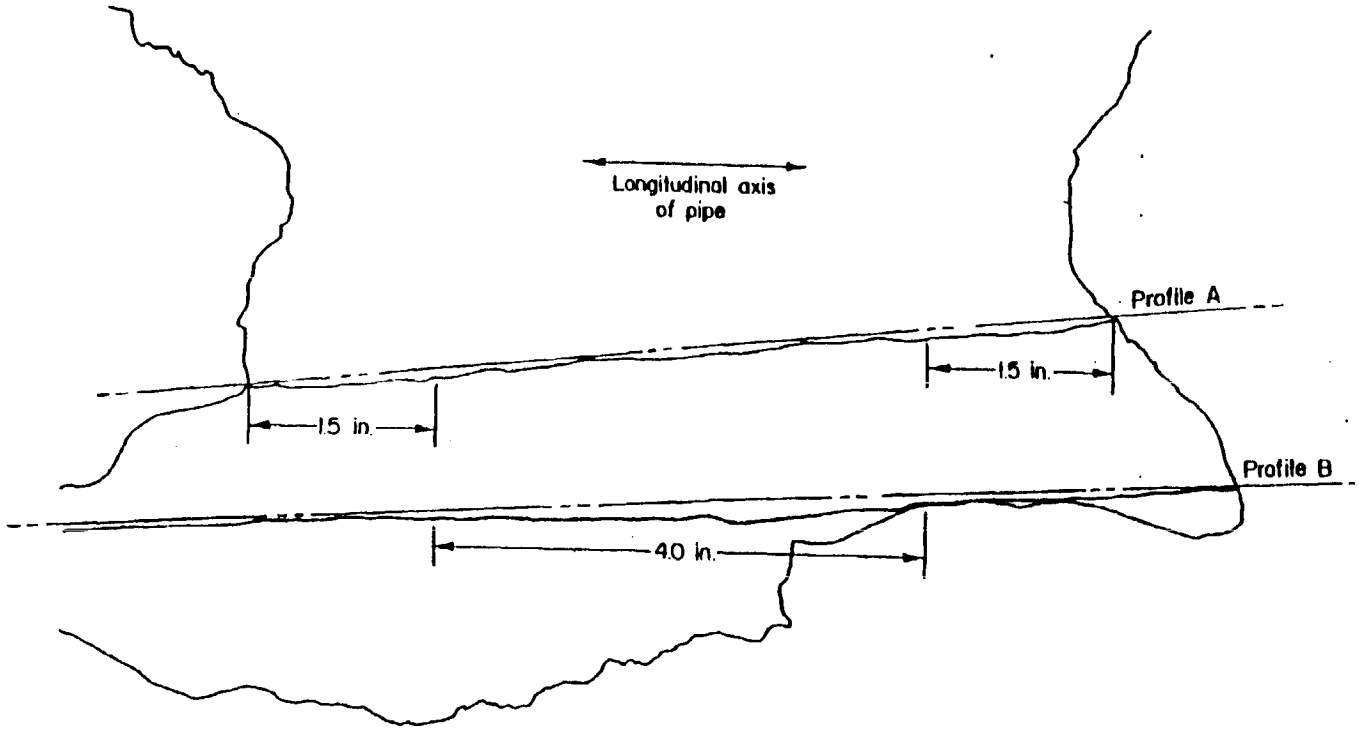

FIGURE A-2. PLAN VIEW AND SELECTED PROFILES OF CORRODED AREA B

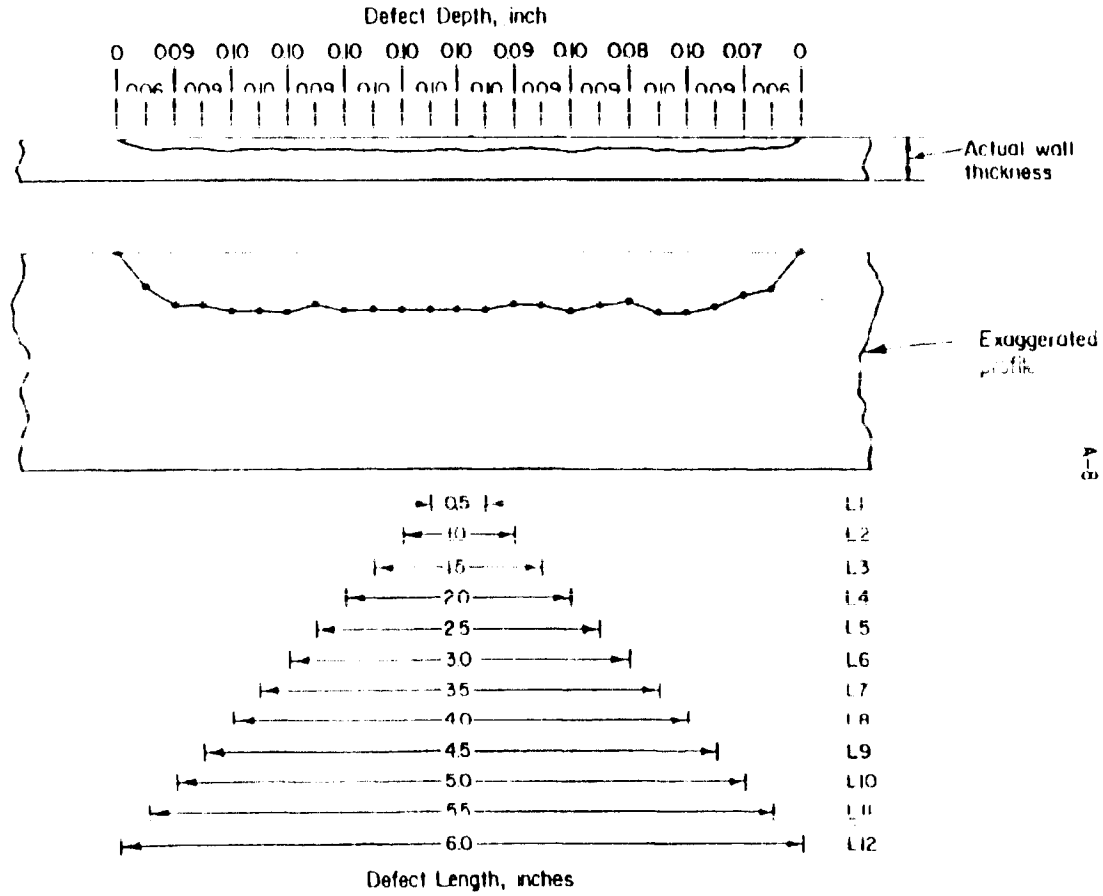

FIGURE A-3. DETAILED MEASUREMENTS FOR CALCULATION OF REMAINING STRENGTH OF CORRODED AREA A

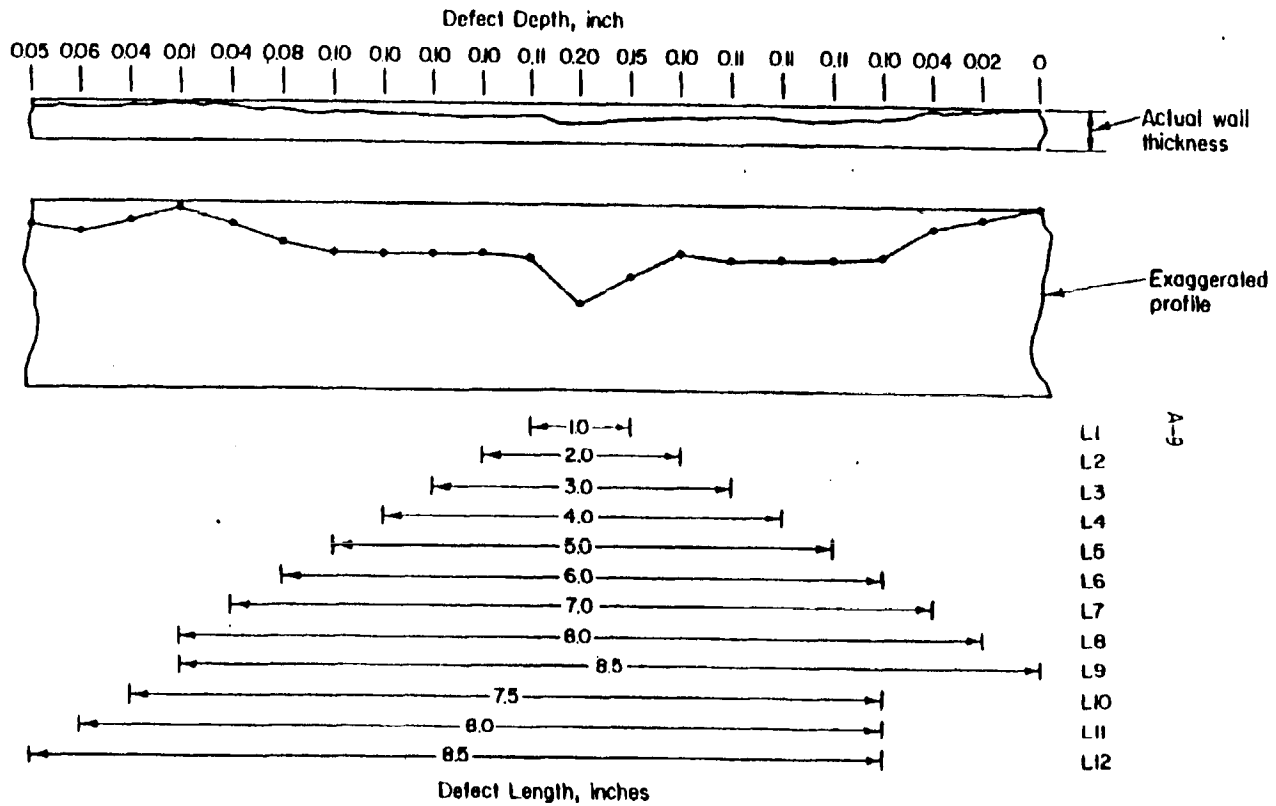

FIGURE A 4. DETAILED MEASUREMENTS FOR CALCULATION OF REMAINING STRENGTH OF CORRODED AREA B

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APPENDIX B

RSTRENG MANUAL

```
RRRRRRR     SSSSSSS   TTTTTTTT   RRRRRRR     EEEEEEE    NN     NN    GGGGGGGG
RR    RR    SS            TT     RR    RR    EE         NNN    NN    GG     GG
RR    RR    SS            TT     RR    RR    EE         NN NN  NN    GG
RRRRRRR     SSSSSSS       TT     RRRRRRR     EEEEE      NN  NN NN    GG  GGGG
RR    RR          SS      TT     RR    RR    EE         NN   NN N    GG  G GG
RR     RR         SS      TT     RR     RR   EE         NN    NNN    GG     GG
RR     RR   SSSSSSS       TT     RR     RR   EEEEEEE    NN     NN    GGGGGGGG
```

Ver. 2.0

This RSTRENG program was developed by Battelle Memorial Institute for the American Gas Association.

Contractual obligations apply to this program which restrict any copying AND use.

Because of the research nature of this work, the user undertakes the sole responsibility for the consequences of any use, misuse or inability to use, any information or results obtained from the RSTRENG program.

INTRODUCTION

RSTRENG has been written to predict the remaining strength of corroded line pipe using methods outlined in the text.. RSTRENG was written to be supported by DOS version 3.0 or higher. Some problems may be encountered if any earlier versions of DOS are used but the program should still be operational.

This version of RSTRENG (Ver. 2.0) is not compatible with the data files that have been generated using the previous version of RSTRENG (Ver. 1.0). The reason for this is that both the Specified Minimum Yield Strength and the actual Yield Strength are both being used as part of the data file. Previously, only the Specified Minimum Yield Strength was being used.

Throughout the program, a display will appear in the upper-left corner of the screen. This display references the location in this manual where the user can obtain additional information or help.

There are 6 main areas that will be described below which include:

A.	Getting started,
B.	INTRODUCTION to the program,
C.	INPUT of the data,
D.	EDIT the data,
E.	ANALYSIS, and
F.	Explanation of output files.

A few terms that will be used throughout this manual are explained below.

<CR>	short for carriage return or enter,
<ARROWS>	arrow keys used to move the cursor around the screen,
<HOME>	the HOME key found on the keyboard,
<PAGE UP>	the PAGE UP key found on the keyboard,
<PAGE DOWN>	the PAGE DOWN key found on the keyboard,
<ECS>	the ESCAPE key found on the keyboard, or
PATH	a location for the disk drive (either hard disk or floppy disk) such as "A:\" or "C:\" or "C:\DATA\",

A. GETTING STARTED

A-1. This program was developed for people with a general knowledge of the DOS operating system. An overview of how-to get started is given below. You can refer to your DOS manual to perform such operations as creating subdirectories and getting around on a hard disk drive system.

If you are going to be operating the program from a 5.25 inch drive system, insert the RSTRENG disk into the drive (for example, the A drive) then type:

A <CR>
RSTRENG <CR>.

At this point, the introduction to the program will be displayed on the screen.

If you are going to be operating the program from the hard disk drive, insert the RSTRENG disk into the floppy disk drive (for example either A: drive or B: drive), move to the location on the hard disk drive where you want to place the program (for example, CD\RSTRENG to move to the subdirectory titled RSTRENG if it exists) then type:

COPY A:* <CR>
RSTRENG <CR>

At this point, the introduction to the program will be displayed on the screen.

B. INTRODUCTION TO THE PROGRAM

B-1. INTRODUCTION. Once the program has been started, the introduction to RSTRENG informs the user of the restrictions for use of the program. This introduction will be displayed each time the program is started.

The version of RSTRENG being used is displayed in the top-right corner of the screen.

User Options

< Hit ANY KEY to continue with the program.

B-2 INTRODUCTION. After hitting any key to continue a short explanation of program is displayed on the screen, filenames for output of the calculated results, and the factors used to determine the predicted failure pressure for a given anomaly. At this point, the user is prompted to decide on filenames to store the results.

There are two files that will be created each time the program is started. The default filenames are displayed on the screen (RSTRENG.OUT and RSTRENG.PLT) and the disk drive being used to store the results (for example, A:\ or C:\) is displayed in the top-right corner. An explanation of the use of these two files can be found in SECTION F of this manual.

If the user decides to use the output filenames displayed on the screen, then enter <CR>. WARNING: If these files exist, they will be overwritten. The user will then proceed with the MAIN MENU of the program which is explained in SECTION B-4.

If the user decides to change the output filenames, then use the ARROW KEYS to move the cursor at the bottom of the screen to highlight "Change OUTPUT filename", then <CR>

B-3. CHANGE OUTPUT FILENAMES. If the user has decided to change the output filenames, then the user will be prompted to enter the first eight characters for the output filename at the bottom of the screen.

User Options

< >	enter any valid character to be used for the output filename (for example, "C:\SAMPLE"),
<BACKSPACE>	to delete any characters,
<ESC>	returns the user to the introduction without making any of the changes, or
<CR>	enters the filename at the bottom of the screen to be used for the output files.

The program will accept up to 8 characters to be used for the output filename and automatically give an extension of ".OUT" and ".PLT". For example, if "C:\SAMPLE" is entered as mentioned in the example above, two files will be created and named "C:\SAMPLE.OUT" and "C:\SAMPLE.PLT". The user will then be returned to the screen explained in SECTION B-2 and will need to enter <CR> to select output filenames as they are displayed in the center of the screen.

B-4. MAIN MENU. The main menu allows the user to either input data, edit data, analyze the data, or quit the program.

User Options

<ARROW KEYS>	highlight the desired module, or
<CR>	selects the highlighted module.

After the desired module has been selected, then the program will continue with the selected module as explained in each section below.

C. INPUT DATA

C-1. INPUT SECTION - The user is prompted to enter a path and filename at the bottom of the screen for the data file. It is suggested that the filename have an extension of ".RST" in order to keep the data used for this program in order (for example, "C:\DATSET1.RST").

User Options

< >	enter any valid character to be used for the filename (for example, "C:\DATSET1.RST").
<BACKSPACE>	to delete any characters,
<ESC>	returns the user to the MAIN MENU, or
<CR>	enters the filename at the bottom of the screen to be used for the data file.

WARNING. If the data file exists, it will be overwritten.

C-2. INPUT SECTION. The user has the option to enter either PIT DEPTH MEASUREMENTS or REMAINING WALL THICKNESS measurements. The filename being used to store the data appears in the top-right corner of the display.

User Options

<ARROW KEY>	highlight option,
<ESC>	returns to the MAIN MENU, or
<CR>	selects the highlighted option.

C-3. INPUT SECTION. The user will be prompted at the bottom of the screen to enter all of the necessary information to be used in the analysis. The user should enter the desired input at the bottom of the screen then <CR> to enter. After each <CR>, the information will be written to the screen. The necessary input are:

SPECIMEN IDENTIFICATION.	enter any identification or <CR> to leave blank,
COMMENT.....	enter any comment or <CR> to leave blank,
DIAMETER.....	enter nominal diameter (inches),
THICKNESS.....	enter actual or nominal wall thickness (inches),
YIELD STRENGTH.....	enter the yield strength (psi.) if available otherwise enter the SMYS (psi.),
SMYS.....	enter the specified minimum yield strength (psi.),
LENGTH.....	enter the length of the anomaly (inches), and
INCREMENT.....	enter the spacing increment between measurements (inches).

The measurements along the anomaly must have an equal spacing between the measurements.

If the user selected to enter pit measurements, then a prompt will appear at the bottom of the screen to enter the pit depths measured in thousandths of an inch (MILS) to the nearest MIL.

If the user selected to enter remaining wall thickness measurements, then a prompt will appear at the bottom of the screen to enter the remaining wall thickness measured in thousandths of an inch (MILS) to the nearest MIL. The remaining wall thickness will be subtracted from the wall thickness-and the pit measurement will be displayed on the screen.

User Options

< >	enter any valid character or number for corresponding input,
<BACKSPACE>	to delete any characters,
<ECS>	returns the user to the MAIN MENU without saving, or

User Options (Cont.)

<CR>	enters the information at the bottom of the screen to be written to the data file.

After the final pit depth measurement or remaining wall thickness measurement has been entered all of the data will be written to the file displayed in the top-right corner. The user will then be returned-to the MAIN MENU.

The data is stored in ASCII format. Table B-I shows an example of a data file that has been created along with an explanation.

D. EDIT SECTION

D-1. EDIT SECTION. The user must first select the file to be edited. If the desired filename exists on the screen, then use the ARROW KEYS to highlight the desired filename then <CR>. If there are more filenames than appear on the screen ("-- PAGE DOWN --" appears near the bottom of the screen), then enter <PAGE DOWN> see more filenames.

User Options

<ARROW KEYS>	highlight filename
<PAGE DOWN>	shows additional filenames if applicable.
<ESC>	returns to MAIN MENU.
<HOME>	to change the path and or default listing (See SECTION D-Z), or
<CR>	selects the highlighted filename and the user proceeds with SECTION D-3

D-2. EDIT SECTION. If the desired filename does not appear on the screen, then the user must change the path and/or default listing. This is accomplished by entering <HOME> in SECTION D-I. The user can enter the location of the files to be listed to select from or simply enter the path and filename to be used.

For Example:

C:*.RST	will list all files that have an extension of "RST" on the C drive,
A:\S*.RST	will list all of the files on the A drive that begin with an S,
C:\S*.RST	will list all of the files on the C drive that begin with an S and have an extension of "RST", or
C:\DATSET1.RST	will list just the filename "DATSET1.RST" to the screen.

User Options

< >	enter any valid character for the path and default listing (for example, C:*.RST),
<BACKSPACE>	to delete any characters,
<ESC>	returns the user to the MAIN MENU without saving, or
<CR>	enters the path and default listing.

D-3. EDIT SECTION. Once a data file has been selected to be edited, the options will appear at the bottom of the screen. The specific data is all of the data located on the left side of the screen and the pit measurements are located on the right side of the screen. The path and filename being edited is displayed in the top-right corner of the screen. Use the ARROW KEYS to highlight the desired option. The choices are:

Edit Specific Data	allows user to edit the data on the left side of the screen,
Edit Pit Measurements	allows user to edit the data on the right side of the screen,
Abort Changes	ignores any changes made and returns to the MAIN MENU, and
Quit and Save	saves the changes as they appear on the screen and returns to the MAIN MENU.

User Options

<ARROW KEYS>	highlight desired option,
<ESC>	returns to MAIN MENU without saving any Changes, OR

User Options (Cont.

<CR selects the highlighted option.

Once "Quit and Save" has been selected the user is returned to the MAIN MENU.

D-4. EDIT SECTION Once one of the four options described above has been selected, the cursor will appear in the appropriate screen (i.e., either the left side or right side of the screen). Use the ARROW KEYS to move the cursor and highlight the data to be changed. Once the data that is to be changed has been highlighted, enter <CR> At this point, a prompt will appear at the bottom of the screen to enter the new data then enter <CR> when done.

User Options

<	enter any appropriate valid character or number.
<BACKSPACE>	to delete any characters or numbers.
<ES	returns the options available in SECTION D-3 without saving the change, or
<CR	enters the new character or number on the screen.

After the new character or number has been entered, the user again has the options available in SECTION D-3

E. ANALYSIS

E-1. ANALYSIS SECTION The user must first select the file to be analyzed. The default listing of filenames lists all of the filenames with an extension of ".RST" in the current directory or drive location.

If the desired filename exists on the screen, then use the ARROW KEYS to highlight the desired filename then <CR> If there are more filenames than appear on the screen, then enter <PAGE DOWN> to see more filenames

User Options

<ARROW KEYS>	highlight filename
<PAGE DOWN>	shows additional filenames if applicable.
<ES	returns to MAIN MENU.

User Options (Cont.)

<HOME>	to change the path and/or default listing (See SECTION E-2), or
<CR>	selects the highlighted filename and the user proceed with SECTION E-3.

E-2. ANALYSIS SECTION. If the desired filename does not appear on the screen, then the user must change the path and/or default listing. This is accomplished by entering <HOME> in SECTION E-l. The user can enter the location of the files to be listed to select from or simply enter the path and filename to be used.

For Example:

C:*.RST	will list all files that have an extension of "RST" on the C drive,
A:\S*.RST	will list all of the files on the A drive that begin with an S,
C:\S*.RST	will list all of the files on the C drive that begin with an S and have an extension of "RST", or
C:\DATSET1.RST	will list just the filename "DATSET1.RST" to the screen.

Once the data files are listed on the screen, the user has the option to select a data file to be analyzed. The user also has the option to select "*** ALL ***" which will analyze all of the data files listed on the screen assuming each of the files are in RSTRENG format. If "*** ALL ***" is selected, an analysis will be performed on each of the data files, the results will be written to the output files of results, and the MAIN MENU will appear when completed.

User Options

< >	enter any valid character for the path and default listing (for example, C:*.RST),
<BACKSPACE>	to delete any characters,
<ESC>	returns the user to the MAIN MENU without saving, or
<CR>	enters the path and default listing.

E-3. ANALYSIS SECTION. If a single data file is selected to be analyzed, "CALCULATING" will appear on the middle of the screen while the program is calculating the results. Once the program has completed the calculations, the results will appear on the screen. The screen will be similar to the output shown in the upper portion of Table B-2

Above the profile data corresponding to the analysis are presented such as the specimen identification date of the analysis, pipe diameter (D), wall thickness (t) yield strength (YS), and any comment that appears in the data file.

A corrosion profile will appear in the middle of the screen The length (in inches) in the axial direction for the anomaly appears above the profile The pit depths (in inches) appear along the left side of the profile The asterisks ("*"s) correspond to each measured pit depth that had been entered into the data file

Below the corrosion profile is the predicted minimum failure stress and failure pressure (related by means of the Barlow equation) based on 100% of the yield strength. The arrows above the corrosion profile indicate the location along the profile where the minimum predicted failure pressure was determined The minimum failure pressure is determined by an iterative approach which encompasses every combination of lengths (L) and areas along the corrosion profile. The predicted failure pressure is determined by:

$$P = (2t/D) * (YS+10\ ksi) * \frac{[1 - A/Ao]}{[1 - (A/Ao)MT^{-1}]} \qquad \text{(B-1)}$$

$$MT = \left[1 + \frac{1.255\ L^2}{2Dt} - \frac{0.0135\ L^4}{4(Dt)^2} \right]^{1/2} \qquad \text{(B-2)}$$

where A exact area effected by corrosion,
Ao original area (L*)
MT 3-term Folias Factor,
P is the predicted failure pressure

The 3-term Folias Factor is valid for $L^2/Dt <= 50$ If $L^2/Dt > 50$ then MT is approximated as

$$MT = \frac{0.032\ L^2}{Dt} + 1.3 \qquad \text{(B-3)}$$

If a predicted failure pressure is displayed on the screen and has used the above MT approximation (for $L^2/Dt > 50$ then a note staturg "USE WITH CAUTION" will appear next to the predicted failure pressure

This analysis is valid only when the maximum measured pit depth (dmax) is less than 80-percent of the wall thickness (t). If the maximum measured pit depth exceeds B&percent of the wall thickness, then a note will appear next to the wall thickness shown above the profile (See Table B-3 for example).

User Options

<CR>	writes the results to the output files of results and returns to the MAIN MENU,
<ESC>	returns to the MAIN MENU without writing the results to the output files
<UP ARROW>	allows the user to redefine the endpoints used in the calculation of predicted failure pressure (SECTION E-4)
<PAGE DOWN>	allows the user to review other calculation methods used to predict the failure pressure (SECTION E-5).

E-4. If the user decided to manually chose the endpoints (by selecting <UP-ARROW> in SECTION E-3), then the user will use the Arrow keys to move across the top on the corrosion profile and select the first and last pit measurement by entering a <DOWN ARROW> to make the selection. By selecting the first and last pit measurement, the user is specifying the length (L) and areas (A and Ao) as defined in Equation B-I.

User Options

<LEFT ARROW>	moves the cursor to the left across the top of the corrosion profile
<RIGHT ARROW>	moves the cursor to the right across the top of the corrosion profile
<DOWN ARROW>	select the point as either the first or last data point
<ESC>	returns the user to the previous corrosion profile and results without making any changes and the user has the User Options in E-4.

Once the user has selected the first and last pit measurement the calculation will be performed and the results will be displayed on the screen. The user again has the User Options given defined in SECTION E-3

CAUTION: Once the user has manually selected endpoints, the predicted failure pressure is no longer the minimum. If the predicted failure pressure is the minimum, then MINIMUM FAILURE STRESS and MINIMUM FAILURE PRESSURE will be displayed below the corrosion profile. If the predicted failure pressure is not the minimum, then PREDICTED FAILURE STRESS and PREDICTED FAILURE PRESSURE will be displayed below the corrosion profile. Table B-3 is an example of predicted failure pressure not being the minimum failure pressure

E-5. If the user decided to review other calculation methods (by selecting <PAGE DOWN> in SECTION E-3) then the results of additional calculation methods along with a listing of the pit measurements will be displayed on the screen. There are two additional calculation methods shown that are based on the FULL LENGTH of the anomaly. These additional predictions are determined by

CASE 2

$$P' = (2t/D)(Y' + 10\ ksi)\frac{[1 - A/Ao]}{[1 - (A/Ao)*MT^{-1}]} \qquad \text{(B-4)}$$

where A = (.85*dmax*L)
Ao = (L*t)
dmax = maximum corrosion pit depth

For L/Dt <= 50, MT is defined by Equation B-2
For L/Dt > 50, MT is defined by Equation B-3

CASE 3

For L/Dt <= 20 then

$$P' = (2t/D)(1.1*SMYS)\frac{[1-A2/Ao]}{[1-(A2/Ao)*MT2^{-1}]} \qquad \text{(B-5)}$$

where A2 = (2/3)(dmax*L)

$$MT2 = \left[1 + \frac{0.8\,L^2}{Dt}\right]^{1/2}$$

For L/Dt > 20 then

$$P' = (2t/D)(1.1*SMYS)[1-dmax/t]. \qquad \text{(B-6)}$$

An example of the output when Equations B-4 and B-6 have been implemented can be found in Table B-2. An example of the output when Equations B-5 and B-7 have been implemented can be found in Table B-3.

User Options

< >	hit any key to return to the corrosion profile.

F. EXPLANATION OF RESULTS

F-I. There are 2 files created to store the results of all of the analyses performed during the program execution. One of the files has an extension of ".OUT" and the other has an extension ".PLT". Each of these files are described below.

F-2. ".OUT". This file has been created to store the results of the analyses and specifically created to be incorporated into a spreadsheet such as LOTUS I-2-3. In order to use the results in this file, refer to the LOTUS manual for IMPORTING NUMBERS into a spreadsheet. If you are familiar with LOTUS, the results-can be brought into the spreadsheet by means of File-Import-Numbers. A sample of the results found in this file can be found in Table B-4. The results given in this table were produced using the 86 anomalies that were evaluated for this project. An explanation for each column of results is given below:

File	filename of data analyzed
Ident.	specimen identification
Diam.	pipe diameter (inch)
Thick.	pipe wall thickness (inch)
Yield Strength	yield strength (psi.)
SMYS	specified minimum yield strength (psi.)
Spacing Increment	length of spacing between measurements (inch)
Total Length	total length of the anomaly (inches)
Start Location	pit measurement number for the starting location of the failure pressure prediction,
Stop Location	pit measurement number for the stopping location of the failure pressure prediction,
Effective Length	effective length of anomaly used for the failure pressure prediction (inches),
Effective Ex. Area	effective exact area of corrosion used for the failure pressure prediction,
Maximum Pit Depth	maximum measured pit depth (dmax) along the total length of the anomaly (inch),
CASE 1 Press.	predicted failure pressure using the Modified Criterion (psi.),

CASE 2		predicted failure pressure using the Modified Criterion except that A = 0.85*dmax*Total Length.'
CASE 3		predicted failure pressure using the B31G criterion and
NOTES	a)	Alerts that the maximum pit depth exceeds 80-percent of the wall thickness,
	b)	Alerts that the predicted failure press (CASE 1) is <u>not</u> the minimum,
	c)	Alerts that (Length)^2/Dt > 50 and the Folias factor (MT) has been approximated for CASE 1,
	d)	Alerts that (Total Length)^2/Dt > 50 and alternative calculation methods outlined in SECTION E-5 have been used for CASE 2, and
	d)	Alerts that (Total Length)^2/Dt > 20 and alternative calculation methods outlined in SECTION E-5 have been used for CASE 3.

F-3. "PLT". This file has been created to store the results of the analyses and specifically created to be incorporated into a word processor (for example, WordPerfect). The output file has been created by namely using ASCII characters so refer to your word processor manual on retrieving DOS text. A sample of the results found in this file can be found in Table B-2.

Explanation of the output along the top of the page

File name	filename of the data file used for the analysis,
Specimen	the specimen identification for the anomal,
Date	the date of the analysis
Diameter	pipe diameter (inches),
Thickness	pipe wall thickness (inch)
Yield Str	yield strength (psi.)
Comment	comment that was entered in the data file.

Explanation of the corrosion profile

A profile of the total length of the corroded area is presented in the center of the page. The asterisks (*'s) designate the location of the pit depth measurements along the anomaly. The numbers above the profile refer to the length of the anomaly (in inches) in the axial direction. The numbers along the left side of the profile indicate the measured pit depth (in inches). The arrows (or exclamation marks) along the top of the corrosion profile indicate the end points used to determine the predicted failure stress and pressure by means of the iterative calculation method. If the MINIMUM failure stress and pressure are being provided,

then the captions below the corrosion profile will specify MINIMUM FAILURE STRESS and MINIMUM FAILURE PRESSURE. If the failure pressure predictions being provided are not the minimums, then the captions below the corrosion profile will specify PREDICTED FAILURE STRESS and PREDICTED FAILURE PRESSURE.

If a predicted failure pressure is displayed on the screen and has used the MT approximation (for $L^2/Dt > 50$), then a note stating "USE WITH CAUTION" will appear next to the predicted failure pressure.

Explanation of the output along the bottom of the page:

All of the pit depth measurements (MILS) are provided along the bottom of the page for the total length of the anomaly. If any of the modified calculation methods for CASE 2 and CASE 3 exceed there corresponding $(\text{Total Length})^2/Dt$ limitations, then a footnote will appear below the pit depth measurements. An example of this can be found in Table B-3.

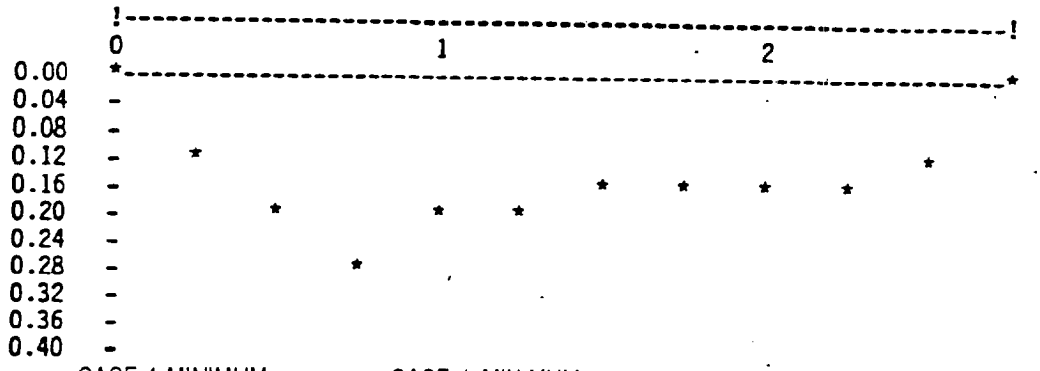
Table B-1

RSTRENG	-	always the first line of file
Sample 1	-	specimen identification
Mile 126.2	-	comment
12	-	number of measurements
24	-	pipe diameter (inches)
.365	-	pipe wall thickness (inch)
41800	-	yield strength (if available) (psi.)
35000	-	specified minimum yield strength (psi.)
2.75	-	length of anomaly
.25	-	length of spacing between measurements
0	-	Pit Depth Measurement (MILS) #1
134	-	Pit Depth Measurement (MILS) #2
185	-	Pit Depth Measurement (MILS) #3
261	-	Pit Depth Measurement (MILS) #4
219	-	Pit Depth Measurement (MILS) #5
185	-	Pit Depth Measurement (MILS) #6
151	-	Pit Depth Measurement (MILS) #7
175	-	Pit Depth Measurement (MILS) #8
175	-	Pit Depth Measurement (MILS) #9
151	-	Pit Depth Measurement (MILS) #10
134	-	Pit Depth Measurement (MILS) #11
0	-	Pit Depth Measurement (MILS) #12

TABLE B-2. EXAMPLE CORROSION PROFILE

FILENAME: A:\DATSET1 .RST

Specimen = Sample 1 Date = 01-22-1990
Diameter = 24.00 in. Thickness = 0.365 in.
Yield Str. = 41,800 psi. Comment = Mile 126.2



CASE 1 MINIMUM Failure Stress psi.	CASE 1 MINIMUM Failure Pressure (NOTE: No Safety Factor Applied) psi.
44,759	1,361

SMYS = 35,000 psi. (NOTE: No Safety Factors Applied to CASE 1, 2 or 3)
CASE 2 MODIFIED METHOD USING AREA = 0.85 dL :
CASE 3 EXISTING B31G METHOD USING AREA = 2/3 dL : 968 psi:

--- PIT DEPTH MEASUREMENTS (MILS) ----- (MAX; Pit Depth = 0.261 inch) ------

0.00	0
0.25	136
0.50	188
0.75	261
1.00	219
1.25	188
1.50	157
1.75	178
2.00	178
2.25	157
2.50	136
2.75	0

TABLE B-3 EXAMPLE OF THE "PLT" FILE

FILENAME: A:\DATSET2.RST

Specimen = Sample 2 Date = 01-22-1990
Diameter = 24.00 in Thickness = 0.375 in. (dmax >0.8t)
Yield Str = 42,000 psi. Comment = Mile 135.2

```
                !-------------------------------------------!
        0   2   4   6   8  10  12  14  16  18  20  22  24  26  28  30  32
0.00    ---------------------------------------------------------------
0.04    -                                                       *******
0.08    ********  *        *
0.12    -
0.16    -        *        *
0.20    -       *                          ***     **        **   *
0.24    -                  *    ***          *** *  ***    **  * *
0.28    -          ***   *   ****   **** ***      *      **       *
0.32    -             ***              *                  **
0.36    -
0.40    -
```

CASE 1 MINIMUM Failure Stress psi 18,791

CASE 1 MINIMUM Failure Pressure (NOTE: No Safety Factor Applied) psi 587

SMYS = 37,000 psi (NOTE: No Safety Factors Applied to CASE 1, 2 or 3)
CASE 2 MODIFIED METHOD USING AREA = 0.85 dL : 441 psi.
CASE 3 EXISTING B31G METHOD USING AREA = 2/3 dL : (*) 180 psi.

-- PIT DEPTH MEASUREMENTS (MILS) -- (MAX Pit Depth = 0.322 inch) ----

0.00	73	7.50	322	15.00	286	22.50	204	30.00	193
0.50	69	8.00	320	15.50	286	23.00	240	30.50	53
1.00	76	8.50	279	16.00	308	23.50	240	31.00	53
1.50	64	9.00	159	16.50	291	24.00	244	31.50	36
2.00	65	9.50	97	17.00	294	24.50	268	32.00	43
2.50	91	10.00	233	17.50	279	25.00	272	32.50	46
3.00	83	10.50	283	18.00	202	25.50	318	33.00	41
3.50	74	11.00	296	18.50	194	26.00	305	33.50	34
4.00	2[illegible]0	11.50	293	19.00	215	26.50	244		
4.50	1[illegible]2	12.00	271	19.50	252	27.00	238		
5.00	98	12.50	230	20.00	258	27.50	204		
5.50	262	13.00	225	20.50	251	28.00	203		
6.00	275	13.50	246	21.00	269	28.50	226		
6.50	294	14.00	280	21.50	247	29.00	280		
7.00	31[illegible]	14.50	281	22.00	193	29.50	259		

(*) L^2/D^[illegible] 20 P = 1*SMYS*2*t/D*[1-dmax/t] for P <SMYS*2*t/D

TABLE B-4. EXAMPLE OF THE ".OUT" FILE WHICH CONTAINS RESULTS OF THE 86 ANOMALIES

<---------- Filename		SPECIFIC DATA Iden	Diam. inch	Thick. inch	Yield Strength psi.	SMYS psi.	Spacing Increment inch	Total Length inch --------->	Start Location	Stop Location	Effective Length in	Effective Ex. Area in^2	Maximum Pit Depth inch	CASE 1 Press. psi.	CASE 2 Press. psi	CASE 3 Press. psi.	NOTES
NUM1	.RST	Sample 1	30.0	0.370	50,700	52,000	0.250	2.500	1	11	2.500	0.233	0.146	1,610	1,426	1,330	
NUM2	.RST	Sample 2	30.0	0.370	50,700	52,000	0.250	2.250	1	10	2.250	0.219	0.146	1,620	1,443	1,342	
NUM3	.RST	Sample 3	30.0	0.370	50,700	52,000	0.250	4.250	1	18	4.250	0.292	0.157	1,500	1,311	1,244	
NUM4	.RST	Sample 4	30.0	0.375	63,000	52,000	0.250	5.500	1	23	5.500	0.472	0.240	1,656	1,060	1,079	
NUM5	.RST	Sample 5	30.0	0.375	50,000	52,000	0.250	4.750	1	20	4.750	0.406	0.269	1,460	1,193	1,187	
NUM6	.RST	Sample 6	24.0	0.365	40,500	35,000	0.250	3.000	1	12	2.750	0.501	0.271	1,215	995	984	
NUM7	.RST	Sample 7	24.0	0.365	40,500	35,000	0.250	4.750	2	18	4.000	0.407	0.251	1,105	893	859	
NUM8	.RST	Sample 8	24.0	0.365	40,500	35,000	0.250	5.250	2	21	4.750	0.939	0.251	1,001	863	859	
NUM9	.RST	Sample 9	24.0	0.370	41,000	35,000	0.250	1.750	1	8	1.750	0.250	0.201	1,506	1,210	1,077	
NUM10	.RST	Sample 10	24.0	0.375	41,000	35,000	0.250	4.250	2	17	3.750	0.711	0.282	1,251	885	870	
NUM11	.RST	Sample 11	24.0	0.365	41,000	35,000	0.250	2.000	1	9	2.000	0.300	0.201	1,455	1,167	1,035	
NUM12	.RST	Sample 12	24.0	0.365	41,000	35,000	0.250	2.250	1	10	2.250	0.287	0.219	1,403	1,191	1,050	
NUM13	.RST	Sample 13	24.0	0.365	41,000	35,000	0.250	2.500	1	11	2.500	0.350	0.230	1,421	1,148	1,021	
NUM14	.RST	Sample 14	24.0	0.365	41,000	35,000	0.250	2.750	1	12	2.750	0.450	0.261	1,301	1,052	988	
NUM15	.RST	Sample 15	24.0	0.380	41,000	35,000	0.250	3.750	1	16	3.750	0.543	0.251	1,305	1,043	987	
NUM16	.RST	Sample 16	24.0	0.370	41,000	35,000	0.250	2.000	1	9	2.000	0.232	0.188	1,516	1,274	1,108	
NUM17	.RST	Sample 17	24.0	0.370	41,000	35,000	0.250	3.000	1	13	3.000	0.403	0.240	1,308	1,095	993	
NUM18	.RST	Sample 18	24.0	0.375	41,000	35,000	0.250	3.750	2	16	3.500	0.307	0.240	1,400	1,047	984	
NUM19	.RST	Sample 19	24.0	0.365	41,000	35,000	0.250	1.750	1	8	1.750	0.272	0.201	1,473	1,194	1,059	
NUM20	.RST	Sample 20	24.0	0.375	41,000	35,000	0.250	2.250	1	10	2.250	0.316	0.251	1,494	1,187	1,059	
NUM21	.RST	Sample 21	24.0	0.375	41,000	35,000	0.250	2.250	2	10	2.000	0.303	0.292	1,430	1,104	1,017	
NUM22	.RST	Sample 22	24.0	0.375	41,000	35,000	0.250	2.500	1	11	2.500	0.271	0.219	1,517	1,210	1,080	
NUM23	.RST	Sample 23	24.0	0.375	41,000	35,000	0.250	2.000	1	9	2.000	0.204	0.188	1,552	1,295	1,124	
NUM24	.RST	Sample 24	24.0	0.375	41,000	35,000	0.250	2.250	1	10	2.250	0.253	0.177	1,527	1,208	1,110	
NUM25	.RST	Sample 25	24.0	0.380	41,000	35,000	0.250	5.000	2	21	4.750	0.869	0.271	1,208	890	871	
NUM26	.RST	Sample 26	30.0	0.375	62,000	52,000	0.250	2.750	1	12	2.750	0.392	0.375	1,030	811	1,031 (a)	
NUM27	.RST	Sample 27	30.0	0.375	61,300	52,000	0.250	5.500	1	22	5.250	0.822	0.146	1,082	1,301	1,240	
NUM28	.RST	Sample 28	30.0	0.375	62,000	52,000	0.250	4.500	1	19	4.500	0.319	0.115	1,070	1,390	1,309	
NUM29	.RST	Sample 29	30.0	0.375	60,200	52,000	0.250	4.000	1	17	4.000	0.421	0.230	1,723	1,190	1,173	
NUM30	.RST	Sample 30	30.0	0.375	70,000	52,000	0.200	1.000	1	9	1.000	0.183	0.209	1,900	1,405	1,385	
NUM31	.RST	Sample 31	30.0	0.375	60,500	52,000	0.200	2.000	1	11	2.000	0.209	0.209	1,845	1,427	1,337	
NUM32	.RST	Sample 32	20.0	0.325	41,000	35,000	0.250	5.750	2	23	5.250	0.576	0.209	1,330	988	883	
NUM33	.RST	Sample 33	20.0	0.325	41,100	35,000	0.250	6.500	3	24	5.250	0.491	0.219	1,394	842	841	
NUM34	.RST	Sample 34	18.0	0.310	28,000	25,000	0.250	4.500	3	18	3.750	0.550	0.230	1,102	755	708	
NUM35	.RST	Sample 35	18.0	0.310	28,000	25,000	0.250	5.000	4	20	4.000	0.609	0.240	1,064	688	670	

TABLE B-4 (Cont'd)

SPECIFIC DATA

Filename		Iden	Diam. inch	Thick inch	Yield Strength psi.	SMYS psi.	Spacing Increment inch	Total Length inch	Start Location	Stop Location	Effective Length in	Effective Ex Area in^2	Maximum Pit Depth inch	CASE 1 Press. psi.	CASE 2 Press. psi	CASE 3 Press. psi.	NOTES
NUM36	.RST	Sample 36	18.0	0.310	28,000	25,000	0.250	6.000	6	19	3.250	0.735	0.282	776	481	546	(a)
NUM37	.RST	Sample 37	18.0	0.310	28,000	25,000	0.250	2.750	2	10	2.000	0.849	0.277	1,209	746	726	(a)
NUM38	.RST	Sample 38	18.0	0.310	28,400	25,000	0.250	6.250	2	23	6.250	0.784	0.199	1,064	798	724	
NUM39	.RST	Sample 39	24.0	0.417	50,200	35,000	0.250	13.000	9	49	10.000	1.983	0.290	1,848	781	817	
NUM40	.RST	Sample 40	24.0	0.410	46,000	35,000	0.250	8.000	3	32	7.250	1.766	0.380	1,093	586	688	(a)
NUM41	.RST	Sample 41	24.0	0.396	50,200	35,000	0.250	5.750	0	22	5.500	0.936	0.360	1,299	598	727	(a)
NUM42	.RST	Sample 42	24.0	0.400	50,200	35,000	0.250	3.250	[illegible]	22	3.000	1.355	0.228	2,075	[illegible]	[illegible]	
NUM43	.RST	Sample 43	24.0	0.388	53,900	35,000	1.000	15.000	10	15	5.000	0.978	0.275	1,340	594	292	(b)
NUM44	.RST	Sample 44	24.0	0.384	52,000	35,000	1.000	13.000	2	11	9.000	1.550	0.254	1,210	671	705	
NUM45	.RST	Sample 45	24.0	0.355	52,000	35,000	0.250	8.500	3	18	8.750	0.687	0.289	1,592	626	688	(a)
NUM46	.RST	Sample 46	24.0	0.319	47,500	35,000	0.250	5.500	1	22	5.250	0.470	0.210	1,384	737	721	
NUM47	.RST	Sample 47	24.0	0.352	46,000	35,000	0.250	4.500	2	16	4.000	0.512	0.220	1,269	838	797	
NUM48	.RST	Sample 48	24.0	0.375	53,000	35,000	1.000	16.000	4	15	11.000	2.083	0.295	785	559	257	(b)
NUM49	.RST	Sample 49	24.0	0.375	48,000	37,000	0.250	9.000	9	32	5.750	1.593	0.320	813	588	604	(a)
NUM50	.RST	Sample 50	20.0	0.312	50,000	35,000	0.250	12.000	1	48	11.750	2.088	0.252	828	549	231	(a) (b)
NUM51	.RST	Sample 51	20.0	0.305	55,100	35,000	0.500	18.500	5	21	9.000	1.411	0.210	1,000	808	719	
NUM52	.RST	Sample 52	24.0	0.301	47,400	35,000	0.500	16.500	11	19	4.000	0.784	0.319	1,254	454	578	(a)
NUM53	.RST	Sample 53	24.0	0.301	41,200	35,000	0.500	12.500	9	14	2.500	0.504	0.205	1,201	557	634	
NUM54	.RST	Sample 54	24.0	0.355	50,300	35,000	0.500	8.500	7	15	4.000	0.430	0.243	1,560	720	748	
NUM55	.RST	Sample 55	24.0	0.371	45,000	35,000	0.500	10.500	5	22	8.500	1.035	0.270	1,321	656	700	
NUM56	.RST	Sample 56	24.0	0.371	45,000	35,000	0.500	10.500	9	20	5.500	0.799	0.291	1,331	804	875	
NUM57	.RST	Sample 57	24.0	0.372	48,200	35,000	0.500	22.000	18	43	12.500	1.022	0.284	1,508	502	282	(b)
NUM58	.RST	Sample 58	24.0	0.384	48,100	35,000	0.500	8.500	1	18	8.500	1.154	0.224	1,384	829	889	
NUM59	.RST	Sample 59	24.0	0.366	43,000	35,000	0.500	12.500	9	24	7.500	0.815	0.242	1,398	723	740	
NUM60	.RST	Sample 60	24.0	0.366	51,500	35,000	0.500	4.000	1	9	4.000	0.725	0.191	1,433	1,097	984	
NUM61	.RST	Sample 61	24.0	0.368	47,700	35,000	0.500	28.000	29	47	9.000	1.025	0.288	1,391	518	257	(b)
NUM62	.RST	Sample 62	20.0	0.283	37,900	35,000	1.000	30.000	13	28	13.000	3.279	0.274	188	258	36	(a) (b)
NUM63	.RST	Sample 63	20.0	0.274	40,500	35,000	0.500	12.000	11	24	6.500	0.500	0.180	1,070	821	554	(b)
NUM64	.RST	Sample 64	20.0	0.311	35,800	35,000	0.500	6.500	6	16	5.000	0.242	0.239	1,298	633	695	
NUM65	.RST	Sample 65	20.0	0.311	35,800	35,000	0.500	11.000	1	19	9.000	0.815	0.105	1,388	1,000	982	
NUM66	.RST	Sample 66	20.0	0.268	40,200	35,000	0.500	15.500	10	32	11.000	0.789	0.144	1,053	716	470	(b)
NUM67	.RST	Sample 67	20.0	0.309	41,900	35,000	0.500	12.000	8	21	6.500	0.393	0.210	1,412	664	350	(b)
NUM68	.RST	Sample 68	30.0	0.372	60,750	52,000	1.000	36.000	15	33	18.000	1.745	0.130	1,387	1,129	973	(b)
NUM69	.RST	Sample 69	30.0	0.370	52,000	52,000	0.500	12.000	1	25	12.000	1.000	0.250	1,002	980	967	
NUM70	.RST	Sample 70	30.0	0.375	60,284	52,000	0.500	12.000	5	25	10.000	1.190	0.140	1,370	1,100	1,100	

TABLE B-4 (Cont'd)

<---------- Filename		SPECIFIC DATA Iden	Diam. inch	Thick. inch	Yield Strength psi.	SMYS psi.	Spacing Increment inch	--------> Total Length inch	Start Location	Stop Location	Effective Length in	Effective Ex. Area in^2	Maximum Pit Depth inch	CASE 1 Press. psi.	CASE 2 Press. psi	CASE 3 Press. psi.	NOTES
NUM71	.RST	Sample 71	30.0	0.362	63,542	52,000	1.000	20.000	2	20	18.000	1.223	0.145	1,011	1,158	984	(b)
NUM72	.RST	Sample 72	30.0	0.370	59,030	52,000	1.000	20.000	2	20	18.000	1.515	0.150	1,422	1,177	930	(b)
NUM73	.RST	Sample 73	30.0	0.370	62,002	52,000	1.000	33.000	2	20	18.000	1.540	0.110	1,489	1,223	1,022	(b)
NUM74	.RST	Sample 74	30.0	0.370	65,419	52,000	1.000	14.000	8	15	9.000	1.000	0.170	1,518	1,098	1,098	
NUM75	.RST	Sample 75	30.0	0.381	52,000	52,000	0.500	12.000	5	10	5.500	1.030	0.300	1,140	870	819	
NUM76	.RST	Sample 76	30.0	0.370	61,221	52,000	0.500	8.000	1	15	7.000	0.670	0.170	1,542	1,179	1,157	
NUM77	.RST	Sample 77	30.0	0.377	61,794	52,000	0.500	12.000	4	25	10.500	1.020	0.160	1,488	1,137	1,120	
NUM78	.RST	Sample 78	30.0	0.370	60,173	52,000	1.000	9.000	2	9	7.000	0.680	0.110	1,493	1,295	1,230	
NUM79	.RST	Sample 79	24.0	0.375	42,000	37,000	0.500	33.500	12	54	21.000	5.433	0.322	587	441	100	(a) (b)
NUM80	.RST	Sample 80	30.0	0.365	50,000	52,000	0.500	16.000	10	31	10.500	2.233	0.229	894	822	519	(b)
NUM81	.RST	Sample 81	30.0	0.375	60,770	52,000	0.500	27.000	1	55	27.000	5.603	0.245	981	769	496	(b)
NUM82	.RST	Sample 82	30.0	0.375	64,400	50,000	0.500	7.500	1	14	6.500	0.542	0.150	1,840	1,310	1,202	
NUM83	.RST	Sample 83	20.0	0.200	61,000	52,000	0.500	16.000	5	33	14.000	2.490	0.210	884	543	240	(a) (b)
NUM84	.RST	Sample 84	30.0	0.330	65,000	65,000	1.000	16.000	3	14	11.000	2.120	0.210	784	714	445	(b)
NUM85	.RST	Sample 85	30.0	0.290	71,000	60,000	1.000	63.000	15	58	41.000	7.057	0.269	726	338	128	(a) (b)
NUM86	.RST	Sample 86	22.0	0.190	60,007	52,000	1.000	6.000	2	7	5.000	0.409	0.140	844	550	830	

CASE 1 MODIFIED METHOD USING EXACT AREA
CASE 2 MODIFIED METHOD USING AREA = 0.85 dL
CASE 3 EXISTING B31G METHOD USING AREA = 2/3 dL

(NOTE: No Safety Factor Applied to CASE 1, CASE 2, or CASE 3)

(a) Maximum Pit Depth exceeds 80% of the wall thickness - USE WITH CAUTION
(b) For CASE 3, L^2/Dt > 20 P'=1.1*SMYS*(2*t/D)*[1-dmax/t] for P' < SMYS*2*t/D
(c) The MINIMUM failure pressure is not shown

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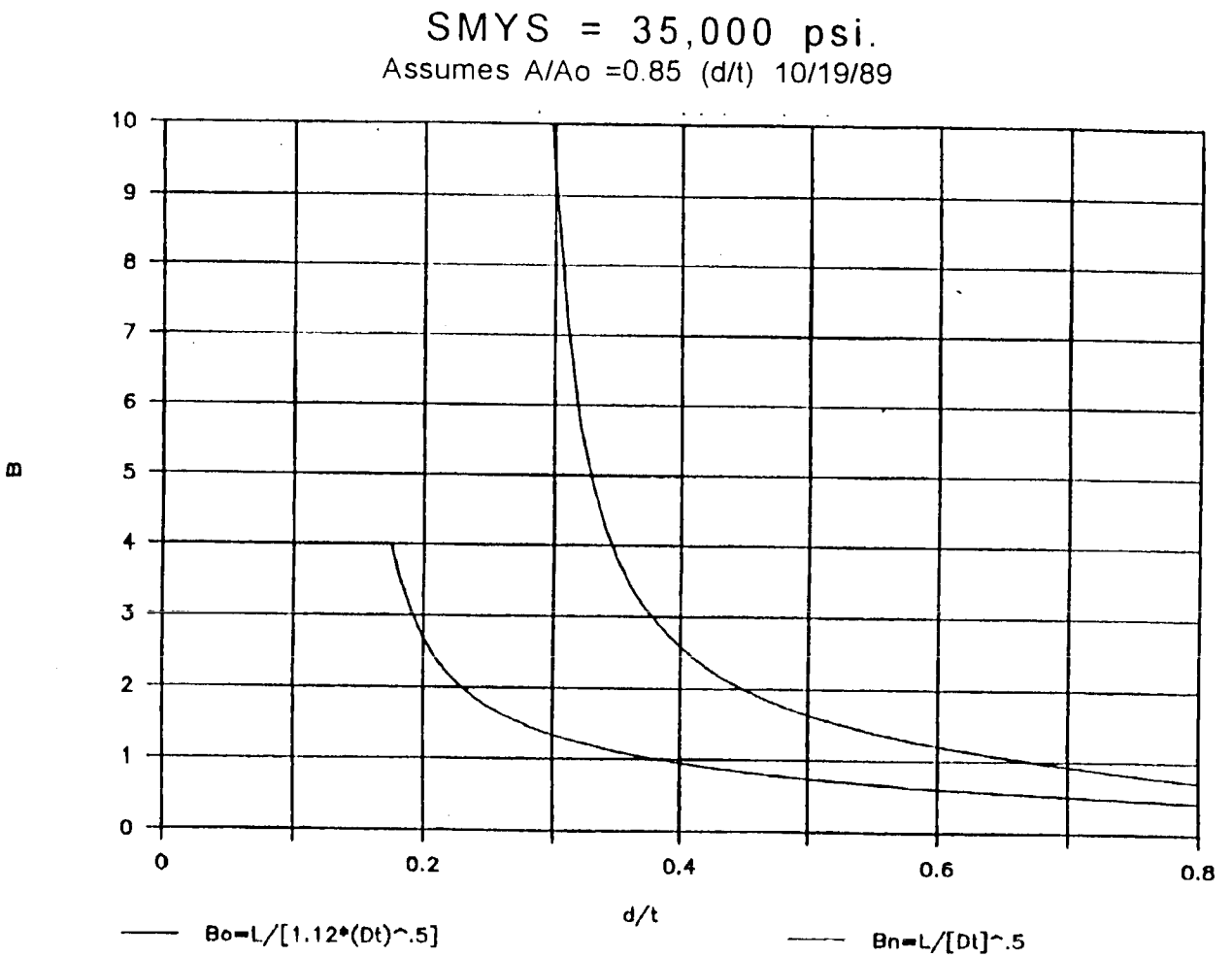
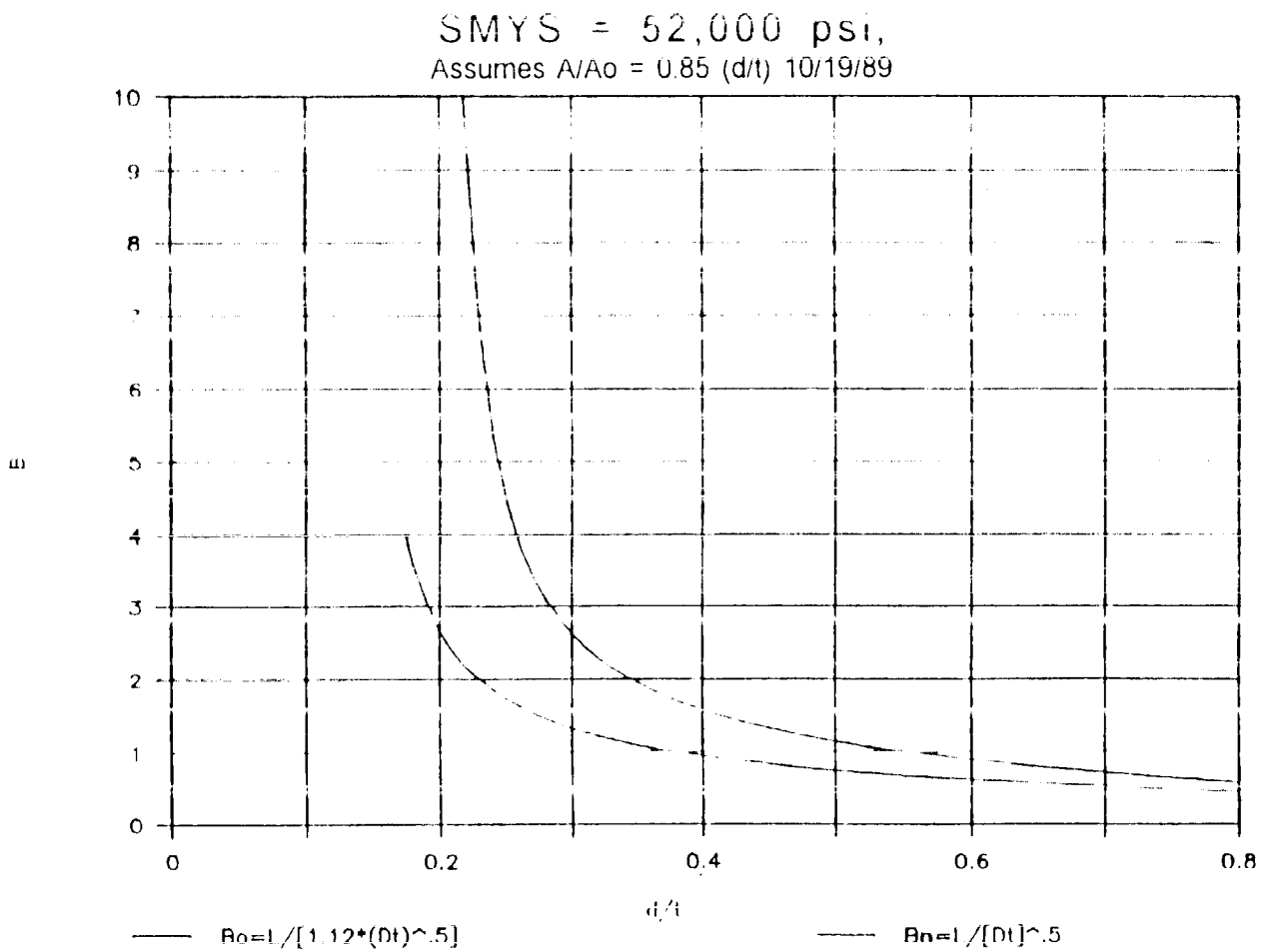
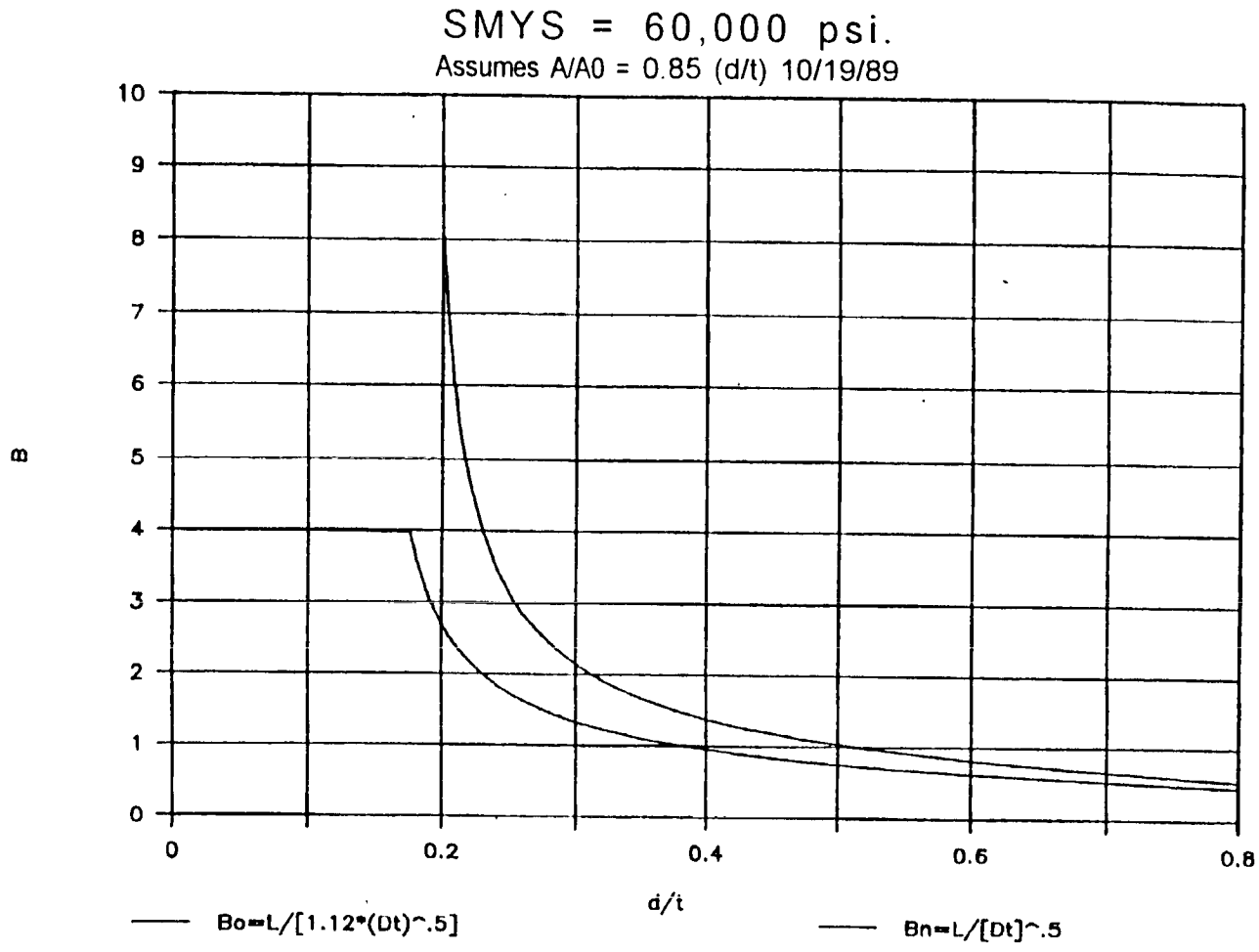
APPENDIX C

TABLES AND CURVES FOR ACCEPTABLE LENGTHS OF CORROSION


SMYS = 35,000 psi.
Assumes A/Ao =0.85 (d/t) 10/19/89
B
10
9
8
7
6
5
4
3
2
1
0
0
0.2
0.4
0.6
0.8
d/t
Bo=L/[1.12*(Dt)^.5]
Bn=L/[Dt]^.5


SMYS = 52,000 psi,
Assumes A/Ao = 0.85 (d/t) 10/19/89
10
9
8
7
6
5
4
3
2
1
0
0
0.2
0.4
0.6
0.8
d/t
Bo=1/[1.12*(Dt)^.5]
Bn=1/[Dt]^.5


SMYS = 60,000 psi.
Assumes A/A0 = 0.85 (d/t) 10/19/89
B
10
9
8
7
6
5
4
3
2
1
0
0
0.2
0.4
0.6
0.8
d/t
Bo=L/[1.12*(Dt)^.5]
Bn=L/[Dt]^.5

Allowable Length of Corrosion Pitting
= 35,000 psi
Diameter = 24.000 inches

Depth of corrosion, inches	Wall Thickness, inch 0.250	0.312	0.375	0.438	0.469	0.500	0.562	0.625
0.02	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)
0.03	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)
0.04	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)
0.05	24.49	(a)	(a)	(a)	(a)	(a)	(a)	(a)
0.06	24.49	(a)	(a)	(a)	(a)	(a)	(a)	(a)
0.07	24.49	27.36	(a)	(a)	(a)	(a)	(a)	(a)
0.08	14.09	27.36	30.00	(a)	(a)	(a)	(a)	(a)
0.09	8.50	27.36	30.00	32.42	(a)	(a)	(a)	(a)
0.10	6.33	15.59	30.00	32.42	33.55	34.64	(a)	(a)
0.11	5.12	10.19	30.00	32.42	33.55	34.64	(a)	(a)
0.12	4.32	7.82	17.25	32.42	33.55	34.64	36.73	(a)
0.13	3.74	6.43	11.88	32.42	33.55	34.64	36.73	38.73
0.14	3.30	5.49	9.31	18.78	32.28	34.64	36.73	38.73
0.15	2.94	4.81	7.75	13.46	19.36	32.12	36.73	38.73
0.16	2.65	4.28	6.69	10.74	14.14	19.92	36.73	38.73
0.17	2.39	3.86	5.90	9.04	11.39	14.80	32.01	38.73
0.18	2.17	3.51	5.29	7.86	9.64	12.02	21.01	38.73
0.19	1.97	3.21	4.80	6.98	8.41	10.23	16.07	32.51
0.20	1.79	2.95	4.39	6.29	7.49	8.95	13.25	22.27
0.21	(b)	2.72	4.04	5.73	6.76	7.99	11.37	17.39
0.22	(b)	2.52	3.74	5.26	6.18	7.24	10.02	14.51
0.23	(b)	2.33	3.48	4.87	5.69	6.62	8.99	12.55
0.24	(b)	2.16	3.24	4.53	5.27	6.11	8.17	11.11
0.25	(b)	(b)	3.03	4.23	4.91	5.67	7.50	10.01
0.26	(b)	(b)	2.84	3.97	4.60	5.29	6.94	9.13
0.27	(b)	(b)	2.66	3.73	4.32	4.96	6.46	8.41
0.28	(b)	(b)	2.50	3.51	4.07	4.67	6.05	7.80
0.29	(b)	(b)	2.34	3.31	3.84	4.40	5.69	7.28
0.30	(b)	(b)	2.19	3.13	3.63	4.16	5.36	6.83
0.31	(b)	(b)	(b)	2.96	3.44	3.95	5.08	6.43
0.32	(b)	(b)	(b)	2.80	3.26	3.75	4.81	6.08
0.33	(b)	(b)	(b)	2.65	3.10	3.56	4.57	5.76
0.34	(b)	(b)	(b)	2.51	2.94	3.39	4.36	5.48
0.35	(b)	(b)	(b)	2.38	2.79	3.22	4.15	5.22
0.36	(b)	(b)	(b)	(b)	2.65	3.07	3.97	4.98
0.37	(b)	(b)	(b)	(b)	2.52	2.93	3.79	4.76
0.38	(b)	(b)	(b)	(b)	(b)	2.79	3.62	4.56
0.39	(b)	(b)	(b)	(b)	(b)	2.66	3.47	4.37
0.40	(b)	(b)	(b)	(b)	(b)	2.53	3.32	4.19
0.41	(b)	(b)	(b)	(b)	(b)	(b)	3.18	4.02
0.42	(b)	(b)	(b)	(b)	(b)	(b)	3.05	3.86
0.43	(b)	(b)	(b)	(b)	(b)	(b)	2.92	3.71
0.44	(b)	(b)	(b)	(b)	(b)	(b)	2.80	3.57
0.45	(b)	(b)	(b)	(b)	(b)	(b)	(b)	3.43
0.46	(b)	(b)	(b)	(b)	(b)	(b)	(b)	3.30
0.47	(b)	(b)	(b)	(b)	(b)	(b)	(b)	3.18
0.48	(b)	(b)	(b)	(b)	(b)	(b)	(b)	3.06
0.49	(b)	(b)	(b)	(b)	(b)	(b)	(b)	2.94
0.50	(b)	(b)	(b)	(b)	(b)	(b)	(b)	2.83
0.51	(b)	(b)	(b)	(b)	(b)	(b)	(b)	(b)

(a) Depth of Pitting <= 20% of Wall Thickness - No Length Limit
(b) Depth of Pitting > 80% of Wall Thickness - Not Allowed

Allowable Lengths of Corrosion Pitting
SMYS = 35,000 psi.
Diameter = 30.000 inches

Depth of corrosion, inches	Wall Thickness, inch 0.250	0.312	0.375	0.438	0.500	0.625	0.688
0.02	(a)	(a)	(a)	(a)	(a)	(a)	(a)
0.03	(a)	(a)	(a)	(a)	(a)	(a)	(a)
0.04	(a)	(a)	(a)	(a)	(a)	(a)	(a)
0.05	27.39	(a)	(a)	(a)	(a)	(a)	(a)
0.06	27.39	(a)	(a)	(a)	(a)	(a)	(a)
0.07	27.39	30.59	(a)	(a)	(a)	(a)	(a)
0.08	15.75	30.59	33.54	(a)	(a)	(a)	(a)
0.09	9.51	30.59	33.54	36.25	(a)	(a)	(a)
0.10	7.08	17.43	33.54	36.25	38.73	(a)	(a)
0.11	5.72	11.39	33.54	36.25	38.73	(a)	(a)
0.12	4.83	8.74	19.29	36.25	38.73	(a)	(a)
0.13	4.18	7.19	13.28	36.25	38.73	43.30	(a)
0.14	3.69	6.14	10.41	20.99	38.73	43.30	45.43
0.15	3.29	5.38	8.67	15.04	35.91	43.30	45.43
0.16	2.96	4.79	7.48	12.01	22.27	43.30	45.43
0.17	2.68	4.32	6.60	10.11	16.55	43.30	45.43
0.18	2.43	3.92	5.91	8.79	13.44	43.30	45.43
0.19	2.21	3.59	5.36	7.80	11.44	36.35	45.43
0.20	2.00	3.30	4.91	7.03	10.01	24.90	45.43
0.21	(b)	3.04	4.52	6.40	8.94	19.45	36.99
0.22	(b)	2.81	4.18	5.89	8.09	16.22	26.24
0.23	(b)	2.60	3.89	5.45	7.40	14.03	20.86
0.24	(b)	2.41	3.63	5.07	6.83	12.43	17.58
0.25	(b)	(b)	3.39	4.73	6.34	11.19	15.31
0.26	(b)	(b)	3.17	4.44	5.92	10.21	13.62
0.27	(b)	(b)	2.97	4.17	5.55	9.40	12.32
0.28	(b)	(b)	2.79	3.93	5.22	8.72	11.26
0.29	(b)	(b)	2.62	3.71	4.92	8.14	10.40
0.30	(b)	(b)	2.45	3.50	4.66	7.63	9.67
0.31	(b)	(b)	(b)	3.31	4.41	7.19	9.04
0.32	(b)	(b)	(b)	3.13	4.19	6.80	8.50
0.33	(b)	(b)	(b)	2.97	3.98	6.44	8.02
0.34	(b)	(b)	(b)	2.81	3.79	6.13	7.59
0.35	(b)	(b)	(b)	2.66	3.61	5.83	7.21
0.36	(b)	(b)	(b)	(b)	3.43	5.57	6.87
0.37	(b)	(b)	(b)	(b)	3.27	5.32	6.55
0.38	(b)	(b)	(b)	(b)	3.12	5.09	6.26
0.39	(b)	(b)	(b)	(b)	2.97	4.88	6.00
0.40	(b)	(b)	(b)	(b)	2.83	4.68	5.75
0.41	(b)	(b)	(b)	(b)	(b)	4.49	5.52
0.42	(b)	(b)	(b)	(b)	(b)	4.32	5.31
0.43	(b)	(b)	(b)	(b)	(b)	4.15	5.11
0.44	(b)	(b)	(b)	(b)	(b)	3.99	4.92
0.45	(b)	(b)	(b)	(b)	(b)	3.84	4.74
0.46	(b)	(b)	(b)	(b)	(b)	3.69	4.57
0.47	(b)	(b)	(b)	(b)	(b)	3.56	4.41
0.48	(b)	(b)	(b)	(b)	(b)	3.42	4.25
0.49	(b)	(b)	(b)	(b)	(b)	3.29	4.11
0.50	(b)	(b)	(b)	(b)	(b)	3.17	3.96
0.51	(b)	(b)	(b)	(b)	(b)	(b)	3.83

(a) Depth of Pitting <= 20% of Wall Thickness - No Length Limit
(b) Depth of Pitting > 80% of Wall Thickness - Not Allowed

Allowable Lengths of Corrosion Fitting
= 35,000 psi
Diameter = 36.000 inches

Depth of corrosion, inches	Wall Thickness, inch 0.250	0.281	0.312	0.375	0.406	0.469	0.562	0.688
0.02	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)
0.03	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)
0.04	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)
0.05	30.00	(a)	(a)	(a)	(a)	(a)	(a)	(a)
0.06	30.00	31.81	(a)	(a)	(a)	(a)	(a)	(a)
0.07	30.00	31.81	33.51	(a)	(a)	(a)	(a)	(a)
0.08	17.25	31.81	33.51	36.74	(a)	(a)	(a)	(a)
0.09	10.41	18.19	33.51	36.74	38.23	(a)	(a)	(a)
0.10	7.75	11.47	19.09	36.74	38.23	41.09	(a)	(a)
0.11	6.27	8.68	12.48	36.74	38.23	41.09	(a)	(a)
0.12	5.29	7.08	9.58	21.13	38.23	41.09	44.98	(a)
0.13	4.58	6.01	7.87	14.55	21.91	41.09	44.98	(a)
0.14	4.04	5.24	6.73	11.41	15.45	39.54	44.98	49.77
0.15	3.61	4.65	5.89	9.50	12.24	23.71	44.98	49.77
0.16	3.24	4.17	5.25	8.19	10.25	17.32	44.98	49.77
0.17	2.93	3.77	4.73	7.23	8.88	13.95	39.20	49.77
0.18	2.66	3.43	4.30	6.48	7.86	11.81	25.73	49.77
0.19	2.42	3.14	3.93	5.88	7.07	10.30	19.68	49.77
0.20	2.19	2.88	3.61	5.38	6.43	9.17	16.22	49.77
0.21	(b)	2.64	3.33	4.95	5.90	8.28	13.93	40.52
0.22	(b)	2.42	3.08	4.58	5.44	7.56	12.27	28.75
0.23	(b)	(b)	2.85	4.26	5.05	6.96	11.01	22.86
0.24	(b)	(b)	2.64	3.97	4.71	6.46	10.01	19.26
0.25	(b)	(b)	(b)	3.71	4.40	6.02	9.19	16.77
0.26	(b)	(b)	(b)	3.48	4.13	5.63	8.50	14.92
0.27	(b)	(b)	(b)	3.26	3.88	5.29	7.92	13.49
0.28	(b)	(b)	(b)	3.06	3.65	4.98	7.41	12.34
0.29	(b)	(b)	(b)	2.87	3.44	4.70	6.97	11.39
0.30	(b)	(b)	(b)	2.69	3.24	4.45	6.57	10.59
0.31	(b)	(b)	(b)	(b)	3.05	4.21	6.22	9.91
0.32	(b)	(b)	(b)	(b)	2.88	3.99	5.90	9.31
0.33	(b)	(b)	(b)	(b)	(b)	3.79	5.60	8.79
0.34	(b)	(b)	(b)	(b)	(b)	3.60	5.33	8.32
0.35	(b)	(b)	(b)	(b)	(b)	3.42	5.09	7.90
0.36	(b)	(b)	(b)	(b)	(b)	3.25	4.86	7.52
0.37	(b)	(b)	(b)	(b)	(b)	3.09	4.64	7.18
0.38	(b)	(b)	(b)	(b)	(b)	(b)	4.44	6.86
0.39	(b)	(b)	(b)	(b)	(b)	(b)	4.25	6.57
0.40	(b)	(b)	(b)	(b)	(b)	(b)	4.07	6.30
0.41	(b)	(b)	(b)	(b)	(b)	(b)	3.90	6.05
0.42	(b)	(b)	(b)	(b)	(b)	(b)	3.73	5.82
0.43	(b)	(b)	(b)	(b)	(b)	(b)	3.58	5.60
0.44	(b)	(b)	(b)	(b)	(b)	(b)	3.43	5.39
0.45	(b)	(b)	(b)	(b)	(b)	(b)	(b)	5.19
0.46	(b)	(b)	(b)	(b)	(b)	(b)	(b)	5.00
0.47	(b)	(b)	(b)	(b)	(b)	(b)	(b)	4.83
0.48	(b)	(b)	(b)	(b)	(b)	(b)	(b)	4.66
0.49	(b)	(b)	(b)	(b)	(b)	(b)	(b)	4.50
0.50	(b)	(b)	(b)	(b)	(b)	(b)	(b)	4.34
0.51	(b)	(b)	(b)	(b)	(b)	(b)	(b)	4.19

(a) Depth of Fitting <= 20% of Wall Thickness - No Length Limit
(b) Depth of Fitting > 80% of Wall Thickness - Not Allowed

Allowable Lengths of Corrosion Pitting
SMYS = 52,000 psi.
Diameter = 24.000 inches

Depth of corrosion, inches	Wall Thickness, inch 0.250	0.312	0.375	0.438	0.469	0.500	0.562	0.625
0.02	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)
0.03	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)
0.04	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)
0.05	24.49	(a)	(a)	(a)	(a)	(a)	(a)	(a)
0.06	13.03	(a)	(a)	(a)	(a)	(a)	(a)	(a)
0.07	7.63	22.36	(a)	(a)	(a)	(a)	(a)	(a)
0.08	5.65	11.10	30.00	(a)	(a)	(a)	(a)	(a)
0.09	4.57	7.91	15.95	32.42	(a)	(a)	(a)	(a)
0.10	3.87	6.30	10.72	23.40	33.55	34.64	(a)	(a)
0.11	3.37	5.29	8.33	14.18	20.18	32.41	(a)	(a)
0.12	2.98	4.59	6.92	10.71	13.71	18.42	36.73	(a)
0.13	2.68	4.07	5.97	8.77	10.73	13.40	24.12	38.73
0.14	2.42	3.66	5.28	7.50	8.96	10.79	16.58	32.01
0.15	2.20	3.33	4.74	6.59	7.75	9.14	13.08	20.60
0.16	2.01	3.05	4.31	5.91	6.87	7.99	10.96	15.80
0.17	1.84	2.81	3.96	5.36	6.19	7.14	9.52	13.05
0.18	1.69	2.60	3.65	4.92	5.65	6.47	8.46	11.24
0.19	1.55	2.41	3.39	4.55	5.20	5.92	7.64	9.93
0.20	1.41	2.24	3.17	4.23	4.83	5.47	6.99	8.94
0.21	(b)	2.09	2.96	3.96	4.50	5.09	6.45	8.15
0.22	(b)	1.95	2.78	3.71	4.22	4.76	6.00	7.51
0.23	(b)	1.82	2.62	3.50	3.97	4.48	5.61	6.97
0.24	(b)	1.69	2.46	3.30	3.75	4.22	5.27	6.52
0.25	(b)	(b)	2.32	3.12	3.54	3.99	4.97	6.12
0.26	(b)	(b)	2.19	2.96	3.36	3.78	4.71	5.77
0.27	(b)	(b)	2.07	2.81	3.19	3.60	4.47	5.47
0.28	(b)	(b)	1.95	2.67	3.04	3.42	4.25	5.19
0.29	(b)	(b)	1.84	2.53	2.89	3.26	4.05	4.94
0.30	(b)	(b)	1.73	2.41	2.76	3.11	3.87	4.72
0.31	(b)	(b)	(b)	2.29	2.63	2.97	3.70	4.51
0.32	(b)	(b)	(b)	2.18	2.51	2.84	3.55	4.32
0.33	(b)	(b)	(b)	2.08	2.39	2.72	3.40	4.14
0.34	(b)	(b)	(b)	1.97	2.29	2.60	3.26	3.98
0.35	(b)	(b)	(b)	1.88	2.18	2.49	3.13	3.83
0.36	(b)	(b)	(b)	(b)	2.08	2.39	3.01	3.68
0.37	(b)	(b)	(b)	(b)	1.99	2.28	2.89	3.55
0.38	(b)	(b)	(b)	(b)	(b)	2.19	2.78	3.42
0.39	(b)	(b)	(b)	(b)	(b)	2.09	2.68	3.30
0.40	(b)	(b)	(b)	(b)	(b)	2.00	2.58	3.18
0.41	(b)	(b)	(b)	(b)	(b)	(b)	2.48	3.07
0.42	(b)	(b)	(b)	(b)	(b)	(b)	2.38	2.96
0.43	(b)	(b)	(b)	(b)	(b)	(b)	2.29	2.86
0.44	(b)	(b)	(b)	(b)	(b)	(b)	2.20	2.76
0.45	(b)	(b)	(b)	(b)	(b)	(b)	(b)	2.67
0.46	(b)	(b)	(b)	(b)	(b)	(b)	(b)	2.58
0.47	(b)	(b)	(b)	(b)	(b)	(b)	(b)	2.49
0.48	(b)	(b)	(b)	(b)	(b)	(b)	(b)	2.40
0.49	(b)	(b)	(b)	(b)	(b)	(b)	(b)	2.32
0.50	(b)	(b)	(b)	(b)	(b)	(b)	(b)	2.24
0.51	(b)	(b)	(b)	(b)	(b)	(b)	(b)	(b)

(a) Depth of Pitting <= 20% of Wall Thickness - No Length Limit
(b) Depth of Pitting > 80% of Wall Thickness - Not Allowed

Allowable Lengths of Corrosion Pitting
SMYS = 52,000 psi
Diameter = 30.000 inche

Depth of corrosion, inches	Wall Thickness, inch 0.250	0.312	0.375	0.438	0.500	0.625	0.688
0.0[illegible]	(a)	(a)	(a)	(a)	(a)	(a)	(a)
0.0[illegible]	(a)	(a)	(a)	(a)	(a)	(a)	(a)
0.0[illegible]	(a)	(a)	(a)	(a)	(a)	(a)	(a)
0.05	27.39	(a)	(a)	(a)	(a)	(a)	(a)
0.06	14.56	(a)	(a)	(a)	(a)	(a)	(a)
0.07	8.53	25.00	(a)	(a)	(a)	(a)	(a)
0.08	6.32	12.41	33.54	(a)	(a)	(a)	(a)
0.09	5.11	8.84	17.84	36.25	(a)	(a)	(a)
0.10	4.33	7.04	11.98	26.16	38.73	(a)	(a)
0.11	3.77	5.92	9.32	15.86	36.23	(a)	(a)
0.12	3.34	5.13	7.74	11.97	20.60	(a)	(a)
0.13	2.99	4.55	6.68	9.80	14.98	43.30	(a)
0.14	2.71	4.09	5.90	8.38	12.06	35.79	45.43
0.15	2.46	3.72	5.30	7.37	10.22	23.03	45.21
0.16	2.25	3.41	4.82	6.60	8.94	17.66	28.80
0.17	2.06	3.14	4.42	6.00	7.98	14.60	21.20
0.18	1.89	2.90	4.09	5.50	7.23	12.57	17.22
0.19	1.73	2.69	3.80	5.09	6.62	11.10	14.68
0.20	1.58	2.51	3.54	4.73	6.12	9.99	12.89
0.21	(b)	2.33	3.31	4.42	5.69	9.11	11.55
0.22	(b)	2.18	3.11	4.15	5.33	8.40	10.50
0.23	(b)	2.03	2.92	3.91	5.00	7.80	9.65
0.24	(b)	1.89	2.75	3.69	4.72	7.28	8.95
0.25	(b)	(b)	2.60	3.49	4.46	6.84	8.35
0.26	(b)	(b)	2.45	3.31	4.23	6.46	7.84
0.27	(b)	(b)	2.31	3.14	4.02	6.11	7.39
0.28	(b)	(b)	2.18	2.98	3.83	5.81	7.00
0.29	(b)	(b)	2.06	2.83	3.65	5.53	6.64
0.30	(b)	(b)	1.94	2.70	3.48	5.28	6.33
0.31	(b)	(b)	(b)	2.56	3.33	5.04	6.04
0.32	(b)	(b)	(b)	2.44	3.18	4.83	5.78
0.33	(b)	(b)	(b)	2.32	3.04	4.63	5.54
0.34	(b)	(b)	(b)	2.21	2.91	4.45	5.32
0.35	(b)	(b)	(b)	2.10	2.79	4.28	5.11
0.36	(b)	(b)	(b)	(b)	2.67	4.12	4.92
0.37	(b)	(b)	(b)	(b)	2.55	3.96	4.74
0.38	(b)	(b)	(b)	(b)	2.44	3.82	4.57
0.39	(b)	(b)	(b)	(b)	2.34	3.68	4.41
0.40	(b)	(b)	(b)	(b)	2.24	3.55	4.26
0.41	(b)	(b)	(b)	(b)	(b)	3.43	4.12
0.42	(b)	(b)	(b)	(b)	(b)	3.31	3.99
0.43	(b)	(b)	(b)	(b)	(b)	3.20	3.86
0.44	(b)	(b)	(b)	(b)	(b)	3.09	3.73
0.45	(b)	(b)	(b)	(b)	(b)	2.98	3.61
0.46	(b)	(b)	(b)	(b)	(b)	2.88	3.50
0.47	(b)	(b)	(b)	(b)	(b)	2.78	3.39
0.48	(b)	(b)	(b)	(b)	(b)	2.69	3.29
0.49	(b)	(b)	(b)	(b)	(b)	2.59	3.18
0.50	(b)	(b)	(b)	(b)	(b)	2.50	3.08
0.51	(b)	(b)	(b)	(b)	(b)	(b)	2.99

(a) Depth of Pitting <= 20% of Wall Thickness - No Length Limit
(b) Depth of Pitting > 80% of Wall Thickness - Not Allowed

Allowable Lengths of Corrosion Pitting
SMYS = 52,000 psi.
Diameter = 36.000 inches

Depth of corrosion, inches	Wall Thickness, inch 0.250	0.281	0.312	0.375	0.406	0.469	0.562	0.688
0.02	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)
0.03	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)
0.04	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)
0.05	30.00	(a)	(a)	(a)	(a)	(a)	(a)	(a)
0.06	15.95	31.81	(a)	(a)	(a)	(a)	(a)	(a)
0.07	9.35	14.36	27.39	(a)	(a)	(a)	(a)	(a)
0.08	6.92	9.50	13.59	36.74	(a)	(a)	(a)	(a)
0.09	5.60	7.33	9.69	19.54	33.96	(a)	(a)	(a)
0.10	4.74	6.05	7.71	13.12	18.08	41.09	(a)	(a)
0.11	4.13	5.19	6.48	10.21	13.03	24.72	(a)	(a)
0.12	3.65	4.56	5.62	8.48	10.44	16.79	44.98	(a)
0.13	3.28	4.08	4.99	7.31	8.81	13.15	29.54	(a)
0.14	2.96	3.68	4.48	6.46	7.68	10.97	20.31	49.77
0.15	2.70	3.35	4.07	5.81	6.84	9.49	16.02	49.52
0.16	2.46	3.07	3.73	5.28	6.18	8.41	13.43	31.55
0.17	2.25	2.83	3.44	4.84	5.65	7.58	11.66	23.22
0.18	2.07	2.61	3.18	4.48	5.20	6.92	10.36	18.87
0.19	1.89	2.41	2.95	4.16	4.82	6.37	9.36	16.08
0.20	1.73	2.23	2.74	3.88	4.50	5.91	8.56	14.12
0.21	(b)	2.06	2.56	3.63	4.21	5.51	7.90	12.65
0.22	(b)	1.91	2.38	3.41	3.95	5.17	7.35	11.50
0.23	(b)	(b)	2.22	3.20	3.72	4.86	6.87	10.57
0.24	(b)	(b)	2.07	3.02	3.51	4.59	6.46	9.80
0.25	(b)	(b)	(b)	2.84	3.31	4.34	6.09	9.15
0.26	(b)	(b)	(b)	2.68	3.14	4.12	5.77	8.59
0.27	(b)	(b)	(b)	2.53	2.97	3.91	5.47	8.10
0.28	(b)	(b)	(b)	2.39	2.81	3.72	5.21	7.66
0.29	(b)	(b)	(b)	2.25	2.67	3.54	4.97	7.28
0.30	(b)	(b)	(b)	2.12	2.53	3.38	4.74	6.93
0.31	(b)	(b)	(b)	(b)	2.39	3.22	4.54	6.62
0.32	(b)	(b)	(b)	(b)	2.27	3.07	4.34	6.33
0.33	(b)	(b)	(b)	(b)	(b)	2.93	4.16	6.07
0.34	(b)	(b)	(b)	(b)	(b)	2.80	4.00	5.83
0.35	(b)	(b)	(b)	(b)	(b)	2.67	3.84	5.60
0.36	(b)	(b)	(b)	(b)	(b)	2.55	3.69	5.39
0.37	(b)	(b)	(b)	(b)	(b)	2.43	3.54	5.19
0.38	(b)	(b)	(b)	(b)	(b)	(b)	3.41	5.01
0.39	(b)	(b)	(b)	(b)	(b)	(b)	3.28	4.84
0.40	(b)	(b)	(b)	(b)	(b)	(b)	3.15	4.67
0.41	(b)	(b)	(b)	(b)	(b)	(b)	3.03	4.52
0.42	(b)	(b)	(b)	(b)	(b)	(b)	2.92	4.37
0.43	(b)	(b)	(b)	(b)	(b)	(b)	2.81	4.22
0.44	(b)	(b)	(b)	(b)	(b)	(b)	2.70	4.09
0.45	(b)	(b)	(b)	(b)	(b)	(b)	(b)	3.96
0.46	(b)	(b)	(b)	(b)	(b)	(b)	(b)	3.83
0.47	(b)	(b)	(b)	(b)	(b)	(b)	(b)	3.71
0.48	(b)	(b)	(b)	(b)	(b)	(b)	(b)	3.60
0.49	(b)	(b)	(b)	(b)	(b)	(b)	(b)	3.49
0.50	(b)	(b)	(b)	(b)	(b)	(b)	(b)	3.38
0.51	(b)	(b)	(b)	(b)	(b)	(b)	(b)	3.27

(a) Depth of Pitting <= 20% of Wall Thickness - No Length Limit
(b) Depth of Pitting > 80% of Wall Thickness - Not Allowed

Allowable Lengths of Corrosion Pitting
SMYS = 60 000 psi
Diameter = 24 000 inches

Depth of corrosion, inches	Wall Thickness, inch 0.250	0.312	0.375	0.438	0.469	0.500	0.562	0.625
0.02	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)
0.03	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)
0.04	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)
0.05	19.69	(a)	(a)	(a)	(a)	(a)	(a)	(a)
0.06	8.57	(a)	(a)	(a)	(a)	(a)	(a)	(a)
0.07	5.96	11.91	(a)	(a)	(a)	(a)	(a)	(a)
0.08	4.69	8.06	16.13	(a)	(a)	(a)	(a)	(a)
0.09	3.92	6.29	10.50	21.57	(a)	(a)	(a)	(a)
0.10	3.38	5.23	8.08	13.26	18.08	27.85	(a)	(a)
0.11	2.98	4.51	6.68	10.05	12.57	16.26	(a)	(a)
0.12	2.67	3.99	5.75	8.24	9.93	12.12	19.66	(a)
0.13	2.41	3.58	5.07	7.07	8.33	9.88	14.38	23.84
0.14	2.19	3.25	4.56	6.23	7.24	8.43	11.62	16.95
0.15	2.00	2.97	4.14	5.59	6.44	7.41	9.87	13.55
0.16	1.84	2.74	3.80	5.08	5.81	6.64	8.65	11.45
0.17	1.69	2.54	3.52	4.67	5.32	6.03	7.74	10.00
0.18	1.55	2.35	3.27	4.32	4.90	5.54	7.03	8.92
0.19	1.42	2.19	3.05	4.02	4.56	5.13	6.45	8.09
0.20	1.30	2.05	2.86	3.76	4.26	4.79	5.98	7.42
0.21	(b)	1.91	2.68	3.54	3.99	4.48	5.57	6.87
0.22	(b)	1.79	2.53	3.33	3.76	4.22	5.22	6.40
0.23	(b)	1.67	2.38	3.15	3.56	3.98	4.92	6.01
0.24	(b)	1.56	2.25	2.98	3.37	3.77	4.65	5.66
0.25	(b)	(b)	2.12	2.83	3.20	3.58	4.41	5.35
0.26	(b)	(b)	2.01	2.69	3.04	3.41	4.19	5.08
0.27	(b)	(b)	1.90	2.56	2.90	3.25	4.00	4.83
0.28	(b)	(b)	1.79	2.43	2.76	3.10	3.81	4.61
0.29	(b)	(b)	1.69	2.32	2.63	2.96	3.65	4.41
0.30	(b)	(b)	1.60	2.21	2.52	2.83	3.49	4.22
0.31	(b)	(b)	(b)	2.10	2.40	2.71	3.35	4.05
0.32	(b)	(b)	(b)	2.00	2.30	2.60	3.21	3.89
0.33	(b)	(b)	(b)	1.91	2.20	2.49	3.09	3.74
0.34	(b)	(b)	(b)	1.82	2.10	2.38	2.97	3.60
0.35	(b)	(b)	(b)	1.73	2.01	2.28	2.86	3.46
0.36	(b)	(b)	(b)	(b)	1.92	2.19	2.75	3.34
0.37	(b)	(b)	(b)	(b)	1.83	2.10	2.65	3.22
0.38	(b)	(b)	(b)	(b)	(b)	2.01	2.55	3.11
0.39	(b)	(b)	(b)	(b)	(b)	1.93	2.45	3.00
0.40	(b)	(b)	(b)	(b)	(b)	1.84	2.36	2.90
0.41	(b)	(b)	(b)	(b)	(b)	(b)	2.28	2.80
0.42	(b)	(b)	(b)	(b)	(b)	(b)	2.19	2.71
0.43	(b)	(b)	(b)	(b)	(b)	(b)	2.11	2.62
0.44	(b)	(b)	(b)	(b)	(b)	(b)	2.03	2.53
0.45	(b)	(b)	(b)	(b)	(b)	(b)	(b)	2.45
0.46	(b)	(b)	(b)	(b)	(b)	(b)	(b)	2.37
0.47	(b)	(b)	(b)	(b)	(b)	(b)	(b)	2.29
0.48	(b)	(b)	(b)	(b)	(b)	(b)	(b)	2.21
0.49	(b)	(b)	(b)	(b)	(b)	(b)	(b)	2.13
0.50	(b)	(b)	(b)	(b)	(b)	(b)	(b)	2.06
0.51	(b)	(b)	(b)	(b)	(b)	(b)	(b)	(b)

(a) Depth of Pitting <= 20% of Wall Thickness - No Length Limit
(b) Depth of Pitting > 80% of Wall Thickness - Not Allowed

Allowable Lengths of Corrosion Pitting
SMYS = 60,000 psi.
Diameter = 30.000 inches

Depth of corrosion, inches	Wall Thickness, inch 0.250	0.312	0.375	0.438	0.500	0.625	0.688
0.02	(a)	(a)	(a)	(a)	(a)	(a)	(a)
0.03	(a)	(a)	(a)	(a)	(a)	(a)	(a)
0.04	(a)	(a)	(a)	(a)	(a)	(a)	(a)
0.05	22.02	(a)	(a)	(a)	(a)	(a)	(a)
0.06	9.58	(a)	(a)	(a)	(a)	(a)	(a)
0.07	6.66	13.31	(a)	(a)	(a)	(a)	(a)
0.08	5.25	9.01	18.03	(a)	(a)	(a)	(a)
0.09	4.38	7.03	11.74	24.12	(a)	(a)	(a)
0.10	3.78	5.85	9.03	14.83	31.14	(a)	(a)
0.11	3.34	5.05	7.47	11.23	18.18	(a)	(a)
0.12	2.98	4.46	6.43	9.22	13.55	(a)	(a)
0.13	2.69	4.00	5.67	7.90	11.04	26.66	(a)
0.14	2.45	3.63	5.10	6.96	9.42	18.95	32.37
0.15	2.24	3.33	4.63	6.25	8.28	15.15	22.13
0.16	2.05	3.06	4.25	5.68	7.42	12.80	17.48
0.17	1.88	2.83	3.93	5.22	6.75	11.18	14.68
0.18	1.73	2.63	3.65	4.83	6.20	9.98	12.77
0.19	1.59	2.45	3.41	4.50	5.74	9.05	11.37
0.20	1.46	2.29	3.19	4.21	5.35	8.30	10.29
0.21	(b)	2.14	3.00	3.95	5.01	7.68	9.43
0.22	(b)	2.00	2.82	3.73	4.72	7.16	8.72
0.23	(b)	1.86	2.66	3.52	4.45	6.71	8.12
0.24	(b)	1.74	2.51	3.33	4.22	6.32	7.61
0.25	(b)	(b)	2.37	3.16	4.00	5.98	7.17
0.26	(b)	(b)	2.24	3.00	3.81	5.68	6.79
0.27	(b)	(b)	2.12	2.86	3.63	5.40	6.44
0.28	(b)	(b)	2.00	2.72	3.46	5.15	6.13
0.29	(b)	(b)	1.89	2.59	3.31	4.93	5.85
0.30	(b)	(b)	1.79	2.47	3.17	4.72	5.60
0.31	(b)	(b)	(b)	2.35	3.03	4.52	5.37
0.32	(b)	(b)	(b)	2.24	2.90	4.34	5.15
0.33	(b)	(b)	(b)	2.13	2.78	4.18	4.95
0.34	(b)	(b)	(b)	2.03	2.66	4.02	4.77
0.35	(b)	(b)	(b)	1.93	2.55	3.87	4.60
0.36	(b)	(b)	(b)	(b)	2.45	3.73	4.43
0.37	(b)	(b)	(b)	(b)	2.35	3.60	4.28
0.38	(b)	(b)	(b)	(b)	2.25	3.48	4.14
0.39	(b)	(b)	(b)	(b)	2.15	3.36	4.00
0.40	(b)	(b)	(b)	(b)	2.06	3.24	3.87
0.41	(b)	(b)	(b)	(b)	(b)	3.13	3.75
0.42	(b)	(b)	(b)	(b)	(b)	3.03	3.63
0.43	(b)	(b)	(b)	(b)	(b)	2.93	3.52
0.44	(b)	(b)	(b)	(b)	(b)	2.83	3.41
0.45	(b)	(b)	(b)	(b)	(b)	2.74	3.30
0.46	(b)	(b)	(b)	(b)	(b)	2.65	3.20
0.47	(b)	(b)	(b)	(b)	(b)	2.56	3.11
0.48	(b)	(b)	(b)	(b)	(b)	2.47	3.01
0.49	(b)	(b)	(b)	(b)	(b)	2.39	2.92
0.50	(b)	(b)	(b)	(b)	(b)	2.30	2.83
0.51	(b)	(b)	(b)	(b)	(b)	(b)	2.75

(a) Depth of Pitting <= 20% of Wall Thickness - No Length Limit
(b) Depth of Pitting > 80% of Wall Thickness - Not Allowed

Allowable Lengths of Corrosion Fitting
SMYS = 60,000 psi
Diameter = 36.000 inche

Depth of corrosion, inches	Wall Thickness, inch 0.250	0.281	0.312	0.375	0.406	0.469	0.562	0.688
0.01	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)
0.02	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)
0.03	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)
0.04	24.12	(a)	(a)	(a)	(a)	(a)	(a)	(a)
0.05	10.50	17.03	(a)	(a)	(a)	(a)	(a)	(a)
0.06	7.30	10.06	14.58	(a)	(a)	(a)	(a)	(a)
0.07	5.75	7.49	9.87	19.75	(a)	(a)	(a)	(a)
0.08	4.80	6.09	7.70	12.86	17.41	(a)	(a)	(a)
0.09	4.14	5.18	6.41	9.90	12.46	22.15	(a)	(a)
0.10	3.65	4.52	5.53	8.18	9.95	15.40	(a)	(a)
0.11	3.27	4.03	4.88	7.04	8.40	12.16	24.08	(a)
0.12	2.95	3.63	4.38	6.22	7.32	10.20	17.61	(a)
0.13	2.68	3.30	3.98	5.58	6.52	8.86	14.23	35.46
0.14	2.45	3.03	3.64	5.08	5.89	7.88	12.09	24.25
0.15	2.25	2.78	3.36	4.66	5.39	7.12	10.60	19.15
0.16	2.06	2.57	3.11	4.31	4.97	6.51	9.48	16.08
0.17	1.90	2.38	2.88	4.00	4.61	6.01	8.61	13.99
0.18	1.74	2.21	2.69	3.74	4.30	5.58	7.90	12.45
0.19	1.60	2.05	2.51	3.50	4.03	5.21	7.32	11.27
0.20	(b)	1.90	2.34	3.29	3.79	4.89	6.82	10.32
0.21	(b)	1.76	2.19	3.09	3.57	4.61	6.40	9.55
0.22	(b)	(b)	2.04	2.92	3.37	4.35	6.03	8.90
0.23	(b)	(b)	1.91	2.75	3.19	4.13	5.70	8.34
0.24	(b)	(b)	(b)	2.60	3.02	3.92	5.40	7.86
0.25	(b)	(b)	(b)	2.46	2.86	3.72	5.14	7.43
0.26	(b)	(b)	(b)	2.32	2.72	3.55	4.89	7.06
0.27	(b)	(b)	(b)	2.19	2.58	3.38	4.67	6.72
0.28	(b)	(b)	(b)	2.07	2.45	3.23	4.47	6.41
0.29	(b)	(b)	(b)	1.96	2.32	3.08	4.28	6.13
0.30	(b)	(b)	(b)	(b)	2.20	2.94	4.10	5.88
0.31	(b)	(b)	(b)	(b)	2.09	2.81	3.94	5.64
0.32	(b)	(b)	(b)	(b)	(b)	2.69	3.78	5.43
0.33	(b)	(b)	(b)	(b)	(b)	2.57	3.64	5.22
0.34	(b)	(b)	(b)	(b)	(b)	2.46	3.50	5.03
0.35	(b)	(b)	(b)	(b)	(b)	2.35	3.37	4.86
0.36	(b)	(b)	(b)	(b)	(b)	2.24	3.24	4.69
0.37	(b)	(b)	(b)	(b)	(b)	(b)	3.12	4.53
0.38	(b)	(b)	(b)	(b)	(b)	(b)	3.00	4.38
0.39	(b)	(b)	(b)	(b)	(b)	(b)	2.89	4.24
0.40	(b)	(b)	(b)	(b)	(b)	(b)	2.79	4.10
0.41	(b)	(b)	(b)	(b)	(b)	(b)	2.68	3.98
0.42	(b)	(b)	(b)	(b)	(b)	(b)	2.58	3.85
0.43	(b)	(b)	(b)	(b)	(b)	(b)	2.49	3.73
0.44	(b)	(b)	(b)	(b)	(b)	(b)	(b)	3.62
0.45	(b)	(b)	(b)	(b)	(b)	(b)	(b)	3.51
0.46	(b)	(b)	(b)	(b)	(b)	(b)	(b)	3.40
0.47	(b)	(b)	(b)	(b)	(b)	(b)	(b)	3.30
0.48	(b)	(b)	(b)	(b)	(b)	(b)	(b)	3.20
0.49	(b)	(b)	(b)	(b)	(b)	(b)	(b)	3.10
0.50	(b)	(b)	(b)	(b)	(b)	(b)	(b)	3.01
0.51	(b)	(b)	(b)	(b)	(b)	(b)	(b)	

(a) Depth of Pitting <= 20% of Wall Thickness - No Length Limit
(b) Depth of Pitting > 80% of Wall Thickness - Not Allowed

APPENDIX D

BURST TEST DATA FOR CORRODED PIPE

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TABLE D-I. COMPLETE LIST OF RESULTS FOR THE 86 ANOMALIES

<-------SPECIFIC DATA File	Diam. inch	Thick. inch	Yield Strength psi.	SMYS psi.	----> Total Length inch	Effect. Length in	Effect. Ex. Area in^2	Maximum Pit Dept inch	CASE 1 Press. psi.	CASE 2 Press. psi	CASE 3 Press. psi.	ACTUAL Failure Press. psi.	LEAK/ RUPTURE	CASE 1 /Actual Press.	CASE 2 /Actual Press.	CASE 3 /Actual Press.	NOTES
1	30.0	0.370	50,700	52,000	2.500	2.500	0.253	0.140	1,610	1,420	1,830	1623	L	0.997	0.880	0.820	
2	30.0	0.370	50,700	52,000	2.250	2.250	0.210	0.140	1,628	1,443	1,842	1620	L	1.004	0.891	0.820	
6	24.0	0.365	40,500	35,000	3.000	2.750	0.501	0.271	1,213	995	934	1100	L	1.103	0.905	0.849	
7	24.0	0.365	40,500	35,000	4.750	4.000	0.807	0.261	1,105	893	859	1105	L	0.949	0.788	0.738	
9	24.0	0.370	41,000	35,000	1.750	1.750	0.250	0.281	1,600	1,210	1,077	1040	L	1.448	1.171	1.036	1st Cycle
10	24.0	0.375	41,000	35,000	4.250	3.750	0.711	0.202	1,251	805	870	1105	L	1.074	0.759	0.747	2nd Cycle
11	24.0	0.365	41,000	35,000	2.000	2.000	0.300	0.281	1,455	1,157	1,035	1020	L	1.427	1.134	1.015	4th Cycle
12	24.0	0.365	41,000	35,000	2.250	2.250	0.207	0.210	1,469	1,191	1,050	1215	L	1.204	0.981	0.864	8th Cycle
13	24.0	0.365	41,000	35,000	2.500	2.500	0.350	0.230	1,421	1,140	1,021	1320	L	1.077	0.860	0.774	14th Cycle
14	24.0	0.365	41,000	35,000	2.750	2.750	0.450	0.281	1,361	1,052	980	1320	L	1.031	0.797	0.739	14th Cycle
15	24.0	0.360	41,000	35,000	3.750	3.750	0.543	0.251	1,395	1,043	967	1335	L	1.045	0.782	0.725	15th Cycle
16	24.0	0.370	41,000	35,000	2.000	2.000	0.232	0.180	1,516	1,274	1,100	1350	L	1.123	0.944	0.819	16th Cycle
17	24.0	0.370	41,000	35,000	3.000	3.000	0.485	0.240	1,300	1,095	993	1375	L	0.995	0.796	0.722	17th Cycle
18	24.0	0.375	41,000	35,000	3.750	3.500	0.387	0.240	1,400	1,047	984	1430	L	1.021	0.720	0.670	20th Cycle
19	24.0	0.365	41,000	35,000	1.750	1.750	0.272	0.281	1,473	1,194	1,050	1450	L	1.016	0.824	0.730	21st Cycle
20	24.0	0.375	41,000	35,000	2.250	2.250	0.316	0.251	1,494	1,187	1,050	1200	L	1.245	0.989	0.882	23rd Cycle
21	24.0	0.375	41,000	35,000	2.250	2.000	0.393	0.292	1,496	1,104	1,017	1490	L	0.984	0.741	0.683	25th Cycle
22	24.0	0.375	41,000	35,000	2.500	2.500	0.271	0.210	1,517	1,210	1,080	1520	L	0.998	0.796	0.703	29th Cycle
23	24.0	0.375	41,000	35,000	2.000	2.000	0.204	0.180	1,552	1,295	1,124	1520	L	1.021	0.852	0.739	29th Cycle
24	24.0	0.375	41,000	35,000	2.250	2.250	0.253	0.177	1,527	1,288	1,110	1520	L	1.005	0.846	0.734	30th Cycle
30	30.0	0.375	70,000	52,000	1.000	1.000	0.100	0.200	1,980	1,465	1,885	2140	L	0.910	0.685	0.630	
32	20.0	0.325	41,000	35,000	5.750	5.250	0.570	0.200	1,830	900	883	1150	L	1.101	0.790	0.768	
33	20.0	0.325	41,100	35,000	6.500	5.250	0.491	0.210	1,894	842	841	1095	L	0.823	0.497	0.498	
34	16.0	0.310	28,000	25,000	4.500	3.750	0.550	0.230	1,102	755	700	1100	L	1.002	0.687	0.644	
35	16.0	0.310	28,000	25,000	5.000	4.000	0.609	0.240	1,084	688	670	1270	L	0.837	0.542	0.527	
37	16.0	0.310	28,000	25,000	2.750	2.000	0.340	0.272	1,289	740	720	890	L	1.059	0.832	0.810	(a)
38	16.0	0.310	28,400	25,000	6.250	5.250	0.704	0.199	1,084	798	724	1290	L	0.825	0.619	0.561	
41	24.0	0.300	50,200	35,000	5.750	3.500	0.935	0.300	1,299	596	727	930	L	1.397	0.640	0.782	(a)
45	24.0	0.355	52,000	35,000	6.500	3.750	0.887	0.209	1,392	626	660	1565	L	0.926	0.410	0.457	(a)
46	24.0	0.310	47,500	35,000	5.500	5.250	0.470	0.210	1,304	737	721	1732	L	0.753	0.425	0.416	
47	24.0	0.332	45,000	35,000	4.500	4.000	0.512	0.220	1,259	830	797	1752	L	0.719	0.470	0.455	
52	24.0	0.361	47,400	35,000	10.500	4.000	0.784	0.310	1,254	464	570	1290	L	0.972	0.352	0.440	(a)
53	24.0	0.361	41,200	35,000	12.500	2.500	0.564	0.265	1,201	557	634	1475	L	0.814	0.378	0.430	
54	24.0	0.355	50,300	35,000	8.500	4.000	0.439	0.243	1,560	729	740	1741	L	0.896	0.419	0.425	
55	24.0	0.371	45,000	35,000	10.500	8.500	1.036	0.270	1,321	656	766	1357	L	0.974	0.483	0.520	

<-------SPECIFIC DATA					---->							ACTUAL					
File	Diam. inch	Thick. inch	Yield Strength psi.	SMYS psi.	Total Length inch	Effect. Length in	Effect. Ex. Area in^2	Maximum Pit Dept inch	CASE 1 Press. psi.	CASE 2 Press. psi	CASE 3 Press. psi.	Failure Press. psi	LEAK/ RUPTURE	CASE 1 /Actual Press.	CASE 2 /Actual Press.	CASE 3 /Actual Press	NOTES
[illegible]	[illegible]	[illegible]	45,000	35,000	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
57	24.0	0.372	40,200	35,000	22.000	12.500	1.022	0.284	1,500	562	282	1590	L	0.943	0.352	0.177	(b)
59	24.0	0.366	43,000	35,000	12.500	7.500	0.615	0.242	1,398	723	740	1808	L	0.772	0.400	0.409	
61	24.0	0.366	47,700	35,000	20.000	9.000	1.025	0.280	1,391	518	257	1530	L	0.909	0.339	0.168	(b)
64	20.0	0.311	35,300	35,000	8.500	5.000	0.242	0.230	1,296	633	696	1694	L	0.766	0.374	0.410	
65	20.0	0.311	35,300	35,000	11.000	9.000	0.315	0.105	1,300	1,000	992	1694	L	0.768	0.642	0.586	
66	20.0	0.288	40,200	35,000	15.500	11.000	0.789	0.144	1,053	716	470	1507	L	0.698	0.475	0.312	(b)
67	20.0	0.309	41,900	35,000	12.000	8.500	0.393	0.210	1,412	864	350	1818	L	0.777	0.386	0.193	(b)
76	30.0	0.361	52,000	52,000	12.000	6.500	1.030	0.300	1,140	678	819	1120	L	1.025	0.605	0.732	
78	30.0	0.370	61,221	52,000	8.000	7.000	0.678	0.170	1,542	1,179	1,157	1720	L	0.898	0.686	0.673	

CASE 1 MODIFIED METHOD USING EXACT AREA
CASE 2 MODIFIED METHOD USING AREA = 0.86 dL
CASE 3 EXISTING B31G METHOD USING AREA = 2/3 dL

(NOTE. No Safety Factor Applied to CASE 1, CASE 2, or CASE 3)

(a) Maximum Pit Depth exceeds 80% of the wall thickness. USE WITH CAUTION
(b) For CASE 3, L^2/Dt > 20 P'=1.1*SMYS*(2*t/D)*[1-dmax/t) for P' < SMYS*2*t/D
(c) The MINIMUM failure pressure is not shown

TABLE D-1 (Cont'd)

<-------SPECIFIC DATA File	Diam. inch	Thick. inch	Yield Strength psi.	SMYS psi.	----> Total Length inch	Effect. Length in	Effect. Ex. Area in^2	Maximum Pit Dept inch	CASE 1 Press. psi.	CASE 2 Press. psi	CASE 3 Press. psi.	ACTUAL Failure Press. psi.	LEAK/ RUPTURE	CASE 1 /Actual Press.	CASE 2 /Actual Press.	CASE 3 /Actual Press.	NOTES
3	30.0	0.375	59,700	52,000	4.250	4.250	0.292	0.167	1,500	1,311	1,244	1700	R	0.934	0.771	0.732	
4	30.0	0.375	63,000	52,000	5.500	5.500	0.472	0.240	1,055	1,000	1,070	1670	R	0.991	0.635	0.646	
5	30.0	0.375	58,000	52,000	4.750	4.750	0.005	0.200	1,400	1,193	1,107	1525	R	0.903	0.782	0.700	
8	24.0	0.305	40,500	35,000	5.250	4.750	0.930	0.251	1,001	003	030	1220	R	0.070	0.707	0.000	
25	24.0	0.300	41,000	35,000	5.000	4.750	0.000	0.271	1,200	690	071	1510	R	0.700	0.500	0.577	
26	30.0	0.375	62,000	52,000	2.750	2.750	0.392	0.375	1,030	011	1,031	1745	R	0.930	0.405	0.591	(a)
27	30.0	0.375	61,300	52,000	5.500	5.250	0.322	0.140	1,002	1,301	1,240	1040	R	0.903	0.707	0.674	
28	30.0	0.375	62,000	52,000	4.500	4.500	0.310	0.115	1,070	1,300	1,300	1005	R	0.005	0.737	0.001	
29	30.0	0.375	60,200	52,000	4.000	4.000	0.421	0.230	1,723	1,190	1,173	1775	R	0.971	0.074	0.001	
31	30.0	0.375	00,500	52,000	2.000	2.000	0.200	0.200	1,045	1,427	1,337	2000	R	0.922	0.714	0.000	
38	16.0	0.310	20,000	25,000	0.000	0.250	0.735	0.202	770	401	540	020	R	0.940	0.503	0.000	(a)
39	24.0	0.417	50,200	35,000	13.000	10.000	1.003	0.290	1,340	701	017	1305	R	0.007	0.500	0.500	
40	24.0	0.410	40,000	35,000	0.000	7.250	1.700	0.300	1,093	505	000	1000	R	0.050	0.004	0.403	(a)
42	24.0	0.444	50,200	35,000	0.250	0.000	1.054	0.220	1,075	1,191	1,101	1000	R	0.001	0.027	0.500	
43	24.0	0.300	50,000	35,000	15.000	5.000	0.970	0.275	1,340	594	292	1400	R	0.012	0.405	0.100	(b)
44	24.0	0.304	52,000	35,000	13.000	9.000	1.550	0.254	1,210	071	705	1204	R	0.002	0.531	0.550	
48	24.0	0.375	53,000	35,000	10.000	11.000	2.003	0.295	705	550	257	742	R	1.050	0.753	0.340	(b)
49	24.0	0.375	40,000	37,000	9.000	5.750	1.503	0.320	013	500	004	700	R	1.032	0.710	0.000	(a)
50	20.0	0.312	50,000	35,000	12.000	11.750	2.000	0.252	020	540	231	710	R	0.077	0.750	0.324	(a) (b)
51	20.0	0.305	55,100	35,000	10.500	8.000	1.411	0.210	1,000	000	710	1070	R	0.030	0.412	0.430	
58	24.0	0.304	40,100	35,000	0.500	0.500	1.154	0.224	1,004	020	000	1045	R	0.703	0.504	0.492	
60	24.0	0.300	51,500	35,000	4.000	4.000	0.725	0.101	1,433	1,007	004	1503	R	0.005	0.003	0.022	
62	20.0	0.203	37,000	35,000	30.000	10.000	3.270	0.274	100	250	35	1000	R	0.170	0.229	0.032	(a) (b)
63	20.0	0.274	40,500	35,000	12.000	0.500	0.500	0.130	1,070	021	554	1730	R	0.020	0.472	0.310	(b)
64	30.0	0.372	00,750	52,000	30.000	10.000	1.746	0.120	1,307	1,129	923	1044	R	0.752	0.012	0.500	(b)
69	30.0	0.370	52,000	52,000	12.000	12.000	1.000	0.230	1,002	000	007	1515	R	0.701	0.000	0.030	
70	30.0	0.375	00,204	52,000	12.000	10.000	1.190	0.140	1,370	1,100	1,100	1015	R	0.755	0.054	0.030	
71	30.0	0.302	03,542	52,000	20.000	10.000	1.223	0.145	1,011	1,150	004	1002	R	0.047	0.000	0.475	(b)
72	30.0	0.370	59,030	52,000	20.000	10.000	1.515	0.130	1,422	1,177	930	1705	R	0.707	0.050	0.520	(b)
73	30.0	0.370	02,002	52,000	33.000	10.000	1.540	0.110	1,400	1,223	1,022	1010	R	0.777	0.030	0.533	(b)
74	30.0	0.370	05,410	52,000	14.000	9.000	1.000	0.170	1,510	1,000	1,000	1775	R	0.055	0.010	0.019	
77	30.0	0.377	01,704	52,000	12.000	15.500	1.020	0.100	1,400	1,107	1,120	1700	R	0.031	0.035	0.029	
78	30.0	0.370	00,173	52,000	9.000	7.000	0.000	0.110	1,493	1,295	1,235	1040	R	0.011	0.704	0.072	
79	24.0	0.375	42,000	37,000	33.500	21.000	5.433	0.322	507	441	100	004	R	0.730	0.540	0.224	(a) (b)
80	30.0	0.305	50,000	52,000	10.000	10.500	2.233	0.220	004	022	510	007	R	0.000	0.033	0.525	(b)

<-------SPECIFIC DATA					---->							ACTUAL					
File	Diam. inch	Thick. inch	Yield Strength psi	SMYS psi	Total Length inch	Effect Length in	Effect Ex. Area in 2	Maximum Pit Dept inch	CASE 1 Press. psi	CASE 2 Press psi	CASE 3 Press psi	Failure Press psi	LEAK/ RUPTURE	CASE 1 /Actual Press.	CASE 2 /Actual Press.	CASE 3 /Actual Press	NOTES
01	30.0	0.375	68,770	52,000	27.000	27.000	5.603	0.245	981	769	498	992	R	0.988	0.775	0.500	(b)
02	30.0	0.375	64,400	56,000	7.500	6.500	8.542	0.150	1.048	1.310	1,282	1970	R	0.837	0.665	0.651	
03	20.0	0.260	61,000	52,000	16.000	14.000	2.498	0.218	884	543	240	835	R	0.820	0.650	0.288	(a) (b)
04	36.0	0.330	65,000	65,000	16.000	11.000	2.120	0.218	734	714	445	775	R	0.947	0.922	0.574	(b)
05	30.0	0.298	71,000	60,000	63.000	41.000	7.067	0.269	725	338	128	815	R	0.889	0.415	0.157	(a) (b)
06	22.0	0.198	60,967	52,000	6.000	5.000	0.489	0.148	844	560	830	820	R	1.019	0.884	0.781	

CASE 1 MODIFIED METHOD USING EXACT AREA
CASE 2 MODIFIED METHOD USING AREA = 0.85 dL
CASE 3 EXISTING B31G METHOD USING AREA = 2/3 dL

(NOTE: No Safety Factor Applied to CASE 1, CASE 2 or CASE 3)

(a) Maximum Pit Depth exceeds 80X of the wall thickness - USE WITH CAUTION
For CASE 3, L^2/Dt > 20 P'=1.1*SMYS*(2*t/D)*[1-dmax/t] for P' < SMYS*2*t/D
The MINIMUM failure pressure is not shown

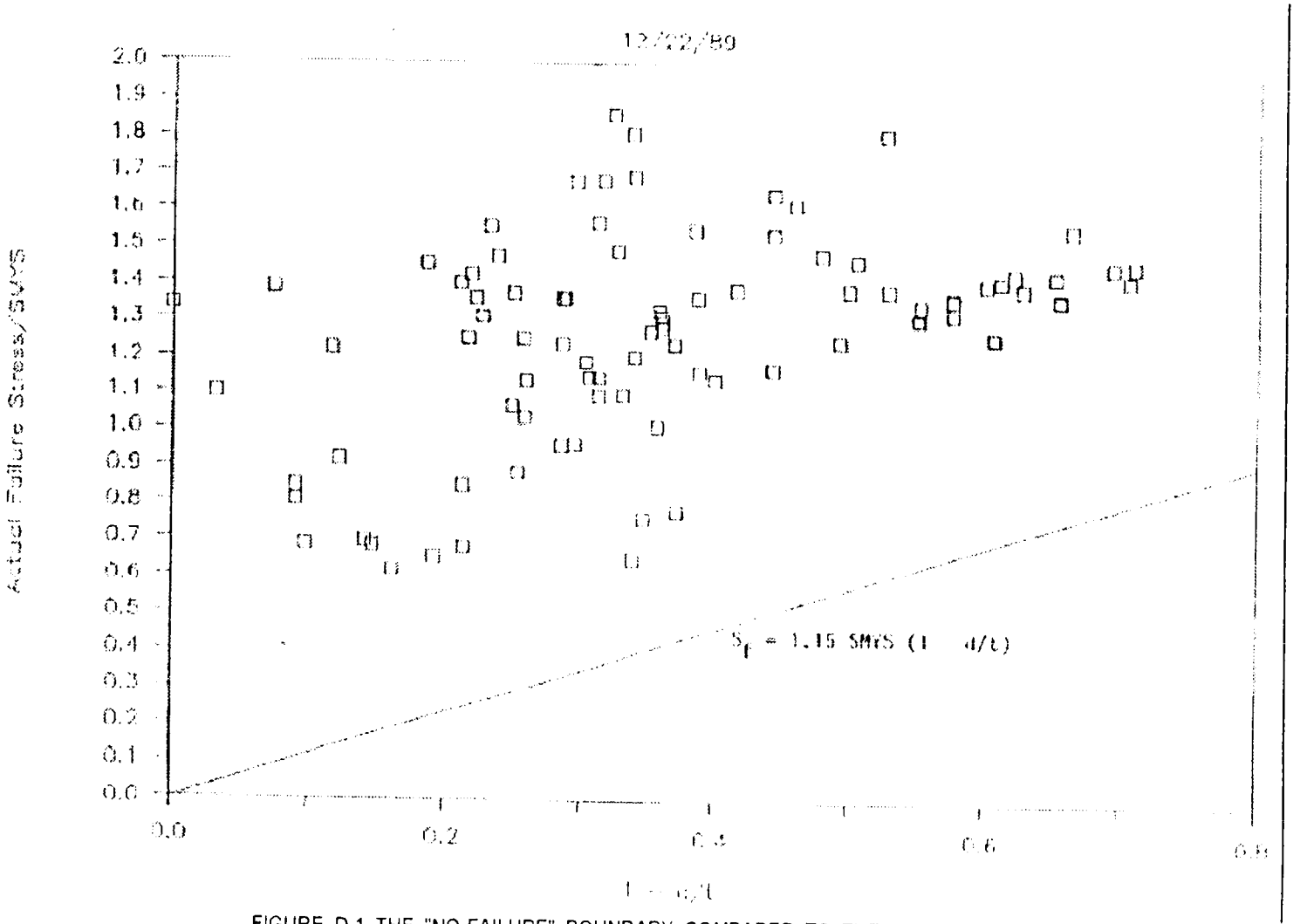

FIGURE D-1 THE "NO-FAILURE" BOUNDARY COMPARED TO THE 86 BURST TESTS

Pressure Testing of Liquid Petroleum Pipelines

API RECOMMENDED PRACTICE 1110
FOURTH EDITION, MARCH 1997

STEP
Strategies for Today's Environmental Partnership

American Petroleum Institute

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STEP

Strategies for Today's Environmental Partnership

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- To counsel customers, transporters and others in the safe use, transportation and disposal of our raw materials, products and waste materials.
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- To extend knowledge by conducting or supporting research on the safety, health and environmental effects of our raw materials, products, processes and waste materials.
- To commit to reduce overall emissions and waste generation.
- To work with others to resolve problems created by handling and disposal of hazardous substances from our operations.
- To participate with government and others in creating responsible laws, regulations and standards to safeguard the community, workplace and environment.
- To promote these principles and practices by sharing experiences and offering assistance to others who produce, handle, use, transport or dispose of similar raw materials, petroleum products and wastes.

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Pressure Testing of Liquid Petroleum Pipelines

Manufacturing, Distribution and Marketing Department

API RECOMMENDED PRACTICE 1110
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FOREWORD

This recommended practice has been prepared by API's Operation Technical Committee under the General Committee on Pipelines, which is composed of experienced pipeline engineers. This recommended practice suggests procedures for pressure testing new and existing petroleum pipelines.

The purpose of this recommended practice is to increase safety and efficiency by encouraging the petroleum pipeline industry to adopt uniform pressure-testing practices for its liquid petroleum pipeline facilities. This recommended practice recommends procedures to be followed, suggests equipment to be used, and points out factors to be considered during the pressure testing. Liquid petroleum pipelines are pressure tested to verify that their test segments have the requisite structural integrity to withstand normal and maximum operating pressures and to verify that they are capable of liquid containment.

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Pressure Testing of Liquid Petroleum Pipelines

1 Scope

This recommended practice covers the pressure testing of new and existing liquid petroleum pipelines. It recommends minimum procedures to be followed, suggests equipment to be used, and points out factors to be considered during the pressure testing of liquid petroleum pipelines. This recommended practice does not address low pressure pneumatic testing.

This recommended practice suggests procedures that are based on sound engineering judgment, but certain governmental requirements may differ from the procedures set forth in this recommended practice. Such requirements should be fulfilled because this recommended practice is not intended to supersede or override them.

Please be advised that this document does not preclude requalifying a line for liquid service under the provisions of ASME 31.8, Appendix N (as provided for 49 *Code of Federal Regulations* 195.5 (a) (1) (I.)).

2 Referenced Publications

Unless otherwise specified, the most recent editions of the following standards, codes, and specifications shall, to the extent specified herein, form a part of this standard.

ASME[1]

B31.4 *Liquid Transportation Systems for Hydrocarbons, Liquid Petroleum Gas, Anhydrous Ammonia, and Alcohols*

DOT[2]

Research and Special Programs Administration (Title 49 *Code of Federal Regulations* Part 195)

3 Pressure Testing of Liquid Petroleum Pipelines

3.1 DEFINITION

In pressure testing, internal pressure above the normal or maximum operating pressure is applied to a segment of pipeline, under no-flow conditions, for a fixed period of time. A liquid test medium is used to apply the internal pressure.

[1]American Society of Mechanical Engineers, 345 East 47th Street, New York, New York 10017.

[2]U.S. Department of Transportation. The *Code of Federal Regulations* is available from the U.S. Government Printing Office, Washington, D.C. 20402.

3.2 CODE REQUIREMENTS FOR PRESSURE TESTING

3.2.1 New Construction and the Replacement of Existing Pipelines

The pressure testing of newly constructed pipelines and replaced segments of existing pipelines should be performed in accordance with ASME B31.4, 49 *Code of Federal Regulations* Part 195 and any other applicable governmental regulations.

3.2.2 Qualification of Existing Pipelines For a Higher Operating Pressure

The qualification of existing piping systems for an operating pressure higher than the previously established operating pressure should be performed in accordance with ASME B31.4, 49 *Code of Federal Regulations* Part 195 and any applicable governmental regulations.

3.2.3 Requalification of Existing Pipelines for Continued Operation at the Current Operating Pressure

The requalification of existing piping systems for continued operation at the previously established operating pressure should be performed in accordance with ASME B31.4, 49 *Code of Federal Regulations* Part 195 and any applicable governmental regulations.

3.3 TEST MEDIUM

A pressure test should be conducted with water; however, liquid petroleum having a Reid vapor pressure[3] less than 7 pounds per square inch absolute may be used as the test medium if all of the following conditions are met:

a. The pipeline or piping segment to be tested is not part of an offshore pipeline or offshore piping facility.

b. The pipeline or piping segment to be tested is not located where a release could adversely impact any environmentally sensitive areas.

c. The pipeline or piping segment to be tested (rated for operation above 275 psig) is outside of cities and/or other highly populated areas.

d. Every building located outside of the owner's piping facility, but within 300 feet (92 meters) of the pipeline or piping segment to be tested, is unoccupied while the test pressure is greater than or equal to a pressure that produces a hoop stress of 50 percent of the specified minimum yield strength (SMYS).

[3]Reid vapor pressure is defined as a liquid's true vapor pressure at 100°F.

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e. The pipeline or piping segment to be tested is kept under regular surveillance by pipeline personnel equipped with portable radios or similar equipment to provide continuous communication with the person in charge.
f. Suitable contingency response equipment and personnel for spill cleanup are strategically placed near the pipeline or piping segment to be tested.
g. Test procedures meet all applicable local, state, or federal government regulations.

3.4 EQUIPMENT AND MATERIALS FOR A PRESSURE TEST

Equipment for a pressure test should be properly selected and be in working order. The measurement equipment should be appropriate for the pressures expected during the pressure test. The following equipment may be required for a pressure test:

a. A high-volume pump that fills the line, ensures adequate pressure to overcome head, maintains sufficient velocity to move debris, minimizes interfaces, ensures turbulent flow, and keeps any pigs moving.
b. A test medium supply line filter that ensures a clean test medium.
c. An injection pump that introduces corrosion inhibitors, leak detection dyes or gases, or other chemicals into the test segment if their use is desired.
d. A meter for measuring line fill or a comparable means of measuring it.
e. A variable speed, positive displacement pump that pressurizes the line to a suitable or appropriate level that exceeds the specified test pressure. The pump should have a known volume per stroke and should be equipped with a stroke counter. (A constant-speed pump with a variable flow rate control may be used in lieu of the above if the liquid test medium injected into the pipeline is measured during pressurization.)
f. A relief valve. This may be included to prevent overpressure of the test segment during both the pressurizing activities and the test.
g. A portable tank or transport into which excess test medium can be discharged and from which make-up volumes can be drawn.
h. A pressure sensing and display device that has the pressure range and increment divisions necessary to indicate anticipated test pressures.
i. A deadweight tester[4] or an equivalent pressure sensing device that is capable of measuring in increments of less than or equal to one (1) pound per square inch (6.7 kilopascals). The device should have a certificate of calibration that is not more than one year old at the start of testing or calibrated in accordance with the manufacturer's recommendations.
j. A continuous-recording pressure measurement device (such as a chart recorder) that provides a permanent record of pressure versus time. This device should be calibrated immediately before each use (using the deadweight tester) or calibrated in accordance with the manufacturer's recommendations.
k. A test medium temperature sensing and display instrument that is properly calibrated to a range suitable for anticipated test temperatures and can be read in increments of no less than 0.1°F (0.05°C).
l. A continuous-recording temperature measurement device that provides a permanent record of pipeline temperature versus time.
m. Facilities that protect all instrumentation from weather extremes.
n. Equipment that indicates ambient temperature.
o. Electronic pressure/temperature monitoring and recording systems that assist in the analysis of test data. Such systems can be used in lieu of the components listed above provided that the individual pressure sensors included in the systems have a level of sensitivity and can be field calibrated in a manner similar to those instruments listed in Items a through m above.
p. Pigs, scrapers, spheres, and similar devices that clean the test segment and facilitate the removal of air from the line.
q. Temporary manifolds and connections, as needed.
r. Equipment, materials, and fluids that are needed to introduce and displace the test medium from the test segments.
s. Communication equipment that is adequate for coordinating test activities.
t. Equipment that isolates line segments for leak determination and facilitates repair.
u. Replacement pipe, valves, gaskets, and so forth, to replace those that fail during pressure test.

CAUTION: If freeze plugs are used to isolate line segments, special handling techniques should be used to ensure personnel safety. Consideration should be given to nondestructive examination for flaws, toughness, and the ductile-to-brittle transition temperature when selecting the joint for the freeze.

3.5 TEST PLAN

When planning a pressure test, the following factors should be considered:

a. The maximum operating pressure anticipated for the life of the facility. Tests should normally be planned so that anywhere in the test segment the pressure level does not produce hoop stress near or above the SMYS. If lines are tested at pressures that develop a hoop stress, based on nominal wall thickness, near the SMYS of the pipe, special care shall be taken to prevent the pipe from overstraining. Close examination of engineering documentation, such as mill test reports

[4]All references to "deadweight tester" in this document include any equivalent pressure sensing device.

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and field maintenance reports, can ensure the minimum grade and wall thickness of pipe in the segment. If internal inspection tools surveys were conducted, the data should be carefully reviewed. For tests at pressure levels near the SMYS, consideration should be given to keeping a pressure-volume (P-V) plot during pressurization to prevent yielding of the pipe. The effects of transporting water through the pipeline upon the operating and static pressure profiles should be considered.

b. Compositions of the pipe and piping components in the test segment. Pipe and piping components should be located by their size, wall thickness, grade type, internal design pressure, and elevation profile. The component that controls maximum test pressure should be identified.

c. The shell pressure and flange rating and the location of all pipeline valves, equipment, air vents, and other connections to the segment that will be exposed to the test pressure. Test pressure shall not exceed the manufacturer's recommended maximum allowable test pressure.

d. The anticipated temperature of the test medium, atmosphere, and ground and the temperature stabilization period of the test medium. Particular care should be taken to prevent freezing of exposed piping during cold weather. Large amounts of exposed piping can result in large temperature-related pressure changes, making a stable test difficult.

e. The test medium's primary and makeup sources and any inhibited or other treating requirements. State and local codes should be reviewed to determine if regulatory requirements for obtaining source water and for disposing of test water exist.

f. Sampling provisions to ensure (and to document) water quality before the line is filled and again before ultimate disposal occurs.

g. Locations and requirements for test medium disposal.

h. Profile and alignment drawing maps.

i. Safety precautions and procedures for personnel who perform the test.

j. A delineation of the responsibilities of various personnel in the testing organization, especially those who prepare documentation.

k. Precautions and procedures to minimize risk to the public and the environment, especially when a test medium other than water is to be used.

l. Notification of proper authorities, agencies, and potential emergency response personnel, as well as landowners along the right-of-way.

m. A plan for dealing with failures, including equipment, personnel, materials, and inspection.

n. Methods for preserving the fractured surfaces on the failed specimens of pipe.

o. Pressure proof test and pressure leak test acceptance criteria.

p. Procedures and materials used for assisting in leak detection and locating, such as dyes or gases.

q. Potential bleed location.

3.6 TEST PROCEDURE

Before testing begins, a pressure test procedure with explanatory notes and data should be prepared. This detailed procedure should provide the following:

a. A diagram indicating the lengths, elevations, and locations of the test segments, including any tested piping manifolds, and set-up of test equipment. Locate the taps for the pressure recording devices on the pipeline. Do not locate the taps on or near the high pressure fill piping. The taps should be located several feet from the high pressure pump injection point in order for the readings to be accurate during the pressurization process.

b. The test medium to be used, fill rates, and the line fill volumes for filling and at test pressure.

c. Methods for cleaning, decommissioning, filling, and recommissioning test segments.

d. Methods for pressurizing the test segments. These methods should indicate the locations of the injection points with respect to recording locations and should provide the specified minimum and maximum test pressures.

e. Methods for isolating the test segments. These methods should indicate which blinds and plugs to install, valves to remove, and cathodic rectifier systems to be de-energized.

f. The minimum test duration for test segments.

g. Methods for removing and disposing of the test medium.

h. Safety precautions and procedures.

i. An identification of and a specification for the weakest link or controlling component in the test section.

The specified test pressure is the minimum test pressure that should be applied to the most elevated point in the test segment. This elevation is not necessarily that of the deadweight tester; therefore, it should be corrected for elevation difference between the pipeline and deadweight tester. The minimum test pressure should be in accordance with ASME B31.4 and 49 *Code of Federal Regulations* Part 195. A detailed analysis of the profile to determine what the pressures will be during the test should be performed so that the pipeline will not be overpressured at points that are at low elevations. Since the test pump and recording equipment are not necessarily at the highest elevation, test personnel should be provided with precise target pressures for the elevation at the pump and recorders.

3.7 LINE FILL AND CLEANING

The line fill operation should perform two functions—clean the line and introduce the necessary test medium into the test segment. It should be noted that pigging operations will not normally remove all hydrocarbons from the piping segment. Before the actual line filling operation, it is advisable to run a sizing pig, caliper or deformation tool in an effort to identify any geometric abnormalities that may exist in the line prior to the test. In addition to running a sizing pig,

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consideration should also be given to running a batch/train of cleaning pigs to remove sediments, paraffins, and so forth, from those pipeline segments that are not under a normal pigging program.

The filling operation normally utilizes several different pieces of equipment, including the following:

a. Large volume (relative to line size) fill pump.
b. Filter screens, if a nonmunicipal water supply is used to filter out sediment/contaminants.
c. Flowmeter.
d. Filling pig(s).
e. Portable tank.

The large volume fill pump should be sized such that the fill pigs will travel at a speed that will maintain a tight fit of the pig and, depending on the terrain, reduce the risk of the introduction of air or another compressible mixture behind the fill pigs, thus making a quality test difficult. A minimum of 2 to 3 mph is a suggested starting point. Unless the line fill is occurring with some form of backpressure, as pigs travel down the line and down a slope, the weight of the column of fluid could cause the pig to travel faster than the filling operation would allow, thus introducing air or gas behind the pig.

If water is used as the test medium, its quality and source should be determined. Water that is not free of sediment and acid may injure the pipe, valves, and equipment, and should not be used unless it is filtered and inhibited. The possible deleterious effect of additives or inhibitors on the processing of liquid petroleum to be transported should be investigated.

A flow meter should be placed in the line so that one can monitor and maintain the design rate of fill. The meter will allow the test personnel to make adjustments as necessary as pressure builds and fill rates drop. It also assists in matching the actual fill volume with the calculated fill volume.

Record the fill medium temperature prior to introduction into the line. This will aid in the determination of line stability.

Pigs or spheres may be inserted to separate the test medium from the rest of the pipeline content. Locators may be inserted in the pigs to track them during the filling process and to ensure that the pigs are where they need to be.

A portable tank is used to make up the difference between the actual water supply and the high volume fill pumps. This may not be necessary if the fill pumps have a direct supply, such as a river.

Excavated segments should be backfilled insofar as practicable before pressurization. The sensor of the recording temperature device(s) should be installed so that it is in contact with the pipeline at a point where it has normal cover and at a distance far enough back from the injection point so that the effect of the exposed piping and make-up injection on temperature is minimal. The backfill around the recording temperature device sensor should be tamped. Insulate, if appropriate, the capillary lines to the temperature recorder, and install the recorder in an insulated box. Large centrifugal pumps and storage tanks will affect the temperature of the test medium. The temperature of the buried line should be recorded until the pressure test is completed.

3.8 CONDUCTING THE PRESSURE TEST

3.8.1 Pressurization

Generally, the filling process is completed using a high volume pump. Pressurization above this point is the scope of this section.

Note: Personnel conducting the test should maintain continuous surveillance over the operation to ensure that it is carefully controlled.

The pressurization of the section of pipe to be tested begins once the segment is full of fluid and the appropriate measures have been taken to bleed any and all air or gas out of that section; in other words, the section is packed. Pressurization involves bringing the section of pipe to be tested up from the static pressure after the fill process to the desired test pressure. The following equipment may be necessary to complete this process:

a. High pressure positive displacement pumps.
b. Flow meter and volume accumulator.
c. Deadweight pressure tester.
d. Temperature recorder.
e. Pressure recorder.
f. Portable tank.

Pressurization of the section should occur at a controlled rate to avoid surging the line. Pipe connections should be periodically checked for leaks during pressurization. The flow rate should be monitored and logged for preparation of a pressure-volume P-V plot, if applicable. Calculations indicating the amount of squeeze fluid required to go from the fill pressure to the test pressure should be made prior to the test and given to test personnel. This information aids in determining the tightness of the segment and assists in determining, along with the P-V plot, if leaks have occurred or if the pipe has yielded.

Once 80 to 90 percent of the test pressure is reached, the rate of pressurization should be reduced, especially when the test is at or near 100 percent SMYS. Once the desired test pressure is reached, the equipment should be stopped and isolated from the section. At this point, prior to the start of the test, it may be desirable to have a stabilization period, which would allow both the temperature and pressure to settle.

Note that pressure charts, sensors, and displays only show an approximation of the actual pressure. The charts provide proof of the continuity of the test. The deadweight tester or electronic equipment provides the actual pressure to be recorded.

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Keep safety in mind at all times! Pipe maintained at high pressure is dangerous. Test personnel should stand at a safe distance from the test section or stand so that there is something substantial between them and the section being tested.

3.8.2 The Test Period

When the test pressure is reached, pumping should stop and all valves and connections to the line should be inspected for leakage. After inspecting for leakage, test personnel should take the time to verify that the specified test pressure is being maintained and temperatures have stabilized. When this verification procedure has been completed, the injection pump should be isolated from the test section. The test period should begin after the injection pump has been stopped, and the system has stabilized. The duration of the test period should be in accordance with ASME B31.4 and 49 *Code of Federal Regulations* Part 195.

Pressure and temperature should be continuously monitored during the test, and all of the pressure readings should be recorded. Deadweight tester comparisons with pressure recorder readings should be made at the beginning of the test, periodically during the test, and at the end of the test. The results of the deadweight tester checks and temperature readings should be recorded on the pressure and temperature logs within at least 30-minute intervals. Weather changes, such as the development of rain or clouds, that could affect the pressure and temperature recording charts should be documented on the deadweight log. The volume or pressure of any added or subtracted test medium should be documented on the deadweight log, as well as the temperature and pressure at that time and be accounted for in the assessment of the results of the pressure test.

Minor or gradual pressure changes during the test can be a result of residual air in the segment, temperature effects, or leaks through small defects or loose flange connections. Extending the test duration can demonstrate that air and temperature effects have been accounted for.

3.8.3 Pressure Test Records

Personnel conducting a pressure test should keep a complete record of the test, including details of the test operation and events such as weather variations, test failures, bleed-offs, repressurizations, and so forth. Any failures that occur during the test should be described in this record. The record should indicate the exact location of each failure, describe the type of failure and its cause, and describe the method of repair. Pipe, fittings, or valves that fail and are replaced should be marked with their pipeline station location and the pressure at which they failed. When appropriate, such materials should be preserved by the operator for failure analysis.

Records of pressure tests are to be maintained by the operator to comply with the requirements of ASME B31.4, 49 *Code of Federal Regulations* Part 195, and all other applicable governmental regulations. Test records may include, but are not necessarily limited to, the following (Appendix A contains sample forms.):

a. Continuous pressure versus time record with appropriate information listed on it (see Figure A-1).
b. Continuous temperature versus time record with appropriate information listed on it (see Figure A-2).
c. Deadweight calibration certificate.
d. Test plan (see 3.5).
e. Pressure test record and certification (see Figure A-3) that includes the following:
   1. Qualification calculations (see Figure A-4).
   2. Pressure and temperature log (see Figure A-5).
   3. Record of the failures that occurred during the test and the reason for the failures (see Figure A-6).
   4. Profile of the pipeline that shows the elevation and test sites over the entire length of the test section, if elevation differences in the test section exceed 100 feet (30 meters).
   5. A drawing of any facility piping tested and the limits of the test. These test records should be signed by the responsible parties and retained for the life of the facility or until new test records supersede them.

3.9 DISPLACEMENT OF TEST MEDIUM

A carrier may choose to displace test water with liquid petroleum, air, or inert gas. If air or inert gas is to be used, careful consideration must be given to the amount of energy stored in the compressed gas.

Test medium may be displaced with spheres, squeegees, or other pigging devices. When water is displaced, it should be disposed of in accordance with all applicable government environmental regulations. It should be noted, though, that all of the test water may have to be stored until permits are received for ultimate disposal. Product quality or internal corrosion control requirements may dictate that a pipeline drying regimen be conducted after the water is displaced.

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APPENDIX A—TEST RECORDS

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SAMPLE PRESSURE RECORD

Company _____
System _____

Description of instrument (make/model) _____
Serial number of instrument _____
Test section no. _____ _____ miles
MP _____ to MP _____ Station no. _____ to Station no. _____
Location of chart recorder MP _____ Station no. _____
Start: Time _____ Date _____
End: Time _____ Date _____
Contractor rep. _____ Title _____ Date _____
Pipeline company rep. _____ Title _____ Date _____
Project engineer _____ Date _____

Notes:
MP = mile post.
This pressure information should be included on the permanent record of pressure versus time. Placing this information on a stick-on label and sticking the label to the permanent record might be considered.

Figure A-1—Sample Pressure Record

SAMPLE TEMPERATURE RECORD

Company _____
System _____

Description of instrument (make/model) _____
Serial number of instrument _____
Test section no. _____ _____ miles
MP _____ to MP _____ Station no. _____ to Station no. _____
Location of chart recorder MP _____ Station no. _____
Start: Time _____ Date _____
End: Time _____ Date _____
Contractor rep. _____ Title _____ Date _____
Pipeline company rep. _____ Title _____ Date _____
Project engineer _____ Date _____

Notes:
MP = mile post.
This temperature information should be included on the permanent record of temperature versus time. Placing this information on a stick-on label and sticking the label to the permanent record, or using a rubber stamp, might be considered.

Figure A-2—Sample Temperature Record

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SAMPLE PRESSURE TEST RECORD AND CERTIFICATION

Test section _____

Date _____

Company _____ System _____

Description from _____ to _____

New construction ○

Requalification ○ Replacement or relocation ○ Pipeline ○ Station ○

Test medium: water ○ Other _____ Inhibitor _____

Design data code: ○ B31.4 ○ B31.8 (Appendix N) ○ Other _____

Pipe design data

Specification and grade	Weld joint factor	Design factor	OD	Wall thickness	SMYS	Design pressure	Comments

Pressure test:

Test pressure should be as follows:

_____ Minimum at high point _____ % SMY _____ Maximum at low point _____ % SMY

Elevations: Low point _____ High point _____ DWT _____

Qualifications:

Date of test: _____ Duration of test _____

Testing and recording witnessed by _____ Date _____

Company _____ Title _____

Company representative _____ Title _____

Testing pressure:

Maximum at low point _____ for % SMYS _____

Minimum at high point _____ for % SMYS _____

Qualified to operate at _____ for % SMYS _____

Report checked by _____ Date _____

Approved by _____ Time _____

Testing company _____

Attached documents:

Pressure record ○ Pressure and temperature log ○ Temperature record ○

Test instrument calibration data ○ Sketch or diagram ○ Qualification calculations ○

Profile ○ Failure records ○

Comments:

_____

_____

_____

_____

Notes:

OD = outside diameter, SMYS = specified minimum yield strength, SMY = specified minimum yield, DWT = deadweight tester.

For test sections containing more than one type of pipe, the maximum test pressure at low point and minimum test pressure at high point and resulting SMYS need to be calculated for each type of pipe.

Figure A-3—Sample Pressure Test Record and Certification

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SAMPLE QUALIFICATION CALCULATIONS

Company _____
System _____

Pipeline Data (at controlling location) _____ OD _____ _____ WT Specification
Internal pressure at SMYS _____ psi
Test medium: Fresh water? (Yes, at 0.433 psi/ft) (No) Other _____ at _____ psi/ft
Design test pressure: Maximum _____ psi Minimum _____ psi
Test section number _____
From station _____ (MP _____) to station _____ (MP _____)
Time and dates: From _____ hours _____ to _____ hours _____
(Time) (Date) (Time) (Date)
Deadweight tester data
Location: Station _____ (MP _____) Elevation _____ ft
Tester pressure: Beginning _____ psi ending _____ psi minimum _____ psi
Acceptable? (Yes) (No)
Use tester pressure of _____ psi at station _____ Elevation _____
(P) (E)

Minimum Pressure in Test Section[a]	Maximum Pressure in Test Section[a]
Highest elevation in test section _____ ft (H)	Lowest elevation in test section _____ ft (L)
Location: Station _____ (MP _____)	Location: Station _____ (MP _____)
Difference in elevation from tester:	Difference in elevation from tester:
_____ (H) – _____ (E) = _____ (H) – (E) ft	_____ (E) – _____ (L) = _____ (E) – (L) ft
Pressure at highest elevation:	Pressure at highest elevation:
= Tester pressure – (Difference in elevation x psi/ft)	= Tester pressure – (Difference in elevation x psi/ft)
= _____ (P) – (_____ (H) – (E) x _____)	= _____ (P) – (_____ (E) – (L) x _____)
= _____ = Minimum test pressure	= _____ = Maximum test pressure
= _____ % SMYS	= _____ % SMYS

Maximum allowable operating pressure in this test section = 72% SMYS = _____ psi or
80% minimum test pressure = _____ psi or
or controlling component _____ (circle whichever is lowest).
Calculated by _____ Approved by _____
Remarks _____
_____
_____ Date _____

Notes: OD = outside diameter, wt = wall thickness, SMYS = specified minimum yield strength, MP= mile post, p = pressure, E = elevation, H = highest, L = lowest.
[a]For test sections containing more than one type of pipe, the 72-percent SMYS minimum test pressure and resulting percentage of SMYS need to be calculated for each type of pipe and used in determining the maximum allowable operating pressure.

Figure A-4—Sample Qualification Calculations

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SAMPLE PRESSURE AND TEMPERATURE LOG

Company _____
System _____

Test section no. _____ From station no. _____ MP
to station no. _____ MP
Pressure/temperature sensor station no. _____
Start of test period: Time _____ Date _____
End of test period: Time _____ Date _____

No.	Time	Pressure (psig)	Pipe temp.	Ambient temp.	No.	Time	Pressure (psig)	Pipe temp.	Ambient temp.
1.					25.				
2.					26.				
3.					27.				
4.					28.				
5.					29.				
6.					30.				
7.					31.				
8.					32.				
9.					33.				
10.					34.				
11.					35.				
12.					36.				
13.					37.				
14.					38.				
15.					39.				
16.					40.				
17.					41.				
18.					42.				
19.					43.				
20.					44.				
21.					45.				
22.					46.				
23.					47.				
24.					48.				

Figure A-5—Sample Pressure and Temperature Log

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SAMPLE PRESSURE TEST RECORD OF FAILURE

Company _____
System _____
Line section _____
From station no. _____ to station no. _____

Date	Time	Leak Station No.	Leak Elevation	Leak (psi)	Deadweight Elevation	Deadweight (psi)	Deadweight Station	Failure Description

Figure A-6—Sample Pressure Test Record of Failure

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Guidance Document for the Qualification of Liquid Pipeline Personnel

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American Petroleum Institute

Helping You Get The Job Done Right.℠

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Guidance Document for the Qualification of Liquid Pipeline Personnel

Pipeline Segment

API PUBL 1161
FIRST EDITION, AUGUST 2000

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SPECIAL NOTES

This API Guidance Document for the Qualification of Pipeline Personnel was developed by the API's subcommittee on Training to help pipeline operators comply with the Research and Special Program Administration's (RSPA) Final Rule on Pipeline Safety: Qualification for Pipeline Personnel.

Special acknowledgement is given to the Consortium On Operator Qualification (COOQ), a group of liquid pipeline representatives, which developed several appendices within this publication, including Example Operator Qualification Premises and Definitions, as well as the Example Covered Task Lists. The Consortium on Operator Qualification's efforts and collaboration with the API Subcommittee on Training was instrumental to the development of this publication.

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Suggested revisions are invited and should be submitted to the general manager of the Pipeline Segment, American Petroleum Institute, 1220 L Street, N.W., Washington, D.C. 20005.

API Guidance Document for the Qualification of Liquid Pipeline Personnel

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American Petroleum Institute's Guidance Document

Department of Transportation
Research and Special Programs Administration
49 CFR Part 195

QUALIFICATION OF LIQUID PIPELINE PERSONNEL

1. *Background*

The United States Department of Transportation (DOT), Research and Special Programs Administration (RSPA), requires that pipeline operators develop a written qualification program to evaluate personnel and contractor ability to perform covered tasks and to recognize and respond to abnormal operating conditions that may be encountered while performing these covered tasks. This is a performance-based qualification program. The regulations can be found in 49 CFR Part 195 and became effective October 26, 1999. A detailed discussion of the rule is included in this guidance document as Appendix A.

To provide guidance to the liquids pipeline industry, the American Petroleum Institute's Subcommittee on Training developed this guidance document to help pipeline operators comply with the rule. Pipeline operators may choose to use all or part of this document to design a program to comply with the qualification rule or may elect to develop their own program independent of this publication. Pipeline operators may also choose to modify an existing program.

This publication represents the consensus position of the pipeline companies involved in the development of this document and is designed as an aid in developing a qualification program. **This is a guidance document and should not be interpreted as a standard or recommended practice.** Pipeline operators should continue to exercise independent judgement is determining whether their programs conform to the regulatory requirements.

2. *Regulatory Deadlines*

The table below shows the compliance deadlines required in the rule:

August 27, 1999	Final rule published: Reference the **Federal Register**, Volume 64, Number 166, published Friday, August 27, 1999, pages 46853-46867.
October 26, 1999	Rule became effective.
April 27, 2001	Operators must have written qualification program complete.
October 28, 2002	Operators must complete the qualification of individuals performing covered tasks.

3. *Affected Personnel*

The personnel affected by the qualification program include any individual who performs a "covered task" and those who have involvement in ensuring a qualified workforce.

Descriptions or titles of individuals who may perform covered tasks include:

- Contractors
- Delivery/Gauger Personnel
- Front-line Supervisors including Lead Persons
- Operations and Maintenance Personnel
- Maintenance Technicians (electrical/instrumentation/mechanical/corrosion)
- Patrol Pilots
- Pipeline Controllers/Dispatchers
- Terminal Operators
- Welders.

Individuals who are involved in ensuring a qualified workforce may include:

- Contractors
- Front-line Supervisors
- Human Resources Personnel
- Operations and Maintenance Trainers
- Operations, Maintenance and Control Center Managers
- Regulatory Compliance Personnel
- Team Leaders.

4. Written Program

The regulation requires that pipeline operators have a written qualification program. Operators without any qualification program must establish a written program to evaluate the individuals performing certain operation and maintenance activities on pipeline facilities that could affect pipeline operation or integrity. **Operators with existing programs may modify those programs as necessary to ensure compliance with the minimum requirements of this rule.**

The written program should include an introduction and address the seven required elements of the qualification rule. Below is a breakdown of the written program.

4.1 Introduction

The written program should include an introduction that addresses the objective of the qualification program, which is to ensure your company has a qualified workforce and to reduce the probability and consequence of accidents caused by human error. It should reference the regulation, 49 CFR Part 195, Subpart G, Sections 195.501 through 195.509. You also may consider including a copy of the regulation as an attachment to the written program for reference.

4.2 Seven Required Elements

The written program must address the following required seven elements of the rule (49 CFR Part 195.505).

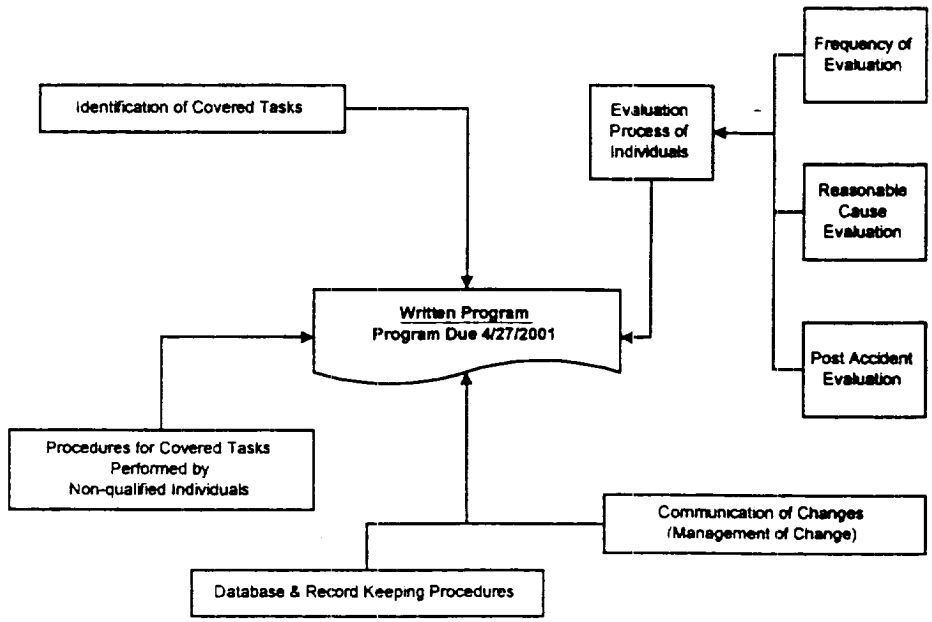
1. Identify covered tasks that personnel perform on your pipeline facilities.
2. Ensure, through evaluation, that individuals are qualified to perform covered tasks.
3. Allow non-qualified individuals to perform a covered task under the direct observation of a qualified person.
4. Evaluate an individual if there is reason to believe that the individual's performance of a covered task contributed to an accident as defined in 49 CFR Part 195.
5. Evaluate an individual if there is reason to believe that the individual is no longer qualified to perform a covered task.
6. Ensure that changes affecting covered tasks are appropriately communicated.
7. Identify the intervals at which re-evaluation of the individual's qualifications is needed

Each of these seven elements is discussed in this guidance document.

5. *Suggested Program*

Paragraphs 5 through 6 of this guidance document provide a basic outline for a written qualification program. Your program does not have to follow these contents, but at a minimum your company should ensure that the seven elements discussed in paragraph 4.2 are included. Figure 1 shows the elements that must be included in the program.

Figure 1
Elements of an Operator Qualification Written Program



5.1 Format

A qualification program should be developed in a format that is convenient to your company, such as paper-based, electronic format, or web-based. The program should be accessible to company users and government regulators.

5.2 Process for Developing the Written Program Content

To develop a written program that encompasses the seven required elements, it is recommended that your company's program be developed using the following components.

- Premises and Definitions
- Task Identification and Analysis
- List of Covered Tasks (This may be included as an attachment)
- Evaluation Methods and Ongoing Evaluation
- Non-Qualified Individuals
- Contractor Personnel
- Record Keeping.

5.3 Premises and Definitions

Premises and definitions are important because they provide a standard for accurately and consistently identifying tasks and determining whether they are covered or not covered.

The premises should address how your company interprets and applies the four-part test used to identify covered tasks and the company's understanding of abnormal operating conditions associated with covered tasks.

Develop the Premises and Definitions for Interpreting the Four-Part Test

When developing premises and definitions, it is helpful to review the rule's four-part test and establish what your company considers:

- a pipeline facility
- an operations or maintenance task
- an activity specifically required of 49 CFR Part 195
- an activity that affects the operation or integrity of the pipeline

An example set of premises and definitions is included in Appendix B.

NOTE: When you have fully established your premises and definitions, strictly adhere to them.

5.4 Task Identification and Analysis

This analysis should be completed for each position, required by your company, which performs operations or maintenance activities including contractor positions.

Record each applicable activity on a master task list. It is important to focus on the activities of the position and not its responsibilities to determine if the activities are covered tasks.

Task identification and analysis may be accomplished by:

- Reviewing 49 CFR Part 195
- Interviewing individuals within each job position
- Reviewing operations, maintenance and safety manuals
- Reviewing contracts
- Reviewing the example covered task list in Appendix C of this guidance document. Review Appendix D for an expanded description of each covered task.

5.5 Identification of Covered Tasks Using the Four-Part Test

To identify which activities are covered tasks for your written program, measure each activity against the rule's four-part test. Adhere to the premises your company developed as you apply the four-part test to identify covered tasks.

The four-part test consists of the criteria listed below:

- Is it performed on a pipeline facility?
- Is it an operations or maintenance task?
- Is it performed as a requirement of 49 CFR Part 195?
- Does it affect the operation or integrity of the pipeline facility?

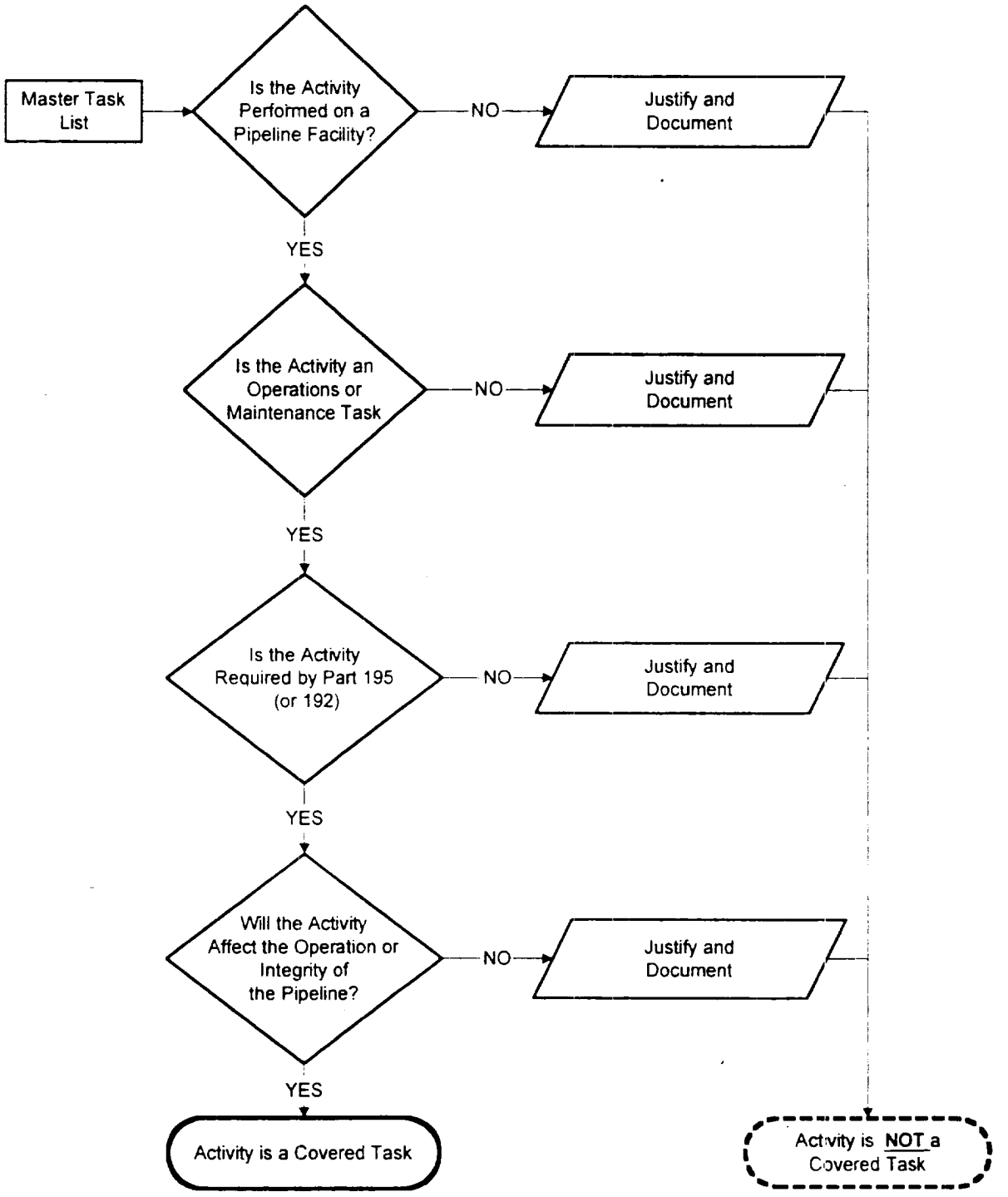
All four questions <u>must</u> be answered "yes" for the activity to be a covered task. Figure 2 shows the process for identifying and documenting covered tasks.

Note: An example list of covered tasks is included in Appendix C with an expanded list in Appendix D.

Additional guidance related to the covered task four-part test can be found in the Supplementary Information of the rule. (See Federal Register, Volume 64, Number 166, published Friday, August 27, 1999, pages 46853-46867.)

It is highly recommended that each company document its reason(s) that an activity does not meet the criteria in the four-part test so the rationale may be referenced during regulatory review.

Figure 2
Application of the Four-Part Test to Identify Covered Tasks



5.6 Evaluation

The written program must provide information on how the operator will evaluate individuals to determine whether they are qualified to perform covered tasks.

5.6.1 Methods

The rule provides several acceptable evaluation methods:

- written exam
- oral exam
- work performance history
- observation during performance on-the-job
- observation during on-the-job training
- simulations
- other forms of assessment

Appendix E provides acceptable evaluation methods for transitional, initial and subsequent qualification.

- **Transitional qualification** is that which is completed by October 28, 2002, for individuals who have been performing a covered task on a regular basis prior to August 27, 1999.
- **Initial qualification** is that done at any time for individuals who were not performing a covered task prior to October 26, 1999.
- **Subsequent qualification** refers to re-evaluating an individual at an interval established by the operator (e.g., annually, every three years, etc.).

Suggestions on the effective use of each evaluation method are listed in Appendix F.

When all covered tasks have been identified, each individual who performs those covered tasks must be evaluated to determine whether they are qualified to perform them. The evaluation method or combination of methods should sufficiently measure the individual's knowledge and skills to perform the covered task.

The evaluator should utilize a covered task evaluation checklist or procedure to ensure accurate and consistent assessment when performing an oral examination. on-the-job performance observation, or an on-the-job training observation.

The operator should determine the acceptable qualification criteria level for each covered task evaluation checklist, written examination, etc. The operator will need to determine what is acceptable performance during the evaluation. This can be in the form of a passing score for a written test and/or steps correctly completed during a performance evaluation.

Although training an individual to perform a covered task may be conducted individually or in a group, the evaluation process should be completed on an individual basis. Written evaluations may be given in a group setting, however the evaluation should reflect an individual's ability.

5.6.2 *Subsequent Evaluation (re-evaluation)*

The rule addresses certain conditions that require re-evaluation when any of the following apply:

- when the time interval, as established by the operator, has expired;
- if there is reason to believe the individual's performance of a covered task contributed to an accident; or
- if there is reason to believe an employee is no longer able to perform a covered task.

These are discussed in the sections below.

Time Interval

The regulation requires the operator to determine the time intervals appropriate for re-evaluation. Time intervals for subsequent evaluations may be based on:

- the frequency of performance of the covered task
- the complexity of the task
- the risk and consequences involved if the task is incorrectly performed

Tasks that are performed frequently and have low risk may have longer re-evaluation periods than tasks performed infrequently and have high risk. For example, a covered task that is:

- performed infrequently, is highly complex, and has severe consequences (high risk) may require frequent re-evaluation.

- performed weekly or more often and has a low degree of complexity with moderate to low consequences may require infrequent re-evaluation.

Establish the subsequent evaluation intervals and list them in the written program.

In Response to an Accident

The pipeline operator should evaluate an individual if the pipeline operator has reason to believe the individual's performance of a covered task contributed to an accident as defined in 49 CFR Part 195. An accident investigation should be performed to determine if an individual contributed to the accident and needs to be re-evaluated. The root cause analysis may also indicate if other individuals performing the same covered task need additional training to prevent recurrence of the same error.

The re-evaluation should sufficiently address both the knowledge and skill components of the covered task to ensure that the individual has been properly re-evaluated. Finally, all re-evaluations must be documented. Paragraph 5.10 provides information on record keeping.

Employee is No Longer Able to Perform a Covered Task

When there is reason to believe that an individual may no longer be able to perform a covered task, re-evaluated and re-qualification prior to performing the covered task should occur. Examples of when this may occur are listed below.

- The individual has spent excessive time away from the job due to a disability, special assignment, or a change in job duties. (The specific time period established by the operator should be reflected in this part of the program.)
- The individual displays unsatisfactory performance of a covered task.
- There are significant changes to equipment or procedures.

5.7 Communicating Changes in Covered Task Procedures

The rule requires that the qualification program include provisions for communicating changes that affect covered tasks to individuals performing those affected covered tasks. When significant changes occur, the operator should consider whether additional qualification requirements are necessary and whether individuals performing the covered task should be evaluated again.

A management of change (MOC) process should be in place to keep individuals properly informed of changes in the procedures for covered tasks. A management of change process may be used in the cases listed below.

- Modifications to company policies or procedures
- Changes in State or Federal regulations
- Utilization of new equipment and/or technology
- New information from equipment or product manufacturers.

As part of the MOC process, all applicable training documentation and evaluation materials should be updated to reflect the changes.

5.8 Non-Qualified Individuals

There may be instances when non-qualified individuals are utilized to perform covered tasks (new employees in training, temporary employees assisting full-time employees, contractor personnel, etc.). In such situations, a non-qualified individual may perform the covered task provided a qualified person is directing and observing the non-qualified individual.

Below are some factors to consider when qualified persons are supervising non-qualified individuals.

- The qualified person must be close enough to each non-qualified individual to direct and observe his/her work and take immediate corrective action in the event an abnormal condition occurs. A qualified person can effectively observe multiple non-qualified individuals performing covered tasks in a close proximity area.
- There should be no obstructions or distance between the non-qualified individuals and the qualified person which would impede the qualified person's ability to directly observe and take immediate corrective action.

5.9 Contractor Personnel

The operator is responsible for ensuring the qualifications of contractor personnel performing covered tasks under 49 CFR Part 195 just as it is responsible for ensuring the qualifications of its own employees.

Contractor personnel may be qualified to perform covered tasks under the operator's qualification program. In addition, contractor personnel can be qualified under their own qualification program or a third-party qualification program provided the applicable qualification program has been approved by the operator and referenced in the operator's written program.

Non-qualified contractor personnel may perform covered tasks if directed and observed by a qualified person. The qualified person may be an operator's employee, an operator's representative (third-party inspector), or a contractor representative (refer to paragraph 5.8).

5.10 Record Keeping

Records on individuals and covered tasks should include the following:

- the qualified individual's name and/or employee/contractor number;
- the covered tasks that the individual is qualified to perform;
- the date(s) of current qualification; and
- the qualification method.

Retain documentation (such as the graded examination or an on-the-job training evaluation checklist) to support the evaluation procedure for a minimum of five years from the qualification date. Also, qualification documentation must be kept for five years after an individual stops performing covered tasks (refer to 49 CFR Part 195.507(b)).

See Appendix G for an example Qualification Record Sheet.

6. Program Maintenance

The qualification program should be evaluated periodically to verify its effectiveness. Changes to covered tasks, evaluation methods, evaluation materials, and associated training materials should be made as needed. The frequency that the operator establishes to evaluate the qualification program should be reflected in this section of the written program.

APPENDIX A – DISCUSSION OF THE RULE

(Excerpted from the DOT Document Published in the Federal Register August 27, 1999)

Qualification of Liquid Pipeline Personnel

This rule requires pipeline operators to develop and maintain a written qualification program for individuals performing covered tasks on pipeline facilities. The intent of this qualification rule is to ensure a qualified workforce and to reduce the probability and consequence of incidents caused by human error.

This rule

- creates new subparts in the gas and hazardous liquid pipeline safety regulations,
- establishes qualification requirements for individuals performing covered tasks, and
- amends certain training requirements in the hazardous liquid regulations.

The rule became effective October 26, 1999.

Introduction

The objective of this rule is to reduce the risk of accidents on pipeline facilities attributable to human error and provide an additional level of safety.

The rule

- requires operators of pipelines to develop a written qualification program to evaluate an individual's ability to perform covered tasks and to recognize and react to abnormal operating conditions that may occur while performing covered tasks;
- sets record-keeping requirements that operators must comply with to successfully demonstrate compliance; and
- provides the information that must be maintained on each individual evaluated and deemed qualified to work on a pipeline facility.

This rule allows operators with existing programs to modify those programs, as necessary, to ensure compliance with the minimum requirements of this rule. The rule also requires those operators without any qualification program to establish a program to evaluate the qualifications of individuals performing certain operation and maintenance activities on pipeline facilities that could affect pipeline operation or integrity.

The following sections provide the applicable regulatory citation in the left column with guidance in the right column.

THE RULE

49 CFR Part 195 Subpart N – Amended
§195.403 Emergency Response Training.

(a) Each operator shall establish and conduct a continuing training program to instruct emergency response personnel to:
(1) Carry out the emergency procedures established under 195.402 that relate to their assignments;
(2) Know the characteristics and hazards of the hazardous liquids or carbon dioxide transported, including, in case of flammable HVL, flammability of mixtures with air, odorless vapors, and water reactions;
(3) Recognize conditions that are likely to cause emergencies, predict the consequences of facility malfunctions or failures and hazardous liquids or carbon dioxide spills, and take appropriate corrective action;
(4) Take steps necessary to control any accidental release of hazardous liquid or carbon dioxide and to minimize the potential for fire, explosion, toxicity, or environmental damage; and
(5) Learn the proper use of firefighting procedures and equipment, fire suits, and breathing apparatus by utilizing, where feasible, a simulated pipeline emergency condition.

(b) At the intervals not exceeding 15 months, but at least once each calendar year, each operator shall:
(1) Review with personnel their performance in meeting the objectives of the emergency response training program set forth in paragraph (a) of this section, and
(2) Make appropriate changes to the emergency response training program as necessary to ensure that it is effective.

(c) Each operator shall require and verify that its supervisors maintain a thorough knowledge of that portion of the emergency response procedures established under §195.402 for which they are responsible to ensure compliance.

GUIDANCE

Previously Section 195.403 prescribed the training requirements for operations, maintenance, and emergencies for operators of hazardous liquid pipelines. The operator qualification rule under subpart G includes a qualification process for operations and maintenance activities, but does not include emergency response qualification requirements. Therefore, 49 CFR §195.403 was amended to address only emergency response activities. This section becomes affective October 28, 2002.

This rule removes the specific operations and maintenance training requirements previously addressed in §195.403. Persons performing operations and maintenance tasks must be qualified in accordance with the new rule.

THE RULE

49 CFR Part 195
Subpart G – Added

§195.501 Scope.

(a) This subpart prescribes the minimum requirements for operator qualification of individuals performing covered tasks on a pipeline facility.

GUIDANCE

The Accountable Pipeline Safety and Partnership Act of 1996 required RSPA to adopt regulations requiring that "all individuals who operate and maintain pipeline facilities shall be qualified to operate and maintain the pipeline facilities" and that employers "shall address the ability [of individuals] to recognize and react appropriately to abnormal operating conditions that may indicate a dangerous situation or a condition exceeding design limits." Such a system offers the advantages of national consistency, including the ability of contractor employees to work for different operators under a single qualification regime.

The mandate is met by a non-prescriptive, performance-based regulation requiring each operator to develop, or have developed, a written program for the qualification of individuals. This allows each program to be tailored to the unique operations and practices of each operator.

Persons Covered by the Rule. This rule applies to operators subject to the requirements of 49 CFR Part 195. The rule also applies to all individuals who perform covered tasks, regardless of whether they are employed by the operator, a contractor, a sub-contractor, or any other entity performing covered tasks on behalf of the operator.

Operators are Responsible for Identifying Covered Tasks. Because of large differences between operations of pipelines across the country, RSPA decided that a uniform list of covered tasks would not be useful and could result in overall increased costs. For example, some operators do not have transmission lines in their pipeline systems, others operate only distribution lines, and others do not have compressors, pump stations, or storage facilities. Some operators perform a large number of covered tasks, while other, smaller operators may have only a limited number of activities that would be classified as covered tasks.

Identification of covered tasks is a key component of the qualification requirements under this rule. Suggested covered tasks are identified in Appendix C and Appendix D.

THE RULE

§195.501 Scope. (cont.)

(b) For the purpose of this subpart, a covered task is an activity, identified by the operator, that:

(1) Is performed on a pipeline facility;

GUIDANCE

Identification of Covered Tasks.
The rule includes a four-part test that each operator must use to determine whether an activity constitutes a covered task. These are shown as numbers 1 – 4 to the left. Each is discussed in detail below.

The words "identified by" means the selection of covered tasks by the operator. The authority to allow pipeline safety regulators to require modifications to programs that fail to meet regulatory requirements is within the scope of federal and state jurisdiction, as is the authority to question particular activities included as covered tasks by the operator.

The operator of a pipeline facility is responsible for identifying which activities performed on that facility are covered tasks. The criteria for identifying such covered tasks on hazardous liquid pipelines are set forth in §195.501.

Although operators are responsible for identifying covered tasks for which individuals must be qualified, pipeline safety regulators remain responsible for reviewing operator qualification programs and ensuring that federal regulatory standards are applied and met nationwide. Regulators may question an operator's inclusion or exclusion of particular activities as covered tasks. Regulators may require modifications to programs that fail to meet the requirements of the rule.

Tasks Performed on a Pipeline Facility. The phrase "performed on a pipeline facility" means an activity that is performed by an individual whose performance directly impacts the pipeline facility. An individual who works on a pipeline component that is physically connected to the pipeline system is performing work "on a pipeline facility" and may be subject to the rule, regardless of whether or not product is flowing through the pipeline.

However, a person who repairs a pipeline component or appurtenance that has been removed from the system is not performing work on the pipeline and, therefore, would not be performing a covered task.

THE RULE

§195.501 Scope. (cont.)

(2) Is an operations or maintenance task;

GUIDANCE

Operations or Maintenance Tasks. The act requires that all individuals who operate and maintain pipeline facilities be qualified to operate and maintain those facilities (49 U.S.C. Section 60102(a)(1)(C)).

Most of the operations and maintenance activities on pipeline facilities are found in 49 CFR Part 195, Subpart F. In addition, the regulations contain other subparts that include requirements for conducting operations and maintenance activities.

For example, monitoring corrosion control systems in accordance with requirements is an operations activity. Taking corrective action as required when deficiencies are found in a corrosion control program is a maintenance activity. Therefore, repairing pipelines affected by corrosion is also a maintenance activity.

Certain tasks performed on pipeline facilities may be covered tasks when performed in the course of operation and maintenance activities but not be covered tasks in the course of other activities. For example, "welding" could be a covered task when performed as an operations and maintenance activity on a pipeline, such as when installing a weld-over sleeve to repair an anomaly. However, "welding" is not a covered task under this subpart when performed during the fabrication of new installations because this would not be an operations and maintenance task.

However, welders are currently subject to qualification requirements in 49 CFR Part 195, Subpart D. To comply with the rule, welders would have to be qualified to recognize and react to abnormal operating conditions when performing welding as a covered task.

THE RULE

§195.501 Scope. (cont.)

(3) Is performed as a requirement of this part; and

(4) Affects the operation or integrity of the pipeline.

GUIDANCE

Tasks Performed Pursuant to a Requirement in 49 CFR Part 195. Covered tasks include only those operations and maintenance activities required by 49 CFR Part 195.

Examples of covered tasks might include:

- inspecting navigable water crossings under §195.412 and
- inspecting breakout tanks under §195.432.

Operators of pipeline facilities may voluntarily conduct operations and maintenance activities that are not required by a specific provision in 49 CFR Part 195. However, an activity does not necessarily become a covered task simply because an operator develops procedures for conducting the activity and includes those procedures in its Operations and Maintenance Program.

For example, an operator may voluntarily choose to maintain a customer's buried piping. It includes procedures for such maintenance activity in its Operations and Maintenance Program. Because such maintenance is not specifically required by 49 CFR Part 195, the associated maintenance activities are not covered tasks.

Tasks Affecting the Operation or Integrity of the Pipeline. Under the rule, covered tasks include only those activities that affect the operation or integrity of the pipeline.

It is important to clarify the term "operation" as used here in the safety context of normal versus abnormal operation, where the latter could result in an unsafe condition. For example, the control of flow and pressure in pipelines could result in abnormal operation if the pressure is allowed to rise above an acceptable limit. Therefore, in this example, activities that include controlling flow and pressure on a pipeline system would be considered covered tasks if the other three criteria for covered tasks were met.

The "integrity" of the pipeline refers to the pipeline's ability to operate safely and to withstand stresses imposed during operations. An example of a short-term effect on integrity would be exceeding the

THE RULE

§195.501 Scope. (cont.)

GUIDANCE

Maximum Operating Pressure (MOP) for liquid pipelines. An example of a long-term effect would be failure from corrosion due to improper coating after repair of a welded joint.

An additional example of a task affecting the integrity of the pipeline would be coating or jacketing of aboveground pipeline components. In the event atmospheric corrosion is present, coating or jacketing the component could affect the integrity of the pipeline. However, painting a pipeline for aesthetic reasons would not affect the integrity of the pipeline.

In identifying covered tasks, operators must consider specific activities and not the job classification of individuals performing the activities, since each job classification may incorporate several activities. For example, an individual with the job classification "meter reader" may be assigned activities other than reading a meter that could be covered tasks; and that individual would need to be qualified for those covered tasks.

EXAMPLES USING THE CRITERIA.

The following are hypothetical examples of how the four-part test can be used to identify a covered task.

If an activity fails to meet any of the four criteria, the activity would not be considered a covered task under this rule.

EXAMPLE #1: MEASURING PIPE-TO-SOIL POTENTIALS

1. Is it performed on a pipeline facility?

   Yes, pipe-to-soil potentials are measured at cathodic test stations attached directly to the pipeline.

2. Is it an operations and maintenance task?

   Yes, pipe-to-soil potentials are read in the course of pipeline operations and maintenance activities.

3. Is it performed as a requirement of this part?

   Yes, pipe-to-soil potential measurements are required by 49 CFR §195.416.

4. Does it affect the operation or integrity of the pipeline?

   Yes, pipe-to soil potential measurements, if taken improperly, will not accurately reflect the level of cathodic protection being provided. While not affecting the immediate operation of the pipeline, the future integrity of the pipeline might be jeopardized (for example, corrosion might develop) if inadequate cathodic protection is applied to the pipeline over a period of time.

Since all four criteria are met, the measurement of pipe-to-soil potentials is a covered task.

EXAMPLES USING THE CRITERIA.

The following are hypothetical examples of how the four-part test can be used to identify a covered task.

If an activity fails to meet any of the four criteria, the activity would not be considered a covered task under this rule.

EXAMPLE #2: METER READING

1. Is it performed on a pipeline facility?

   Yes, a meter is a part of a pipeline facility.

2. Is it an operations and maintenance task?

   Yes, meters are read in the course of pipeline operations and maintenance activities.

3. Is it performed as a requirement of this part?

   No, meter reading is not a requirement of Part 195.

4. Does it affect the operation or integrity of the pipeline?

   No, meter reading has no impact on pipeline operation or integrity.

Because meter reading fails to meet at least one of the four criteria, meter reading is not considered a covered task.

THE RULE

§195.503 Definitions.

Abnormal operating condition means a condition identified by the operator that may indicate a malfunction of a component or deviation from normal operations that may:

(a) indicate a condition exceeding design limits; or

(b) result in a hazard(s) to persons, property, or the environment.

GUIDANCE

This definition is derived from the Accountable Pipeline Safety and Partnership Act of 1996 and codified in 49 CFR Part 195.402(d)(1)(v).

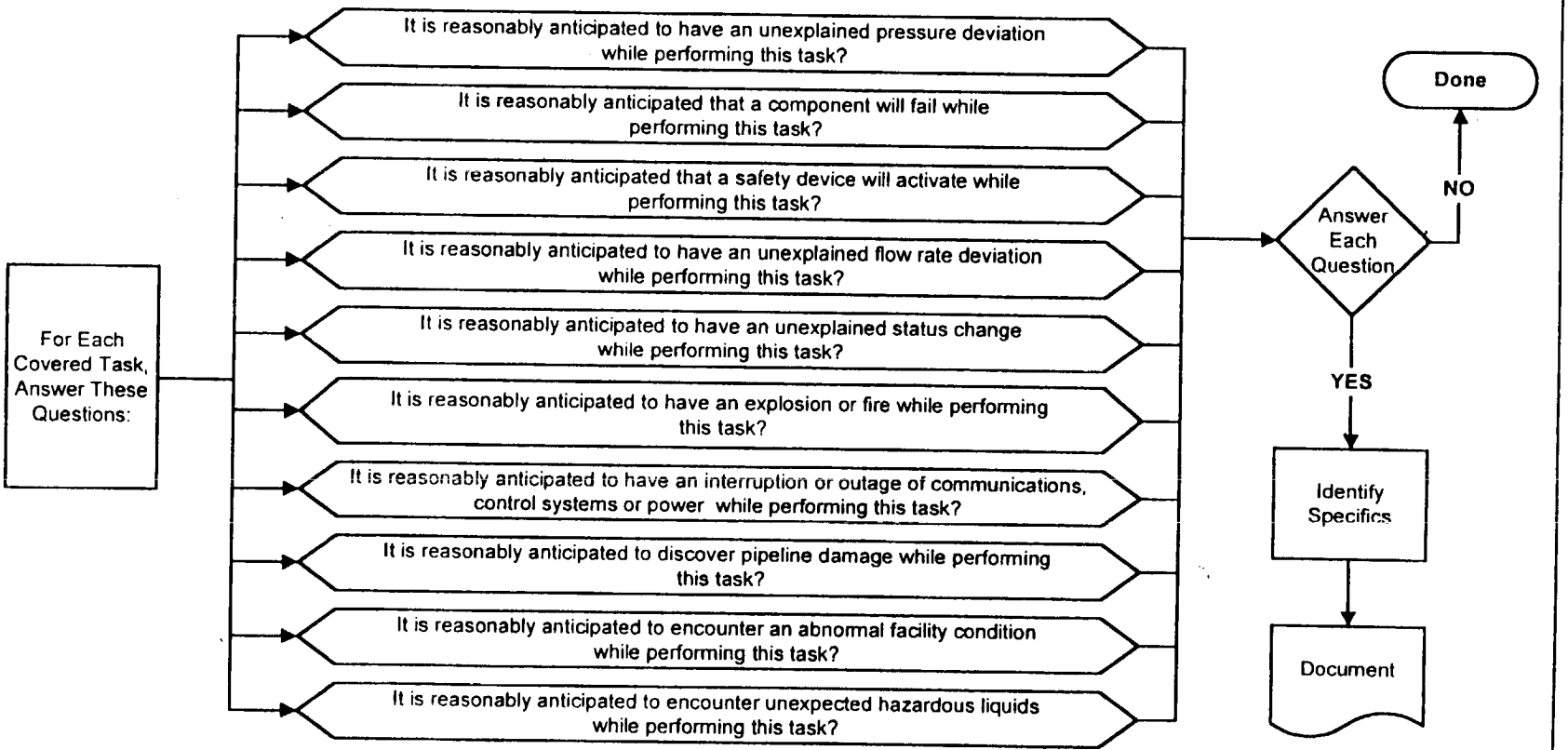
"Abnormal operating conditions" is also referenced in the definition of the term "qualified" (see below).

Not all atypical (unusual) operating conditions are abnormal. An example of an atypical operating condition that is not abnormal is a pipeline which can (not to exceed Maximum Operating Pressure (MOP)) operate up to 200 pounds per square inch (psig), but which typically operates at 50 psig. Operating this pipeline at 150 psig would be atypical, but not abnormal.

If, however, the atypical operating condition could cause the pressure in the pipeline to exceed its allowable limits or cause a hazard to persons, property or the environment, an abnormal operating condition would result. A qualified individual performing control of pressure and flow who observes an unanticipated pressure increase in such a pipeline segment should know to investigate the cause of the change before it reaches the MOP of the line.

Figure A-1 provides information on determining abnormal operating conditions for covered tasks.

Figure A-1
Abnormal Operating Conditions for Each Covered Task



THE RULE

Evaluation means a process, established and documented by the operator, to determine an individual's ability to perform a covered task by any of the following:

(a) written examination

(b) oral examination

(c) work performance history review

(d) observation during

(e) performance on the job

(f) on the job training

(g) simulations

(h) other forms of assessment

GUIDANCE

The evaluation of an individual's qualifications should be an objective, consistent process that documents an individual's ability to perform the covered task. This includes the individual's ability to recognize and react to abnormal operating conditions that the operator could reasonably anticipate the qualified individual will encounter while performing the covered task.

The operator should establish the acceptance criteria for the evaluation method used (for example, for on-the-job training, spell out the performance criteria; for a written exam, establish the cutoff score). Although the definition lists several acceptable methods for evaluation, the list is not all-inclusive. Operators might select other methods.

The table in Appendix E shows acceptable evaluation methods for "transitional," "initial" and "subsequent" qualification.

Under §195.509(c), a work performance history review may not be used as a sole evaluation method after October 28, 2002.

"Transitional" qualification may rely on a work performance history review as the sole evaluation method.

"Initial" qualification may not rely on only a work performance history review.

"Subsequent" qualifications may rely on work performance history review if used in conjunction with at least one other evaluation method.

Prior to the October 28, 2000, operators may use work performance history review as the sole method for evaluation when qualifying individuals Who performed the covered task prior to August 29, 2002, If work performance history review is used, it must be combined with at least one other form of assessment. Any of the other forms of assessment specified in the definition of evaluation may be used as the sole method of evaluation both before and after the three-year compliance date. When an operator has qualified an individual prior to the three

THE RULE

Qualified means that an individual has been evaluated and can

(a) perform assigned covered tasks and

(b) recognize and react to abnormal operating conditions.

GUIDANCE

year compliance date and used work performance history review as the sole method of evaluation, the operator is not required to re-evaluate each individual using additional criteria until the next scheduled evaluation, which may vary by covered task.

The operator must establish the parameters for the work performance history review. For example, a work performance history review may include:

searching existing records for documentation of an individual's past satisfactory performance of covered task(s)

verifying that the individual's work performance history contains no indications of substandard work or involvement in an accident (Part 195), caused by an error in performing a covered task

- verifying that the individual has successfully performed the covered task on a regular basis prior to the effective date of the rule.

An individual may be qualified using any of the evaluation methods specified in the operator's written qualification program.

To be qualified, an individual needs to be able to properly perform assigned covered tasks and be able to recognize and react to an abnormal operating condition that may be encountered while performing the covered task. For example, this may include notifying the responsible parties or taking corrective action to mitigate the condition.

As an example, an individual who is qualified to perform control of pressure and flow should be able to recognize and react to an abnormal operating pressure in a pipeline segment.

THE RULE

§195.505 Qualification program.

Each operator shall have and follow a written qualification program. The program shall include provisions to:

(a) Identify covered tasks

(b) Ensure through evaluation that individuals performing covered tasks are qualified

GUIDANCE

The seven elements (a – g at left) are required in the operator's written qualification program:

The operator must identify the tasks that the operator considers to be covered. This is determined by using the four criteria in §195.501(b). Because operators are responsible for identifying covered tasks, variations among qualification programs are expected.

Although a periodic review requirement is not included in the rule, an operator may consider a periodic review to ensure the accuracy of its covered task list.

The written program must provide information on how the operator intends to evaluate individuals to qualify them for covered tasks.

The pipeline operator is responsible for all individuals working on their pipeline systems. This includes operator, as well as contractor personnel. Persons performing evaluations should possess the required knowledge

(1) to ascertain an individual's ability to perform covered tasks and

(2) to substantiate an individual's ability to recognize and react to abnormal operating conditions that might surface while performing those tasks.

This does not necessarily mean that the persons performing evaluations should be physically able to perform the covered tasks themselves.

Because the operator is responsible for the development and implementation of the evaluation methods, the operator should also be responsible for selecting appropriately knowledgeable individuals to perform evaluations. The rule requires a qualification program that focuses on ensuring an individual can properly perform a covered task(s) rather than the credentials of persons conducting evaluations.

THE RULE	GUIDANCE
(c) Allow individuals that are not qualified pursuant to this subpart to perform a covered task if directed and observed by an individual that is qualified	Individuals who have not been qualified may perform covered tasks as long as a qualified individual directly observes the non-qualified individual(s) and is able to take immediate corrective actions when necessary. For example, an operator may use a three-person crew to repair a leak. Two of the crew members could be non-qualified. The crew excavates and makes the repair under the direct and close observation of the qualified member of the crew. The intent of this provision is to ensure that non-qualified individuals performing covered tasks are subject to close observation of a qualified individual. Ultimately, the qualified member of the crew is responsible for the repair. The ratio of non-qualified individuals to qualified individuals should be kept to a minimum.
(d) Evaluate an individual if the operator has reason to believe that the individual's performance of a covered task contributed to an accident as defined in Part 195	If so, the individual's qualification should be evaluated to determine if the individual continues to be qualified to perform the covered task.
(e) Evaluate an individual if the operator has reason to believe that the individual is no longer qualified to perform a covered task	This could occur if the individual displays unsatisfactory performance of the task or if there is reason to believe the individual no longer can perform the covered task. The operator's qualification program must include provisions for evaluating an individual's qualification if the circumstances warrant.

THE RULE

(f) Communicate changes that affect covered tasks to individuals performing those covered tasks

(g) Identify those covered tasks and the intervals at which evaluation of the individual's qualifications is needed.

GUIDANCE

This paragraph recognizes that changes may occur that impact how a covered task is performed. Changes that may need to be communicated to individuals performing covered tasks may include:

- modifications to company policies or procedures
- changes in state or federal regulations
- utilization of new equipment and/or technology
- new information from equipment or product manufacturers

The rule requires that the qualification program include provisions for communicating information on substantive changes to the individuals performing the affected covered tasks. When significant changes occur, the operator should consider whether additional qualification requirements are necessary and whether individuals performing the covered task should be evaluated again.

It is left to the operator to determine which tasks are covered and the interval at which subsequent qualification of an individual performing a covered task will occur. The appropriate interval may vary depending on the task. The evaluation intervals could be specified in units of time, frequency of task performance, or other appropriate units. Subsequent evaluation methods may differ from initial qualification methods.

The rule does not require that the written qualification program be incorporated into an operator's Operations and Maintenance Program. The operator may expand any of the seven required elements and add additional elements to their program but will only be held accountable to meet the requirements of this subpart.

THE RULE

§195.507 Record Keeping.

Each operator shall maintain records that demonstrate compliance with this subpart.

(a) Qualification records shall include
  (1) Identification of qualified individual(s)
  (2) Identification of the covered tasks the individual is qualified to perform
  (3) Date(s) of current qualification; and
  (4) Qualification method(s).

(b) Records supporting an individual's current qualification shall be maintained while the individual is performing the covered task. Records of prior qualification and records of individuals no longer performing covered tasks shall be retained for a period of five years.

§195.509 General.

(a) Operators must have a written qualification program by April 27, 2001.

(b) Operators must complete the qualification of individuals performing covered tasks by October 28, 2002.

(c) Work performance history review may be used as a sole evaluation method for individuals who were performing a covered task prior to August 27, 1999.

(d) After October 28, 2002, work performance history may not be used as a sole evaluation method.

GUIDANCE

Under the rule, each operator is required to maintain records that demonstrate compliance, including the information shown at left.

Records of an individual's current qualifications must be maintained while the individual is performing the covered tasks for which he/she is qualified. When an individual is evaluated for subsequent qualification, the prior qualification records must be maintained for a period of five years. Also, when an individual stops performing a covered task (for example, the individual retires or is promoted) the individual's qualification records must be retained for a period of five years. The records may be kept in paper, electronic, or any other appropriate format. The records may be kept at a central location or at multiple locations.

The rule does not address whether a certification or other record of qualification need be issued to each qualified individual. This matter is solely within the discretion of the operator.

This will allow operators with more limited resources and differing budget cycles adequate time to complete the qualification process. Those operators who are able to comply before the mandatory compliance date are encouraged to do so. The rule does not intend to penalize early compliance. Therefore, the starting time for subsequent evaluation intervals determined by the operator is not required to begin untilOctober 28, 2002.

Finally, work performance history review will only be allowed as the sole method of evaluation during the three-year period prior to the mandatory compliance with the rule. After this time, work performance history review will be an acceptable method of evaluating individuals only in combination with another evaluation method.

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The following is provided as an example of the types of premises and definitions that operators may want to include in their written program. This is only an example, and each company should make its own interpretations in preparing its premises and definitions.

A Covered Task

- is a discrete activity performed by an individual or group of individuals
- has a beginning and an ending point
- has two or more steps
- can be observed and measured
- is identified by the Company and
- meets all four of the conditions discussed below.

1. **Performed on a pipeline facility** means an **activity** that is performed by an individual or group of individuals whose performance directly impacts the pipeline facility.

   A. **Pipeline facility** is new and existing pipe, rights-of-way and any equipment, facility or building used in the transportation of hazardous liquid.

   B. **Activity** means physical, visual or mental effort directed at achieving a result.

   C. **Removed from the system** means that a part of the **pipeline system** is physically removed from the **pipeline system.**

   D. **Pipeline system** means all parts of a pipeline facility through which a hazardous liquid moves in transportation (line pipe, valves, appurtenances, pumps, meters, tanks, etc).

2. **Operations and maintenance** tasks are **activities** done by an individual or group of individuals (1) to perform a function on a **pipeline facility** or, (2) to provide upkeep of a **pipeline facility.**

   A. A "new construction task" changes to an **operations and maintenance task** when the **pipeline facility** is being commissioned or during the act of connecting to an active **pipeline facility**.

   B. The following are not operations and maintenance tasks:

      - Activities on pipelines that have never been in service and not physically attached to an operating pipeline.
      - Fabrication of new installations.
      - Emergency response activities.

3. **Required by Part 195** means only those tasks specifically required to be addressed in Part 195. State and local requirements are not applicable to this rule.

4. **Affects the operation or integrity** of the **pipeline** means any **activity** that could directly or indirectly cause the release of hazardous liquid to the environment or result in a hazard to persons or property.

   A. Pipeline means Pipeline System (See 1 D).

   B. An affect can be either immediate (direct) or delayed (indirect).

   C. The integrity of the pipeline refers to the pipeline's ability to operate safely and to withstand stresses imposed during operations.

Evaluation means a process, established and documented by the Company, to determine an individual's ability to perform a covered task.

Qualified means

- that an individual has passed an evaluation
- the individual can perform assigned covered tasks
- the individual can recognize and react to abnormal operating conditions and
- compliance documentation is completed.

Individual means a person who, on behalf of the Company, performs one or more covered tasks on a pipeline facility operated by the Company.

Operate means starting, stopping or monitoring.

Abnormal Operating Condition (AOC) means a condition identified by the Company that may indicate a malfunction of a component or a deviation from normal operations that may indicate an operating condition that could exceed design limits or result in hazard(s) to persons, property, or the environment.

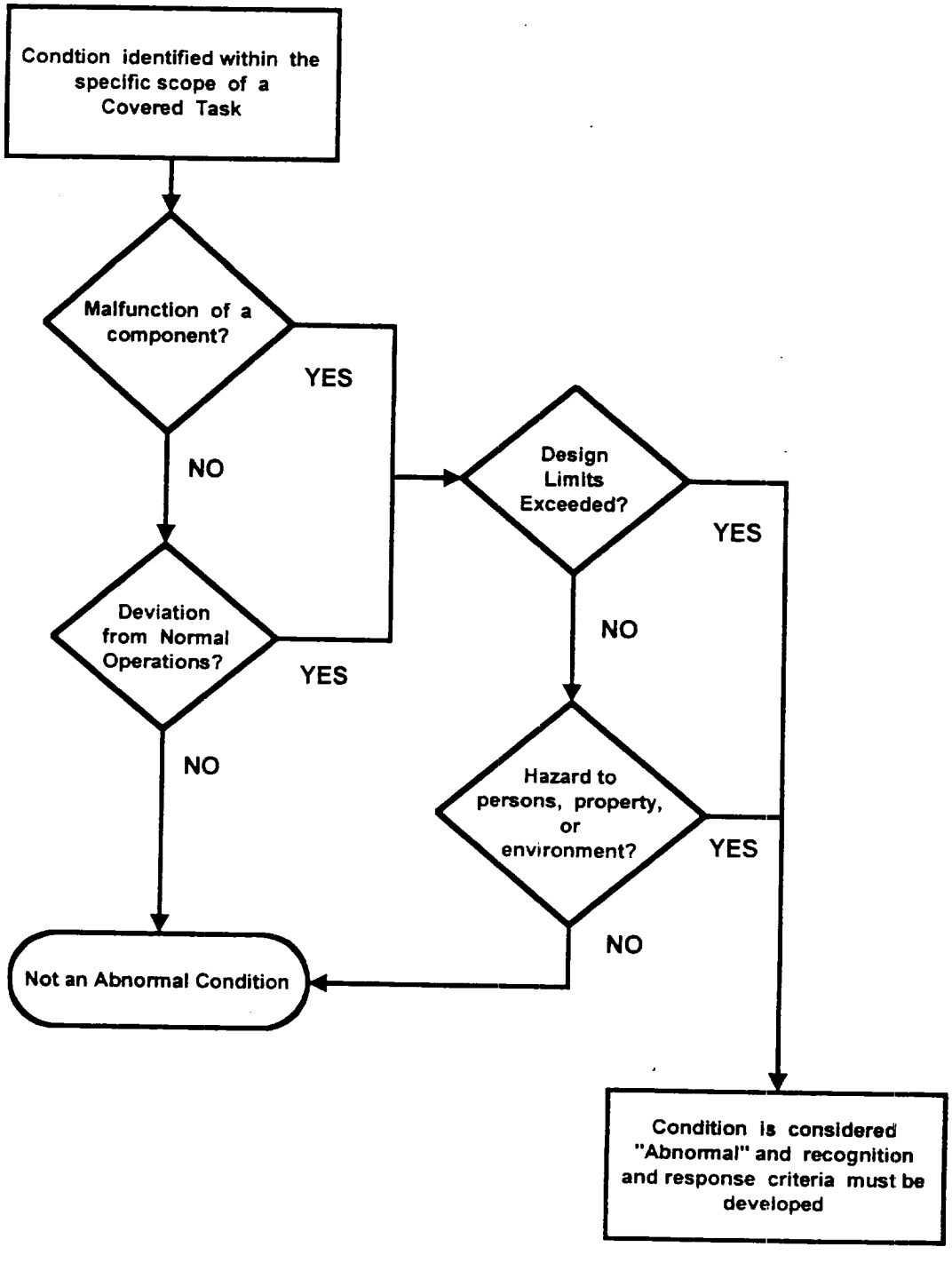
NOTE: A deviation from normal operation does not necessarily mean an abnormal operating condition exists. Refer to Figure B-1 for the Abnormal Condition Decision Flow Chart.

Some examples of AOC may include but are not limited to those shown below:

- Unexpected hazardous liquid or carbon dioxide encounter (unauthorized release, vapors, hazardous atmosphere, and contamination).
- Unexplained pressure deviations (increase, decrease, high, low, absent).
- Activation of a safety device (pressure relief, emergency shut downs, high pressure shut downs, case pressure shutdowns, high temperature shutdowns, etc.).
- Unexplained flow rate deviations (high flow, low flow, no flow).
- Unexplained status change (unit start-up, unit shut-down, valve open, valve close, gravity change, tank level, temperature, flash, haze, S&W, co-mingling of product, etc.).
- Fire/explosion.
- Interruption or failure of communications/control system/power.
- Pipeline system damage (line hit, lighting strikes, tornado, flood, earthquake, damaged pipeline support, etc.).
- Abnormal facility condition (exposed pipe, low cathodic protection levels, missing line markers, frayed or broken test lead wires, line crossing, excessive atmospheric corrosion, exposed river crossing).
- Component failure or malfunctioning component (field and SCADA components including meter failure).

Items listed above may be indications of an abnormal condition or may create an abnormal operating condition related to a specific covered task.

Figure B-1
Abnormal Condition Decision Flowchart



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The tasks in this document are intended to be a **guideline** for developing an Operator's Covered Task List. Some of the items in this list are categories that contain several tasks. For each category, an Operator must determine what tasks are performed as part of that category. Some Covered Tasks may not be included on this list and some items may not be a covered task in all situations. Each Operator must evaluate its specific situations for performing a task and determine if it meets the four-part test.

Task ID From Appendix D	Covered Task Name	Regulatory Citation
1	Conduct Annual Surveys	195.416 (a)
2	Maintain Test Leads	195.416 (b) 195.244
3	Inspect Rectifier	195.416 (c) 195.242
4	Maintain Rectifier	195.416 (c) 195.242
5	Inspect Buried Pipe When Exposed	195.416 (e) 195.242
6	Electrically Inspect Bare Pipe	195.416 (d) 195.242
7	Prevention Of Atmospheric Corrosion	195.238
8	Measure Wall Thickness of Pipe	195.416 (h)
9	Cathodic Protection Remediation	195.242
10	Monitoring For Internal Corrosion	195.418 (a) 195.418 (b) 195.242
11	Internal Corrosion Remediation	195.418 (b)
12	Inspect Internal Pipe Surfaces	195.418 (d)
13	Application and Repair Of External Coatings	195.238 (a)
14	Place and Maintain Line Markers	195.410 (a) 195.410 (c)
15	Inspect Surface Conditions Of Right Of Way	195.412 (a)
16	Inspect Navigable Waterway Crossing	195.412 (b)
17	Provide Temporary Marking Of Buried Pipeline Prior To Excavation	195.442
18	Inspection Following Excavation Activities And Leak Survey After Blasting	195.442 (c) 6
19	Maintain Valves	195.420 (a)
20	Inspect Valves	195.420
21	Repair Valves	195.420
22	Inspect, Test, And Calibrate Relief Valves	195.428
23	Maintain/Repair Relief Valves	195.428
24	Inspect, Test, And Calibrate Pressure Limiting Devices	195.428
25	Inspect, Test, And Calibrate Pressure Switches And Transmitters	195.428
26	Verify Or Set Protection Parameters For Programmable Controllers And/Or Instrumentation Control Loops	195.428
27	Inspect And Repair Breakout Tanks	195.432

Task ID From Appendix D	Covered Task Name	Regulatory Citation
28	Provide Security For Pipeline Facilities	195.436
29	Protect Breakout Tanks From Static Electricity, Lightning, And Stray Electrical Currents	195.405
30	Test Overfill Protective Devices	195.428
31	Inspect And Calibrate Overfill Protective Devices	195.428
32	Repair Overfill Protective Devices	195.428
33	Moving In-Service Pipe	195.424
34	Inspect Existing Pipe Following Movement	195.246 195.252
35	Inspection Of Clearance Of Existing Pipe To Underground Structures	195.250
36	Abandoning, Safe Disconnect, Purging, And Sealing Of Pipeline Facilities	195.402 (c) (10)
37	Installation Or Repair Of Support Structures On Existing Aboveground Components	195.254 195.422
38	Inspection Activities For Tie-Ins, Pipe Replacements, Or Other Components Connecting To An Existing Pipeline	195.204 195.206 195.422
39	Backfilling A Trench Following Maintenance	195.252 195.422
40	Perform General Pipeline Repair Activities	195.422
41	Conduct Pressure Tests	195 Subpart E 195.406
42	Welding On Existing Pipeline Systems	195.214 195.226 195.230
43	Operations Of Pipeline System	195.402 195.406
44	CPM Leak Detection	195.444
45	Operate Pressure Relieving Devices For Launching And Receiving Facilities	195.426

APPENDIX D – EXPANDED COVERED TASK LIST FOR LIQUID PIPELINES

NOTE: The tasks in this document are intended to be a guideline for developing an Operator's Covered Task List. Some of the items in this list are categories that contain several tasks. For each category, an Operator must determine what tasks are performed as part of that category. Some Covered Tasks may not be included on this list and some items may not be a covered task in all situations. Each Operator must evaluate its specific situations for performing a task and determine if it meets the four-part test.

Task ID: 1

Covered Task Name: Conduct Annual Surveys

Description:

Annual surveys are conducted each calendar year for each operator's pipeline system that is under cathodic protection to ensure that the protection is adequate. This task is related to the collection of data and does not include analysis.

Elements of this task may include:

- Measurement of pipe-to-soil potentials
- Measurement of casing-to-soil potentials
- Testing to detect interference and/or to ensure electrical isolation from foreign structures
- Inspection and electrical test of bonds
- Measurement of tank bottom-to-soil potentials

Four-Part Test for the Covered Task:

Is task performed on the pipeline?
Yes

Is the task an Operations or Maintenance Task?
Yes

Is the task required by Part 195 (or 192)?
Yes – 195.416 (a)

Does task affect the operation or integrity of the pipeline?
Yes

Notes:

The majority of liquid pipelines are under cathodic protection; this is a standard O&M task in corrosion control. A close interval survey may be used as an annual survey but is not required.

Abnormal Operating Conditions and Examples:

Abnormal facility condition
CP reading outside of expected ranges
Fire/Explosion
Ignition of hydrocarbons
Unexpected hazardous liquid or carbon dioxide encountered
Employee could discover a leak while performing this task

Task ID:	**2**
Covered Task Name:	**Maintain Test Leads**
Description:	Test leads required for cathodic protection must be maintained to ensure that accurate measurements can be obtained. Elements of this task may include: • Recognize electrical discontinuity • Replace broken test lead • Repair broken test lead
Four-Part Test for the Covered Task:	***Is task performed on the pipeline?*** **Yes** ***Is the task an Operations or Maintenance Task?*** **Yes** ***Is the task required by Part 195 (or 192)?*** **Yes – 195.416 (b), 195.244** ***Does task affect the operation or integrity of the pipeline?*** **Yes**
Notes:	The majority of liquid pipelines are under cathodic protection; this is a standard O&M task in corrosion control.
Abnormal Operating Conditions and Examples:	**Component failure** Discover broken leads **Fire/Explosion** Burn through during cadweld, ignition of vapor **Pipeline System damage** Burn through during cadweld, dents, and gouges **Unexpected hazardous liquid or carbon dioxide encountered** Employee could discover a leak while performing this task

Task ID:	**3**
Covered Task Name:	**Inspect Rectifier**
Description:	Pipeline operators are required to inspect each of its cathodic protection rectifiers at least six times each calendar year. Inspection activities may include: • Obtaining a voltage and current output readings from a rectifier • Checking for proper operation • Visual inspection of components
Four-Part Test for the Covered Task:	***Is task performed on the pipeline?*** **Yes** ***Is the task an Operations or Maintenance Task?*** **Yes** ***Is the task required by Part 195 (or 192)?*** **Yes – 195.416 (c), 195.242** ***Does task affect the operation or integrity of the pipeline?*** **Yes**
Notes:	**None applicable.**
Abnormal Operating Conditions and Examples:	**Abnormal facility condition** Abnormal rectifier output **Communications, Control System or Power interruption or failure** Power failure **Component failure** Broken leads, failed rectifier

Task ID:	**4**
Covered Task Name:	**Maintain Rectifier**
Description:	Impressed current type cathodic protection systems depend on the rectifier or other power sources for proper operation. Rectifier maintenance activities may include: • Repair/replace defective components (for example: switches, diodes, etc.) • Check/repair rectifier connections (bonds) • Adjustment/calibration of rectifier
Four-Part Test for the Covered Task:	***Is task performed on the pipeline?*** **Yes** ***Is the task an Operations or Maintenance Task?*** **Yes** ***Is the task required by Part 195 (or 192)?*** **Yes – 195.416 (c), 195.242** ***Does task affect the operation or integrity of the pipeline?*** **Yes**
Notes:	**None applicable.**
Abnormal Operating Conditions and Examples:	**Abnormal facility condition** Abnormal rectifier output **Communications, Control System or Power interruption or failure** Power failure **Component failure** Broken leads, failed rectifier

Task ID:	**5**
Covered Task Name:	**Inspect Buried Pipe When Exposed**
Description:	Any time buried pipe is exposed, pipeline operators must examine the pipe for evidence of external corrosion. Elements of this task may include: • Inspect for physical damage • Inspect for corrosion • Inspect the condition of coating
Four-Part Test for the Covered Task:	***Is task performed on the pipeline?*** **Yes** ***Is the task an Operations or Maintenance Task?*** **Yes** ***Is the task required by Part 195 (or 192)?*** **Yes – 195.416 (e), 195.242** ***Does task affect the operation or integrity of the pipeline?*** **Yes**
Notes:	This task takes place when the opportunity to visually inspect normally buried pipe for external corrosion and/or for the condition of the pipe coating occurs. This does not apply to abandoned pipelines.
Abnormal Operating Conditions and Examples:	**Abnormal facility condition** Corrosion **Fire/Explosion** Ignition of hydrocarbon **Pipeline system damage** Dent or gouge in pipe, damaged coating **Unexpected hazardous liquid or carbon dioxide encountered** Leak from exposed pipeline

Task ID:	**6**
Covered Task Name:	**Electrically Inspect Bare Pipe**
Description:	Pipeline operators must electrically inspect bare pipe in its pipeline systems that is not cathodically protected at intervals not exceeding 5 years. Elements of this task may include: • Measure soil resistivity • Perform soil-to-soil surveys
Four-Part Test for the Covered Task:	***Is task performed on the pipeline?*** **Yes** ***Is the task an Operations or Maintenance Task?*** **Yes** ***Is the task required by Part 195 (or 192)?*** **Yes – 195.416(d), 195.242** ***Does task affect the operation or integrity of the pipeline?*** **Yes**
Notes:	A close interval survey may be used but is not required.
Abnormal Operating Conditions and Examples:	**Abnormal facility condition** Out of spec resistivity or low potential readings **Fire/Explosion** Ignition of hydrocarbons **Unexpected hazardous liquid or carbon dioxide encountered** Employee could discover a leak while performing this task

Task ID: 7

Covered Task Name: Prevention of Atmospheric Corrosion

Description:

Each component in the pipeline system that is exposed to the atmosphere must be cleaned and coated with a suitable material to prevent atmospheric corrosion, and this protection must be maintained.

Elements of this task may include:

- Sandblasting and/or surface preparation
- Application of coating
- Inspection of coatings
- Inspection of insulation

Four-Part Test for the Covered Task:

Is task performed on the pipeline?
Yes

Is the task an Operations or Maintenance Task?
Yes

Is the task required by Part 195 (or 192)?
Yes – 195.238

Does task affect the operation or integrity of the pipeline?
Yes

Notes:

This is a standard O&M task and is normally considered as painting. "Coating" is used in the regulations, which emphasize corrosion control as opposed to painting for cosmetic reasons. This will include the inspection of spans, elevated sections of pipe, or other areas subject to atmospheric corrosion. Special attention to the inspection of pipeline systems that have insulation installed may be necessary to detect corrosion under the insulation.

Abnormal Operating Conditions and Examples:

Abnormal facility condition
Presence of atmospheric corrosion, pitting, etc.
Fire/Explosion
Ignition of hydrocarbons
Unexpected hazardous liquid or carbon dioxide encountered
Preparing surfaces for coating

Task ID:	**8**
Covered Task Name:	**Measure Wall Thickness of Pipe**
Description:	Elements of this task may include: • Using pit depth gauge • Using ultrasonic thickness tester • Measuring the affected corroded area
Four-Part Test for the Covered Task:	***Is task performed on the pipeline?*** **Yes** ***Is the task an Operations or Maintenance Task?*** **Yes** ***Is the task required by Part 195 (or 192)?*** **Yes – 195.416 (h)** ***Does task affect the operation or integrity of the pipeline?*** **Yes**
Notes:	Pipe strength analysis and/or other engineering evaluations conducted off-site are not covered tasks. However, activities to obtain pit depth or wall thickness measurements are covered tasks. Any pipe that is found to be corroded/pitted so that the remaining wall thickness is less than the minimum thickness required by the pipe specification tolerances must be replaced or repaired. Based on actual remaining wall thickness, operating pressures may be reduced in lieu of pipe repair or replacement. The strength of the pipe, based on actual remaining wall thickness measurements described above, may be determined by using the procedure in ASME B31G manual for Determining the Remaining Strength of Corroded Pipelines. The procedure developed by AGA/Batelle—A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe (with RSTRENG disk) may also be used.
Abnormal Operating Conditions and Examples:	**Abnormal facility condition** Internal or external corrosion **Fire/Explosion** Ignition of hydrocarbon **Pipeline System damage** Line hit, gouges **Unexpected hazardous liquid or carbon dioxide encountered** Insufficient wall thickness

Task ID: 9

Covered Task Name: Cathodic Protection Remediation

Description:

Cathodic protection systems installed on pipeline facilities must be tested and maintained to ensure adequate protection. As a result of annual surveys and other tests, remedial measures must be taken to correct changing conditions on the pipeline system. Retrofitting cathodic protection in these circumstances is a covered task.

Elements of this task may include:

- Install bonds and/or bond interface
- Install anodes
- Install rectifiers
- Install groundbeds
- Install test leads
- Conduct electrolyte resistivity measurements
- Clear, fill or monitor shorted casings

Four-Part Test for the Covered Task:

Is task performed on the pipeline?
Yes
Is the task an Operations or Maintenance Task?
Yes
Is the task required by Part 195 (or 192)?
Yes – 195.242
Does task affect the operation or integrity of the pipeline?
Yes

Notes:

Rectifiers may break down and need to be replaced or additional rectifiers may be required. Operators also replace anodes that have exceeded their useful lives. Installing an anode in these circumstances is a covered task. Installing test leads (test stations), checking soil resistivity and installing groundbeds are also covered tasks in these situations. Clearing a shorted casing, while not specifically addressed in Part 195, is considered a covered task. Failure to correct a shorted casing can seriously impair the cathodic protection system and produce accelerated localized corrosion.

Abnormal Operating Conditions and Examples:

Abnormal facility condition
Low CP levels
Component failure
Failure of rectifiers, coating, anodes, leads, etc.
Fire/Explosion
Burn through during cadweld, ignition of vapors
Pipeline System damage
Burn through during cadweld, dents, and gouges
Unexpected hazardous liquid or carbon dioxide encountered
Leak within casings

Task ID: 10

Covered Task Name: **Monitoring for Internal Corrosion**

Description:

Pipeline operators must take adequate steps to ensure that any corrosive effect of the transported liquid is mitigated. At least twice a year operators must examine coupons or other types of monitoring equipment to determine the effectiveness of the inhibitors or the extent of corrosion.

Elements of this task may include:

- Insertion and removal of coupons
- Monitor probes

Four-Part Test for the Covered Task:

Is task performed on the pipeline?
Yes

Is the task an Operations or Maintenance Task?
Yes

Is the task required by Part 195 (or 192)?
Yes – 196.418 (a) & (b), 195.242

Does task affect the operation or integrity of the pipeline?
Yes

Notes:

If the transported liquid is identified as corrosive to the pipe or other components of the pipeline system, the operator must take adequate steps to mitigate or control the corrosion. The analysis of a coupon at an off site laboratory would not be considered part of this task.

Abnormal Operating Conditions and Examples:

Abnormal facility condition
Discovery of internal corrosion
Fire/Explosion
Ignition of hydrocarbon
Unexpected hazardous liquid or carbon dioxide encountered
Leak from coupon holder

Task ID:	**11**
Covered Task Name:	**Internal Corrosion Remediation**
Description:	If corrosion inhibitors are used to mitigate internal corrosion, the operator must inject the inhibitor in sufficient quantities to ensure design coverage of the inhibitor. This task has the associated activities of starting, stopping or controlling inhibitor injection. Elements of this task may include: • Controlling the injection rate of the inhibitor • Monitoring the injection rate of the inhibitor
Four-Part Test for the Covered Task:	***Is task performed on the pipeline?*** **Yes** ***Is the task an Operations or Maintenance Task?*** **Yes** ***Is the task required by Part 195 (or 192)?*** **Yes – 195.418 (b)** ***Does task affect the operation or integrity of the pipeline?*** **Yes**
Notes:	If the transported liquid is identified as corrosive to the pipe or other components of the pipeline system, the operator must take adequate steps to mitigate or control the corrosion.
Abnormal Operating Conditions and Examples:	**Component failure** Malfunction of pump, meters, connecting lines of corrosion inhibitor

Task ID:	**12**
Covered Task Name:	**Inspect Internal Pipe Surfaces**
Description:	The operator must inspect the internal surface for evidence of corrosion whenever any pipe is removed from the pipeline system. If the pipe is corroded such that the remaining wall thickness is less than minimum requirements, the operator must investigate and inspect the adjacent pipe to determine the extent of corrosion. Elements of this task may include: • Visual inspection of the internal surface • Measurement of wall thickness
Four-Part Test for the Covered Task:	***Is task performed on the pipeline?*** **Yes** ***Is the task an Operations or Maintenance Task?*** **Yes** ***Is the task required by Part 195 (or 192)?*** **Yes – 195.418 (d)** ***Does task affect the operation or integrity of the pipeline?*** **Yes**
Notes:	Pipe strength analysis and/or other engineering evaluations conducted off-site are not covered tasks. However, activities to obtain pit depth or wall thickness measurements are covered tasks. Any pipe that is found to be corroded or pitted so that the remaining wall thickness is less than the minimum thickness required by the pipe specification tolerances must be replaced. Based on actual remaining wall thickness, operating pressures may be reduced in lieu of pipe repair or replacement.
Abnormal Operating Conditions and Examples:	**Abnormal facility condition** Inadequate wall thickness **Fire/Explosion** Ignition of hydrocarbons **Unexpected hazardous liquid or carbon dioxide encountered** Failure of isolation

Task ID: 13

Covered Task Name: Application and Repair of External Coatings

Description:

This task is performed when the external protective coating on in-service pipe is found to be damaged or defective (i.e. contains a "holiday", has disbonded, or deteriorated for any reason, etc.). This task includes field application and re-coating procedures. Coating application or repairs made off-site or prior to the pipeline being put into service (during construction) are not covered tasks.

Elements of this task may include:

- Removal of pipe coating in area of defect
- Cleaning and preparation of pipe to accept coating repair
- Preparation of coating material to be applied
- Application of new coating to defective area

Four-Part Test for the Covered Task:

Is task performed on the pipeline?
Yes

Is the task an Operations or Maintenance Task?
Yes

Is the task required by Part 195 (or 192)?
Yes – 195.238 (a)

Does task affect the operation or integrity of the pipeline?
Yes

Notes:

Applying or repairing coating as part of maintenance of an existing line is a covered task. Applying coating at a mill, coating facility or other location away from the pipeline facility is not a covered task. Re-coating an existing pipeline because the coating has deteriorated or applying coating to an existing uncoated line are maintenance tasks performed on the pipeline facility and are covered tasks. Applying coating patches after coating has been removed to allow repairs is also a covered task.

Field application of external coating is considered a construction task if performed on a new pipeline segment that is not tied to an active line. This includes applying coating at joints after construction-related welding.

Abnormal Operating Conditions and Examples:

Component failure
Damaged coating

Fire / Explosion
Fire from use of torches, etc.

Pipeline System damage
Dents, gouges, etc.

Unexpected hazardous liquid or carbon dioxide encountered
Employee could discover a leak while performing this task

Task ID:	**14**
Covered Task Name:	**Place and Maintain Line Markers**
Description:	Each operator is required to place and maintain line markers over each buried pipeline so that the pipeline location is accurately communicated. Elements of this task may include: • Locate line • Install marker
Four-Part Test for the Covered Task:	***Is task performed on the pipeline?*** **Yes** ***Is the task an Operations or Maintenance Task?*** **Yes** ***Is the task required by Part 195 (or 192)?*** **Yes – 195.410 (a) & (c)** ***Does task affect the operation or integrity of the pipeline?*** **Yes**
Notes:	Line markers must meet the specifications outlined in Part 195.410 (a).
Abnormal Operating Conditions and Examples:	**Abnormal facility condition** Line marker is missing or installed in wrong location **Pipeline System damage** Damaging the pipe/coating while installing the marker

Task ID:	**15**
Covered Task Name:	**Inspect Surface Conditions of Right-of-Way**
Description:	Each operator is required to inspect the surface conditions of the pipeline Right Of Way (ROW) and adjacent areas at least 26 times each year, with the intervals not exceeding three weeks. Walking, driving, flying or other appropriate means of traversing the right-of-way are methods of performing this task. Air patrol pilots (line flyers) are performing this covered task when they fly the right-of-way. Elements of this task may include: • Visual inspection of the surface • Reporting protocols
Four-Part Test for the Covered Task:	***Is task performed on the pipeline?*** **Yes** ***Is the task an Operations or Maintenance Task?*** **Yes** ***Is the task required by Part 195 (or 192)?*** **Yes – 195.412 (a)** ***Does task affect the operation or integrity of the pipeline?*** **Yes**
Notes:	**None Applicable**
Abnormal Operating Conditions and Examples:	**Abnormal facility condition** Wash out, construction on ROW, equipment on ROW **Fire/Explosion** Ignition of released hydrocarbon **Pipeline system damage** Vandalism, support damage **Unexpected hazardous liquid or carbon dioxide encountered** Dead vegetation, product on water

Task ID: 16

Covered Task Name: Inspect Navigable Waterway Crossing

Description:

At least every five years, operators are required to inspect each crossing under a navigable waterway to determine the condition of the crossing.

Elements of this task may include:

- Use of probing equipment
- Use of sonar equipment
- Reporting protocols

Four-Part Test for the Covered Task:

Is task performed on the pipeline?
Yes

Is the task an Operations or Maintenance Task?
Yes

Is the task required by Part 195 (or 192)?
Yes – 195.412 (b)

Does task affect the operation or integrity of the pipeline?
Yes

Notes:

Offshore pipelines are exempt from this task.

Abnormal Operating Conditions and Examples:

Abnormal facility condition
Exposed/undercut pipe, inadequate pipeline support
Pipeline System damage
Coating anomalies, pipe damage
Unexpected hazardous liquid or carbon dioxide encountered
Employee could discover a leak while performing this task

Task ID:	**17**
Covered Task Name:	**Provide Temporary Marking of Buried Pipeline Prior to Excavation**
Description:	Pipeline operators are required to provide temporary marking of all buried pipelines in the areas of excavation activity as far in advance of the actual excavation work as practical. Monitoring and inspection during the excavation must also be provided to verify the integrity of the pipeline. Elements of this task may include: • Locate line • Install appropriate temporary markers • Determine depth of pipeline
Four-Part Test for the Covered Task:	***Is task performed on the pipeline?*** **Yes** ***Is the task an Operations or Maintenance Task?*** **Yes** ***Is the task required by Part 195 (or 192)?*** **Yes – 195.442** ***Does task affect the operation or integrity of the pipeline?*** **Yes**
Notes:	Persons who perform this task need to follow the local and state requirements. This may include permitting, one-call systems, etc. Offshore pipelines are exempt from this task.
Abnormal Operating Conditions and Examples:	**Abnormal facility condition** Line marker is missing or installed in the wrong location

Task ID:	**18**
Covered Task Name:	**Inspection Following Excavation Activities and Leak Survey After Blasting**
Description:	Inspection after excavation activities must be performed to verify the integrity of the pipeline. Excavation activities include excavation, blasting, boring, tunneling, backfilling, the removal of aboveground structures by either explosive or mechanical means, and other earth moving operations. In the case of blasting, any inspection must include leakage surveys. Elements of this task may include: • Utilize leak survey techniques • Monitor for pressure loss • Inspect for physical damage • Inspect for corrosion • Inspect for condition of coating
Four-Part Test for the Covered Task:	***Is task performed on the pipeline?*** Yes ***Is the task an Operations or Maintenance Task?*** Yes ***Is the task required by Part 195 (or 192)?*** Yes – 195.442 (c) 6 ***Does task affect the operation or integrity of the pipeline?*** Yes
Notes:	The leakage survey is typically a visual inspection of the right-of-way or area closest to the blasting impact to check for any evidence of leaks or damage to the pipeline. The monitoring for pressure loss is often performed by Pipeline Controllers.
Abnormal Operating Conditions and Examples:	**Abnormal facility condition** Corrosion **Fire/Explosion** Ignition of released hydrocarbon **Pipeline System damage** Damaged pipe, unexpected soil movement **Unexpected hazardous liquid or carbon dioxide encountered** Employee could discover a leak while performing this task

Task ID: 19

Covered Task Name: **Maintain Valves**

Description:

This task consists of the maintenance activities performed on each valve that is necessary for safe operation of a pipeline. This applies to block valves, manifold valves, tank valves, pump suction/discharge valves, check valves, pressure control valves and any other valves (except relief valves) that are in service and physically connected to the pipeline system.

Elements of this task may include:

- Maintenance or adjustment of the valve actuator
- Winterization of valve
- Lubrication and/or packing
- Drain valve body

Four-Part Test for the Covered Task:

Is task performed on the pipeline?
Yes

Is the task an Operations or Maintenance Task?
Yes

Is the task required by Part 195 (or 192)?
Yes – 195.420 (a)

Does task affect the operation or integrity of the pipeline?
Yes

Notes:

Mechanical Technicians, Electrical Technicians and/or Craftsmen normally perform this task. Pipeliners, Pipeline Maintenance Foremen, contract valve service companies, or contractor maintenance personnel could also perform this task.

Abnormal Operating Conditions and Examples:

Component failure
Grease button failure, bevel gear operator
Fire/Explosion
Ignition of released hydrocarbon
Unexpected hazardous liquid or carbon dioxide encountered
Packing leaks, seat may not reseal

Task ID: 20

Covered Task Name: Inspect Valves

Description:

This task consists of the inspection activities performed on each valve that is necessary for safe operation of a pipeline. This applies to block valves, manifold valves, tank valves, pump suction/discharge valves, check valves, pressure control valves and any other valves (except relief valves) that are in service and physically connected to the pipeline system.

Elements of this task may include:

- Verify location of valve to be inspected
- Check the accessibility of the valve
- Verify the valve number and nameplate data
- Verify valve type and manufacturer
- Check for leaks, damage or corrosion
- Operate the valve to verify that it operates properly
- Return valve to original position
- Re-lock in proper position or provide security as appropriate
- Document results

Four-Part Test for the Covered Task:

Is task performed on the pipeline?
Yes

Is the task an Operations or Maintenance Task?
Yes

Is the task required by Part 195 (or 192)?
Yes – 195.420

Does task affect the operation or integrity of the pipeline?
Yes

Notes:

Mechanical Technicians, Pipeliners, Pipeline Maintenance Foremen, or contractor personnel normally perform this task.

Abnormal Operating Conditions and Examples:

Activation of a safety device
System overpressure

Communications, control system or power interruption or failure
Interruption while operating valve

Component failure
Valve stem damage, operator failure

Fire/Explosion
Ignition of released hydrocarbon

Unexpected hazardous liquid or carbon dioxide encountered
Gasket failure, seal failure, thermal relief leaking

Task ID: 21

Covered Task Name: Repair Valves

Description:

This task consists of the repair activities performed on each valve that is necessary for safe operation of a pipeline. This applies to block valves, manifold valves, tank valves, pump suction/ discharge valves, check valves, pressure control valves and any other valves (except relief valves) that are in service and physically connected to the pipeline system.

Elements of this task may include:

- Disassembly of valve
- Cleaning and inspection of valve's internal components
- Repair or replacement of failed or worn components
- Re-assembly of valve and return to operating condition
- Repair or adjustment of the valve actuator
- Document results

Four-Part Test for the Covered Task:

Is task performed on the pipeline?
Yes

Is the task an Operations or Maintenance Task?
Yes

Is the task required by Part 195 (or 192)?
Yes – 195.420

Does task affect the operation or integrity of the pipeline?
Yes

Notes:

Mechanical Technicians and/or Electrical Technicians normally perform this task. Pipeliners, Pipeline Maintenance Foremen, contract valve service companies, or contractor maintenance personnel could also perform this task.

Abnormal Operating Conditions and Examples:

Activation of a safety device
During isolation process, after repair, resetting limits, etc.

Communications, control system or power interruption or failure
After repair, potential communication or control system problems

Component failure
Stem or operator failure, worn, defective components

Fire/Explosion
Ignition of released hydrocarbon

Unexpected hazardous liquid or carbon dioxide encountered
Pressurized trapped hydrocarbons within valve body, failure of isolation

Task ID: 22

Covered Task Name: Inspect, Test, and Calibrate Relief Valves

Description:

This task consists of the activities performed on a relief valve to verify that it is functioning properly, in good mechanical condition, and is adequate for the application.

Elements of this task may include:

- Verify location of valve to be inspected
- Verify the valve number and nameplate data
- Verify valve type and manufacturer
- Test and calibrate valve
- Visually inspect valve for leaks or corrosion
- Apply security seal to valve as required by procedures
- Document results

Four-Part Test for the Covered Task:

Is task performed on the pipeline?
Yes

Is the task an Operations or Maintenance Task?
Yes

Is the task required by Part 195 (or 192)?
Yes – 195.428

Does task affect the operation or integrity of the pipeline?
Yes

Notes:

Mechanical Technicians or Electrical Technicians normally perform this task. Pipeliners, Pipeline Maintenance Foremen, contract valve service companies, or contractor maintenance personnel could also perform this task.

Abnormal Operating Conditions and Examples:

Component failure
Exceed maximum design pressure

Fire/Explosion
Ignition of released hydrocarbon

Unexpected hazardous liquid or carbon dioxide encountered
Leaking isolation valve, trapped pressurized hydrocarbons within valve body

Task ID: 23

Covered Task Name: **Maintain / Repair Relief Valves**

Description:

This task consists of the repair and maintenance activities performed on a relief valve in service on an existing pipeline system. This applies to maintaining or restoring design function.

Elements of this task may include:

- Disassembly of valve
- Cleaning and inspection of valve's internal components
- Repair or replacement of failed or worn components
- Re-assembly of valve and return to operating condition
- Repair, adjustment, or calibration of relief valve sensing or control devices
- Document results

Four-Part Test for the Covered Task:

Is task performed on the pipeline?
Yes

Is the task an Operations or Maintenance Task?
Yes

Is the task required by Part 195 (or 192)?
Yes – 195.428

Does task affect the operation or integrity of the pipeline?
Yes

Notes:

Mechanical Technicians or Electrical Technicians normally perform this task. Pipeliners, Pipeline Maintenance Foremen, contract valve service companies, or contractor maintenance personnel may also perform this task.

Abnormal Operating Conditions and Examples:

Component failure
Incorrect re-assembly of valve
Fire/Explosion
Ignition of released hydrocarbon
Unexpected hazardous liquid or carbon dioxide encountered
Leaking isolation valve

Task ID: 24

Covered Task Name: Inspect, Test and Calibrate Pressure Limiting Devices

Description:

This task consists of the inspection, testing and calibration activities performed on an overpressure safety device to verify that it is functioning properly, in good operating condition, and is adequate for the application. This does not include relief valves.

Elements of this task may include:

- Inspect and test pilot operated devices
- Inspect and test control valve positioner or sensing device
- Inspect and replace rupture discs
- Document results

Four-Part Test for the Covered Task:

Is task performed on the pipeline?
Yes

Is the task an Operations or Maintenance Task?
Yes

Is the task required by Part 195 (or 192)?
Yes – 195.428

Does task affect the operation or integrity of the pipeline?
Yes

Notes:

Electrical Technicians, Instrument Technicians, or Mechanical Technicians normally perform this task. Contract valve service companies or contractor maintenance personnel could also carry out this task.

Abnormal Operating Conditions and Examples:

Activation of a safety device
Improper sizing of rupture disc, improper parameter settings of components

Component failure
Isolation valve malfunction, mechanical malfunctions of device

Fire/Explosion
Ignition of released hydrocarbon

Unexpected hazardous liquid or carbon dioxide encountered
Leaking isolation valve, leaking valve stem

Task ID: 25

Covered Task Name: **Inspect, Test and Calibrate Pressure Switches and Transmitters**

Description:

This task consists of the inspection, testing and calibration activities performed on a pressure measurement or control device to verify that it is functioning properly, in good operating condition, and is adequate for the application.

Elements of this task may include:

- Inspect, test, and calibrate pressure switches
- Inspect, test, and calibrate pressure transmitters
- Document results

Four-Part Test for the Covered Task:

Is task performed on the pipeline?
Yes

Is the task an Operations or Maintenance Task?
Yes

Is the task required by Part 195 (or 192)?
Yes – 195.428

Does task affect the operation or integrity of the pipeline?
Yes

Notes:

None applicable

Abnormal Operating Conditions and Examples:

Abnormal facility condition
Station lock-out; unit lock-out
Activation of a safety device
Improper calibration.
Communications, Control System or Power interruption or failure

Fire/Explosion
Ignition of released hydrocarbon
Unexpected hazardous liquid or carbon dioxide encountered
Failure to close or plug bleeder valve
Unexplained status change
Unit starts/stops unintentionally

Task ID: 26

Covered Task Name: **Verify or Set Protection Parameters for Programmable Controllers and/or Other Instrumentation Control Loops**

Description:

This task consists of the inspection, testing and calibration activities performed on a Programmable Logic Controller (PLC), process controller, or other instrumentation control loop to verify that it is functioning properly., in good operating condition, and is adequate for the application.

Elements of this task may include:

- Zero, span, and differential adjustments
- Adjusting pressure set point
- Adjusting timers or sequence events
- On-site changes or corrections to ladder logic
- Implementation of new or revised programming (software)
- Document results

Four-Part Test for the Covered Task:

Is task performed on the pipeline?
Yes

Is the task an Operations or Maintenance Task?
Yes

Is the task required by Part 195 (or 192)?
Yes – 195.428

Does task affect the operation or integrity of the pipeline?
Yes

Notes:

Engineers, Programmers, Electrical Technicians, Instrument Technicians, or Electronics Technicians normally perform this task. Contract instrument service companies or contract control equipment personnel could also carry out this task.

Abnormal Operating Conditions and Examples:

Activation of a safety device
Activate relief valve.

Communications, control system or power interruption of failure

Unexplained status change
Unintentional station shutdown

Task ID:	27
Covered Task Name:	**Inspect and Repair Breakout Tanks**
Description:	This task consists of the following referenced maintenance, inspection, and repair activities. Elements of this task: • Reference section 4 of API Standard 653, "Tank Inspection, Repair, Alteration, and Reconstruction" • Reference section 6 of API Standard 510, "Pressure Vessel Inspection Code: Maintenance Inspection, Rating, Repair, and Alteration"
Four-Part Test for the Covered Task:	***Is task performed on the pipeline?*** **Yes** ***Is the task an Operations or Maintenance Task?*** **Yes** ***Is the task required by Part 195 (or 192)?*** **Yes – 195.432** ***Does task affect the operation or integrity of the pipeline?*** **Yes**
Notes:	Tank Coordinators, Pipeliners, Pipeline Maintenance Foremen, and Operations Personnel normally perform this task. Contract tankage service companies and contract maintenance personnel could also carry out this task.
Abnormal Operating Conditions and Examples:	**Abnormal facility condition** Shell integrity (corrosion), foundation failure **Activation of a safety device** Alarm systems, activation of relief valve **Component failure** Manway gasket leak, seals, vents, roof failures (damaged or sunk) **Fire/Explosion** Ignition of hydrocarbon **Unexpected hazardous liquid or carbon dioxide encountered** Roof drain failures, shell integrity (corrosion)

Task ID: 28

Covered Task Name: Provide Protection for Pipeline Facilities

Description:

This task consists of the practices necessary to prevent vandalism and unauthorized entry into a breakout tank area, pumping station or other exposed facility.

Elements of this task may include:

- Inspect perimeter fencing and signs
- Monitoring by remote security devices
- Maintain integrity of fence

Four-Part Test for the Covered Task:

Is task performed on the pipeline?
Yes

Is the task an Operations or Maintenance Task?
Yes

Is the task required by Part 195 (or 192)?
Yes – 195.436

Does task affect the operation or integrity of the pipeline?
Yes

Notes:

Tank Coordinators, Pipeliners, Pipeline Maintenance Foremen, and Operations Personnel normally perform this task. Contract tankage service companies and contract maintenance personnel could also carry out this task. This is a combination task of ensuring that safeguards are in place (gates, locks, barriers, etc.) and also a task of awareness for unauthorized personnel.

Abnormal Operating Conditions and Examples:

Abnormal facility condition
Vandalism or other breach of security

Task ID:	**29**
Covered Task Name:	**Protect Breakout Tanks from Static Electricity, Lightning, and Stray Electrical Currents**
Description:	This task consists of the activities necessary to protect breakout tanks from the hazards of static electricity, lightning, and stray electrical currents. Elements of this task: • Reference API Recommended Practice 2003, "Protection Against Ignitions Arising Out of Static, Lightning, and Stray Currents."
Four-Part Test for the Covered Task:	***Is task performed on the pipeline?*** **Yes** ***Is the task an Operations or Maintenance Task?*** **Yes** ***Is the task required by Part 195 (or 192)?*** **Yes – 195.405** ***Does task affect the operation or integrity of the pipeline?*** **Yes**
Notes:	Tank Coordinators, Pipeliners, Pipeline Maintenance Foremen, and Operations Personnel normally perform this task. Contract tankage service companies and contract maintenance personnel may also perform this task.
Abnormal Operating Conditions and Examples:	**None Assigned**

Task ID: 30

Covered Task Name: Test Overfill Protective Devices

Description:

This task consists of the inspection, testing, and adjustment activities performed on a breakout tank overfill protective device to ensure that it is functioning properly, is in good operating condition, and is adequate from the standpoint of reliability for its intended purpose.

Elements of this task may include:

- Liquid level/oil height adjustments
- Verifying alarm parameters
- Adjusting timers or sequence events
- On-site changes or corrections to ladder logic
- Implementation of new or revised programming (software)
- Document results

Four-Part Test for the Covered Task:

Is task performed on the pipeline?
Yes

Is the task an Operations or Maintenance Task?
Yes

Is the task required by Part 195 (or 192)?
Yes – 195.428

Does task affect the operation or integrity of the pipeline?
Yes

Notes:

Electrical Technicians, Instrument Technicians, Operations Personnel, or Communication Technicians normally perform this task. Contract instrument service companies or contract control equipment personnel could also carry out this task.

Abnormal Operating Conditions and Examples:

Component failure
Seals, faulty monitoring devices
Fire/Explosion
Ignition of released hydrocarbon
Unexpected hazardous liquid or carbon dioxide encountered
Free product in casing vent pipe

Task ID:	31
Covered Task Name:	**Inspect and Calibrate Overfill Protective Devices**
Description:	This task consists of the inspection, testing and adjustment activities performed on a breakout tank overfill protective device to ensure that it is functioning properly, is in good operating condition, and is adequate for the application. Elements of this task may include: • Liquid level/oil height adjustments • Verifying alarm parameters • Verify operation of relief flow and indication devices • Adjusting timers or sequence events • On-site changes or corrections to ladder logic • Implementation of new or revised programming (software)
Four-Part Test for the Covered Task:	***Is task performed on the pipeline?*** **Yes** ***Is the task an Operations or Maintenance Task?*** **Yes** ***Is the task required by Part 195 (or 192)?*** **Yes – 195.428** ***Does task affect the operation or integrity of the pipeline?*** **Yes**
Notes:	Electrical Technicians, Instrument Technicians, Operations Personnel, or Communication Technicians normally perform this task. Contract instrument service companies or contract control equipment personnel could also carry out this task.
Abnormal Operating Conditions and Examples:	**Component failure** Seals, faulty monitoring devices **Fire/Explosion** Ignition of released hydrocarbon **Unexpected hazardous liquid or carbon dioxide encountered** Free product in standpipe

Task ID:	**32**
Covered Task Name:	**Repair Overfill Protective Devices**
Description:	This task consists of the repair activities performed on a breakout tank overfill protection device to ensure that it is functioning properly and is adequate for the application. Elements of this task may include: • Replacement of device • Liquid level/oil height adjustments • Verifying alarm parameters • Adjusting timers or sequence events
Four-Part Test for the Covered Task:	***Is task performed on the pipeline?*** Yes ***Is the task an Operations or Maintenance Task?*** Yes ***Is the task required by Part 195 (or 192)?*** Yes – 195.428 ***Does task affect the operation or integrity of the pipeline?*** Yes
Notes:	Not Applicable
Abnormal Operating Conditions and Examples:	**Component failure** Seals, faulty monitoring devices **Fire/Explosion** Ignition of released hydrocarbon **Unexpected hazardous liquid or carbon dioxide encountered** Free product in standpipe

Task ID: 33

Covered Task Name: **Moving In-Service Pipe**

Description:

This task consists of the activities required to move or reposition (raise, lower, lateral) a section of the pipeline while it is in operation.

Elements of this task may include:

- Determine the product type (consideration for HVL)
- Determine allowable line pressure
- Pipe lifting
- Support pipe

Four-Part Test for the Covered Task:

Is task performed on the pipeline?
Yes

Is the task an Operations or Maintenance Task?
Yes

Is the task required by Part 195 (or 192)?
Yes – 195.424

Does task affect the operation or integrity of the pipeline?
Yes

Notes:

This task is normally performed or supervised by Pipeline Maintenance Foremen, Pipeliners, Project Engineers, or designated inspectors. Contract pipeline construction companies and contract pipeline maintenance personnel also commonly carry out this task.

Abnormal Operating Conditions and Examples:

Abnormal facility condition
Corrosion
Component failure
Valve failure, weld/seam failure, flange, joint
Fire/Explosion
Ignition of released hydrocarbon
Pipeline System damage
Wrinkle, buckle, over-stress, gouge, dent, unexpected movement of pipe, damage of coating
Unexpected hazardous liquid or carbon dioxide encountered
Failure of pipe, discovery of previous leak

Task ID: 34

Covered Task Name: Inspect Existing Pipe Following Movement

Description:

This task consists of the observation and awareness activities required when moving a section of pipe in a ditch (trench).

Elements of this task may include:

- Ensure that secondary stresses are minimized
- Ensure that pipe or coating is not damaged

Four-Part Test for the Covered Task:

Is task performed on the pipeline?
Yes

Is the task an Operations or Maintenance Task?
Yes

Is the task required by Part 195 (or 192)?
Yes – 195.246; 195.252

Does task affect the operation or integrity of the pipeline?
Yes

Notes:

This task is normally performed or supervised by Pipeline Maintenance Foremen, Pipeliners, Project Engineers, or designated inspectors. Contract pipeline construction companies and contract pipeline maintenance personnel also commonly perform this task.

Abnormal Operating Conditions and Examples:

Component failure
Valve failure, weld/seam failure, flange, joint
Fire/Explosion
Ignition of released hydrocarbon
Pipeline System damage
Wrinkle, buckle, over-stress, gouge, dent
Unexpected hazardous liquid or carbon dioxide encountered

Task ID:	**35**
Covered Task Name:	**Inspection of Clearance of Existing Pipe to Underground Structures**
Description:	This task consists of the inspection activities required to ensure that adequate clearance is provided between the outside of the pipe and the extremity of any other underground structures. Elements of this task may include: • Foreign crossing inspections • Inspection/testing for proper corrosion control • Conducting interference tests
Four-Part Test for the Covered Task:	***Is task performed on the pipeline?*** **Yes** ***Is the task an Operations or Maintenance Task?*** **Yes** ***Is the task required by Part 195 (or 192)?*** **Yes – 195.250** ***Does task affect the operation or integrity of the pipeline?*** **Yes**
Notes:	This task is normally performed or supervised by Pipeline Maintenance Foremen, Corrosion Technicians, Pipeliners, Project Engineers, or designated inspectors. Contract pipeline construction companies and contract pipeline maintenance personnel also carry out this task.
Abnormal Operating Conditions and Examples:	**Abnormal facility condition** Corrosion **Fire/Explosion** Ignition of released hydrocarbon **Pipeline system damage** Corrosion, coating damage **Unexpected hazardous liquid or carbon dioxide encountered** Leak from exposed pipeline

Task ID:	**36**
Covered Task Name:	**Abandoning, Safe Disconnect, Purging and Sealing of Pipeline Facilities**
Description:	This task consists of decommissioning or removing a pipeline facility from service, permanently or temporarily. Elements of this task may include: • safe disconnect • purging • sealing
Four-Part Test for the Covered Task:	***Is task performed on the pipeline?*** **Yes** ***Is the task an Operations or Maintenance Task?*** **Yes** ***Is the task required by Part 195 (or 192)?*** **Yes – 195.402 (c)(10)** ***Does task affect the operation or integrity of the pipeline?*** **Yes**
Notes:	**Not Applicable**
Abnormal Operating Conditions and Examples:	**Fire/Explosion** Ignition of released hydrocarbon **Unexpected hazardous liquid or carbon dioxide encountered** Release during purging.

Task ID: 37

Covered Task Name: **Installation or Repair of Support Structures on Existing Aboveground Components**

Description:

This task consists of the activities required to fit or mount additional or revised support elements to existing aboveground structures, such as:

- Overhead crossings of highways, railroads, or a body of water
- Spans over ditches and gullies
- Scraper traps or block valves
- Manifold valves and piping

Elements of this task may include:

- Proper installation techniques to protect the pipe and coating from damage
- Inspection of support and pipe to ensure that pipe is protected against stress

Four-Part Test for the Covered Task:

Is task performed on the pipeline?
Yes

Is the task an Operations or Maintenance Task?
Yes

Is the task required by Part 195 (or 192)?
Yes – 195.254, 195.422

Does task affect the operation or integrity of the pipeline?
Yes

Notes:

This task is normally performed or supervised by Pipeline Maintenance Foremen, Pipeliners, Project Engineers, or designated inspectors. Contract pipeline construction companies and contract pipeline maintenance personnel also commonly carry out this task. Support for each aboveground structure must provide protection from the forces exerted by the anticipated loads.

Abnormal Operating Conditions and Examples:

Component failure
Valve failure, weld/seam failure, flange, joint
Fire/Explosion
Ignition of released hydrocarbon
Pipeline System damage
Wrinkle, buckle, over-stress, gouge, dent
Unexpected hazardous liquid or carbon dioxide encountered

Task ID: 38

Covered Task Name: **Inspection Activities for Tie-Ins, Pipe Replacements, or Other Components Connecting to an Existing Pipeline**

Description:

This task consists of inspection activities required during the various removal and installation activities performed as maintenance on a pipeline system.

Elements of this task may include:

- Ensure proper installation
- Ensure that pipe, coating, or component is not damaged
- Ensure that material meets specifications
- Visual inspection and/or non-destructive testing

Four-Part Test for the Covered Task:

Is task performed on the pipeline?
Yes

Is the task an Operations or Maintenance Task?
Yes

Is the task required by Part 195 (or 192)?
Yes – 195.204, 195.206, 195.422

Does task affect the operation or integrity of the pipeline?
Yes

Notes:

This task is normally performed or supervised by Pipeline Maintenance Foremen, Pipeliners, Project Engineers, or designated inspectors. Contract pipeline construction companies and contract pipeline maintenance personnel may also carry out this task.

Abnormal Operating Conditions and Examples:

Abnormal facility condition
Material does not meet specifications
Component failure
Valve failure, weld/seam failure, flange, joint
Fire/Explosion
Ignition of released hydrocarbon
Pipeline System damage
Wrinkle, buckle, over-stress, gouge, dent
Unexpected hazardous liquid or carbon dioxide encountered
Failure of isolation device

Task ID: 39

Covered Task Name: **Backfilling a Trench Following Maintenance**

Description:

This task consists of backfilling or replacing the soil back into the ditch and over the pipeline after maintenance or repairs.

Elements of this task may include:

- Inspection of backfill for damaging materials
- Protect pipe coating
- Provide adequate support for the pipe

Four-Part Test for the Covered Task:

Is task performed on the pipeline?
Yes

Is the task an Operations or Maintenance Task?
Yes

Is the task required by Part 195 (or 192)?
Yes – 195.252, 195.422

Does task affect the operation or integrity of the pipeline?
Yes

Notes:

This task is normally performed or supervised by Pipeline Maintenance Foremen, Pipeliners, Project Engineers, or designated inspectors. Contract pipeline construction companies and contract pipeline maintenance personnel also commonly carry out this task.

Abnormal Operating Conditions and Examples:

Pipeline system damage
Coating damage from coarse backfill materials.

Task ID: 40

Covered Task Name: Perform General Pipeline Repair Activities

Description:

This task encompasses the general maintenance and repair activities that are involved in the safeguarding and prudent operation of a pipeline system.

Typical activities may include but are not limited to:

- Installing pipe repair sleeves (Weld+Ends™, Clocksprings™, full encirclements, etc.)
- Pipe or pipeline component replacement
- Installing stopple fittings or stoppling devices
- Hot tapping
- Venting and/or blow-down of inert gases or entrained air

Four-Part Test for the Covered Task:

Is task performed on the pipeline?
Yes

Is the task an Operations or Maintenance Task?
Yes

Is the task required by Part 195 (or 192)?
Yes – 195.422

Does task affect the operation or integrity of the pipeline?
Yes

Notes:

This task is normally performed or supervised by Pipeline Maintenance Foremen, Pipeliners, Project Engineers, or designated inspectors. Contract pipeline construction companies and contract pipeline maintenance personnel also commonly carry out this task.

Abnormal Operating Conditions and Examples:

Abnormal facility condition
Corrosion or pipe defect in area to be welded
Component failure

Fire/Explosion
Ignition of released hydrocarbon
Pipeline system damage

Unexpected hazardous liquid or carbon dioxide encountered

Task ID: 41

Covered Task Name: **Conduct Pressure Tests**

Description:

This task consists of the activities required for the pressure testing of the pipeline and components of the pipeline system, such as:

- Pressure testing for MOP certification or upgrade
- Pressure testing of pipe at tie-ins

Elements of this task may include:

- Performing pressure test
- Recording pressure test results

Four-Part Test for the Covered Task:

Is task performed on the pipeline?

Yes

Testing of components that are tested off of the pipeline facility are not covered tasks

Is the task an Operations or Maintenance Task?

Yes

Is the task required by Part 195 (or 192)?

Yes – 195 Subpart E and 195.406

Does task affect the operation or integrity of the pipeline?

Yes

Notes:

This task is normally performed or supervised by Pipeline Maintenance Foremen, Pipeliners, Project Engineers, Mechanical Technicians, Electrical Technicians, Instrument Technicians, or designated inspectors. Contract pipeline construction companies, contract inspection service companies, and contract pipeline maintenance personnel may also carry out this task.

Abnormal Operating Conditions and Examples:

Component failure

Valve failures, piping failure

Fire/Explosion

Ignition of released hydrocarbon

Unexpected hazardous liquid or carbon dioxide encountered

Hydrocarbons trapped in system during test are released due to component failure.

Unexplained pressure deviations

Pipe failure during test.

Task ID: 42

Covered Task Name: Welding on Existing Pipelines

Description:

This task includes all activities and procedures that are required for maintenance welding jobs; i.e., any welding performed on an existing, in-service pipeline.

Elements of this task may include:

- Repair and/or removal or arc burns
- Repair and/or removal of defective welds
- Tie in welds
- Fittings

Four-Part Test for the Covered Task:

Is task performed on the pipeline?
Yes

Is the task an Operations or Maintenance Task?
Yes

Is the task required by Part 195 (or 192)?
Yes – 195.214, 195.226, 195.230

Does task affect the operation or integrity of the pipeline?
Yes

Notes:

This task is normally a supervision or inspection task performed by Pipeline Maintenance Foremen, Pipefiners, Project Engineers, or designated inspectors. Contract pipeline construction companies, contract inspection service companies, and contract pipeline maintenance personnel may also carry out this task. Whether the pipeline operator's own welders or contract welders perform this task, welding on an existing, in-service pipeline system is a covered task. The qualification of welders is covered under 49 CFR 195.222 in accordance with section 3 of API Standard 1104 or section IX of the ASME Boiler and Pressure Vessel Code.

Abnormal Operating Conditions and Examples:

Abnormal facility condition
Corrosion
Fire/Explosion
Ignition of released hydrocarbon
Pipeline System damage
Pipe defect in area to be welded, arc burn
Unexpected hazardous liquid or carbon dioxide encountered
Failure of isolation device, burn through

Task ID:	**43**
Covered Task Name:	**Operations of Pipeline System**
Description:	This task includes activities and procedures that are required for safe and prudent operation of the pipeline. Elements of this task may include: • Start-up/Shutdown • Maintain pressure within allowable limits • Manually or remotely open or close valves or other equipment • Monitor and operate control devices • Monitor flow rates • Monitor communications • Monitor leak detection and line integrity
Four-Part Test for the Covered Task:	***Is task performed on the pipeline?*** **Yes** ***Is the task an Operations or Maintenance Task?*** **Yes** ***Is the task required by Part 195 (or 192)?*** **Yes – 195.402, 195.406** ***Does task affect the operation or integrity of the pipeline?*** **Yes**
Notes:	Pipeline controllers, control centers, or field operations personnel normally perform the tasks in this group of covered tasks. In some instances contract personnel could perform some types of pipeline operations covered tasks. Control centers, although usually remote from the pipeline, are connected to the components that they monitor and/or operate and are therefore considered part of the pipeline facility.
Abnormal Operating Conditions and Examples:	**Abnormal facility condition** **Activation of a safety device** **Communications, control system or power interruption or failure** **Fire/Explosion** **Pipeline system damage** **Unexpected hazardous liquid or carbon dioxide encountered** **Unexplained flow rate deviation** **Unexplained pressure deviations** **Unexplained status change**

Task ID:	**44**
Covered Task Name:	**CPM Leak Detection**
Description:	If this system is utilized, this task consists of the inspection, testing, and adjustment activities performed on a leak detection or line integrity system to verify that it is functioning properly, in good operating condition, and to verify that the leak detection system meets its design parameters.
Four-Part Test for the Covered Task:	***Is task performed on the pipeline facility?*** **Yes** ***Is the task an Operations or Maintenance Task?*** **Yes** ***Is the task required by Part 195 (or 192)?*** **Yes – 195.444** ***Does task affect the operation or integrity of the pipeline?*** **Yes**
Notes:	Engineers, Programmers, Electrical Technicians, Instrument Technicians, Communications Technicians, or Electronics Technicians normally perform this task. Contract instrumentation service companies or contract control equipment personnel could also carry out this task.
Abnormal Operating Conditions and Examples:	**Communications, control system or power interruption or failure** **Unexplained flow rate deviation** **Unexplained pressure deviations** Sudden pressure loss **Unexplained status change** Equipment failure

Task ID:	45
Covered Task Name:	**Operate Pressure-Relieving Devices for Launching and Receiving Facilities**
Description:	This task consists of the activities required to relieve pressure and verify the absence of pressure prior to opening the launching/receiving device.
Four-Part Test for the Covered Task:	***Is task performed on the pipeline?*** **Yes** ***Is the task an Operations or Maintenance Task?*** **Yes** ***Is the task required by Part 195 (or 192)?*** **Yes – 195.426** ***Does task affect the operation or integrity of the pipeline?*** **Yes**
Notes:	Electrical Technicians, Instrument Technicians, Communications Technicians, or Electronics Technicians normally perform this task. Contract instrumentation service companies, or contract control equipment personnel could also carry out this task.
Abnormal Operating Conditions and Examples:	**Component failure** Relief valve failure, launch pin failure, stuck pig **Fire/Explosion** Ignition of released hydrocarbon **Unexpected hazardous liquid or carbon dioxide encountered** Trap o-ring leak **Unexplained pressure deviations** Pressure still in launch/receive barrel

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APPENDIX E – ACCEPTABLE EVALUATION METHODS

Evaluation method	"Transitional" qualification[1]	"Initial" qualification[2]	"Subsequent" qualification[3]
Written Exam	Yes	Yes	Yes
Oral Exam	Yes	Yes	Yes
Work Performance History Review	Yes	May not be used as the sole evaluation method.	May not be used as the sole evaluation method after the three-year compliance date.
Performance On the Job	Yes	Yes	Yes
On-the-Job Training	Yes	Yes	Yes
Simulation	Yes	Yes	Yes
Other	Yes	Yes	Yes

Notes:

1 "Transitional" qualification means qualification completed by October 28, 2002, of individuals who have been performing a covered task on a regular basis prior to August 27,1999.

2 "Initial" qualification means qualification, at any time, of individuals who were not performing a covered task on a regular basis prior to the effective date of the rule.

3 "Subsequent" qualification means evaluation of an individual's qualification, after "transitional" or "initial" qualification, at the interval established by the operator.

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APPENDIX F – EFFECTIVE USE OF EVALUATION METHODS

Note: It may appear that creation of evaluations can be easy, but a background in instructional design is necessary to create any valid evaluation method.

Method	Evaluates	Strengths	Weaknesses	Description / Comments
Written Exam	Knowledge	Easy to administer. Person administering the test does not need to know the subject. Can provide objective measurement of knowledge if multiple choice, true/false, or matching questions are used.	Unable to evaluate skills or performance. Poorly written questions may not provide accurate measurement.	A written test utilizes a series of questions typically requiring a specific answer. A variety of questions may be used including True/False, Multiple Choice, Matching, Fill-in-the-Blank, and Short Answer. A written test may be performed using pen and paper or electronic formats like those in computer-based or web-based training.
Oral Exam	Knowledge	Preparation is similar to written exam. More difficult to administer than written exam. Good for probing individual's depth of knowledge.	Person administering needs to have detailed understanding of subject. Scoring is subjective.	Oral exams involve an experienced individual asking questions of the person being evaluated. A line of questioning should be prepared prior to the exam. This is necessary to ensure the knowledge items are adequately covered. It is best to use open-ended questions.

Method	Evaluates	Strengths	Weaknesses	Description / Comments
Work Performance History Review	Past Responsibilities	Indicator of past responsibility. Relatively little preparation time required and simple to administer.	Very subjective and lacks ability to truly measure knowledge or skills. Can be difficult to document unless extensive written procedures were used. Does not measure whether task was performed correctly, only that no accident occurred.	The Work Performance History Review will typically involve reviewing an individual's personnel records, performance appraisals, and other job-related documents to identify performance weaknesses. This may also involve employee interviews or a review of training records to determine past experience.
Observation during On-the-Job Training (OJT) and during job performance	Knowledge, Skills	Measures ability to perform the skills required for the job. Can be effectively administered as actual or simulated performance.	Can be difficult to create if accurate procedures do not exist. Is subjective but can be more objective if critical steps and standards are identified in advance. Low trainee to evaluator ratio makes this method expensive.	Usually involves the use of a checklist (Job Performance Measure – See Appendix H for example) of tasks that have been performed. The checklist is completed following training and practice of the tasks under supervision of an experienced individual.

Method	Evaluates	Strengths	Weaknesses	Description / Comments
Lab or mock-up simulation	Knowledge, Skills	Allows evaluation to take place in controlled conditions. No danger to facility equipment and no effect on operation.	Requires high level of preparation. Care must be taken to duplicate actual conditions as close as possible.	Simulations involve evaluating an individual in a setting that represents the actual work conditions. This may include use of computer programs or workshop mock-ups. This often involves using checklists (Job Performance Measures) to assess the performance.
Other: Self-Assessment with Supervisor Review	Knowledge	Easy to administer.	Moderate amount of preparation required. Poor method to evaluate actual performance or knowledge. Difficult to defend to regulators.	This method involves an individual rating their ability to perform a task based on established criteria. The individual's supervisor then performs a comparison evaluation using the same criteria. The supervisor and employee then meet to discuss any differences and come to an agreement on the individual's ability.

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APPENDIX G – EXAMPLE QUALIFICATION RECORD SHEET

Company Name _____

Employee/Contractor Name: _____

Employee/Contractor Number: _____

Covered Task	Date of Qualification	Re-Qualification Due Date	Method of Evaluation	Evaluator's Name	Score (If applicable)	Comments

* *Attach documentation if necessary.*

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EVALUATOR'S INSTRUCTIONS

NOTE

Questions asked by the evaluator will be limited to the information contained in the Objectives section of the Progression Guide and associated operating procedures pertaining to this JPM.

1. Use the Objectives in the Progression Guide to develop questions to be discussed prior to performance of this JPM.
2. Knowledge Questions will be documented in the appropriate section of this JPM.
3. Attach any supporting documentation used during the performance of this JPM.
4. Sign the appropriate section of the JPM.
5. If evaluation is satisfactory (**SAT**), Initial & Date the applicable items in the Operator's Progression Guide.
6. Forward JPM evaluation to the Operations Manager for review.

THE EVALUATOR SHALL REVIEW THE FOLLOWING WITH THE TRAINEE:

1. The evaluator shall explain the JPM initial conditions and clarify as required.
2. The trainee may use any references that are normally available.
3. The trainee shall indicate all required log entries, status board updates, chart recorder annotations, and communications.
4. The trainee shall make oral reports for annunciators and any abnormal indications observed. The examiner will act as the Controller or other operators for communications purposes if the JPM is to be simulated.
5. The trainee shall verbally inform the evaluator of all actions performed during the performance of this JPM to ensure knowledge and understanding.

EVALUATION QUESTIONS AND RESPONSE

Evaluator Instructions: Prior to starting the skills portion of the JPM, the evaluator shall ask questions, based on the Objectives as defined in the Progression Guide, that are specific to the tasks being performed. The evaluator will document the questions and answers below.

Question 1: _____

_____

_____

Response: _____

_____

_____

_____

Question 2: _____

_____

_____

Response: _____

_____

_____

_____

Question 3: _____

_____

_____

Response: _____

_____

_____

_____

Example Job Performance Measure (JPM)

STEP	ELEMENT	Action: P – Perform S – Simulate	SATISFACTORY / UNSATISFACTORY	COMMENTS (Reason for unsat)
1.8	**Isolate AND Tag** hydraulic supply to Valve actuators: • Trap Bypass Valve • Trap Isolation Valve • Trap Block Valve	 P P P	SAT / UNSAT	
1.9	**Depressurize AND Drain** Trap as follows:		-----	
1.9.1	**Open** Vent Valve to Sump	P	SAT / UNSAT	
1.9.2	**Open** Trap Drain Valve	P	SAT / UNSAT	
1.9.3	**Open** Atmospheric Vent Valve	P	SAT / UNSAT	
1.10	**Monitor** Booster Station Sump to ensure that trap stops draining.	P	SAT / UNSAT	
1.11	**Place** STOP signs on driveway	P	SAT / UNSAT	
1.11	**ENSURE** Safety vent indicates no pressure	P	SAT / UNSAT	
1.13	**When** trap is drained **LOOSEN** safety clasp nut on top of Trap Door	P	SAT / UNSAT	

CAUTION

Water must be running on concrete pad before tray is pulled out of trap to prevent pad from becoming saturated with product.

STANDARD: Trap is DEPRESSURIZED and OPEN

Job Performance Measure

Task: Receive PIG(s) in Main Line #1.

Method of Accomplishment: Perform

Associated Task ID: C-XXX-XX-XXX-XX

Approved for Independent Performance?: Yes

Trainee Name: _____ **Social Security Number:** _____

Knowledge check complete: _____ _____
Trainer Name Date

SAT / UNSAT

Training complete: _____ _____
Trainer Name Date

Successful Completion of this JPM Evaluation consists of
Satisfactory Performance of ALL Critical Step Items defined within.

Evaluation complete: _____ _____
Trainer Name Date

SAT / UNSAT

Comments: _____

_____

_____

_____

_____

_____

Concurrence: _____ _____
Trainee Signature Date

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Computational Pipeline Monitoring

0 Introduction

Computational Pipeline Monitoring (CPM) is a new term that has been developed to refer to algorithmic monitoring tools that are used to enhance the abilities of a Pipeline Controller to recognize anomalies which may be indicative of a commodity release. In the past, these systems have been generally called leak detection systems. However leak detection can be accomplished by a variety of techniques such as: aerial/ground line patrol; third party reports; inspections by company staff; sensors; SCADA monitoring of line conditions by Pipeline Controllers; and software based monitoring. Consequently the term CPM was developed to specifically cover leak detection, using algorithmic tools.

The API Computational Pipeline Monitoring Task Force (CPM-TF) was formed in April 1994. The purpose of the group was to develop an API publication for CPM as used in the pipeline industry. The existence of this task force was entered into the Department of Transportation—Office of Pipeline Safety's public docket.

This action to address the needs of industry and regulators in the subject of software methods of detecting pipeline leaks is a further demonstration of the API's commitment to be proactive in helping the pipeline industry to protect the public and our environment. This publication and the working Task Force was suggested as a logical extension of a 5 year API research project on leak detection.

Recognizing that the document produced will need changes in the future, not only because of developing technology but also because of regulatory requirements, the work of the CPM-TF has been fully documented. Documentation, available from the API, will provide an understanding of the basis for the approach for future modifiers of this publication.

1 Scope

1.1 PURPOSE

This publication focuses on the design, implementation, testing and operation of Computational Pipeline Monitoring (CPM) systems which use an algorithmic approach to detect anomalies in pipeline operating parameters. The primary purpose of these systems is to provide tools that assist Pipeline Controllers in detecting commodity releases that are within the sensitivity of the algorithm. It is intended that the CPM system would provide an alarm and display other related data to the Pipeline Controllers to aid in decision-making. The Pipeline Controllers would undertake an immediate investigation, confirm the reason for the alarm and initiate a response to the anomaly when it represents an operational upset or commodity release.

The purpose of this publication is to assist the pipeline operator in the selection, implementation, testing, and operation of a CPM system. When used in conjunction with other API publications, this publication will prove useful to identify the complexities, limitations and other implications of detecting anomalies on liquid pipelines using CPM systems.

1.2 CONTENTS

This publication includes definitions, source and reference documents, concepts of data acquisition, discussion of design and operation of a pipeline as related to CPM, field instrumentation for CPM purposes, alarm credibility, Pipeline Controller response, incident analysis, record retention, maintenance, system testing, training, considerations for setting alarm limits, trending and recommendations for data presentation. The relationship between the Pipeline Controller and the CPM system is also discussed.

1.3 SCOPE LIMITATIONS

This publication is intended to apply to single phase, liquid pipelines. It is recognized that one particular methodology or technology may not be applicable to all pipelines; each pipeline system is unique in design and operation. In addition, detection of releases by these means is technically complex with detectable limits difficult to quantify, so limits must be determined and validated on a system-by-system basis.

This publication is not all inclusive. The reader must have an intimate knowledge of the pipeline and may have to refer to other publications for background information.

The user of this publication must be familiar with the requirements of local jurisdiction regulations that must be considered in the application of CPM to pipelines.

CPM is intended as another tool to be used in pipeline operation. Pipeline Controllers must be familiar with the pipeline to effectively operate CPM systems. Operational usage and application of CPM systems require human judgment and intervention. An example of this type of action would be activation of Emergency Flow Restricting Devices (EFRDs).

This publication complements but does not replace other procedures for monitoring the integrity of the line. For example: trained Pipeline Controllers analyzing SCADA-presented operating data can be effective at detecting many commodity releases. Also, third party reports; pipeline patrols; employee on-site examinations are other effective procedures used to verify integrity of the pipeline. This publication is in keeping with standard industry practice and commonly used technology; however, it is not intended to exclude other effective commodity release detection methods.

CPM systems, as well as other commodity release detection techniques, each have a detection threshold below which commodity release detection cannot be expected. This

publication will not reduce the threshold at which a commodity release can be detected.

Figure 1 (along with the discussion in Appendix B) indicates that CPM is only addressing commodity releases above some practical detection limit.

2 References

2.1 REFERENCES CITED HEREIN

The following standards, codes, and specifications are cited herein:

API

RP 1149 *Pipeline Variable Uncertainties and Their Effects on Leak Detectability*

RP 1155 *Evaluation Methodology for Software Based Leak Detection Systems*

RP 1119 *Training and Qualification of Liquid Pipeline Operators*

2.2 OTHER APPLICABLE REFERENCES

API

RP 1113 *Developing a Pipeline Supervisory Control Center*

Manual of Petroleum Measurement Standards (instruments and trends)

CSA[1]

CAN/CSA-Z183-M90, *Oil Pipeline Systems — A National Standard of Canada*, Appendix H, "Recommended Practice for Leak Detection"

DOT[2]

49 *Code of Federal Regulations* Part 1 95

ISA[3]

"A Fog Index for CRT Displays," by Richard S. Shirley, *Proceedings of the ISA 1985 Conference*

3 Definitions

For the purposes of this standard, the following definitions apply. Other particular definitions or words or phrases used in CPM are included in the glossary.

[1]Canadian Standards Association, 78 Rexdale Boulevard, Rexdale, Ontario M9W 1R3.

[2]Department of Transportation. Available from U.S. Government Printing Office, Washington, D.C. 20402.

[3]Instrument Society of America, P.O. Box 12277, Research Triangle Park, North Carolina 27709.

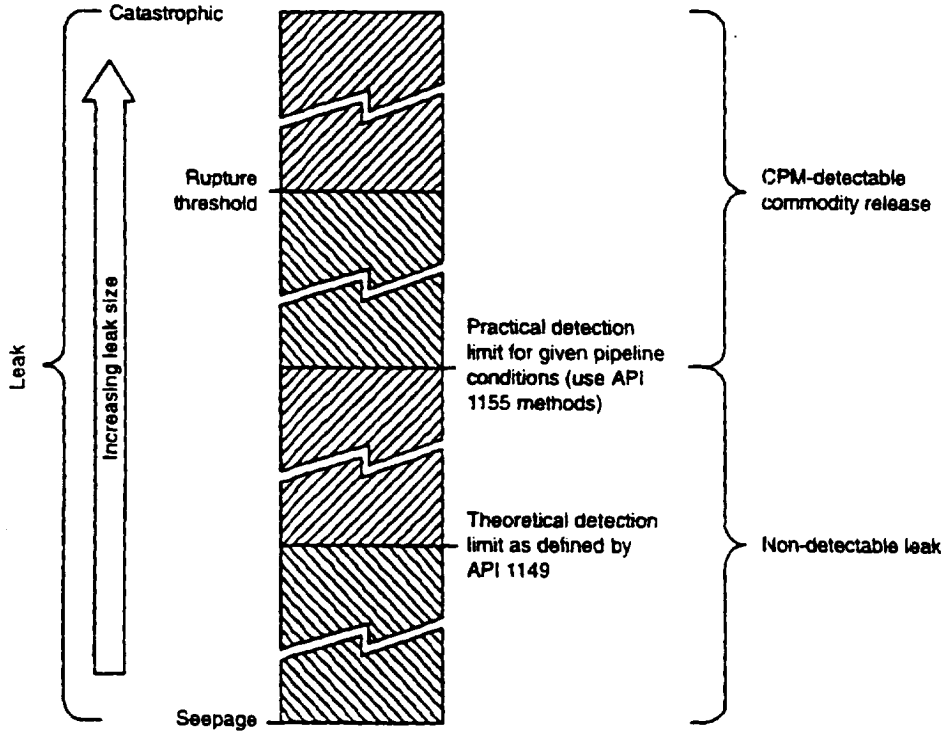

Figure 1—Representation of a Leak/Rupture

3.1 computational pipeline monitoring or CPM: an algorithmic monitoring tool that allows the Pipeline Controller to respond to a pipeline operating anomaly which may be indicative of a commodity release.

3.2 commodity release: a loss of fluid from the pipeline. Within the context of this publication, a commodity release, when referenced to leak rate, must be above the practical detection limit of the particular CPM system and pipeline. Another industry term is product release.

3.3 pipeline rupture: in the context of Computational Pipeline Monitoring (CPM), a rupture is a type of pipeline leak that is characterized by registering a great differential (larger than system "noise" at the time of occurrence) in some measured/trended values on the SCADA system. It is a commodity release caused by some significant mechanical damage to the pipeline system that creates this large hydraulic transient in the pipeline. The commodity release then causes an impairment to the operation of the pipeline. A pipeline rupture can be defined in part by referring to other definitions. A more detailed definition and explanation is provided in Appendix B of this publication.

3.4 transient operating conditions: when any pipeline operating parameter is changing with respect to time.

3.5 steady state conditions: when no pipeline operating parameter is changing with respect to time.

4 Technical Overview

4.1 METHODOLOGIES

The field and control center hardware and software will be covered by this publication. Sensor data must be sent from field sites via telemetry to a control center for data presentation, computation, evaluation and appropriate action by the Pipeline Controller. The degree of complexity in processing field data varies from simple comparisons of a particular parameter relative to a threshold limit to more extensive analysis of multiple parameters with interlocking and/or dynamic threshold limits. All CPM algorithms are based on certain assumptions which need to be completely met to ensure accuracy. Methods used to detect commodity releases can be classified as externally or internally based.

4.1.1 Externally Based Systems

This publication does not include externally based systems which operate on the non-algorithmic principle of physical detection of an escaping commodity. In these systems, the local detector sends an alarm signal to the control center for display and annunciation. Since the externally based methods do not meet the requirement of performing computation on field parameters for inferring a commodity release, they are excluded.

Types of externally based systems or devices that will not be discussed are:

- Fiber optic cable.
- Vapor sensing tube.
- Dielectric cable.
- Acoustic emissions.
- Gas sensors.

Each of the CPM methods has its strengths and limitations. No one technology is suitable for all pipeline applications.

4.1.2 Internally Based Systems

Internally based systems which use CPM techniques utilize field sensors to monitor internal pipeline parameter(s) such as: pressure, temperature, viscosity, density, flow rate, product sonic velocity, product interface, etc. which are inputs for inferring a commodity release by manual or electronic computation.

The types of CPM internally based methodologies that will be discussed are:

- Line balance.
- Volume balance.
- Modified volume balance.
- Real time transient model.
- Pressure/flow monitoring.
- Acoustic/negative pressure wave.
- Statistical analysis.

The following is a brief description of each internally based methodology:

4.1.2.1 Line Balance (LB)

This meter-based method determines the measurement imbalance between the incoming (receipt) and outgoing (delivery) volumes. The imbalance is compared against a predefined alarm threshold for a select time interval (time window). There is no compensation for the change in pipeline inventory due to pressure, temperature or composition. Imbalance calculations are typically performed from the receipt and delivery meters, but less timely and less accurate volumes can be determined from tank gauging. Line balancing can be accomplished manually because of its simplicity.

4.1.2.2 Volume Balance (VB)

This method is an enhanced line balance technique with limited compensation for changes in pipeline inventory due to temperature and/or pressure. Pipeline inventory correction is accomplished by taking into account the volume increase or decrease in the pipeline inventory due to changes in the system's pressure and/or temperature. It is difficult to manually compensate for changes in pipeline inventory because of the complexity of the imbalance computation. There is usually no correction for the varying inventory density. A representative bulk modulus is used for line pack calculation.

4.1.2.3 Modified Volume Balance (MVB)

This meter-based method is an enhanced volume balance technique. Line pack correction is accomplished by taking into account the volume change in the pipeline inventory utilizing a dynamic bulk modulus. This modulus is derived from the bulk moduli of the various commodities as a function of their percentage of line fill volume.

4.1.2.4 Real Time Transient Model (RTTM)

The real time transient model approach is perhaps the most sophisticated CPM method. The fundamental improvement which RTTM provides over the MVB method is that it models all the fluid dynamic characteristics (flow, pressure, temperature). Extensive configuration of physical pipeline parameters (length, diameter, thickness, pipe composition, route topology, internal roughness, pumps, valves, equipment location, etc.) and commodity characteristics (accurate bulk modulus value, viscosity, etc.) are required to design a pipeline specific RTTM. The application software generates a real time transient hydraulic model by this configuration with field inputs from meters, pressures, temperatures, densities at strategic receipt and delivery locations, referred to as software boundary conditions. Fluid dynamic characteristic values are modelled throughout the pipeline, even during system transients. The RTTM software compares the measured data for a segment of pipeline with its corresponding modelled conditions.

4.1.2.5 Pressure/Flow Monitoring

Three approaches to using pressure or flow information can be used. Pressure/flow values which exceed a predetermined alarm threshold are classified as excursion alarms. Initially, excursion thresholds are set out of range of the system operating fluctuations. After the system has reached a steady-state condition, it may be appropriate to set thresholds close to operating values for early anomaly recognition.

Pressure/flow trending is the representation of current and recent historical pressure or flow rate or both. These trends may be represented in a tabular or graphical format on the control center monitor to enable a Controller to be cognizant of these parameter fluctuations. This method can be used to display operating changes which can infer commodity releases.

Rate-of-change (ROC) calculates the variation in a process variable with respect to a defined time interval. The rate at which line pressure or flow or both changes with respect to time are the two most common forms of ROC for pipeline operation. The intent of this approach is to identify rates of change in pressure or flow or both aside from normal operating conditions, thereby inferring a commodity release if operating anomalies cannot be explained.

4.1.2.6 Acoustic/Negative Pressure Wave

The acoustic/negative pressure wave technique takes advantage of the rarefaction waves produced when the commodity breaches the pipe wall. The leak produces a sudden drop in pressure in the pipe at the leak site which generates two negative pressure or rarefaction waves, travelling upstream and downstream. High response rate/moderate accuracy pressure transmitters at select locations on the pipeline continuously measure the fluctuation of the line pressure. A rapid pressure drop and recovery will be reported to the central facility. At the central facility, the data from all monitored sites will be used to determine whether to initiate a CPM alarm.

4.1.2.7 Statistical Analysis

The degree of statistical involvement varies widely with the different methods in this classification. In a simple approach, statistical limits may be applied to a single parameter to indicate an operating anomaly. Conversely, a more sophisticated statistical approach may correlate the averaging of one or more parameters over short and long time intervals in order to identify an anomaly.

The statistical process control (SPC) approach includes statistical analysis on pressure or flow or both. SPC techniques can be applied to generate sensitive CPM alarm thresholds from empirical data for a select time window. A particular method of statistical process control may use line balance "over/short" data from normal operations to establish upper and lower volume imbalance limits. If the volume imbalance for the evaluated time window violates the statistical process control tests, the CPM system will alarm.

4.2 SELECTION CRITERIA

Each CPM methodology contains different combinations of features with varying degrees of sophistication. CPM performance is contingent on the interrelationship of many factors, for example, measurement capabilities, communications reliability, pipeline operating condition, product type, etc. Under appropriate circumstances, rupture detection may benefit by employing multiple CPM techniques such as a volume balance system in concert with pressure trending for validation or redundancy. The independence of parameters (flow, pressure, etc.) used in some methodologies potentially allows for independent validation or redundancy. The following is a list of desirable CPM features and functionality. These listed items are not in any particular order nor is there any attempt to weight the importance of each. It should be noted that no one methodology possesses all features or functionality and certain features will be more appropriate for specific pipeline systems:

- Possesses accurate commodity release alarming.
- Possesses high sensitivity to commodity release.
- Allows for timely detection of commodity release.
- Offers efficient field and control center support.
- Requires minimum software configuration and tuning.
- Requires minimum impact from communication outages.
- Accommodates complex operating conditions.

- Is available during transients.
- Is configurable to complex pipeline network.
- Performs an imbalance calculation on meters at one instant in time.
- Possesses dynamic alarm thresholds.
- Possesses dynamic liquid pack constant.
- Accommodates commodity blending.
- Accounts for heat transfer.
- Provides the pipeline system's real time pressure profile from a hydraulic model.
- Accommodates slack line conditions.
- Accommodates all types of liquids.
- Identifies leak location with appropriate mile post locations.
- Identifies leak rate.
- Accommodates commodity measurement and inventory compensation for various corrections (temperature, pressure, density, meter factor).
- Accounts for effects of drag reducing additive.

API Publication 1155 can be consulted for additional details on CPM performance criteria.

4.3 COMMODITY PROPERTIES

The fluid to be monitored must be in fully liquid phase in order for it to be mathematically characterized. This characterization is typical of most crude oils and refined products. For Newtonian fluids, simpler CPM packages may characterize the fluid with a bulk modulus which is independent of viscosity. Other commodities such as high paraffin crude oils are highly viscous and may have non-Newtonian fluid characteristics. However, these fluids can be mathematically represented with sophisticated equations when being applied to a Real Time Transient Model (RTTM). Highly volatile liquids (HVLs) are in liquid phase if temperature and pressure are sufficient to maintain the fluid above the critical point. Highly volatile liquids are more compressible than crude oils, thereby making it more difficult to discern anomalies from normal pipeline operations.

4.4 TRANSPORTATION SYSTEMS

This publication is written for liquid onshore or offshore trunkline systems but much of this content may be applicable to other piping systems such as: select gathering systems, production flow lines, marine vessel loading or unloading, tank terminaling operations, etc. CPM has typically been applied to steel pipeline systems but may be applied to pipelines constructed of other materials such as PVC, polyethylene, fiberglass, concrete. The successful application of CPM may be limited by the characteristics of these other materials.

Pipeline systems vary widely in their physical characteristics of: diameter, length, pipe wall thickness, internal roughness coefficient, pipe composition, complexity of pipe network, pipeline topology, pump station configuration, instrumentation (quality, accuracy, location), etc. These same pipeline systems can also be categorized by operational factors such as: flow rate, magnitude and frequency of rate/pressure fluctuations, blending, batching, batch stripping schemes, product type, viscosity, density, sonic velocity, bulk modulus, vapor pressure, pressure, temperature, heat transfer etc. Current CPM technologies cannot properly characterize periodic or permanent slack line conditions.

5 Technical Details

5.1 FIELD INSTRUMENTATION

This portion of the publication defines good operating practice in the design and maintenance of the field instrumentation necessary to adequately support a CPM system.

API Publication 1149, *Pipeline Variable Uncertainties and Their Effects on Leak Detectability*, documents the importance of instrumentation to CPM performance. This methodology can demonstrate that inadequate instrumentation reduces CPM effectiveness, and may also be used to determine where the most cost effective improvements can be made. Such analysis may be used repeatedly over the life of the pipeline system to achieve incremental performance improvement on a cost/benefit basis.

Note that different CPM methodologies require varying levels and types of instrumentation. Instrumentation costs may vary significantly for each method. Some methodologies may have very specialized instrumentation needs.

5.1.1 Selection of Instrumentation

Ranges and specifications should be carefully matched to pipeline operating design, pressure, flow, temperature, density, etc. to make best use of the instrument manufacturer's stated accuracy and linearity. Since instrument accuracy is generally stated in terms of percent of full range, the smallest available range greater than the desired range is the preferred choice. There is no value in over specification of instrumentation accuracy if system accuracy is limited by the analog resolution or vice versa of the SCADA system. Such limitations are generally imposed by the resolution, measured in bits, of the analog-to-digital (A/D) conversion hardware.

A/D Bits	Percent Resolution
8	0.4
10	0.1
12	0.025
16	0.0015

5.1.2 Installation of Instrumentation

Instruments should be installed in accordance with manufacturer's recommendations and applicable industry codes and standards. The location of instrumentation in relation to

the process equipment is important, and should be carefully designed with due consideration to variations in operating conditions.

The design of the instrumentation process piping should include provision for convenient testing and calibration of the instrument with minimum disruption of pipeline operations. (See API *Manual of Petroleum Measurement Standards* for instrumentation.)

5.1.3 Calibration and Maintenance of CPM Instrumentation

A CPM performance system that has adequate instrumentation to achieve the desired commodity release sensitivity may be limited in its effectiveness by instrument calibration drift. A system that receives inaccurate data will yield inaccurate results.

Instruments should be calibrated in accordance with manufacturer's recommendations and should be traceable to National Institute for Standards and Technology. Operating experience will provide the basis for determining an appropriate test and recalibration interval. For example, the recalibration interval might be twice per year at an interval not to exceed seven months. The CPM system performance itself may in some cases be the best indication of the necessity to test and re-calibrate a particular instrument.

To maximize CPM performance, each pipeline company should prepare a test and calibration plan as part of a CPM operating and maintenance procedure. This plan should recognize the importance of the CPM system to the safe operation of the pipeline and provide for the priority of CPM instrument repair. Note that such a plan could result in instrumentation calibration practices that may exceed DOT minimum requirements.

Test and recalibration events should be documented, and such records shall, at a minimum, include the date of the test and initials of the person performing the test. Test and recalibration records should be retained in accordance with each company's written procedures.

When developing a maintenance history for field instrumentation, consideration should be given to recording "as found" and "as left" calibrations.

Procedures should be developed to coordinate the test and recalibration of field instrumentation with Pipeline Controllers and CPM system maintenance personnel, since recalibration may affect performance of the system.

5.1.4 Signal Conditioning

Noise is that part of the signal received that does not represent the quantity being measured. Noise typically exists to some degree in all measured data. Noise reduces the performance of the CPM system.

All practical means should be employed to reduce mechanical or electrical sources of noise at the instrument. For example, instrument mounts and process piping should be designed to minimize resonance. Electrical noise in sensor wiring can often be reduced through use of shielded signal cables and proper grounding.

When attempts to eliminate noise are unsuccessful, signal conditioning techniques may be used to limit bandwidth and thus attenuate noise. For example, API 1149 describes a digital low pass filter which was effective in reducing noise and thus improving the leak sensitivity under test conditions.

Note that excessive signal conditioning may remove desired information. Signal conditioning techniques also introduce time lags in changing data which may reduce the effectiveness of the CPM system.

5.2 SCADA/COMMUNICATIONS

The Supervisory Control And Data Acquisition, or SCADA, system is typically a computer-based communications system that gathers, processes and displays data from field instrumentation. This section focuses on the design of the data gathering sub-system and its impact on CPM.

Both manual and automated CPM systems will generally use data gathered by the pipeline SCADA system. Manual systems permit the operator to evaluate the SCADA data and combine it with data from other sources, but are usually labor intensive and slow except on simple systems. Automated CPM systems may be interfaced with the SCADA system to receive pipeline data as it becomes available. Automatic transfer of the data makes it possible for the CPM system to analyze the data at a much faster rate. Such automation does require that all necessary data be available from the SCADA system.

The following paragraphs describe several SCADA system design factors that can impact the quality and timeliness of the data required by a CPM system.

5.2.1 Communications Media and Error Detection

Any data communications medium can be used for SCADA, but the most common media in the liquid pipeline industry are dedicated telephone circuits and various forms of terrestrial and satellite-based radio systems. These media vary in quality, but all are subject to noise and interference causing data corruption. Virtually all SCADA systems are designed to detect and reject corrupted messages. "Data quality bits" are often available in the SCADA system to indicate lost messages, and should be used by the CPM system to identify missing or questionable data.

5.2.2 Communications Message Structure

SCADA systems gather data from field instrumentation via a Remote Terminal Unit (RTU) located at the field site. Data is collected in one or more computers called the Master Terminal Unit (MTU) associated with the pipeline operations control center. The specifications of the messages between RTU and MTU are collectively referred to as the communications protocol.

The protocol is said to be "polled" when the MTU requests data from each RTU in turn. When the last RTU has been polled, the MTU will return to the first, repeating the cycle endlessly. The time interval required to poll all RTUs and return to the first is referred to as "polling time" or "scan time."

An RTU may fail to report when polled due to equipment failure or noise in the communications channel. This fault condition, sometimes called "no reply" is often indicated by SCADA system quality bits.

If the RTU always reports all its data in response to a poll, the system is said to be "strictly polled." Scan time is thus a constant and is determined by the quantity of data to be reported by the RTUs. To gain efficiency on the communications channel, some protocols permit the RTU to respond with only the data that has changed since the previous poll. Such protocols are referred to as "Report by Exception." Scan time in a Report by Exception protocol may vary depending on system design.

SCADA communications may also be non-polled. "Quiescent" or "unsolicited" operation refers to RTUs which report without being polled, either on a time scheduled basis or when field data changes. Refer to 5.2.4 for a description of analog data change. The design of quiescent systems may include provision for the MTU to poll for all RTU data. Such a poll is used to verify the validity of the data image in the MTU and is called an "integrity scan."

5.2.3 Communications Timing

In polled systems the variation in reporting times from one RTU to another is called "time skew." Designers of CPM systems must also consider the impact of time skew in the data.

Quiescent systems that report on data change and Report by Exception protocols have no defined scan time so the age of a particular item of data may be in question. To deal with this situation, some SCADA systems generate "time tags,"either in the RTU at the time data changes or in the MTU at the time data is received. "Time tags" may be used by CPM systems designed to analyze transient conditions in the pipeline. Some SCADA systems are capable of capturing volumetric measurement simultaneously in all RTUs. This feature is usually called "accumulator freeze" and effectively permits all volume data to be polled at one reference time. CPM systems not equipped to handle time tags may use this method to eliminate time skew.

5.2.4 Analog Deadband

Measured variables from instrumentation are sometimes called SCADA "Analogs." Report-by-exception protocols and Quiescent systems that report changed data sometimes permit "Analog Deadbands." When the Analog Deadband is enabled, the value of the Analog must change more than the deadband value before the new value is reported to the MTU.

Analog Deadbands are generally used to reduce traffic on the communications channel. Noise in the analog signal will appear to be a valid change in data in quiescent and report-by-exception systems. In such a case, the analog deadband is increased to reduce the effect of noise and minimize unwanted messages.

When the precision of the SCADA system's analog-to-digital conversion hardware exceeds the repeatability of the sensor, it is appropriate to reduce the precision through the use of an analog deadband. Care must be taken not to use an excessively large analog deadband since this technique effectively reduces the precision of the analog value.

5.2.5 The Impact of SCADA System Design on CPM

CPM systems that rely on the SCADA System for data gathering must be designed with an understanding of the underlying communications protocol. It is possible to have variation in communications protocol within one SCADA system. It is not unusual to find that multiple protocols may be used in layers or sequentially to complete transmission of one RTU to MTU message. The use of multiple protocols may adversely affect scan time.

5.2.6 Data Processing

Field data received by the SCADA system is generally coded in the most compact manner possible to maximize efficiency on the communications link. Such data is said to be "raw." The data processing function in the SCADA system is responsible for converting the data to a format suitable for display and use by applications such as CPM systems. This section describes data processing features that enable or improve CPM functionality.

5.2.6.1 Time Tagging

Time tags record when a particular data point was last updated. Some systems generate the time tags in the RTU, but it is more common for the SCADA MTU to create the time tag at the time the data is processed. Time tags can be used by the CPM system to reduce the effect of time skew, especially when accumulator freeze is not available.

5.2.6.2 Data Quality

Data quality information may be stored with processed data. Typical data quality values are:

- "Nonupdated" caused by an RTU that is off-line or not responsive.
- "Manual data" when manually entered data overrides scanned values.
- "Range error" when a raw analog value falls outside specified hardware limits.

Data quality values may be used by the CPM system to help recognize and compensate for questionable data.

5.2.6.3 Analog Processing

Analog values represent measured variables such as pressure or flow rate. Raw analog values are scaled into engineering units such as pounds per square inch (PSI), or barrels per hour (BPH), by the analog processor. The scaled analog values are usually compared to predefined threshold values to detect when the values fall outside the desired range. The rate of change is a calculated analog value, which is calculated by change in value divided by the change in time.

CPM systems generally rely on the scaled analog values from the SCADA system. SCADA analog processing alone can be used to implement a pressure/flow monitoring CPM (see 5.1).

5.2.6.4 Status Processing

Status data records the state of an item of field equipment. Status pairs such as on/off or opened/closed can be stored in one binary digit or bit. Some SCADA systems permit the configuration of status in 2-bit (4 state) or 3-bit (8 state) combinations. For example, valve status is sometimes represented by the four states: opened/in travel/closed/fault.

Changes in equipment state are generally logged to a printer or other permanent recording device by the status processor. Such a set of records is usually referred to as an "event log."

CPM systems may need status information to determine if transient conditions are the result of change in equipment state. The event log is a good source of information when interpreting CPM alarms.

5.2.6.5 Accumulator Processing

Accumulator values represent an accumulated total of some process quantity since the start of the totalization process. In liquid pipeline SCADA service, accumulators are typically used to record volumetric or mass quantities passing a given point in the system.

A line balance CPM system may be based upon simple arithmetic operations on accumulator values representing liquid volumes pumped in and out of the pipeline system. More complex CPM systems may also require accumulated volumetric data.

5.2.6.6 Alarm Processing

Alarms are a special case of events which indicate a transition into an unexpected or abnormal state. The return transition to the normal state is generally referred to as "return to normal."

Alarms can be configured to trigger an audible signal, which can be acknowledged or silenced by the Pipeline Controller. The Controller may also be required to acknowledge each alarm as it is displayed. Many SCADA systems have special summary lists related to alarms:

- Chronological alarm logs/files.
- Unacknowledged alarm summaries.
- Summaries of points in an abnormal state.

CPM systems may be closely integrated with the SCADA system and make use of the alarm processing system to display, annunciate and log CPM alarms and events.

5.2.6.7 Data Archiving

The SCADA system may, at specified time intervals, store data values to a historical database. This process is referred to as archiving. The SCADA system or other applications such as CPM systems may access the archive for historical data. The ability to replay archived SCADA data in a test mode can be useful in analysis and tuning of the CPM.

5.3 DATA PRESENTATION

Data presentation capabilities vary widely depending on the SCADA/CPM system. The contents of this section are intended to assist the pipeline company to achieve the best possible results in the existing system.

Effective presentation of Operating and CPM data will enable the Pipeline Controller to more easily identify and interpret anomalies.

Interpretation of results from manual CPM systems are based on Controller training. Therefore, this section is primarily concerned with the presentation of data from an automated CPM system.

5.3.1 Display Ergonomics

Displays need to be simple, easy to read, and presented in an uncomplicated screen arrangement. The CRT's should be positioned in a manner to avoid causing body and eye strain. It is important to consult the user during the design of the CPM system, so that the Pipeline Controller is satisfied with the layout and design. The display should limit the number of colors (see Shirley's Fog Index in Section 2).

Uppercase letters may be more readable on some screens. The information displayed should be easy to read on the specific display equipment that the Controller is using. Screen savers should not be used. If other tasks are on the same CRT, care should be taken to prevent interference with the monitoring of the CPM system.

5.3.2 Trending

Trending operating parameters (flow rate, pressure, viscosity, density, over/short and temperature) of the SCADA system values may help determine what caused the alarm. The trend will have to cover a long enough duration to see values from before the CPM alarm occurs right through the time when the alarm ends, or the current time. Trending analog values can aid in the troubleshooting of alarms because the analog device alone cannot always give all of the infor-

mation needed to make a correct Leak Declaration. Tabular trends are not as easy to analyze as graphical trends, but are still effective ways to display historical data.

5.3.3 Alarm Display

CPM alarms should be consistent with SCADA system alarms and should have an appropriate priority. The alarm should have an audible tone, and can be varied for different categories of alarms. Alarms should have different colors if there are different categories of alarms. Acknowledged and unacknowledged alarms should be available to the Controller without using several steps to get to the alarms. A time stamp should be part of the alarm when it is displayed.

Alarms should be presented as both audible and visual. Visual alarms should be presented in such a way as to persist for some period of time, especially so as not to be overwritten irrevocably by newer alarms. Acknowledged alarms which are still in the alarm state should remain readily available to the Controller.

Provision should be made against an alarm being easily defeated, or inhibited without just cause. The use of screen savers or any other screen blanking is strongly discouraged.

5.3.4 Integration of CPM and SCADA

The display of alarms from the CPM system and SCADA system should preferably be integrated and put on the same alarm display. If the CPM and SCADA systems cannot be integrated, the CPM alarms should be displayed so that they will be readily noticed. In either case alarms should be logged and retained.

Non-integrated systems should provide event and alarm retention for the CPM. All displays and data should be easily accessible by the Controller to aid in operations of the CPM system along with the SCADA system. The hardware designed should provide sufficient resources, either by organization of displays or providing sufficient CRT's to display needed information for analyzing alarms. One useful reference in the design of Pipeline Controller systems is Shirley's Fog Index.

6 Operation, Maintenance, and Testing

6.1 CPM OPERATIONS

CPM systems use a set of procedures defined for a given pipeline and instrument data, configuration data, product accounting data, and/or data calculated using various hydraulic algorithms to alarm a possible commodity release on a given operating pipeline.

In the context of CPM, an alarm is an automated or manual signal or other presentation of data to the Pipeline Controller (via a SCADA system operator interface or manual tabulation sheets) that defines an abnormal condition on a pipeline system. An alarm could be triggered by equipment failure, abnormal pipeline operating condition or an unintentional commodity release. Since the potential of alarm information identifies conditions other than just commodity releases which need attention, the company procedures should also require that all alarms be evaluated.

The quality of measured pipeline data and calculated data values and the analysis of this data determines the credibility of an alarm. An alarm condition on a monitored pipeline is not the end of the analysis.

6.1.1 Alarm Credibility

The credibility of a CPM system is determined by an analysis of the CPM alarm. In this publication, CPM alarms are subdivided into three classes, which are: data failure, transient operating conditions, and possible commodity release.

6.1.1.1 Data Failure

This alarm would be used when input data is missing or is determined to be incorrect. A communication failure at a location is a type of missing input data. An example of incorrect data could be a pressure instrument that consistently reports values that have no hydraulic relation to other pressure and flow data on the pipeline. A procedural failure could be when a required report is not passed along to the Pipeline Controller on schedule. These incidents would be presented as types of data failure alarms. These alarms could be automatically generated by a computer or as manual entries in a Pipeline Controller's shift log. Some CPM systems would indicate the impact the data failure situation would have on continued CPM operation. The impact of this class of alarm could range from the system being disabled to a fixed percentage error in future location calculations. At this point analysis by the Pipeline Controller would be required. The main issue is that the failure of one or a series of measured or calculated data points should not trigger a Leak Declaration. The CPM analysis system should identify data failure situations and notify the Pipeline Controller that a problem exists.

6.1.1.2 Transient Pipeline Operating Condition

This alarm would be used when a data set was outside normal operating ranges, fails all tests for a data failure condition and does not meet all tests for a possible commodity release. This class of alarm is intended to provide a third diagnostic condition between normal pipeline operation and a correct Leak Declaration. If the data analysis section of the CPM system cannot determine to a set level of certainty that a commodity release situation does exist, then the CPM system would call for an abnormal pipeline operating condition alarm. The purpose of this class of alarm is to minimize incorrect Leak Declarations. The abnormal pipeline operating condition alarm would notify a Pipeline Controller of a problem that requires immediate investigation.

The Pipeline Controller would review all current operating data and make a decision on what action to take. The procedures the Pipeline Controller would follow under this situation would be as defined by the individual pipeline company for the particular CPM system. The abnormal pipeline operation alarm could supply data to the Pipeline Controller to aid in the situation analysis. Continued refinement of the analysis section of the CPM system would reduce the numbers of this class of alarm, allowing the CPM system to properly classify more alarms as data failure or possible commodity releases. The main issue is to minimize the occurrence of a Leak Declaration until the data indicates with a high probability the presence of an actual unintentional discharge condition.

6.1.1.3 Possible Commodity Release

In the case where the CPM alarm does not meet the condition for data failure as described above and does not appear to be part of transient operating conditions, then a Leak Declaration may be made. A Pipeline Controller determines if a Leak Declaration must be made, as opposed to a purely automatic system. In this manner, company policy and applicable regulations can be properly applied.

6.1.2 Operational Responses to Alarms

The following items should be considered when responding to CPM alarms:

- CPM alarms will be probabilistic, and should be assessed in light of the current sensitivity threshold.
- Known cases where the Transient Pipeline Operating Condition alarms have been generated should be well documented to assist the Controller in making informed decisions.
- All occurrences of a Leak Declaration should be historically documented as to cause and Controller response.
- Instances of automatic closed-loop control response to alarm conditions should be avoided, in that appropriate Controller response is preferable to automatic valve closures. Automatic valve closures can potentially result in excessive surge pressure in liquid pipeline systems. If automatic valve closures are unavoidable, then the Controller must have the capability to override the automatic system for just cause.
- Consideration should be made for an indication of CPM system failure, especially if automatic closed-loop control is provided.
- Possible causes should be accounted for, including computer failure, but also including possible types of system analysis failure. These and other CPM alarms should be presented to the Controller in a way that clearly identifies the alarm as distinct from a SCADA alarm.

6.2 SYSTEM TESTING

Effective testing of automated CPM systems provides assurance that the expected level of performance has been achieved or maintained. This section outlines testing methods and intervals.

6.2.1 Testing Method

CPM systems should be tested with actual or simulated commodity releases. Possible methods of testing include:

- Removal of test quantities of commodity from the line.
- Editing of CPM configuration parameters to simulate commodity loss (software simulations).
- Altering an instrument output, for example a meter factor, to simulate a volume imbalance, or a pressure output to simulate a hydraulic anomaly.

The method used will be specific to the particular CPM application and pipeline system.

CPM tests may be "announced" or "unannounced." An unannounced test is started without the knowledge of the Pipeline Controller and tests the CPM system as well as the response of the Pipeline Controller. Generally, unannounced tests are preceded by successful announced tests. An announced test is started with the awareness of the Pipeline Controller and tests only the CPM system.

6.2.2 Initial Tests During CPM Commissioning

A new CPM system must be tested to verify that it has achieved the expected performance. Throughout the startup procedure, there will likely be a variety of tests. Consideration should be given to testing by actual removal of commodity from the pipeline.

6.2.3 Retesting

CPM applications should be tested on a 5-year interval to demonstrate their continued effectiveness. It is not necessary to test each pipeline system which uses the same CPM application, but consideration should be given to rotation of the tested pipeline and the location of the test from one test to the next. Consideration should be given to testing by actual removal of commodity from the pipeline.

Operational use of a CPM system, for example successful detection of a commodity release, is an acceptable substitute for periodic retesting.

6.2.4 Record Keeping

Records detailing the initial or retest results shall be retained until the subsequent test and should include:

- Date, time, and duration of the test.
- Method, location, and description of the commodity withdrawal.
- Operating conditions at the time of the test.
- Details of any alarms generated during the test.
- Analysis of the performance of the CPM system and, for tests, the effectiveness of the response by operating personnel.

• Documentation of corrective measures taken or mitigated as a result of the test.

6.2.5 Maintenance Testing

Throughout the life of the CPM system it will be necessary to reconfigure and retest the software when the pipeline system, SCADA system or instrumentation changes significantly. When documented in accordance with 6.2.4, such maintenance tests may set the start of a new testing interval.

6.2.6 Self Testing

Some automated CPM systems may be capable of running self diagnostics on a scheduled basis. Such diagnostics typically introduce perturbations in the input data to see if the appropriate alarms are generated. This may be a desirable system feature if the disruptive effect of these diagnostic alarms on the Pipeline Controllers can be minimized.

6.2.7 CPM Testing and Reduced Performance

When testing the CPM system, consideration should be given to the potential for a reduced level of pipeline monitoring during the test. Pipeline Controllers should be alert to the possibility of an inadvertent commodity release which might otherwise be ignored or misdiagnosed during the test interval.

6.3 SYSTEM MAINTENANCE

Provisions shall be made to minimize the effect of maintenance on the integrity of the CPM during periods of hardware, software and field equipment maintenance and system upgrades.

6.3.1 Security

Provisions shall be made to limit access to making changes to the SCADA/CPM system, logic solver (that is, PLC, RTU, etc.), alarm limits, and to deactivation of sensors. The access protection may be in the form of passwords, locked cabinets, "read only" or "write protected" data, and administrative procedures. Access protection may have varying levels of accessibility for the different users, for example, systems designers, technicians, Pipeline Controllers.

Provisions should be made against any alarm, parameter, and/or sensor being inhibited without just cause.

Access control and security should be provided by a combination of application logic and passwords for any CPM user interface device, parameter, alarm inhibit, and/or limit which could interfere with or degrade the performance of the CPM function.

System changes can be made in a number of ways. These changes should be coordinated or otherwise managed, for example by segregating the degree of changes by multiple levels of accessibility. It is desirable that any changes be audited and the changes should not go on-line or active until validation is complete. Any parameter or function which requires validation after the change should not be immediately incorporated in the on-line production system, but instead should be accessible and tested only in an off-line mode, if possible.

It is desirable that the system build a "read only" data file which records relevant changes to software and parameters. An audit trail should be maintained to include date, time, parameter, original setting, new setting and person performing the change.

All alarms and operator initiated commands and events which are part of data retention should be stored in hard copy or "read only" format. All "read only" files should be protected from loss and unauthorized tampering.

The operating company should develop and implement a revision and release policy for software or firmware or both used in a CPM system, including field devices which input data to the CPM system.

6.3.2 Parameter and Limits

Consideration should be given to allow the Pipeline Controller to make changes to limits that are important to day-to-day or shift specific operation. The system design should include provisions to allow the Controller to modify and adjust limits within fixed boundaries. Changes that affect the long-term operation of CPM should not be allowed by the Controller.

The ability to make changes in the CPM system boundaries should only be accessible to authorized personnel and under the control of appropriate written procedures.

6.3.3 System Degradation

The Controller must be informed or have an indication whenever a CPM system sensor is inhibited or disabled or both which causes the system to operate in a degraded mode. This should include sensor's calibration problems, communications problems and software failures.

System maintenance should be performed under the control of a formal maintenance procedure that addresses the effect of field and system maintenance on the CPM performance. The procedure should also address the communications requirements between maintenance personnel and the Pipeline Controller.

6.4 DATA RETENTION

The retention of data and reports from a CPM system will be governed by several factors, including regulators' requirements, legal requirements, engineering and operations requirements and Controller training requirements.

The data retention plan of the CPM system must first identify each CPM report and data set. After the CPM data has been identified it must be classified as to reason for retention. The data will be archived for regulatory, engineering and operations, operator training, or a combination of reasons. Each reason for archiving may have a different retention requirement. The CPM data retention plan should

take this fact into account. The plan should define the manner and location of all data which will be archived.

In general, regulatory and legal requirements for the retention of data will be defined by others. Data retained for engineering, operations and Controller training can be defined by the pipeline company. The pipeline company should prepare a schedule for the retention of appropriate CPM system reports and data sets. Retained CPM data and reports, such as alarm reports, can be used by engineering groups to refine the operation of the CPM system. Operations groups can use retained CPM data to analyze abnormal pipeline operation and refine pipeline operations. In addition, retained data can be used to train Pipeline Controllers in the operation of the CPM system.

6.5 PIPELINE CONTROLLER TRAINING

Appropriate Controller training is recommended for any CPM system. CPM alarms may be the most complex type of alarm experienced by the Controller and therefore specific training and reference material is necessary to prepare the Controller to adequately recognize and respond to these alarms.

Pipeline Controllers must be trained in the recognition of CPM alarms. This requires both a knowledgeable perspective on the alarms themselves as well as the nature of the alarms. The American Petroleum Institute has created a Recommended Practice for Controller Training which considers many important issues outside the scope of this publication. Refer to the API Publication 1119 for more detailed information regarding Controller training.

The following technical areas should be considered:

6.5.1 Hydraulics

6.5.1.1 Steady State

The Pipeline Controllers must be trained in the basic concepts of pipeline steady state hydraulics. The gradual change of the line hydraulics due to movement of different fluid batches or temperature change, for example, should be part of a Controller's education.

6.5.1.2 Transient

Everyday pipeline transients can cause upsets in a CPM system. The upsets may cause operating alarms which are well within the realm of normal system behavior. A Controller must be trained to recognize the effects of pump start-ups/shutdowns, a valve operation switch, etc. Any of these will cause a system transient to appear and will therefore potentially be a problem for the CPM system.

6.5.2 Alarming

6.5.2.1 SCADA

Some SCADA alarms impact CPM system performance. The Controller should be able to recognize and react to all types of CPM-related SCADA alarms, such as "Communication Outage."

6.5.2.2 Instrumentation

The Controller should be able to qualitatively identify the impact of an instrument failure on the potential of the CPM system. The person should be trained to link the alarm event with the concept that the CPM system would be impaired.

6.5.3 Validating CPM Alarms

It is recommended that the Pipeline Controller be trained to recognize abnormal conditions and to take appropriate action.

6.5.4 Inventory Control

6.5.4.1 Line Pack

A fundamental component of inventory control is the calculation of mass balance, or the comparison of net-barrels-in versus net-barrels-out. Controllers should be trained to recognize hydraulic changes due to varying line pack. This would include the ability to recognize the packing behavior of the pipeline(s) which they operate.

6.5.4.2 Slack Line Flow

A Controller should be knowledgeable about sections of the pipeline that are susceptible to "slack line flow," that is, a pipeline which is flowing with some type of liquid/gaseous interface.

6.5.4.3 Trending

A Controller should be able to recognize that trending and analysis of certain pipeline variables provides a simple form of CPM system. Trending can be presented graphically, but is often simply a tabular display of historical data.

6.5.5 CPM System Operation

6.5.5.1 Operation

Each CPM system has a unique presentation. It is important that the Controller be trained to understand the CPM system and concepts of its operation. A portion of Controller training should include periodic review of the use of the CPM system.

6.5.5.2 Alarms

CPM alarms should be readily recognizable. Therefore the Controller must be trained to interpret alarms correctly and in a timely manner.

6.5.5.3 Data Presentation

The presentation of CPM alarm data is a crucial component, such as the trend of the probability of a leak or the description of the location for which possible commodity release has occurred. A Controller must be trained in the recognition

of the first CPM notification and must be trained to research the alarm (Possible Commodity Release or Abnormal Condition) in order to pursue the appropriate response.

6.5.5.4 Abnormal Functions

The Controller must be trained to react to the abnormal function of a CPM system in the same way as for the abnormal function of the SCADA system. The loss of either must elicit certain predefined actions intended to preserve system integrity.

6.6 CPM DOCUMENTATION

Each CPM system employed on a pipeline should be fully described and readily available for reference by those employees responsible for the CPM system on the pipeline. It is recommended that the following information be available:

- System map, profile and detailed physical description for each pipeline segment.
- Summary of the characteristics of each product transported.
- Tabulation of the inputs used in the CPM procedure for each pipeline segment and a description of how the data is gathered.
- List of special considerations or step-by-step procedures to be used in evaluating CPM results.

APPENDIX A—GLOSSARY

accumulator data: A SCADA data value that represents an accumulated quantity, usually volume in liquid pipeline service.

accumulator freeze: A feature of some SCADA protocols that allows all volumetric data to be captured simultaneously. It may be used to eliminate time skew in volumetric data.

alarm: A notification to the Pipeline Controller that an anomaly has been detected that is outside preset limits. The event requires a response from the Pipeline Controller. Alarms are usually displayed in a prominent manner with an audible signal to the Pipeline Controller. This may be declared visually or audibly or both.

alarm acknowledgment: An action by the Pipeline Controller, signifying that the alarm event is recognized.

analog data: A SCADA data value that represents some measured quantity, for example temperature or pressure.

analog deadband: A SCADA parameter that defines the increment of change in an analog value that is significant. An analog value change less than the deadband will be ignored.

false alarm: A commonly misused term in the context of CPM systems to refer to transient alarms (see 6.1.1. Alarm Credibility, for discussion) that are not caused by an actual commodity release or other emergency or abnormal condition.

excursion alarm: An alarm that indicates an anomaly has occurred that is outside the defined limits; typically a SCADA or CPM system generated event that alerts the Pipeline Controller to an analog data value that has been detected outside a preset range. Also called a threshold alarm.

communication failure: An interrupt in SCADA messaging usually between the MTU and RTU. It may be loss of communication either by total outage of the communication link or by failure of the remote site to respond to MTU definition needed requests.

communications messaging protocol: See protocol.

data archiving: A SCADA system feature that records data in an historical database.

data quality: A SCADA system feature that creates status bits that reflect the validity of process data.

event log: A SCADA system feature that creates a permanent record of changes to the system's state in chronological order.

filter: A device or algorithm to remove unwanted components from a process signal. Also called signal conditioning.

fluid properties: The characteristics of the fluid that describe its hydraulic behavior density, compressibility (or bulk modulus), coefficient of expansion and thermal capacity.

historical data: Data that is retrievable in chronological order, typically maintained by a SCADA system data archival subsystem.

integrity scan: A special message in a "report-by-exception" SCADA communication protocol that verifies that the MTU has an accurate picture of RTU data. Since only changed data is reported by the RTU in such a protocol, lost RTU to MTU messages could result in inaccurate data in the MTU.

Leak Declaration: A Leak Declaration is made if the Pipeline Controller has determined or confirmed that a product release has occurred on the pipeline. For example, a Leak Declaration would be made after a possible commodity release has been field verified. A Leak Declaration initiates a number of events in the operations, for example shutting down the line. See also possible commodity release.

possible commodity release: A condition where the CPM system has alarmed, and data failure or transient operating conditions causes have been ruled out. A possible commodity release may not be a reason to shutdown the pipeline but would trigger a full investigation of the cause(s). A possible commodity release in which the Pipeline Controller has a high degree of confidence that it is true could be immediately escalated to a Leak Declaration. A company procedure may require that all possible commodity releases be classified as Leak Declarations. See also *Leak Declaration.*

manual system: A CPM system which is based upon non-software algorithmic calculations.

material balance: A mathematical procedure based upon the laws of conservation of mass and fluid mechanics which is used to determine if a commodity release has developed in a pipeline system. May also sometimes be called mass balance.

master terminal unit or MTU: A component of a SCADA system, usually located at the Control Center, that gathers and displays process data from the RTUs. In addition, the Pipeline Controller's operational commands are initiated on the MTU for transmission to the selected RTU. Also a generic term that refers to any device that issues request for information to an RTU or receives information from an RTU.

noise: An unwanted component in a process signal. Noise may be reduced by filtering.

no reply: A state in SCADA communications in which the RTU does not make a valid response to the MTU's request for process data. No reply is expected some percentage of the time, depending on the design of the communication channel.

polling: One type of SCADA communications protocol in which sequential requests for process data from RTUs are is-

sued by the MTU. These requests, called polls, typically proceed in a continuous cyclic manner.

pipeline controller: A person who is responsible for the monitoring and direct control of a pipeline. This is the new accepted industry term for this position (as outlined in API Publication 1118). Other industry terms used are operator or dispatcher.

protocol: The specifications of the messages between RTU and MTU are collectively referred to as the communications protocol.

quiescent protocol: One type of SCADA communication protocol is which the RTUs initiate messages containing process data for transmission to the MTU. Such messages can be triggered by a change in process data or created on a time-driven basis. Also called unsolicited protocol.

report-by-exception: A feature of some SCADA communication protocols intended to improve communication efficiency by reporting only the data that has changed since the previous poll.

rate of change: A calculated value that reflects the change in an analog data value per unit time.

return to normal: The transition from alarm to normal state that signifies that an alarm condition has ended.

reliability: A measure of the ability of a CPM system to render accurate decisions about the possible existence of a commodity release on a pipeline, while operating within an envelope established by the CPM system design. This term is fully defined and discussed in API Publication 1155.

remote terminal unit or RTU: A SCADA system component, typically installed at a field site, that gathers process data from sensors for transmission to the MTU. The RTU also accepts control command messages from the MTU and transforms those commands to electrical output signals. Also a generic term that refers to any device that can respond to requests for information from an MTU or PLC or can send unsolicited information in a non-polled environment.

SCADA: An acronym for Supervisory Control and Data Acquisition, the technology that makes it possible to remotely monitor and control pipeline facilities.

sensitivity: A composite measure of the size of a leak that a CPM system is capable of detecting and the time required for the system to issue an alarm in the event that a commodity release of that size should occur. This term is fully defined and discussed in API Publication 1155.

scan time: The time interval required to poll all RTUs on a SCADA communication channel. Also called polling time.

status data: A SCADA data value that represents the operational state of an item of field equipment.

single phase: A fluid state, either liquid or gaseous, based upon commodity, vapor pressure, pipeline pressure and temperature.

slack line: The condition where a pipeline segment is not entirely filled with liquid or is partly void. May also be called column separation.

time skew: The variation in reporting times from one RTU to another in a polled SCADA communications protocol.

time tag: A SCADA system feature that records the time that a measurement or event occurs along with the data.

APPENDIX B—DISCUSSION OF PIPELINE RUPTURE DEFINITION

Pipeline rupture is defined in this appendix in the context of how it relates to CPM. Figure B-1 provides a representation of rupture as it relates to other types of pipeline leaks. The definition of a rupture in this figure also references other definitions to help the reader understand its relationship to various detectability thresholds.

A rupture in any case cannot be considered to be at a fixed value of product release relative to the line flow rate or volume of the pipeline. The following factors characterize a rupture:

- Volume of product loss that occurs in a rupture will be different for each individual pipeline.
- Operating conditions of the pipeline (steady or transient) will influence the minimum size of commodity release above which a leak can be called a rupture.
- Time interval should be considered in defining a pipeline rupture.

If a requirement exists to recognize a commodity release size above which a rupture is defined, it should be done by the pipeline operator. In defining a rupture on an individual pipeline, the pipeline operating company may need to consider the following:

- Slack line flow.
- Line pressure.
- Operating state.
- CPM methodology.
- SCADA scan time.
- Flow rate.
- Temperature gradient.
- CPM pipeline segmentation.
- Pipe volume and length.

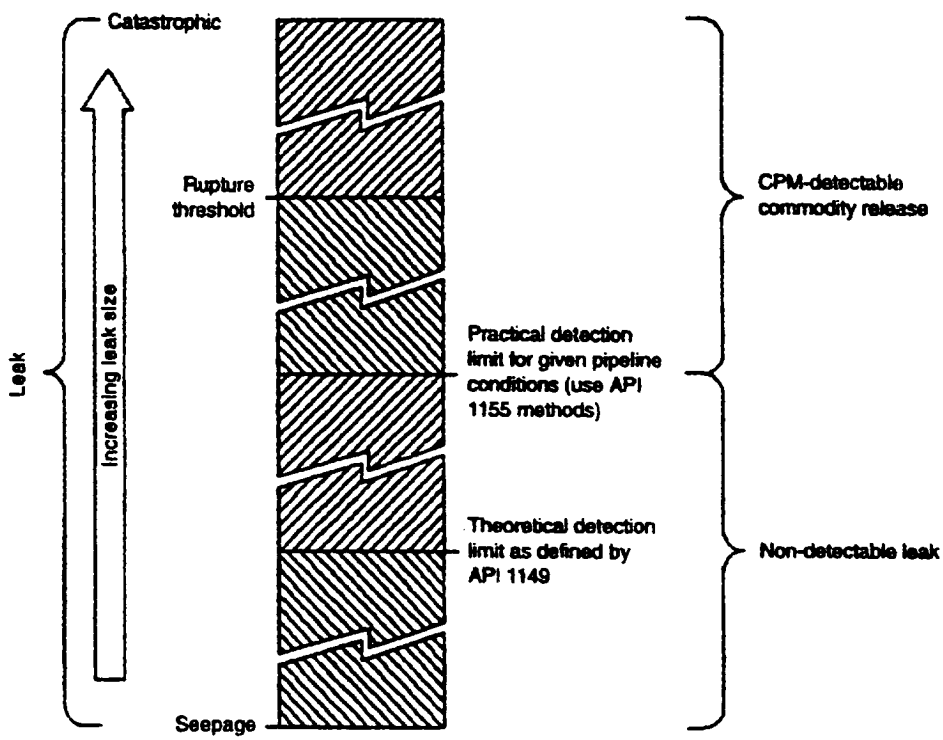

Figure B–1—Definition of a Leak/Rupture

The American Society of Mechanical Engineers

AN AMERICAN NATIONAL STANDARD

PIPELINE TRANSPORTATION SYSTEMS FOR LIQUID HYDROCARBONS AND OTHER LIQUIDS

ASME CODE FOR PRESSURE PIPING, B31

ASME B31.4-2002

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FOREWORD

The need for a national code for pressure piping became increasingly evident from 1915 to 1925. To meet this need the American Engineering Standards Committee (later changed to the American Standards Association) initiated Project B31 in March 1926 at the request of The American Society of Mechanical Engineers, and with that society as sole sponsor. After several years' work by Sectional Committee B31 and its subcommittees, a first edition was published in 1935 as an American Tentative Standard Code for Pressure Piping.

A revision of the original tentative standard was begun in 1937. Several more years' effort was given to securing uniformity between sections and to eliminating divergent requirements and discrepancies, as well as to keeping the code abreast of current developments in welding technique, stress computations, and references to new dimensional and material standards. During this period a new section was added on refrigeration piping, prepared in cooperation with The American Society of Refrigeration Engineers and complementing the American Standard Code for Mechanical Refrigeration. This work culminated in the 1942 American Standard Code for Pressure Piping.

Supplements 1 and 2 of the 1942 code, which appeared in 1944 and 1947, respectively, introduced new dimensional and material standards, a new formula for pipe wall thickness, and more comprehensive requirements for instrument and control piping. Shortly after the 1942 code was issued, procedures were established for handling inquiries that require explanation or interpretation of code requirements, and for publishing such inquiries and answers in *Mechanical Engineering* for the information of all concerned.

Continuing increases in the severity of service conditions, with concurrent developments of new materials and designs equal to meeting these higher requirements, had pointed to the need by 1948 for more extensive changes in the code than could be provided by supplements alone. The decision was reached by the American Standards Association and the sponsor to reorganize the Sectional Committee and its several subcommittees, and to invite the various interested bodies to reaffirm their representatives or to designate new ones. Following its reorganization, Sectional Committee B31 made an intensive review of the 1942 code, and a revised code was approved and published in February 1951 with the designation ASA B31.1-1951, which included:

(a) a general revision and extension of requirements to agree with practices current at the time;

(b) revision of references to existing dimensional standards and material specifications, and the addition of references to new ones; and

(c) clarification of ambiguous or conflicting requirements.

Supplement No. 1 to B31.1 was approved and published in 1953 as ASA B31.1a-1953. This Supplement and other approved revisions were included in a new edition of B31.1 published in 1955 with the designation ASA B31.1-1955.

A review by B31 Executive and Sectional Committees in 1955 resulted in a decision to develop and publish industry sections as separate code documents of the American Standard B31 Code for Pressure Piping. ASA B31.4-1959 was the first separate code document for Oil Transportation Piping Systems and superseded that part of Section 3 of the B31.1-1955 code covering Oil Transportation Piping Systems. In 1966 B31.4 was revised to expand coverage on welding, inspection, and testing, and to add new chapters covering construction requirements and operation and maintenance procedures affecting the safety of the piping systems. This revision was published with the designation USAS B31.4-1966, Liquid Petroleum Transportation Piping Systems, since the American Standards Association was reconstituted as the United States of America Standards Institute in 1966.

The United States of America Standards Institute, Inc., changed its name, effective October 6, 1969, to the American National Standards Institute, Inc., and USAS B31.4-1966 was redesignated as ANSI B31.4-1966. The B31 Sectional Committee was redesignated as American National Standards Committee B31 Code for Pressure Piping, and, because of the wide field involved, more than 40 different engineering societies, government bureaus, trade associations, institutes, and the like had one or more representatives on Standards

Committee B31, plus a few "Individual Members" to represent general interests. Code activities were subdivided according to the scope of the several sections, and general direction of Code activities rested with Standards Committee B31 officers and an Executive Committee whose membership consisted principally of Standards Committee officers and chairmen of the Section and Technical Specialists Committees.

The ANSI B31.4-1966 Code was revised and published in 1971 with the designation ANSI B31.4-1971.

The ANSI B31.4-1971 Code was revised and published in 1974 with the designation ANSI B31.4-1974.

In December 1978, American National Standards Committee B31 was converted to an ASME Committee with procedures accredited by ANSI. The 1979 revision was approved by ASME and subsequently by ANSI on November 1, 1979, with the designation ANSI/ASME B31.4-1979.

Following publication of the 1979 Edition, the B31.4 Section Committee began work on expanding the scope of the code to cover requirements for the transportation of liquid alcohols. References to existing dimensional standards and material specifications were revised, and new references were added. Other clarifying and editorial revisions were made in order to improve the text. These revisions led to the publication of two addenda to B31.4. Addenda "b" to B31.4 was approved and published in 1981 as ANSI/ASME B31.4b-1981. Addenda "c" to B31.4 was approved and published in 1986 as ANSI/ASME B31.4c-1986.

The 1986 Edition of B31.4 was an inclusion of the two previously published addenda into the 1979 Edition.

Following publication of the 1986 Edition, clarifying and editorial revisions were made to improve the text. Additionally, references to existing standards and material specifications were revised, and new references were added. These revisions led to the publication of an addenda to B31.4, which was approved and published in 1987 as ASME/ANSI B31.4a-1987.

The 1989 Edition of B31.4 was an inclusion of the previously published addenda into the 1986 Edition.

Following publication of the 1989 Edition, clarifying revisions were made to improve the text. Additionally, references to existing standards and material specifications were revised and updated. These revisions led to the publication of an addenda to B31.4, which was approved and published in 1991 as ASME B31.4a-1991.

The 1992 Edition of B31.4 was an inclusion of the previously published addenda into the 1989 Edition and a revision to valve maintenance. The 1992 Edition was approved by the American National Standards Institute on December 15, 1992, and designated as ASME B31.4-1992 Edition.

The 1998 Edition of B31.4 was an inclusion of the previously published addenda into the 1992 Edition. Also included in this Edition were other revisions and the addition of Chapter IX, Offshore Liquid Pipeline Systems. The 1998 Edition was approved by the American National Standards Institute on November 11, 1998, and designated as ASME B31.4-1998 Edition.

The 2002 Edition of B31.4 is an inclusion of the previously published addenda into the 1998 Edition along with revisions to the maintenance section and updated references. This 2002 Edition was approved by the American National Standards Institute on August 5, 2002, and designated as ASME B31.4-2002.

ASME CODE FOR PRESSURE PIPING, B31

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INTRODUCTION

The ASME B31 Code for Pressure Piping consists of a number of individually published Sections, each an American National Standard. Hereafter, in this Introduction and in the text of this Code Section B31.4, where the word "Code" is used without specific identification, it means this Code Section.

The Code sets forth engineering requirements deemed necessary for safe design and construction of pressure piping. While safety is the basic consideration, this factor alone will not necessarily govern the final specifications for any piping system. The designer is cautioned that the Code is not a design handbook; it does not do away with the need for the designer or for competent engineering judgment.

To the greatest possible extent, Code requirements for design are stated in terms of basic design principles and formulas. These are supplemented as necessary with specific requirements to assure uniform application of principles and to guide selection and application of piping elements. The Code prohibits designs and practices known to be unsafe and contains warnings where caution, but not prohibition, is warranted.

This Code Section includes:

(a) references to acceptable material specifications and component standards, including dimensional requirements and pressure-temperature ratings;

(b) requirements for design of components and assemblies, including pipe supports;

(c) requirements and data for evaluation and limitation of stresses, reactions, and movements associated with pressure, temperature changes, and other forces;

(d) guidance and limitations on the selection and application of materials, components, and joining methods;

(e) requirements for the fabrication, assembly, and erection of piping;

(f) requirements for examination, inspection, and testing of piping;

(g) procedures for operation and maintenance that are essential to public safety; and

(h) provisions for protecting pipelines from external corrosion and internal corrosion/erosion.

It is intended that this Edition of Code Section B31.4 and any subsequent Addenda not be retroactive. Unless agreement is specifically made between contracting parties to use another issue, or the regulatory body having jurisdiction imposes the use of another issue, the latest Edition and Addenda issued at least 6 months prior to the original contract date for the first phase of activity covering a piping system or systems shall be the governing document for all design, materials, fabrication, erection, examination, and testing for the piping until the completion of the work and initial operation.

Users of this Code are cautioned against making use of Code revisions without assurance that they are acceptable to the proper authorities in the jurisdiction where the piping is to be installed.

Code users will note that paragraphs in the Code are not necessarily numbered consecutively. Such discontinuities result from following a common outline, insofar as practicable, for all Code Sections. In this way, corresponding material is correspondingly numbered in most Code Sections, thus facilitating reference by those who have occasion to use more than one Section.

The Code is under the direction of ASME Committee B31, Code for Pressure Piping, which is organized and operates under procedures of The American Society of Mechanical Engineers which have been accredited by the American National Standards Institute. The Committee is a continuing one and keeps all Code Sections current with new developments in materials, construction, and industrial practice. Addenda are issued periodically. New editions are published at intervals of 3 to 5 years.

When no Section of the ASME Code for Pressure Piping specifically covers a piping system, at his discretion the user may select any Section determined to be generally applicable. However, it is cautioned that supplementary requirements to the Section chosen may be necessary to provide for a safe piping system for the intended application. Technical limitations of the various Sections, legal requirements, and possible applicability of other codes or standards are some of the factors to be considered by the user in determining the applicability of any Section of this Code.

The Committee has established an orderly procedure to consider requests for interpretation and revision of

Code requirements. To receive consideration, inquiries must be in writing and must give full particulars (see Mandatory Appendix covering preparation of technical inquiries).

The approved reply to an inquiry will be sent directly to the inquirer. In addition, the question and reply will be published as part of an Interpretation Supplement issued to the applicable Code Section.

A Case is the prescribed form of reply to an inquiry when study indicates that the Code wording needs clarification or when the reply modifies existing requirements of the Code or grants permission to use new materials or alternative constructions. Proposed Cases are published in *Mechanical Engineering* for public review. In addition, the Case will be published on the B31.4 web site at http://www.asme.org/codes/.

A Case is normally issued for a limited period, after which it may be renewed, incorporated in the Code, or allowed to expire if there is no indication of further need for the requirements covered by the Case. However, the provisions of a Case may be used after its expiration or withdrawal, providing the Case was effective on the original contract date or was adopted before completion of the work, and the contracting parties agree to its use.

Materials are listed in the stress tables only when sufficient usage in piping within the scope of the Code has been shown. Materials may be covered by a Case. Requests for listing shall include evidence of satisfactory usage and specific data to permit establishment of allowable stresses, maximum and minimum temperature limits, and other restrictions. Additional criteria can be found in the guidelines for addition of new materials in the ASME Boiler and Pressure Vessel Code, Section II and Section VIII, Division 1, Appendix B. (To develop usage and gain experience, unlisted materials may be used in accordance with para. 423.1.)

Requests for interpretation and suggestions for revision should be addressed to the Secretary, ASME B31 Committee, Three Park Avenue, New York, NY 10016

SUMMARY OF CHANGES

Changes given below are identified on the pages by a margin note, **02**, placed next to the affected area.

Page	*Location*	*Change*
xi	Foreword	(1) Next-to-last paragraph revised (2) New last paragraph added
2	400.2	(1) Definition for *blunt imperfection* added (2) Footnote 2 added
10	402.3.2	Subparagraph (e) added
41–46	434.8	Revised in its entirety
47	434.13.4	Subparagraph (c) revised
48	434.18	Revised in its entirety
57	451.3	Revised in its entirety
58, 59	451.6.2	(1) Subparagraph (a)(1) revised (2) Subparagraph (a)(2)(d) added (3) Subparagraphs (b)(2)(a) and (b)(3) revised
61	451.6.3	Subparagraph (b) revised
	451.9	Subparagraph (a) revised
92	Index	Welding qualification records entry revised to to reflect revision of para. 434.8.3

NOTE:

(1) The Interpretations to ASME B31.4 issued between January 1, 2001, and December 31, 2001, follow the last page of this Edition as a separate supplement, Interpretations No. 7.

CHAPTER I

SCOPE AND DEFINITIONS

400 GENERAL STATEMENTS

(a) This Liquid Transportation Systems Code is one of several sections of the ASME Code for Pressure Piping, B31. This Section is published as a separate document for convenience. This Code applies to hydrocarbons, liquid petroleum gas, anhydrous ammonia, alcohols, and carbon dioxide. Throughout this Code these systems will be referred to as Liquid Pipeline Systems.

(b) The requirements of this Code are adequate for safety under conditions normally encountered in the operation of liquid pipeline systems. Requirements for all abnormal or unusual conditions are not specifically provided for, nor are all details of engineering and construction prescribed. All work performed within the Scope of this Code shall comply with the safety standards expressed or implied.

(c) The primary purpose of this Code is to establish requirements for safe design, construction, inspection, testing, operation, and maintenance of liquid pipeline systems for protection of the general public and operating company personnel as well as for reasonable protection of the piping system against vandalism and accidental damage by others and reasonable protection of the environment.

(d) This Code is concerned with employee safety to the extent that it is affected by basic design, quality of materials and workmanship, and requirements for construction, inspection, testing, operation, and maintenance of liquid pipeline systems. Existing industrial safety regulations pertaining to work areas, safe work practices, and safety devices are not intended to be supplanted by this Code.

(e) The designer is cautioned that the Code is not a design handbook. The Code does not do away with the need for the engineer or competent engineering judgment. The specific design requirements of the Code usually revolve around a simplified engineering approach to a subject. It is intended that a designer capable of applying more complete and rigorous analysis to special or unusual problems shall have latitude in the development of such designs and the evaluation of complex or combined stresses. In such cases the designer is responsible for demonstrating the validity of his approach.

(f) This Code shall not be retroactive or construed as applying to piping systems installed before date of issuance shown on document title page insofar as design, materials, construction, assembly, inspection, and testing are concerned. It is intended, however, that the provisions of this Code shall be applicable within 6 months after date of issuance to the relocation, replacement, and uprating or otherwise changing existing piping systems; and to the operation, maintenance, and corrosion control of new or existing piping systems. After Code revisions are approved by ASME and ANSI, they may be used by agreement between contracting parties beginning with the date of issuance. Revisions become mandatory or minimum requirements for new installations 6 months after date of issuance except for piping installations or components contracted for or under construction prior to the end of the 6 month period.

(g) The users of this Code are advised that in some areas legislation may establish governmental jurisdiction over the subject matter covered by this Code and are cautioned against making use of revisions that are less restrictive than former requirements without having assurance that they have been accepted by the proper authorities in the jurisdiction where the piping is to be installed. The Department of Transportation, United States of America, rules governing the transportation by pipeline in interstate and foreign commerce of petroleum, petroleum products, and liquids such as anhydrous ammonia or carbon dioxide are prescribed under Part 195 — Transportation of Hazardous Liquids by Pipeline, Title 49 — Transportation, Code of Federal Regulations.

400.1 Scope

400.1.1 This Code prescribes requirements for the design, materials, construction, assembly, inspection, and testing of piping transporting liquids such as crude

oil, condensate, natural gasoline, natural gas liquids, liquefied petroleum gas, carbon dioxide, liquid alcohol, liquid anhydrous ammonia, and liquid petroleum products between producers' lease facilities, tank farms, natural gas processing plants, refineries, stations, ammonia plants, terminals (marine, rail, and truck), and other delivery and receiving points. (See Fig. 400.1.1.)

Piping consists of pipe, flanges, bolting, gaskets, valves, relief devices, fittings, and the pressure containing parts of other piping components. It also includes hangers and supports, and other equipment items necessary to prevent overstressing the pressure containing parts. It does not include support structures such as frames of buildings, stanchions, or foundations, or any equipment such as defined in para. 400.1.2(b).

Requirements for offshore pipelines are found in Chapter IX.

Also included within the scope of this Code are:

(a) primary and associated auxiliary liquid petroleum and liquid anhydrous ammonia piping at pipeline terminals (marine, rail, and truck), tank farms, pump stations, pressure reducing stations, and metering stations, including scraper traps, strainers, and prover loops;

(b) storage and working tanks, including pipe-type storage fabricated from pipe and fittings, and piping interconnecting these facilities;

(c) liquid petroleum and liquid anhydrous ammonia piping located on property which has been set aside for such piping within petroleum refinery, natural gasoline, gas processing, ammonia, and bulk plants;

(d) those aspects of operation and maintenance of Liquid Pipeline Systems relating to the safety and protection of the general public, operating company personnel, environment, property, and the piping systems [see paras. 400(c) and (d)].

400.1.2 This Code does not apply to:

(a) auxiliary piping, such as water, air, steam, lubricating oil, gas, and fuel;

(b) pressure vessels, heat exchangers, pumps, meters, and other such equipment including internal piping and connections for piping except as limited by para. 423.2.4(b);

(c) piping designed for internal pressures:

(1) at or below 15 psi (1 bar) gage pressure regardless of temperature;

(2) above 15 psi (1 bar) gage pressure if design temperature is below minus 20°F (−30°C) or above 250°F (120°C);

(d) casing, tubing, or pipe used in oil wells, wellhead assemblies, oil and gas separators, crude oil production tanks, and other producing facilities;

(e) petroleum refinery, natural gasoline, gas processing, ammonia, carbon dioxide processing, and bulk plant piping, except as covered under para. 400.1.1(c);

(f) gas transmission and distribution piping;

(g) the design and fabrication of proprietary items of equipment, apparatus, or instruments, except as limited by para. 423.2.4(b);

(h) ammonia refrigeration piping systems provided for in ASME B31.5, Refrigeration Piping Code;

(i) carbon dioxide gathering and field distribution system.

400.2 Definitions 02

Some of the more common terms relating to piping are defined below.[1]

accidental loads: any unplanned load or combination of unplanned loads caused by human intervention or natural phenomena.

blunt imperfection: an imperfection characterized by smoothly contoured variations in wall thickness.[2]

breakaway coupling: a component installed in the pipeline to allow the pipeline to separate when a predetermined axial load is applied to the coupling.

buckle: a condition where the pipeline has undergone sufficient plastic deformation to cause permanent wrinkling in the pipe wall or excessive cross-sectional deformation caused by loads acting alone or in combination with hydrostatic pressure.

carbon dioxide: a fluid consisting predominantly of carbon dioxide compressed above its critical pressure and, for the purpose of this Code, shall be considered to be a liquid.

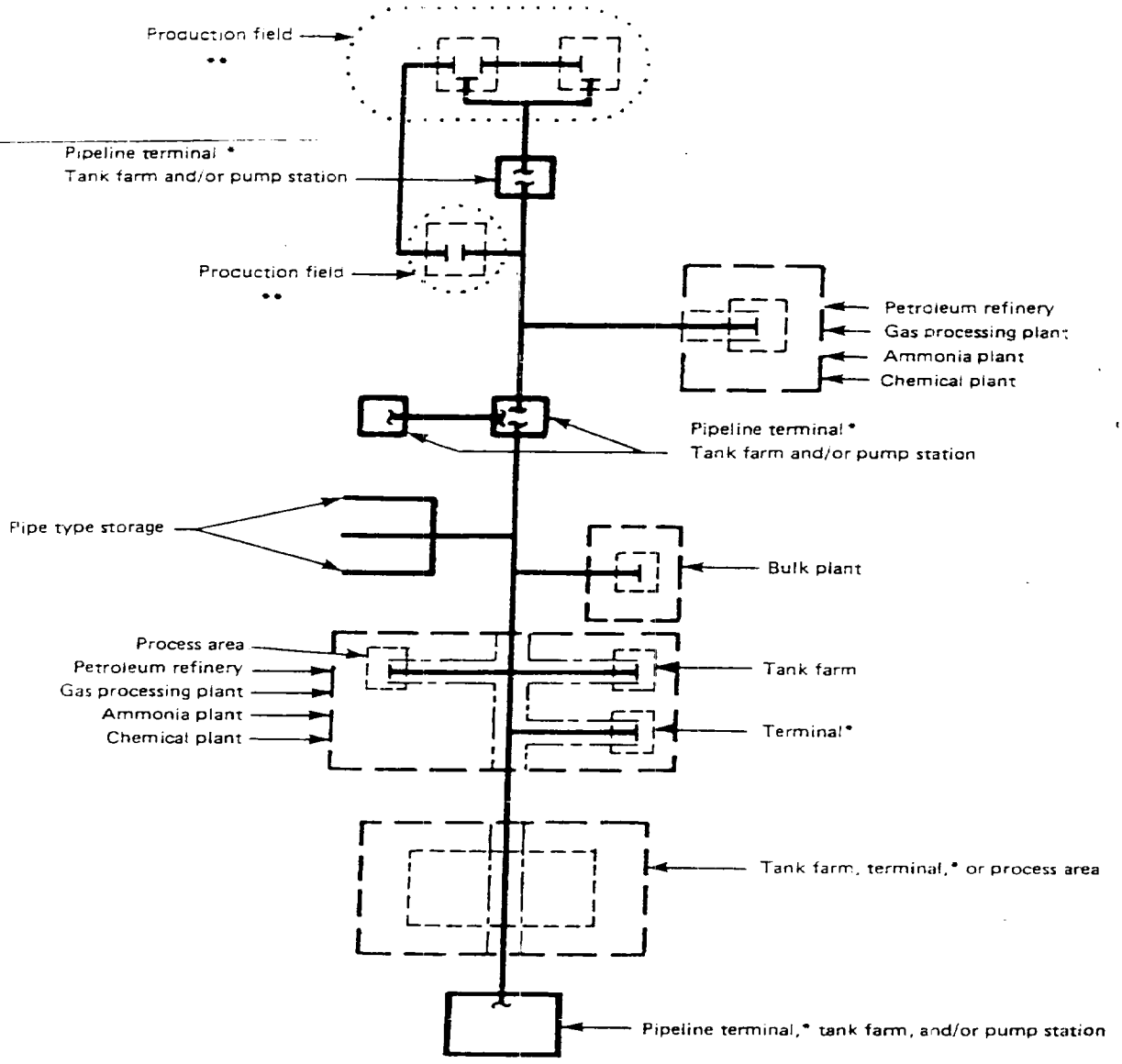
cold springing: deliberate deflection of piping, within its yield strength, to compensate for anticipated thermal expansion.

column buckling: buckling of a beam or pipe under compressive axial load in which loads cause unstable lateral deflection, also referred to as upheaval buckling.

connectors: component, except flanges, used for the purpose of mechanically joining two sections of pipe.

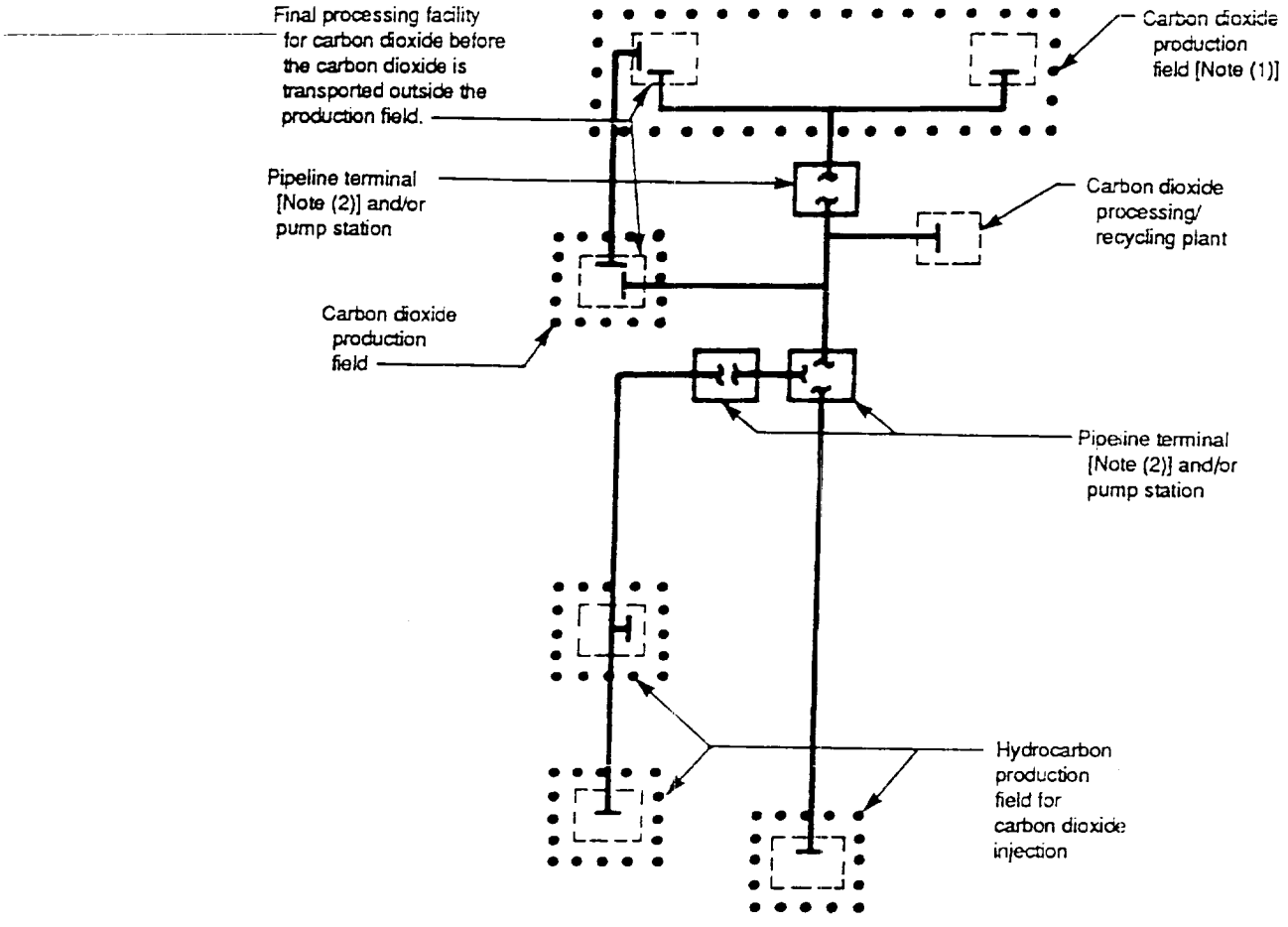
[1] Welding terms which agree with AWS Standard A3.0 are marked with an asterisk (*). For welding terms used in this Code but not shown here, definitions in accordance with AWS A3.0 apply.

[2] Sharp imperfections may be rendered blunt by grinding, but the absence of a sharp imperfection must be verified by visual and nondestructive examination.



*	Marine, rail, or truck (all loading or unloading)
**	Onshore or offshore
———	Piping within B31.4 scope
———	Continuation of B31.4 scope through area
———	Start or end at B31.4 scope within plot area
· · · · · · · ·	Limits of production lease or field
— — — — —	Plot (or platform) limits of production, petroleum refinery, chemical plant, ammonia plant, bulk plant, or gas processing operating facilities
— — —	Corridor within property of petroleum refinery, chemical plant, ammonia plant, or gas processing plant set aside for B31.4 piping
— —	Property line of petroleum refinery, chemical plant, ammonia plant, gas processing plant, or bulk plant

FIG. 400.1.1 DIAGRAM SHOWING SCOPE OF ASME B31.4 EXCLUDING CARBON DIOXIDE PIPELINE SYSTEMS (SEE FIG. 400.1.2)



Piping within B31.4 Scope
Continuation of B31.4 Scope through area
Start or end at B31.4 Scope within plot area
Limits of production lease or field
Plot (or platform) limits of production, petroleum refinery, chemical plant, carbon dioxide processing plant, or gas processing operating facilities

NOTES:

(1) Onshore or offshore.

(2) Marine, rail, or truck (all loading or unloading).

FIG. 400.1.2 DIAGRAM SHOWING SCOPE OF ASME B31.4 FOR CARBON DIOXIDE PIPELINE SYSTEMS

defect: an imperfection of sufficient magnitude to warrant rejection.

design life: a period of time used in design calculations, selected for the purpose of verifying that a replaceable or permanent component is suitable for the anticipated period of service. Design life does not pertain to the life of the pipeline system because a properly maintained and protected pipeline system can provide liquid transportation service indefinitely.

engineering design: detailed design developed from operating requirements and conforming to Code requirements, including all necessary drawings and specifications, governing a piping installation.

general corrosion: uniform or gradually varying loss of wall thickness over an area.

girth weld: a complete circumferential butt weld joining pipe or components.

imperfection: a discontinuity or irregularity which is detected by inspection.

internal design pressure: internal pressure used in calculations or analysis for pressure design of a piping component (see para. 401.2.2).

liquefied petroleum gas(es) (LPG): liquid petroleum composed predominantly of the following hydrocarbons, either by themselves or as mixtures: butane (normal butane or isobutane), butylene (including isomers), propane, propylene, and ethane.

liquid alcohol: any of a group of organic compounds containing only hydrogen, carbon, and one or more hydroxyl radicals which will remain liquid in a moving stream in a pipeline.

liquid anhydrous ammonia: a compound formed by the combination of the two gaseous elements, nitrogen and hydrogen, in the proportion of one part of nitrogen to three parts of hydrogen, by volume, compressed to a liquid state.

maximum steady state operating pressure: maximum pressure (sum of static head pressure, pressure required to overcome friction losses, and any back pressure) at any point in a piping system when the system is operating under steady state conditions.

miter: two or more straight sections of pipe matched and joined on a line bisecting the angle of junction so as to produce a change in direction.

nominal pipe size (NPS): see ASME B36.10M p. 1 for definition.

operating company: owner or agent currently responsible for the design, construction, inspection, testing, operation, and maintenance of the piping system.

petroleum: crude oil, condensate, natural gasoline, natural gas liquids, liquefied petroleum gas, and liquid petroleum products.

pipe: a tube, usually cylindrical, used for conveying a fluid or transmitting fluid pressure, normally designated "pipe" in the applicable specification. It also includes any similar component designated as "tubing" used for the same purpose. Types of pipe, according to the method of manufacture, are defined as follows.

(a) electric resistance welded pipe: pipe produced in individual lengths or in continuous lengths from coiled skelp, having a longitudinal or spiral butt joint wherein coalescence is produced by the heat obtained from resistance of the pipe to the flow of electric current in a circuit of which the pipe is a part, and by the application of pressure.

(b) furnace lap welded pipe: pipe having a longitudinal lap joint made by the forge welding process wherein coalescence is produced by heating the preformed tube to welding temperature and passing it over a mandrel located between two welding rolls which compress and weld the overlapping edges.

(c) furnace butt welded pipe

(1) furnace butt welded pipe, bell welded: pipe produced in individual lengths from cut-length skelp, having its longitudinal butt joint forge welded by the mechanical pressure developed in drawing the furnace heated skelp through a cone-shaped die (commonly known as the "welding bell") which serves as a combined forming and welding die.

(2) furnace butt welded pipe, continuous welded: pipe produced in continuous lengths from coiled skelp and subsequently cut into individual lengths, having its longitudinal butt joint forge welded by the mechanical pressure developed in rolling the hot formed skelp through a set of round pass welding rolls.

(d) electric fusion welded pipe: pipe having a longitudinal or spiral butt joint wherein coalescence is produced in the preformed tube by manual or automatic electric arc welding. The weld may be single or double and may be made with or without the use of filler metal. Spiral welded pipe is also made by the electric fusion welded process with either a lap joint or a lock-seam joint.

(e) electric flash welded pipe: pipe having a longitudinal butt joint wherein coalescence is produced simultaneously over the entire area of abutting surfaces by

the heat obtained from resistance to the flow of electric current between the two surfaces, and by the application of pressure after heating is substantially completed. Flashing and upsetting are accompanied by expulsion of metal from the joint.

(f) double submerged arc welded pipe: pipe having a longitudinal or spiral butt joint produced by at least two passes, one of which is on the inside of the pipe. Coalescence is produced by heating with an electric arc or arcs between the bare metal electrode or electrodes and the work. The welding is shielded by a blanket of granular, fusible material on the work. Pressure is not used and filler metal for the inside and outside welds is obtained from the electrode or electrodes.

(g) seamless pipe: pipe produced by piercing a billet followed by rolling or drawing, or both.

(h) electric induction welded pipe: pipe produced in individual lengths or in continuous lengths from coiled skelp having a longitudinal or spiral butt joint wherein coalescence is produced by the heat obtained from resistance of the pipe to induced electric current, and by application of pressure.

pipe nominal wall thickness: the wall thickness listed in applicable pipe specifications or dimensional standards included in this Code by reference. The listed wall thickness dimension is subject to tolerances as given in the specification or standard.

pipe supporting elements: pipe supporting elements consist of fixtures and structural attachments as follows.

(a) fixtures: fixtures include elements which transfer the load from the pipe or structural attachment to the supporting structure or equipment. They include hanging type fixtures such as hanger rods, spring hangers, sway braces, counterweights, turnbuckles, struts, chains, guides and anchors, and bearing type fixtures such as saddles, bases, rollers, brackets, and sliding supports.

(b) structural attachments: structural attachments include elements which are welded, bolted, or clamped to the pipe, such as clips, lugs, rings, clamps, clevises, straps, and skirts.

pressure: unless otherwise stated, pressure is expressed in pounds per square inch (bar) above atmospheric pressure, i.e., gage pressure as abbreviated psig (bar).

shall: "shall" or "shall not" is used to indicate that a provision is mandatory.

should: "should" or "it is recommended" is used to indicate that a provision is not mandatory but recommended as good practice.

soil liquefaction: a soil condition, typically caused by dynamic cyclic loading (e.g., earthquake, waves) where the effective shear strength of the soil is reduced such that the soil exhibits the properties of a liquid.

span: a section of pipe that is unsupported

temperatures: are expressed in degrees Fahrenheit (°F) unless otherwise stated.

weight coating: any coating applied to the pipeline for the purpose of increasing the pipeline specific gravity.

arc welding:* a group of welding processes wherein coalescence is produced by heating with an electric arc or arcs, with or without the application of pressure and with or without the use of filler metal.

automatic welding:* welding with equipment which performs the entire welding operation without constant observation and adjustment of the controls by an operator. The equipment may or may not perform the loading and unloading of the work.

fillet weld:* a weld of approximately triangular cross section joining two surfaces approximately at right angles to each other in a lap joint, tee joint, or corner joint.

full fillet weld:* a fillet weld whose size is equal to the thickness of the thinner member joined.

gas welding:* a group of welding processes wherein coalescence is produced by heating with a gas flame or flames, with or without the application of pressure, and with or without the use of filler metal.

gas metal arc welding:* an arc welding process wherein coalescence is produced by heating with an electric arc between a filler metal (consumable) electrode and the work. Shielding is obtained from a gas, a gas mixture (which may contain an inert gas), or a mixture of a gas and a flux. (This process has sometimes been called Mig welding or CO_2 welding.)

gas tungsten arc welding:* an arc welding process wherein coalescence is produced by heating with an electric arc between a single tungsten (nonconsumable) electrode and the work. Shielding is obtained from a gas or gas mixture (which may contain an inert gas). Pressure may or may not be used and filler metal may or may not be used. (This process has sometimes been called Tig welding.)

semiautomatic arc welding:* arc welding with equipment which controls only the filler metal feed. The advance of the welding is manually controlled.

shielded metal arc welding:* an arc welding process wherein coalescence is produced by heating with an electric arc between a covered metal electrode and the work. Shielding is obtained from decomposition of the electrode covering. Pressure is not used and filler metal is obtained from the electrode.

submerged arc welding:* an arc welding process wherein coalescence is produced by heating with an electric arc or arcs between a bare metal electrode or electrodes and the work. The welding is shielded by a blanket of granular, fusible material on the work. Pressure is not used, and filler metal is obtained from the electrode and sometimes from a supplementary welding rod.

tack weld:* a weld made to hold parts of a weldment in proper alignment until subsequent welds are made

weld:* a localized coalescence of metal wherein coalescence is produced by heating to suitable temperatures, with or without the application of pressure, and with or without the use of filler metal. The filler metal shall have a melting point approximately the same as the base metal.

welder:* one who is capable of performing a manual or semiautomatic welding operation.

welding operator:* one who operates machine or automatic welding equipment.

welding procedures:* the detailed methods and practices including joint welding procedures involved in the production of a weldment.

CHAPTER II
DESIGN

PART 1
CONDITIONS AND CRITERIA

401 DESIGN CONDITIONS

401.1 General

Paragraph 401 defines the pressures, temperatures, and various forces applicable to the design of piping systems within the scope of this Code. It also takes into account considerations that shall be given to ambient and mechanical influences and various loadings.

401.2 Pressure

401.2.2 Internal Design Pressure. The piping component at any point in the piping system shall be designed for an internal design pressure which shall not be less than the maximum steady state operating pressure at that point, or less than the static head pressure at that point with the line in a static condition. The maximum steady state operating pressure shall be the sum of the static head pressure, pressure required to overcome friction losses, and any required back pressure. Credit may be given for hydrostatic external pressure, in the appropriate manner, in modifying the internal design pressure for use in calculations involving the pressure design of piping components (see para. 404.1.3). Pressure rise above maximum steady state operating pressure due to surges and other variations from normal operations is allowed in accordance with para. 402.2.4.

401.2.3 External Design Pressure. The piping component shall be designed to withstand the maximum possible differential between external and internal pressures to which the component will be exposed.

401.3 Temperature

401.3.1 Design Temperature. The design temperature is the metal temperature expected in normal operation. It is not necessary to vary the design stress for metal temperatures between −20°F (−30°C) and 250°F (120°C). However, some of the materials conforming to specifications approved for use under this Code may not have properties suitable for the lower portion of the temperature band covered by this Code. Engineers are cautioned to give attention to the low temperature properties of the materials used for facilities to be exposed to unusually low ground temperatures, low atmospheric temperatures, or transient operating conditions.

401.4 Ambient Influences

401.4.2 Fluid Expansion Effects. Provision shall be made in the design either to withstand or to relieve increased pressure caused by the heating of static fluid in a piping component.

401.5 Dynamic Effects

401.5.1 Impact. Impact forces caused by either external or internal conditions shall be considered in the design of piping systems.

401.5.2 Wind. The effect of wind loading shall be provided for in the design of suspended piping.

401.5.3 Earthquake. Consideration in the design shall be given to piping systems located in regions where earthquakes are known to occur.

401.5.4 Vibration. Stress resulting from vibration or resonance shall be considered and provided for in accordance with sound engineering practice.

401.5.5 Subsidence. Consideration in the design shall be given to piping systems located in regions where subsidence is known to occur.

401.5.6 Waves and Currents. The effects of waves and currents shall be provided for in the design of pipelines across waterways.

401.6 Weight Effects

The following weight effects combined with loads and forces from other causes shall be taken into account in the design of piping that is exposed, suspended, or not supported continuously.

401.6.1 Live Loads. Live loads include the weight of the liquid transported and any other extraneous materials such as ice or snow that adhere to the pipe. The impact of wind, waves, and currents are also considered live loads.

401.6.2 Dead Loads. Dead loads include the weight of the pipe, components, coating, backfill, and unsupported attachments to the piping.

401.7 Thermal Expansion and Contraction Loads

Provisions shall be made for the effects of thermal expansion and contraction in all piping systems.

401.8 Relative Movement of Connected Components

The effect of relative movement of connected components shall be taken into account in design of piping and pipe supporting elements.

402 DESIGN CRITERIA

402.1 General

Paragraph 402 pertains to ratings, stress criteria, design allowances, and minimum design values, and formulates the permissible variations to these factors used in the design of piping systems within the scope of this Code.

The design requirements of this Code are adequate for public safety under conditions usually encountered in piping systems within the scope of this Code, including lines within villages, towns, cities, and industrial areas. However, the design engineer shall provide reasonable protection to prevent damage to the pipeline from unusual external conditions which may be encountered in river crossings, inland coastal water areas, bridges, areas of heavy traffic, long self-supported spans, unstable ground, vibration, weight of special attachments, or forces resulting from abnormal thermal conditions. Some of the protective measures which the design engineer may provide are encasing with steel pipe of larger diameter, adding concrete protective coating, increasing the wall thickness, lowering the line to a greater depth, or indicating the presence of the line with additional markers.

402.2 Pressure-Temperature Ratings for Piping Components

402.2.1 Components Having Specific Ratings. Within the metal temperature limits of −20°F (−30°C) to 250°F (120°C), pressure ratings for components shall conform to those stated for 100°F (40°C) in material standards listed in Table 423.1. The nonmetallic trim, packing, seals, and gaskets shall be made of materials which are not injuriously affected by the fluid in the piping system and shall be capable of withstanding the pressures and temperatures to which they will be subjected in service. Low temperatures due to pressure reduction situations, such as blow downs and other events, shall be considered when designing carbon dioxide pipelines.

402.2.2 Ratings — Components Not Having Specific Ratings. Piping components not having established pressure ratings may be qualified for use as specified in paras. 404.7 and 423.1(b).

402.2.3 Normal Operating Conditions. For normal operation the maximum steady state operating pressure shall not exceed the internal design pressure and pressure ratings for the components used.

402.2.4 Ratings — Allowance for Variations From Normal Operations. Surge pressures in a liquid pipeline are produced by a change in the velocity of the moving stream that results from shutting down of a pump station or pumping unit, closing of a valve, or blockage of the moving stream.

Surge pressure attenuates (decreases in intensity) as it moves away from its point of origin.

Surge calculations shall be made, and adequate controls and protective equipment shall be provided, so that the level of pressure rise due to surges and other variations from normal operations shall not exceed the internal design pressure at any point in the piping system and equipment by more than 10%.

402.2.5 Ratings — Considerations for Different Pressure Conditions. When two lines that operate at different pressure conditions are connected, the valve segregating the two lines shall be rated for the more severe service condition. When a line is connected to a piece of equipment which operates at a higher pressure condition than that of the line, the valve segregating the line from the equipment shall be rated for at least the operating condition of the equipment. The piping between the more severe conditions and the valve shall be designed to withstand the operating conditions of the equipment or piping to which it is connected.

402.3 Allowable Stresses and Other Stress Limits

402.3.1 Allowable Stress Values

(a) The allowable stress value S to be used for

design calculations in para. 404.1.2 for new pipe of known specification shall be established as follows:

$$S = 0.72 \times E \times \text{specified minimum yield strength of the pipe, psi (MPa)}$$

where

0.72 = design factor based on nominal wall thickness. In setting design factor, due consideration has been given to and allowance has been made for the underthickness tolerance and maximum allowable depth of imperfections provided for in the specifications approved by the Code.

E = weld joint factor (see para. 402.4.3 and Table 402.4.3)

Table 402.3.1(a) is a tabulation of examples of allowable stresses for reference use in transportation piping systems within the scope of this Code.

(b) The allowable stress value S to be used for design calculations in para. 404.1.2 for used (reclaimed) pipe of known specification shall be in accordance with (a) above and limitations in para. 405.2.1(b).

(c) The allowable stress value S to be used for design calculations in para. 404.1.2 for new or used (reclaimed) pipe of unknown or ASTM A 120 specification shall be established in accordance with the following and limitations in para. 405.2.1(c).

$$S = 0.72 \times E \times \text{minimum yield strength of the pipe, psi (MPa) [24,000 psi (165 MPa)] or yield strength determined in accordance with paras. 437.6.6 and 437.6.7]}$$

where

0.72 = design factor based on nominal wall thickness. In setting design factor, due consideration has been given to and allowance has been made for the underthickness tolerance and maximum allowable depth of imperfections provided for in the specifications approved by the Code.

E = weld joint factor (see Table 402.4.3)

(d) The allowable stress value S to be used for design calculations in para. 404.1.2 for pipe which has been cold worked in order to meet the specified minimum yield strength and is subsequently heated to 600°F (300°C) or higher (welding expected) shall be 75% of the applicable allowable stress value as determined by para. 402.3.1(a), (b), or (c).

(e) Allowable stress values in shear shall not exceed 45% of the specified minimum yield strength of the pipe, and allowable stress values in bearing shall not exceed 90% of the specified minimum yield strength of the pipe.

(f) Allowable tensile and compressive stress values for materials used in structural supports and restraints shall not exceed 66% of the specified minimum yield strength. Allowable stress values in shear and bearing shall not exceed 45% and 90% of the specified minimum yield strength, respectively. Steel materials of unknown specifications may be used for structural supports and restraints, provided a yield strength of 24,000 psi (165 MPa) or less is used.

(g) In no case where the Code refers to the specified minimum value of a physical property shall a higher value of the property be used in establishing the allowable stress value.

402.3.2 Limits of Calculated Stresses Due to Sustained Loads and Thermal Expansion 02

(a) Internal Pressure Stresses. The calculated stresses due to internal pressure shall not exceed the applicable allowable stress value S determined by para. 402.3.1 (a), (b), (c), or (d) except as permitted by other subparagraphs of para. 402.3.

(b) External Pressure Stresses. Stresses due to external pressure shall be considered safe when the wall thickness of the piping components meets the requirements of paras. 403 and 404.

(c) Allowable Expansion Stresses. The allowable stress values for the equivalent tensile stress in para. 419.6.4(b) for restrained lines shall not exceed 90% of the specified minimum yield strength of the pipe. The allowable stress range S_A in para. 419.6.4(c) for unrestrained lines shall not exceed 72% of the specified minimum yield strength of the pipe.

(d) Additive Longitudinal Stresses. The sum of the longitudinal stresses due to pressure, weight, and other sustained external loadings [see para. 419.6.4(c)] shall not exceed 75% of the allowable stress value specified for S_A in (c) above.

(e) Effective Stresses. The sum of the circumferential, longitudinal, and radial stresses from internal design pressure and external loads in pipe installed under railroads or highways, as combined in API RP 1102 shall not exceed 0.90 SMYS (specific minimum yield strength). Loads shall include earth load, cyclic rail load, and thermal stresses.

402.3.3 Limits of Calculated Stresses Due to Occasional Loads

(a) Operation. The sum of the longitudinal stresses produced by pressure, live and dead loads, and those

TABLE 402.3.1(a)
TABULATION OF EXAMPLES OF ALLOWABLE STRESSES FOR REFERENCE USE IN PIPING SYSTEMS WITHIN THE SCOPE OF THIS CODE

Specification	Grade	Specified Min. Yield Strength, psi (MPa)	Weld Joint Factor E	Allowable Stress Value S, −20°F to 250°F (−30°C to 120°C), psi (MPa)
Seamless				
API 5L	A25	25,000 (172)	1.00	18,000 (124)
API 5L, ASTM A 53, ASTM A 106	A	30,000 (207)	1.00	21,600 (149)
API 5L, ASTM A 53, ASTM A 106	B	35,000 (241)	1.00	25,200 (174)
API 5L	X42	42,000 (289)	1.00	30,250 (208)
API 5L	X46	46,000 (317)	1.00	33,100 (228)
API 5L	X52	52,000 (358)	1.00	37,450 (258)
API 5L	X56	56,000 (386)	1.00	40,300 (278)
API 5L	X60	60,000 (413)	1.00	43,200 (298)
API 5L	X65	65,000 (448)	1.00	46,800 (323)
API 5L	X70	70,000 (482)	1.00	50,400 (347)
API 5L	X80	80,000 (551)	1.00	57,600 (397)
ASTM A 106	C	40,000 (278)	1.00	28,800 (199)
ASTM A 333	6	35,000 (241)	1.00	25,000 (174)
ASTM A 524	I	35,000 (241)	1.00	25,200 (174)
ASTM A 524	II	30,000 (207)	1.00	21,600 (149)
Furnace Butt Welded, Continuous Welded				
ASTM A 53	...	25,000 (172)	0.60	10,800 (74)
API 5L Classes I and II	A25	25,000 (172)	0.60	10,800 (74)
Electric Resistance Welded and Electric Flash Welded				
API 5L	A25	25,000 (172)	1.00	18,000 (124)
API 5L, ASTM A 53, ASTM A 135	A	30,000 (207)	1.00	21,600 (149)
API 5L, ASTM A 53, ASTM A 135	B	35,000 (241)	1.00	25,200 (174)
API 5L	X42	42,000 (289)	1.00	30,250 (208)
API 5L	X46	46,000 (317)	1.00	33,100 (228)
API 5L	X52	52,000 (358)	1.00	37,450 (258)
API 5L	X56	56,000 (386)	1.00	40,300 (279)
API 5L	X60	60,000 (413)	1.00	43,200 (297)
API 5L	X65	65,000 (448)	1.00	46,800 (323)
API 5L	X70	70,000 (482)	1.00	50,400 (347)
API 5L	X80	80,000 (551)	1.00	57,600 (397)
ASTM A 333	6	35,000 (241)	1.00	25,000 (174)

(continued)

TABLE 402.3.1(a) (CONT'D)
TABULATION OF EXAMPLES OF ALLOWABLE STRESSES FOR REFERENCE USE IN PIPING SYSTEMS WITHIN THE SCOPE OF THIS CODE

Specification	Grade	Specified Min. Yield Strength, psi (MPa)	Weld Joint Factor E	Allowable Stress Value S, −20°F to 250°F (−30°C to 120°C), psi (MPa)
Electric Fusion Welded				
ASTM A 134	...	...	0.80	...
ASTM A 139	A	30,000 (207)	0.80	17,300 (119)
ASTM A 139	B	35,000 (241)	0.80	20,150 (139)
ASTM A 671	...	Note (1)	1.00 [Notes (2), (3)]	...
ASTM A 671	...	Note (1)	0.70 [Note (4)]	...
ASTM A 672	...	Note (1)	1.00 [Notes (2), (3)]	...
ASTM A 672	...	Note (1)	0.80 [Note (4)]	...
Submerged Arc Welded				
API 5L	A	30,000 (207)	1.00	21,600 (149)
API 5L	B	35,000 (241)	1.00	25,200 (174)
API 5L	X42	42,000 (289)	1.00	30,250 (208)
API 5L	X46	46,000 (317)	1.00	33,100 (228)
API 5L	X52	52,000 (358)	1.00	37,450 (258)
API 5L	X56	56,000 (386)	1.00	40,300 (278)
API 5L	X60	60,000 (413)	1.00	43,200 (298)
API 5L	X65	65,000 (448)	1.00	46,800 (323)
API 5L	X70	70,000 (482)	1.00	50,400 (347)
API 5L	X80	80,000 (551)	1.00	57,600 (397)
ASTM A 381	Y35	35,000 (241)	1.00	25,200 (174)
ASTM A 381	Y42	42,000 (290)	1.00	30,250 (209)
ASTM A 381	Y46	46,000 (317)	1.00	33,100 (228)
ASTM A 381	Y48	48,000 (331)	1.00	34,550 (238)
ASTM A 381	Y50	50,000 (345)	1.00	36,000 (248)
ASTM A 381	Y52	52,000 (358)	1.00	37,450 (258)
ASTM A 381	Y60	60,000 (413)	1.00	43,200 (298)
ASTM A 381	Y65	65,000 (448)	1.00	46,800 (323)

GENERAL NOTES:

(a) Allowable stress values S shown in this Table are equal to $0.72E$ (weld joint factor) × specified minimum yield strength of the pipe.

(b) Allowable stress values shown are for new pipe of known specification. Allowble stress values for new pipe of unknown specification, ASTM A 120 specification, or used (reclaimed) pipe shall be determined in accordance with para. 402.3.1.

(c) For some Code computations, particularly with regard to branch connections [see para. 404.3.1(d)(3)] and expansion, flexibility, structural attachments, supports, and restraints (Chapter II, Part 5), the weld joint factor E need not be considered.

(d) For specified minimum yield strength of other grades in approved specifications, refer to that particular specification.

(e) Allowable stress value for cold worked pipe subsequently heated to 600°F (300°C) or higher (welding excepted) shall be 75% of the value listed in Table.

(f) Definitions for the various types of pipe are given in para. 400.2.

(g) Metric stress levels are given in MPa (1 megapascal = 1 million pascals).

NOTES:

(1) See applicable plate specification for yield point and refer to para. 402.3.1 for calculation of S.

(2) Factor applies for Classes 12, 22, 32, 42, and 52 only.

(3) Radiography must be performed after heat treatment.

(4) Factor applies for Classes 13, 23, 33, 43, and 53 only.

produced by occasional loads, such as wind or earthquake, shall not exceed 80% of the specified minimum yield strength of the pipe. It is not necessary to consider wind and earthquake as occurring concurrently.

(b) Test. Stresses due to test conditions are not subject to the limitations of para. 402.3. It is not necessary to consider other occasional loads, such as wind and earthquake, as occurring concurrently with the live, dead, and test loads existing at the time of test.

402.4 Allowances

402.4.1 Corrosion. A wall thickness allowance for corrosion is not required if pipe and components are protected against corrosion in accordance with the requirements and procedures prescribed in Chapter VIII.

402.4.2 Threading and Grooving. An allowance for thread or groove depth in inches (mm) shall be included in A of the equation under para. 404.1.1 when threaded or grooved pipe is allowed by this Code (see para. 414).

402.4.3 Weld Joint Factors. Longitudinal or spiral weld joint factors E for various types of pipe are listed in Table 402.4.3.

402.4.5 Wall Thickness and Defect Tolerances. Wall thickness tolerances and defect tolerances for pipe shall be as specified in applicable pipe specifications or dimensional standards included in this Code by reference in Appendix A.

402.5 Fracture Propagation in Carbon Dioxide Pipelines

402.5.1 Design Considerations. The possibility of brittle and ductile propagating fractures shall be considered in the design of carbon dioxide pipelines. The design engineer shall provide reasonable protection to limit the occurrence and the length of fractures throughout the pipeline with special consideration at river crossings, road crossings, and other appropriate areas or intervals.

402.5.2 Brittle Fractures. Brittle fracture propagation shall be prevented by selection of a pipe steel which fractures in a ductile manner at operating temperatures. API 5L supplementary requirements or similar specifications shall be used for testing requirements to ensure the proper pipe steel selection.

402.5.3 Ductile Fractures. Ductile fracture propagation shall be minimized by the selection of a pipe steel with appropriate fracture toughness and/or by the installation of suitable fracture arrestors. Design consideration shall include pipe diameter, wall thickness, fracture toughness, yield strength, operating pressure, operating temperature, and the decompression characteristics of carbon dioxide and its associated impurities.

PART 2
PRESSURE DESIGN OF PIPING COMPONENTS

403 CRITERIA FOR PRESSURE DESIGN OF PIPING COMPONENTS

The design of piping components, considering the effects of pressure, shall be in accordance with para. 404. In addition, the design shall provide for dynamic and weight effects included in para. 401 and design criteria in para. 402.

404 PRESSURE DESIGN OF COMPONENTS

404.1 Straight Pipe

404.1.1 General

(a) The *nominal* wall thickness of straight sections of steel pipe shall be equal to or greater than t_n determined in accordance with the following equation.

$$t_n = t + A$$

(b) The notations described below are used in the equations for the pressure design for straight pipe.

t_n = nominal wall thickness satisfying requirements for pressure and allowances

t = pressure design wall thickness as calculated in inches (mm) in accordance with para. 404.1.2 for internal pressure. As noted under para. 402.3.1 or para. A402.3.5, as applicable, in setting design factor, due consideration has been given to and allowance has been made for the underthickness tolerance and maximum allowable depth of imperfections provided for in the specifications approved by the Code.

A = sum of allowances for threading and grooving as required under para. 402.4.2, corrosion as required under para. 402.4.1, and increase in wall thickness if used as protective measure under para. 402.1.

P_i = internal design gage pressure (see para. 401.2.2), psi (bar)

D = outside diameter of pipe, in. (mm)

TABLE 402.4.3
WELD JOINT FACTOR E

Specification No.	Pipe Type [Note (1)]	Weld Joint Factor E
ASTM A 53	Seamless	1.00
	Electric resistance welded	1.00
	Furnace butt welded	0.60
ASTM A 106	Seamless	1.00
ASTM A 134	Electric fusion (arc) welded	0.80
ASTM A 135	Electric resistance welded	1.00
ASTM A 139	Electric fusion (arc) welded	0.80
ASTM A 333	Seamless	1.00
	Electric resistance weld	1.00
ASTM A 381	Double submerged arc welded	1.00
ASTM A 671	Electric fusion welded	1.00 [Notes (2), (3)] 0.80 [Note (4)]
ASTM A 672	Electric fusion welded	1.00 [Notes (2), (3)] 0.80 [Note (4)]
API 5L	Seamless	1.00
	Electric resistance welded	1.00
	Electric induction welded	1.00
	Submerged arc welded	1.00
	Furnace butt welded, continuous welded	0.60
Known	Known	Note (5)
Unknown	Seamless	1.00 [Note (6)]
Unknown	Electric resistance welded	1.00 [Note (6)]
Unknown	Electric Fusion welded	0.80 [Note (6)]
Unknown	Over NPS 4	0.80 [Note (7)]
Unknown	NPS 4 and smaller	0.60 [Note (8)]

NOTES:
(1) Definitions for the various pipe types (weld joints) are given in para. 400.2.
(2) Factor applies for Classes 12, 22, 32, 42, and 52 only.
(3) Radiography must be performed after heat treatment.
(4) Factor applies for Classes 13, 23, 33, 43, and 53 only.
(5) Factors shown above apply for new or used (reclaimed) pipe if pipe specification and pipe type are known.
(6) Factor applies for new or used pipe of unknown specification and ASTM A 120 if type of weld joint is known.
(7) Factor applies for new or used pipe of unknown specification and ASTM A 120 or for pipe over NPS 4 if type of joint is unknown.
(8) Factor applies for new or used pipe of unknown specification and ASTM A 120 or for pipe NPS 4 and smaller if type of joint is unknown.

S = applicable allowable stress value, psi (MPa), in accordance with para. 402.3.1(a), (b), (c), or (d)

404.1.2 Straight Pipe Under Internal Pressure. The internal pressure design wall thickness t of steel pipe shall be calculated by the following equation.

$$t = \frac{P_i D}{2S} \qquad \left(t = \frac{P_i D}{20S}\right)$$

404.1.3 Straight Pipe Under External Pressure. Pipelines within the scope of this Code may be subject to conditions during construction and operation where

the external pressure exceeds the internal pressure (vacuum within the pipe or pressure outside the pipe when submerged). The pipe wall selected shall provide adequate strength to prevent collapse, taking into consideration mechanical properties, variations in wall thickness permitted by material specifications, ellipticity (out-of-roundness), bending stresses, and external loads (see para. 401.2.2).

404.2 Curved Segments of Pipe

Changes in direction may be made by bending the pipe in accordance with para. 406.2.1 or installing factory made bends or elbows, in accordance with para. 406.2.3.

404.2.1 Pipe Bends. The wall thickness of pipe before bending shall be determined as for straight pipe in accordance with para. 404.1. Bends shall meet the flattening limitations of para. 434.7.1.

404.2.2 Elbows

(a) The minimum metal thickness of flanged or threaded elbows shall not be less than specified for the pressures and temperatures in the applicable American National Standard or the MSS Standard Practice.

(b) Steel butt welding elbows shall comply with ASME B16.9, ASME B16.28, or MSS SP-75 and shall have pressure and temperature ratings based on the same stress values as were used in establishing the pressure and temperature limitations for pipe of the same or equivalent materials.

404.3 Intersections

404.3.1 Branch Connections. Branch connections may be made by means of tees, crosses, integrally reinforced extruded outlet headers, or welded connections, and shall be designed in accordance with the following requirements.

(a) Tees and Crosses

(1) The minimum metal thickness of flanged or threaded tees and crosses shall not be less than specified for the pressures and temperatures in the applicable American National Standard or the MSS Standard Practice.

(2) Steel butt welding tees and crosses shall comply with ASME B16.9 or MSS SP-75 and shall have pressure and temperature ratings based on the same stress values as were used in establishing the pressure and temperature limitations for pipe of the same or equivalent material.

(3) Steel butt welding tees and crosses may be used for all ratios of branch diameter to header diameter and all ratios of design hoop stress to specified minimum yield strength of the adjoining header and branch pipe, provided they comply with (2) above.

(b) Integrally Reinforced Extruded Outlet Headers

(1) Integrally reinforced extruded outlet headers may be used for all ratios of branch diameter to header diameter and all ratios of design hoop stress to specified minimum yield strength of the joining header and branch pipe, provided they comply with (2) through (8) immediately following.

(2) When the design meets the limitations on geometry contained herein, the rules established are valid and meet the intent of the Code. These rules cover minimum requirements and are selected to assure satisfactory performance of extruded headers subjected to pressure. In addition, however, forces and moments are usually applied to the branch by such agencies as thermal expansion and contraction, by vibration, by dead weight of piping, valves and fittings, covering and contents, and by earth settlement. Consideration shall be given to the design of extruded header to withstand these forces and moments.

(3) Definition

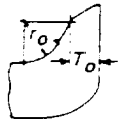
(a) An *extruded outlet header* is defined as a header in which the extruded lip at the outlet has a height above the surface of the header which is equal to or greater than the radius of curvature of the external contoured portion of the outlet, i.e., $h_o \geq r_o$. See nomenclature and Fig. 404.3.1(b)(3).

(b) These rules do not apply to any nozzle in which additional nonintegral material is applied in the form of rings, pads, or saddles.

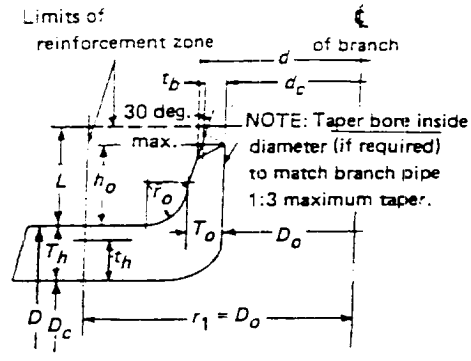
(c) These rules apply only to cases where the axis of the outlet intersects and is perpendicular to the axis of the header.

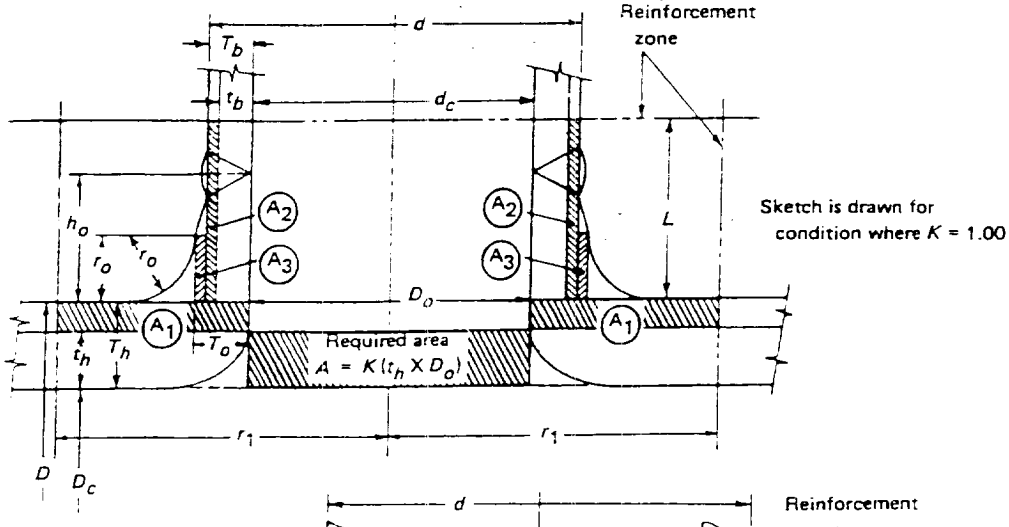
(4) Notation. The notation used herein is illustrated in Fig. 404.3.1(b)(3). All dimensions are in inches (mm).

d = outside diameter of branch pipe
d_c = internal diameter of branch pipe
D = outside diameter of header
D_c = internal diameter of header
D_o = internal diameter of extruded outlet measured at the level of the outside surface of header
h_o = height of the extruded lip. This must be equal to or greater than r_o except as shown in (4)(b) below.
L = height of the reinforcement zone
$= 0.7\sqrt{dT_o}$
t_b = required thickness of the branch pipe according to the wall thickness equation in para. 404.1.2



Sketch to show method of establishing T_o when the taper encroaches on the crotch radius





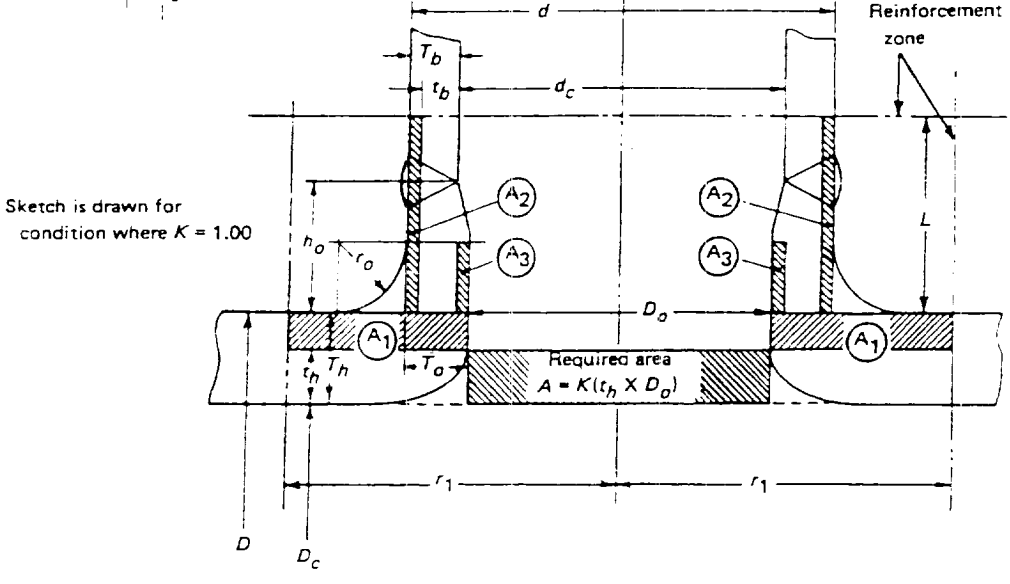


FIG. 404.3.1(b)(3) REINFORCED EXTRUDED OUTLETS

T_b = actual nominal wall thickness of branch
t_h = required thickness of the header according to the wall thickness equation in para. 404.1.2
T_h = actual nominal wall thickness of header
T_o = finished thickness of extruded outlet measured at a height equal to r_o above the outside surface of the header
r_1 = half-width of reinforcement zone (equal to D_o)
r_o = radius of curvature of external contoured portion of outlet measured in the plane containing the axes of the header and branch. This is subject to the following limitations.

(a) Minimum Radius. This dimension shall not be less than $0.05d$, except that on branch diameters larger than NPS 30 it need not exceed 1.50 in. (38 mm).

(b) Maximum Radius. For outlet pipe sizes NPS 8 and larger, this dimension shall not exceed $0.10d + 0.50$ in. (13 mm). For outlet pipe sizes less than NPS 8, this dimension shall not be greater than 1.25 in. (32 mm).

(c) When the external contour contains more than one radius, the radius of any arc sector of approximately 45 deg. shall meet the requirements of (a) and (b) above.

(d) Machining shall not be employed in order to meet the above requirements.

(5) Required Area. The required area is defined as $A = K(t_h D_o)$, where K shall be taken as follows:

(a) for d/D greater than 0.60, $K = 1.00$;

(b) for d/D greater than 0.15 and not exceeding 0.60, $K = 0.6 + \frac{2}{3} d/D$;

(c) for d/D equal to or less than 0.15, $K = 0.70$.

The design must meet the criteria that the reinforcement area defined in (6) below is not less than the required area.

(6) Reinforcement Area. The reinforcement area shall be the sum of areas $A_1 + A_2 + A_3$ as defined below.

(a) Area A_1. The area lying within the reinforcement zone resulting from any excess thickness available in the header wall, i.e.,

$$A_1 = D_o (T_h - t_h)$$

(b) Area A_2. The area lying within the reinforcement zone resulting from any excess thickness available in the branch pipe wall, i.e.,

$$A_2 = 2L (T_b - t_b)$$

(c) Area A_3. The area lying within the reinforcement zone resulting from excess thickness available in the extruded outlet lip, i.e.,

$$A_3 = 2r_o (T_o - T_b)$$

(7) Reinforcement of Multiple Openings. The requirements outlined in para. 404.3.1(e) shall be followed, except that the required area and reinforcement shall be as given in (5) and (6) above.

(8) The manufacturer shall be responsible for establishing and marking on the section containing extruded outlets, the design pressure and temperature, "Established under provisions of ASME B31.4," and the manufacturer's name or trademark.

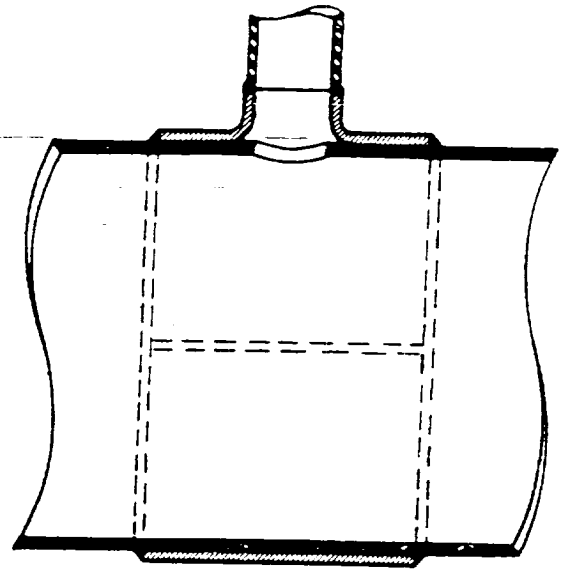
(c) Welded Branch Connections. Welded branch connections shall be as shown in Figs. 404.3.1(c)(1), 404.3.1(c)(2), and 404.3.1(c)(3). Design shall meet the minimum requirements listed in Table 404.3.1(c) and described by items (1), (2), (3), and (4). Where reinforcement is required, items (5) and (6) shall apply.

(1) Smoothly contoured wrought tees or crosses of proven design or integrally reinforced extruded headers are preferred. When such tees, crosses, or headers are not used, the reinforcing member shall extend completely around the circumference of the header [see Fig. 404.3.1(c)(1) for typical constructions]. The inside edges of the finished opening whenever possible shall be rounded to a ⅛ in. (3 mm) radius. If the encircling member is thicker than the header and its ends are to be welded to the header, the ends shall be chamfered (at approximately 45 deg.) down to a thickness not in excess of the header thickness, and continuous fillet welds shall be made. Pads, partial saddles, or other types of localized reinforcements are prohibited.

(2) The reinforcement member may be of the complete encirclement type [see Fig. 404.3.1(c)(1)], pad or saddle type [see Fig. 404.3.1(c)(2)], or welding outlet fitting type. Where attached to the header by fillet welding, the edges of the reinforcement member shall be chamfered (at approximately 45 deg.) down to a thickness not in excess of the header thickness. The diameter of the hole cut in the header pipe for a branch connection shall not exceed the outside diameter of the branch connection by more than ¼ in. (6 mm).

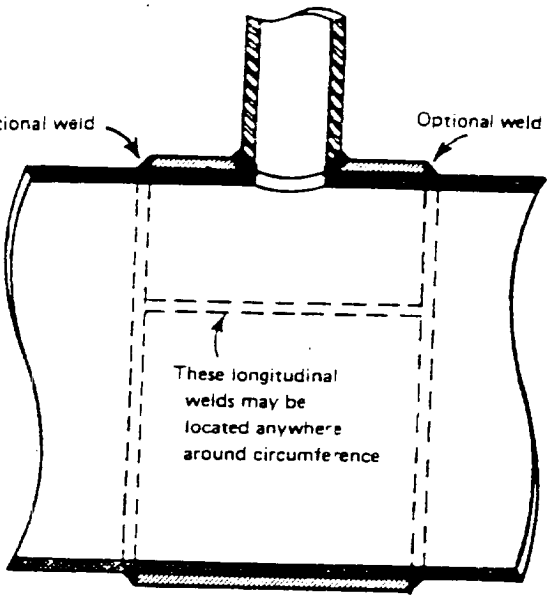
(3) Reinforcement for branch connections with hole cut NPS 2 or smaller is not required [see Fig. 404.3.1(c)(3) for typical details]; however, care shall be taken to provide suitable protection against vibrations and other external forces to which these small branch connections are frequently subjected.

(4) Reinforcement of opening is not mandatory; however, reinforcement may be required for cases in-



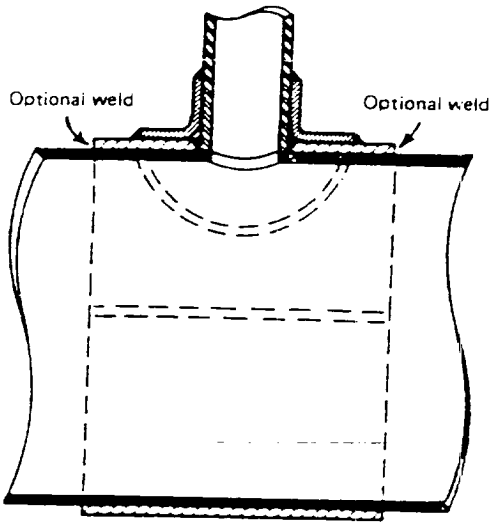
GENERAL NOTE:
Since fluid pressure is exerted on both sides of pipe metal under tee, the pipe metal does not provide reinforcement.

Tee Type

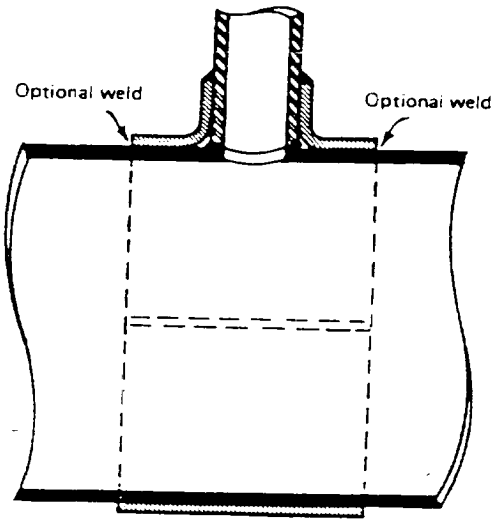


GENERAL NOTE:
Provide hole in reinforcement to reveal leakage in buried welds and to provide venting during welding and heat treatment [see para. 404.3.1(d)(8)]. Not required for tee type.

Sleeve Type



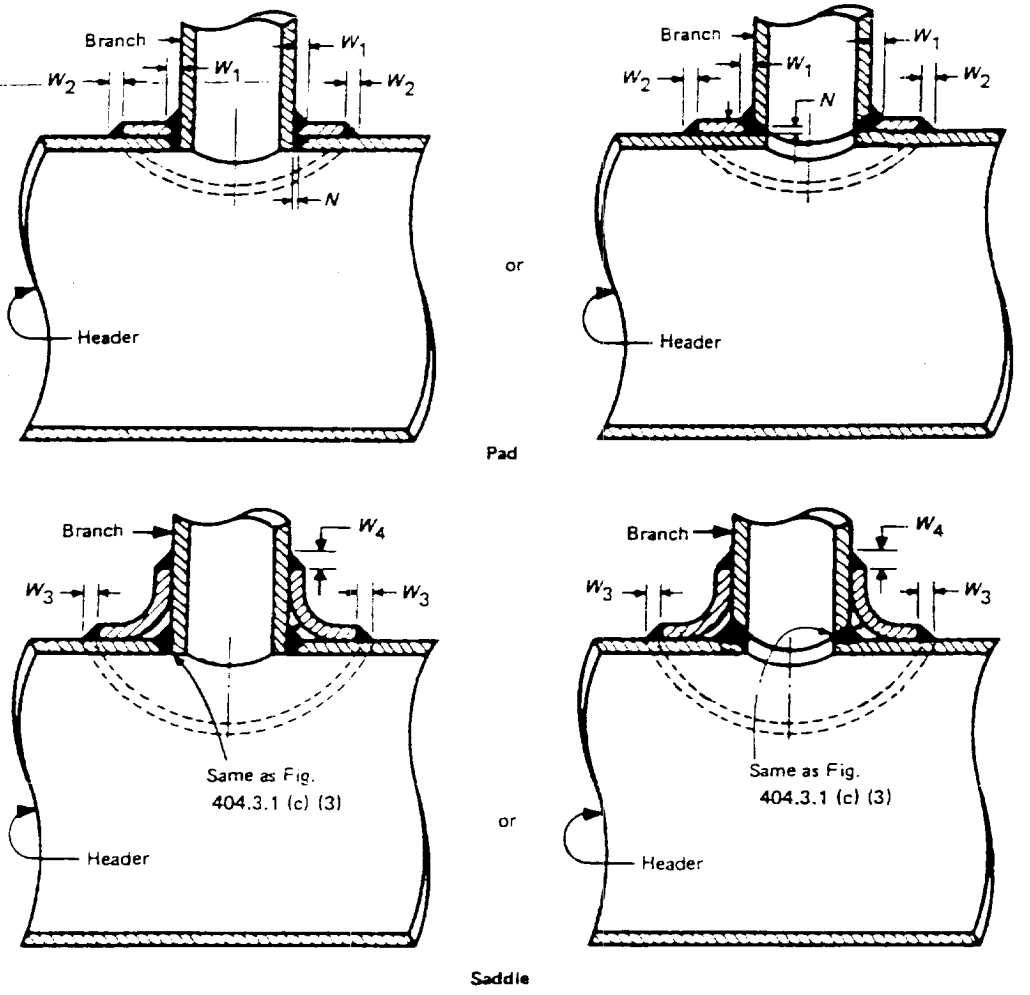
Saddle and Sleeve Type



Saddle Type

GENERAL NOTE:
If the encircling member for tee, sleeve, or saddle type is thicker than the header and its ends are to be welded to the header, the ends shall be chamfered (at approximately 45 deg.) down to a thickness not in excess of the header thickness.

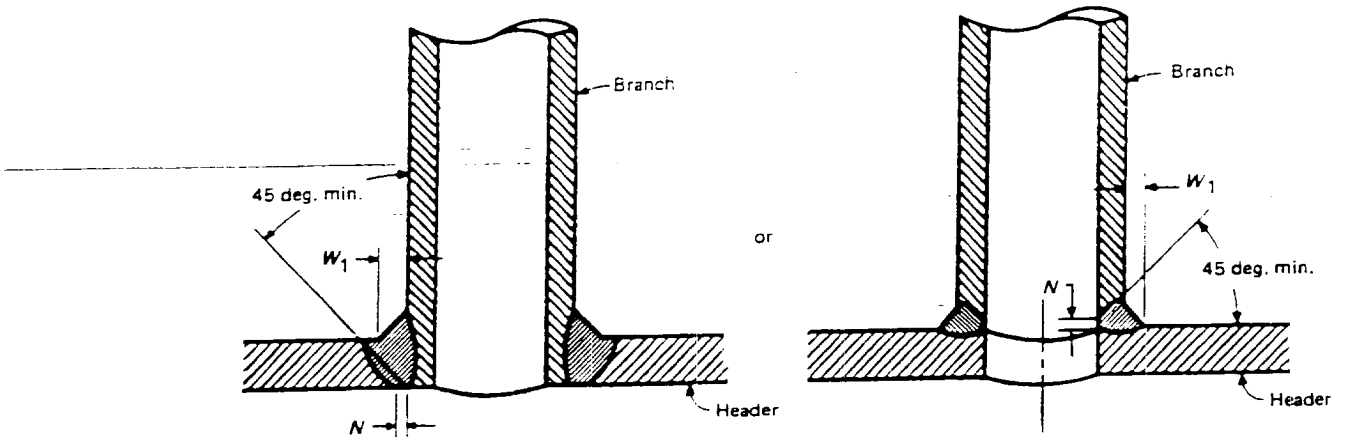
FIG. 404.3.1(c)(1) WELDING DETAILS FOR OPENINGS WITH COMPLETE ENCIRCLEMENT TYPES OF REINFORCEMENT



M = nominal wall thickness of pad reinforcement member
M_b = nominal wall thickness of saddle at branch end
M_h = nominal wall thickness of saddle at header end
N = 1/16 in. (1.5 mm) (min.), 1/8 in. (3 mm) (max.)(unless back welded or backing strip is used)
T_b = nominal wall thickness of branch
T_h = nominal wall thickness of header
W_1 (min.) = the smaller of T_b, M, or 3/8 in. (10 mm)
W_2 (max.) = approx. T_h
W_2 (min.) = the smaller of 0.7 T_h, 0.7 M, or 1/2 in. (13 mm)
W_3 (max.) = approx. T_h
W_3 (min.) = the smaller of 0.7 T_h, 0.7 M_h, or 1/2 in. (13 mm)
W_4 (min.) = the smaller of T_b, M_b, or 3/8 in. (10 mm)

GENERAL NOTES:
(a) All welds are to have equal leg dimensions and a minimum throat equal to 0.707 × leg dimension.
(b) If the reinforcing member is thicker at its edge than the header, the edge shall be chamfered (at approximately 45 deg.) down to a thickness such that leg dimensions of the fillet weld shall be within the minimum and maximum dimensions specified above.
(c) A hole shall be provided in reinforcement to reveal leakage in buried welds and to provide venting during welding and heat treatment [see para. 404.3.1(d)(8)].

FIG. 404.3.1(c)(2) WELDING DETAILS FOR OPENINGS WITH LOCALIZED TYPE REINFORCEMENT



GENERAL NOTE:
When a welding saddle is used, it shall be inserted over this type of connection. See Fig. 404.3.1 (c) (2).

T_h = nominal wall thickness of header
T_b = nominal wall thickness of branch
W_1 (min.) = the smaller of T_h, T_b or 3/8 in. (10 mm)
N = 1/16 in. (1.5 mm) (min.), 1/8 in. (3 mm) (max.) unless back welded or backing strip is used

FIG. 404.3.1(c)(3) WELDING DETAILS FOR OPENINGS WITHOUT REINFORCEMENT OTHER THAN THAT IN HEADER AND BRANCH WALLS

TABLE 404.3.1(c)
DESIGN CRITERIA FOR WELDED BRANCH CONNECTIONS

Ratio of Design Hoop Stress to Specfied Min. Yield Strength of the Header	Ratio of Diameter of Hole Cut for Branch Connection to Nominal Header Diameter		
	25% or less	More than 25% Through 50%	More Than 50%
20% or less	(4)	(4)	(4)(5)
More than 20% through 50%	(2)(3)	(2)	(1)
More than 50%	(2)(3)	(2)	(1)

volving pressure over 100 psi (7 bar), thin wall pipe, or severe external loads.

(5) If a reinforcement member is required, and the branch diameter is such that a localized type of reinforcement member would extend around more than half the circumference of the header, then a complete encirclement type of reinforcement member shall be used, regardless of the design hoop stress, or a smoothly contoured wrought steel tee or cross of proven design or extruded header may be used.

(6) The reinforcement shall be designed in accordance with para. 404.3.1(d).

(d) Reinforcement of Single Openings

(1) When welded branch connections are made to pipe in the form of a single connection, or in a header or manifold as a series of connections, the design shall be adequate to control the stress levels in the pipe within safe limits. The construction shall take cognizance of the stresses in the remaining pipe wall due to the opening in the pipe or header, the shear stresses produced by

the pressure acting on the area of the branch opening, and any external loading due to thermal movement, weight, vibration, etc., and shall meet the minimum requirements listed in Table 404.3.1(c). The following paragraphs provide design rules based on the stress intensification created by the existence of a hole in an otherwise symmetrical section. External loadings, such as those due to thermal expansion or unsupported weight of connecting pipe, have not been evaluated. These factors should be given attention in unusual designs or under conditions of cyclic loading.

When pipe which has been cold worked to meet the specified minimum yield strength is used as a header containing single or multiple welded branch connections, stresses shall be in accordance with para. 402.3.1(d).

(2) The reinforcement required in the crotch section of a welded branch connection shall be determined by the rule that the metal area available for reinforcement shall be equal to or greater than the required cross-sectional area as defined in (3) below and in Fig. 404.3.1(d)(2).

(3) The required cross-sectional area A_R is defined as the product of d times t_h:

$$A_R = dt_h$$

where

d = length of the finished opening in the header wall measured parallel to the axis of the header

t_h = design header wall thickness required by para. 404.1.2. For welded pipe, when the branch does not intersect the longitudinal or spiral weld of the header, the allowable stress value for seamless pipe of comparable grade may be used in determining t_h for the purpose of reinforcement calculations only. When the branch does intersect the longitudinal or spiral weld of the header, the allowable stress value S of the header shall be used in the calculation. The allowable stress value S of the branch shall be used in calculating t_b.

(4) The area available for the reinforcement shall be the sum of:

(a) the cross-sectional area resulting from any excess thickness available in the header thickness (over the minimum required for the header as defined in para. 404.1.2) and which lies within the reinforcement area as defined in para. 404.3.1(d)(5) below;

(b) the cross-sectional area resulting from any excess thickness available in the branch wall thickness over the minimum thickness required for the branch and which lies within the reinforcement area as defined in para. 404.3.1(d)(5) below;

(c) the cross-sectional area of all added reinforcing metal, including weld metal, which is welded to the header wall and lies within the reinforcement area as defined in para. 404.3.1(d)(5) below.

(5) The reinforcement area is shown in Fig. 404.3.1(d)(2) and is defined as a rectangle whose length shall extend a distance d [see para. 404.3.1(d)(3)] on each side of the transverse centerline of the finished opening and whose width shall extend a distance of 2½ times the header wall thickness from the outside surface of the header wall, except that in no case shall it extend more than 2½ times the thickness of the branch wall from the outside surface of the header or of the reinforcement if any.

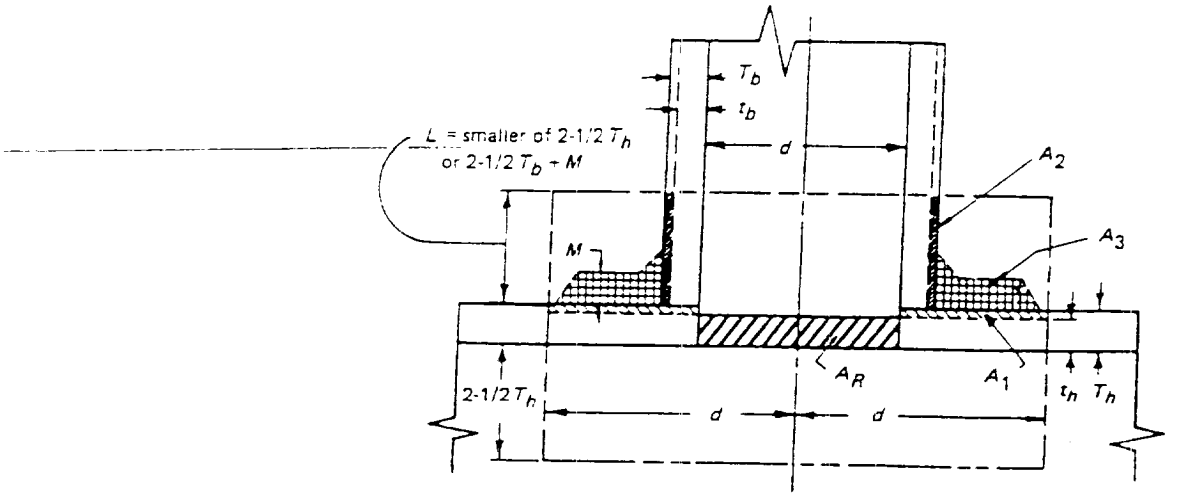
(6) The material of any added reinforcement shall have an allowable working stress at least equal to that of the header wall, except that material of lower allowable stress may be used if the area is increased in direct ratio of the allowable stresses for header and reinforcement material respectively.

(7) The material used for ring or saddle reinforcement may be of specifications differing from those of the pipe, provided the cross-sectional area is made in correct proportions to the relative strength of the pipe and reinforcement materials at the operating temperatures, and provided it has welding qualities comparable to those of the pipe. No credit shall be taken for the additional strength of material having a higher strength than that of the part to be reinforced.

(8) When rings or saddles are used which cover the weld between branch and header, a vent hole shall be provided in the ring or saddle to reveal leakage in the weld between branch and header and to provide venting during welding and heat treating operations. Vent holes shall be plugged during service to prevent crevice corrosion between pipe and reinforcing member, but no plugging material shall be used that would be capable of sustaining pressure within the crevice.

(9) The use of ribs or gussets shall not be considered as contributing to reinforcement to the branch connection. This does not prohibit the use of ribs or gussets for purposes other than reinforcement, such as stiffening.

(10) The branch shall be attached by a weld for the full thickness of the branch or header wall plus a fillet weld W_1 as shown in Figs. 404.3.1(c)(2) and 404.3.1(c)(3). The use of concave fillet welds is to be preferred to minimize corner stress concentration. Ring or saddle reinforcement shall be attached as shown by



"Area of reinforcement" enclosed by ——— - - - ——— lines
Reinforcement area required $A_R = dt_h$
Area available as reinforcement = $A_1 + A_2 + A_3$
$A_1 = (T_h - t_h)\,d$
$A_2 = 2\,(T_b - t_b)\,L$
A_3 = summation of area of all added reinforcement, including weld areas that lie within the "area of reinforcement"
$A_1 + A_2 + A_3$ must be equal to or greater than A_R
where
T_h = nominal wall thickness of header
T_b = nominal wall thickness of branch
t_b = design branch wall thickness required by para. 404.1.2
t_h = design header wall thickness required by para. 404.1.2
d = length of the finished opening in the header wall (measured parallel to the axis of the header)
M = actual (by measurement) or nominal thickness of added reinforcement

FIG. 404.3.1(d)(2) REINFORCEMENT OF BRANCH CONNECTIONS

Fig. 404.3.1(c)(2). If the reinforcing member is thicker at its edge than the header, the edge shall be chamfered (at approximately 45 deg.) down to a thickness so leg dimensions of the fillet weld shall be within the minimum and maximum dimensions specified in Fig. 404.3.1(c)(2).

(11) Reinforcement rings and saddles shall be accurately fitted to the parts to which they are attached. Figures 404.3.1(c)(1) and 404.3.1(c)(2) illustrate some acceptable forms of reinforcement.

Branch connections attached at an angle less than 90 deg. to the header become progressively weaker as the angle becomes less. Any such design shall be given individual study, and sufficient reinforcement shall be provided to compensate for the inherent weakness of such construction. The use of encircling ribs to support the flat or reentering surfaces is permissible and may be included in the strength considerations. The designer is cautioned that stress concentrations near the ends of partial ribs, straps, or gussets may defeat their reinforcing value, and their use is not recommended.

(e) Reinforcement of Multiple Openings

(1) Two adjacent branches should preferably be spaced at such a distance that their individual effective areas of reinforcement do not overlap. When two or more adjacent branches are spaced at less than two times their average diameter (so that their effective areas of reinforcement overlap), the group of openings shall be reinforced in accordance with para. 404.3.1(d). The reinforcing metal shall be added as a combined

reinforcement, the strength of which shall equal the combined strengths of the reinforcements that would be required for the separate openings. In no case shall any portion of a cross section be considered to apply to more than one opening, or be evaluated more than once in a combined area.

(2) When more than two adjacent openings are to be provided with a combined reinforcement, the minimum distance between centers of any two of these openings shall preferably be at least $1\frac{1}{2}$ times their average diameter, and the area of reinforcement between them shall be at least equal to 50% of the total required for these two openings on the cross section being considered.

(3) When two adjacent openings as considered under para. 404.3.1(e)(2) have the distance between centers less than $1\frac{1}{2}$ times their average diameter, no credit for reinforcement shall be given for any of the metal between these two openings.

(4) When pipe which has been cold worked to meet the specified minimum yield strength is used as a header containing single or multiple welded branch connections, stresses shall be in accordance with para. 402.3.1(d).

(5) Any number of closely spaced adjacent openings, in any arrangement, may be reinforced as if the group were treated as one assumed opening of a diameter enclosing all such openings.

404.3.4 Attachments. External and internal attachments to piping shall be designed so they will not cause flattening of the pipe, excessive localized bending stresses, or harmful thermal gradients in the pipe wall. See para. 421.1 for design of pipe supporting elements.

404.5 Pressure Design of Flanges

404.5.1 General

(a) The design of flanges manufactured in accordance with para. 408.1 and the standards listed in Table 426.1 shall be considered suitable for use at the pressure-temperature ratings as set forth in para. 402.2.1.

(b) It is permissible to inside taper bore the hubs on welding neck flanges having dimensions complying with ASME B16.5 when they are to be attached to thin wall pipe. It is recommended that the taper shall not be more abrupt than a ratio of 1:3. MSS SP-44, NPS 26, and larger "pipeline" flanges are designed for attachment to thin wall pipe and are preferred for this service.

(c) Where conditions require the use of flanges other than those covered in para. 408.1, the flanges shall be designed in accordance with Appendix II of Section VIII, Division 1, of the ASME Boiler and Pressure Vessel Code.

(d) Slip-on flanges of rectangular cross section shall be designed so that flange thickness is increased to provide strength equal to that of the corresponding hubbed slip-on flange covered by ASME B16.5, as determined by calculations made in accordance with the ASME Boiler and Pressure Vessel Code, Section VIII, Division 1.

404.6 Reducers

(a) Reducer fittings manufactured in accordance with ASME B16.5, ASME B16.9, or MSS SP-75 shall have pressure-temperature ratings based on the same stress values as were used in establishing the pressure-temperature limitations for pipe of the same or equivalent material.

(b) Smoothly contoured reducers fabricated to the same nominal wall thickness and of the same type of steel as the adjoining pipe shall be considered suitable for use at the pressure-temperature ratings of the adjoining pipe. Seam welds of fabricated reducers shall be inspected by radiography or other accepted nondestructive methods (visual inspection excepted).

(c) Where appropriate, changes in diameter may be accomplished by elbows, reducing outlet tees, or valves.

404.7 Pressure Design of Other Pressure Containing Components

Pressure containing components which are not covered by the standards listed in Tables 423.1 or 426.1 and for which design equations or procedures are not given herein may be used where the design of similarly shaped, proportioned, and sized components has been proven satisfactory by successful performance under comparable service conditions. (Interpolation may be made between similarly shaped proved components with small differences in size or proportion.) In the absence of such service experience, the pressure design shall be based on an analysis consistent with the general design philosophy embodied in this Code, and substantiated by at least one of the following:

(a) proof tests (as are described in UG-101 of Section VIII, Division 1, of the ASME Boiler and Pressure Vessel Code);

(b) experimental stress analysis (such as described in Appendix 6 of Section VIII, Division 2, of the ASME Boiler and Pressure Vessel Code);

(c) engineering calculations.

PART 3
DESIGN APPLICATIONS OF PIPING COMPONENTS SELECTION AND LIMITATIONS

405 PIPE

405.2 Metallic Pipe

405.2.1 Ferrous Pipe

(a) New pipe of the specifications listed in Table 423.1 may be used in accordance with the design equation of para. 404.1.2 subject to the testing requirements of paras. 437.1.4, 437.4.1, and 437.4.3.

(b) Used pipe of known specification listed in Table 423.1 may be used in accordance with the design equation of para. 404.1.2 subject to the testing requirements of paras. 437.4.1, 437.6.1, 437.6.3, and 437.6.4.

(c) New or used pipe of unknown or ASTM A 120 specification may be used in accordance with the design equation in para. 404.1.2 with an allowable stress value as specified in para. 402.3.1(c) and subject to the testing requirements of paras. 437.4.1, 437.4.3, 437.6.1, 437.6.3, 437.6.4, and 437.6.5, if 24,000 psi (165 MPa) yield strength is used to establish an allowable stress value; or para. 437.4.1, and paras. 437.6.1 through 437.6.7 inclusive, if a yield strength above 24,000 psi (165 MPa) is used to establish an allowable stress value.

(d) Pipe which has been cold worked in order to meet the specified minimum yield strength and is subsequently heated to 600°F (300°C) or higher (welding excepted) shall be limited to a stress value as noted in para. 402.3.1(d).

(e) Coated or Lined Pipe. External or internal coatings or linings of cement, plastics, or other materials may be used on steel pipe conforming to the requirements of this Code. These coatings or linings shall not be considered to add strength.

406 FITTINGS, ELBOWS, BENDS, AND INTERSECTIONS

406.1 Fittings

406.1.1 General

(a) Steel Butt Welding Fittings. When steel butt welding fittings [see paras. 404.2.2(b), 404.3.1(a)(2), and 404.3.1(a)(3)] are used, they shall comply with ASME B16.9, ASME B16.28, or MSS SP-75.

(b) Steel Flanged Fittings. When steel flanged fittings [see paras. 404.3.1(a)(1) and 404.5.1] are used, they shall comply with ASME B16.5.

(c) Fittings Exceeding Scope of Standard Sizes. Fittings exceeding scope of standard sizes or otherwise departing from dimensions listed in the standards referred to in para. 406.1.1(a) or 406.1.1(b) may be used, provided the designs meet the requirements of paras. 403 and 404.

406.2 Bends, Miters, and Elbows

406.2.1 Bends Made From Pipe

(a) Bends may be made by bending the pipe when they are designed in accordance with para. 404.2.1 and made in accordance with para. 434.7.1.

(b) Except as permitted under para. 406.2.1(c), the minimum radius of field cold bends shall be as follows:

Nominal Pipe Size	Minimum Radius of Bend in Pipe Diameters
NPS 12 and smaller	18D
14	21
16	24
18	27
NPS 20 and larger	30

In some cases, thin wall pipe will require the use of an internal mandrel when being bent to the minimum radii tabulated above.

(c) Bends may be made by bending the pipe in sizes NPS 14 and larger to a minimum radius of 18D; however, bending pipe to radii approaching 18D that will meet requirements in para. 434.7.1(b) will be dependent upon wall thickness, ductility, ratio of pipe diameter to wall thickness, use of bending mandrel, and skill of bending crew. Test bends shall be made to determine that the field bending procedure used produces bends meeting the requirements of para. 434.7.1(b) and that the wall thickness after bending is not less than the minimum permitted by the pipe specification.

406.2.2 Mitered Bends. In systems intended to operate at a hoop stress of more than 20% of the specified minimum yield strength of the pipe, miter bends are prohibited. Miter bends not exceeding 12½ deg. may be used in systems operated at a hoop stress of 20% or less of the specified minimum yield strength of the pipe, and the minimum distance between miters measured at the crotch shall not be less than one pipe diameter. When the system is to be operated at a hoop stress of less than 10% of the specified minimum yield strength of the pipe, the restriction to 12½ deg. maximum miter and distance between miters will not apply. Deflections caused by misalignment up to 3 deg. are not considered miter bends.

406.2.3 Factory Made Bends and Elbows

(a) Factory made bends and factory made wrought steel elbows may be used provided they meet the design requirements of paras. 404.2.1 and 404.2.2 and the construction requirements of para. 434.7.3. Such fittings shall have approximately the same mechanical properties and chemical composition as the pipe to which they are welded.

(b) If factory made elbows are used in cross-country lines, care should be taken to allow for passage of pipe-line scrapers.

406.2.4 Wrinkle Bends. Wrinkle bends shall not be used.

406.3 Couplings

Cast, malleable, or wrought iron threaded couplings are prohibited.

406.4 Reductions

406.4.1 Reducers. Reductions in line size may be made by the use of smoothly contoured reducers selected in accordance with ASME B16.5, ASME B16.9, or MSS SP-75, or designed as provided in para. 404.6.

406.4.2 Orange Peel Swages. Orange peel swages are prohibited in systems operating at hoop stresses of more than 20% of the specified minimum yield strength of the pipe.

406.5 Intersections

Intersection fittings and welded branch connections are permitted within the limitations listed in para. 406.1 (see para. 404.3 for design).

406.6 Closures

406.6.1 Quick Opening Closures. A quick opening closure is a pressure containing component (see para. 404.7) used for repeated access to the interior of a piping system. It is not the intent of this Code to impose the requirements of a specific design method on the designer or manufacturer of a quick opening closure.

Quick opening closures used for pressure containment under this Code shall have pressure and temperature ratings equal to or in excess of the design requirements of the piping system to which they are attached. See paras. 401.2.2 and 402.2.

Quick opening closures shall be equipped with safety locking devices in compliance with Section VIII, Division 1, UG-35(b) of the ASME Boiler and Pressure Vessel Code.

Weld end preparation shall be in accordance with para. 434.8.6.

406.6.2 Closure Fittings. Closure fittings commonly referred to as "weld caps" shall be designed and manufactured in accordance with ASME B16.9 or MSS SP-75.

406.6.3 Closure Heads. Closure heads such as flat, ellipsoidal (other than in para. 406.6.2 above), spherical, or conical heads are allowed for use under this Code. Such items shall be designed in accordance with Section VIII, Division 1, of the ASME Boiler and Pressure Vessel Code. The maximum allowable stresses for materials used in these closure heads shall be established under the provisions of para. 402.3.

If welds are used in the construction of these heads, they shall be 100% radiographically inspected in accordance with the provisions of Section VIII, Division 1.

Closure heads shall have pressure and temperature ratings equal to or in excess of the requirement of para. 401.2.2. It is not the intent of this Code to necessarily extend the design requirements of Section VIII, Division 1, to other components in which closure heads are part of a complete assembly.

406.6.4 Fabricated Closures. Orange peel bull plugs are prohibited on systems operating at a hoop stress more than 20% of the specified minimum yield strength of the pipe. Fishtails and flat closures are permitted for NPS 3 pipe and smaller, operating at less than 100 psi (7 bar). Fishtails on pipe larger than NPS 3 are prohibited.

406.6.5 Bolted Blind Flange Closures. Bolted blind flange closures shall conform to para. 408.

407 VALVES

407.1 General

(a) Steel valves conforming to standards and specifications listed in Tables 423.1 and 426.1 may be used. These valves may contain certain cast, malleable, or wrought iron parts as provided for in API 6D.

(b) Cast iron valves conforming to standards and specifications listed in Tables 423.1 and 426.1 may be used for pressures not to exceed 250 psi (17 bar). Care shall be exercised to prevent excessive mechanical loadings (see para. 408.5.4).

(c) Working pressure ratings of the steel parts of steel valves are applicable within the temperature limita-

tions of −20°F (−30°C) to 250°F (120°C) (see para. 401.3.1). Where resilient, rubberlike, or plastic materials are used for sealing, they shall be capable of withstanding the fluid, pressures, and temperatures specified for the piping system.

407.8 Special Valves

Special valves not listed in Tables 423.1 and 426.1 shall be permitted, provided that their design is of at least equal strength and tightness and they are capable of withstanding the same test requirements as covered in these standards, and structural features satisfy the material specification and test procedures of valves in similar service set forth in the listed standards.

408 FLANGES, FACINGS, GASKETS, AND BOLTING

408.1 Flanges

408.1.1 General

(a) Flanged connections shall conform to the requirements of paras. 408.1, 408.3, 408.4, and 408.5.

(b) Steel Flanges Within Scope of Standard Sizes. Welding neck, slip-on, threaded, and lapped companion flanges, reducing flanges, blind flanges, and flanges cast or forged integral with pipe, fittings, or valves, conforming to ASME B16.5 or MSS SP-44, are permitted in the sizes listed in these standards and for the pressure-temperature ratings shown in para. 402.2.1. The bore of welding neck flanges should correspond to the inside diameter of the pipe with which they are to be used. See para. 404.5.1 for design.

(c) Cast Iron Flanges Within Scope of Standard Sizes. Cast iron flanges are prohibited, except those which are an integral part of cast iron valves, pressure vessels, and other equipment and proprietary items [see para. 407.1(b) and 423.2.4(b)].

(d) Flanges Exceeding Scope of Standard Sizes. Flanges exceeding scope of standard sizes or otherwise departing from dimensions listed in ASME B16.5 or MSS SP-44 may be used provided they are designed in accordance with para. 404.5.1.

(e) Flanges of Rectangular Cross Section. Slip-on flanges of rectangular cross section may be used provided they are designed in accordance with para. 404.5.1(d).

408.3 Flange Facings

408.3.1 General

(a) Standard Facings. Steel or cast iron flanges shall have contact faces in accordance with ASME B16.5 or MSS SP-6.

(b) Special Facings. Special facings are permissible provided they are capable of withstanding the same tests as those in ASME B16.5. See para. 408.5.4 for bolting steel to cast iron flanges.

408.4 Gaskets

408.4.1 General. Gaskets shall be made of materials which are not injuriously affected by the fluid in the piping system, and shall be capable of withstanding the pressures and temperatures to which they will be subjected in service.

408.4.2 Standard Gaskets

(a) Gaskets conforming to ASME B16.20 or to ASME B16.21 may be used.

(b) Metallic gaskets other than ring type or spirally wound metal asbestos shall not be used with ANSI Class 150 or lighter flanges.

(c) The use of metal or metal jacketed asbestos (either plain or corrugated) is not limited [except as provided in para. 408.4.2(b)] as to pressure, provided that the gasket material is suitable for the service temperature. These types of gaskets are recommended for use with the small male and female or the small tongue and groove facings. They may also be used with steel flanges with any of the following facings: lapped, large male and female, large tongue and groove, or raised face.

(d) Asbestos composition gaskets may be used as permitted in ASME B16.5. This type of gasket may be used with any of the various flange facings except small male and female, or small tongue and groove.

(e) Rings for ring joints shall be of dimensions established in ASME B16.20. The materials for these rings shall be suitable for the service conditions encountered and shall be softer than the flanges.

408.4.3 Special Gaskets. Special gaskets, including insulating gaskets, may be used provided they are suitable for the temperatures, pressures, fluids, and other conditions to which they may be subjected.

408.5 Bolting

408.5.1 General

(a) Bolts or stud bolts shall extend completely through the nuts.

(b) Nuts shall conform with ASTM A 194 or A 325, except that A 307 Grade B nuts may be used on ASME Class 150 and ASME Class 300 flanges.

408.5.2 Bolting for Steel Flanges. Bolting shall conform to ASME B16.5.

408.5.3 Bolting for Insulating Flanges. For insulating flanges, 1/8 in. (3 mm) undersize bolting may be used provided that alloy steel bolting material in accordance with ASTM A 193 or A 354 is used.

408.5.4 Bolting Steel to Cast Iron Flanges. When bolting Class 150 steel flanges to Class 125 cast iron flanges, heat treated carbon steel or alloy steel bolting (ASTM A 193) may be used only when both flanges are flat face and the gasket is full face; otherwise, the bolting shall have a maximum tensile strength no greater than the maximum tensile strength of ASTM A 307 Grade B. When bolting Class 300 steel flanges to Class 250 cast iron flanges, the bolting shall have a maximum tensile strength no greater than the maximum tensile strength of ASTM A 307 Grade B. Good practice indicates that the flange should be flat faced.

408.5.5 Bolting for Special Flanges. For flanges designed in accordance with para. 404.5.1 [see paras. 408.1.1(d) and 408.1.1(e)], bolting shall conform to the applicable section of Section VIII, Division 1, of the ASME Boiler and Pressure Vessel Code.

409 USED PIPING COMPONENTS AND EQUIPMENT

Used piping components, such as fittings, elbows, bends, intersections, couplings, reducers, closures, flanges, valves, and equipment, may be reused. [Reuse of pipe is covered by para. 405.2.1(b).] However, such components and equipment shall be cleaned and examined; reconditioned, if necessary, to insure that they meet all requirements for the intended service; and sound and free of defects.

In addition, reuse shall be contingent on identification of the specification under which the item was originally produced. Where the specification cannot be identified, use shall be restricted to a maximum allowable operating pressure based on a yield strength of 24,000 psi (165 MPa) or less.

PART 4
SELECTION AND LIMITATION OF PIPING JOINTS

411 WELDED JOINTS

411.2 Butt Welds

Butt welded joints shall be in accordance with Chapter V.

412 FLANGED JOINTS

412.1 General

Flanged joints shall meet the requirements of para. 408.

414 THREADED JOINTS

414.1 General

All external pipe threads on piping components shall be taper pipe threads. They shall be line pipe threads in accordance with API 5B, or NPT threads in accordance with ASME B1.20.1. All internal pipe threads on piping components shall be taper pipe threads, except for sizes NPS 2 and smaller with design gage pressures not exceeding 150 psi (10 bar), in which case straight threads may be used.

Least nominal wall thickness for threaded pipe shall be standard wall (see ASME B36.10M).

418 SLEEVE, COUPLED, AND OTHER PATENTED JOINTS

418.1 General

Steel connectors and swivels complying with API 6D may be used. Sleeve, coupled, and other patented joints, except as limited in para. 423.2.4(b), may be used provided:

(a) a prototype joint has been subject to proof tests to determine the safety of the joints under simulated service conditions. When vibration, fatigue, cyclic conditions, low temperature, thermal expansion, or other severe conditions are anticipated, the applicable conditions shall be incorporated in the tests.

(b) adequate provision is made to prevent separation of the joint and to prevent longitudinal or lateral movement beyond the limits provided for in the joining member.

PART 5
EXPANSION, FLEXIBILITY, STRUCTURAL ATTACHMENTS, SUPPORTS, AND RESTRAINTS

419 EXPANSION AND FLEXIBILITY

419.1 General

(a) This Code is applicable to both aboveground and buried piping and covers all classes of materials permitted by this Code. Formal calculations shall be required where reasonable doubt exists as to the adequate flexibility of the piping.

(b) Piping shall be designed to have sufficient flexibility to prevent expansion or contraction from causing excessive stresses in the piping material, excessive bending moments at joints, or excessive forces or moments at points of connection to equipment or at anchorage or guide points. Allowable forces and moments on equipment may be less than for the connected piping.

(c) Expansion calculations are necessary for buried lines if significant temperature changes are expected, such as when the line is to carry a heated oil. Thermal expansion of buried lines may cause movement at points where the line terminates, changes in direction, or changes in size. Unless such movements are restrained by suitable anchors, the necessary flexibility shall be provided.

(d) Expansion of aboveground lines may be prevented by anchoring them so that longitudinal expansion, or contraction, due to thermal and pressure changes is absorbed by direct axial compression or tension of the pipe in the same way as for buried piping. In addition, however, beam bending stresses shall be included and the possible elastic instability of the pipe, and its supports, due to longitudinal compressive forces shall be considered.

419.5 Flexibility

419.5.1 Means of Providing Flexibility. If expansion is not absorbed by direct axial compression of the pipe, flexibility shall be provided by the use of bends, loops, or offsets; or provision shall be made to absorb thermal strains by expansion joints or couplings of the slip joint, ball joint, or bellows type. If expansion joints are used, anchors or ties of sufficient strength and rigidity shall be installed to provide for end forces due to fluid pressure and other causes.

419.6 Properties

419.6.1 Coefficient of Thermal Expansion. The linear coefficient of thermal expansion for carbon and low alloy high tensile steel may be taken as 6.5×10^{-6} in./in./°F for temperatures up to 250°F (11.7×10^{-6} mm/mm/°C for temperatures up to 120°C).

419.6.2 Moduli of Elasticity. Flexibility calculations shall be based on the modulus of elasticity at ambient temperature.

419.6.3 Poisson's Ratio. Poisson's ratio shall be taken as 0.3 for steel.

419.6.4 Stress Values

(a) General. There are fundamental differences in loading conditions for the buried, or similarly restrained, portions of the piping and the aboveground portions not subject to substantial axial restraint. Therefore, different limits on allowable longitudinal expansion stresses are necessary.

(b) Restrained Lines. The net longitudinal compressive stress due to the combined effects of temperature rise and fluid pressure shall be computed from the equation:

$$S_L = E\alpha(T_2 - T_1) - \nu S_h$$

where

S_L = longitudinal compressive stress, psi (MPa)
S_h = hoop stress due to fluid pressure, psi (MPa)
T_1 = temperature at time of installation, °F (°C)
T_2 = maximum or minimum operating temperature, °F (°C)
E = modulus of elasticity of steel, psi (MPa)
α = linear coefficient of thermal expansion, in./in./°F (mm/mm/°C)
ν = Poisson's ratio = 0.30 for steel

Note that the net longitudinal stress becomes compressive for moderate increases of T_2 and that according to the commonly used maximum shear theory of failure, this compressive stress adds directly to the hoop stress to increase the equivalent tensile stress available to cause yielding. As specified in para. 402.3.2(c), this equivalent tensile stress shall not be allowed to exceed 90% of the specified minimum yield strength of the pipe, calculated for nominal pipe wall thickness. Beam bending stresses shall be included in the longitudinal stress for those portions of the restrained line which are supported above ground.

(c) Unrestrained Lines. Stresses due to expansion for those portions of the piping without substantial

axial restraint shall be combined in accordance with the following equation:

$$S_E = \sqrt{S_b^2 + 4S_t^2}$$

where

S_E = stress due to expansion

$$S_b = \frac{\sqrt{(i_i M_i)^2 + (i_o M_o)^2}}{Z}$$

= equivalent bending stress, psi (MPa)

S_t = $M_t/2Z$ = torsional stress, psi (MPa)

M_i = bending moment in plane of member (for members having significant orientation, such as elbows or tees; for the latter the moments in the header and branch portions are to be considered separately), in.-lb (N·m)

M_o = bending moment out of, or transverse to, plane of member, in.-lb (N·m)

M_t = torsional moment, in.-lb (N·m)

i_i = stress intensification factor under bending in plane of member [from Fig. 419.6.4(c)]

i_o = stress intensification factor under bending out of, or transverse to, plane of member [from Fig. 419.6.4(c)]

Z = section modulus of pipe, in.^{3} (cm^3)

The maximum computed expansion stress range — S_E without regard for fluid pressure stress, based on 100% of the expansion, with modulus of elasticity for the cold condition — shall not exceed the allowable stress range S_A, where S_A = 0.72 of specified minimum yield strength of the pipe as noted in para. 402.3.2(c).

The sum of the longitudinal stresses due to pressure, weight, and other sustained external loadings shall not exceed $0.75S_A$ in accordance with para. 402.3.2(d).

The sum of the longitudinal stresses produced by pressure, live and dead loads, and those produced by occasional loads, such as wind or earthquake, shall not exceed 80% of the specified minimum yield strength of the pipe, in accordance with para. 402.3.3(a). It is not necessary to consider wind and earthquake as occurring concurrently.

As noted in para. 402.3.3(b), stresses due to test conditions are not subject to the limitations of para. 402.3. It is not necessary to consider other occasional loads, such as wind and earthquake, as occurring concurrently with the live, dead, and test loads existing at the time of test.

419.7 Analysis

419.7.3 Basic Assumptions and Requirements

(a) The effect of restraints, such as support friction, branch connections, lateral interferences, etc., shall be considered in the stress calculations.

(b) Calculations shall take into account stress intensification factors found to exist in components other than plain straight pipe. Credit may be taken for extra flexibility of such components. In the absence of more directly applicable data, the flexibility factors and stress intensification factors shown in Fig. 419.6.4(c) may be used.

(c) Nominal dimensions of pipe and fittings shall be used in flexibility calculations.

(d) Calculations of pipe stresses in loops, bends, and offsets shall be based on the total range from minimum to maximum temperature normally expected, regardless of whether piping is cold sprung or not. In addition to expansion of the line itself, the linear and angular movements of the equipment to which it is attached shall be considered.

(e) Calculations of thermal forces and moments on anchors and equipment such as pumps, meters, and heat exchangers shall be based on the difference between installation temperature and minimum or maximum anticipated operating temperature, whichever is greater.

420 LOADS ON PIPE SUPPORTING ELEMENTS

420.1 General

The forces and moments transmitted to connected equipment, such as valves, strainers, tanks, pressure vessels, and pumping machinery, shall be kept within safe limits.

421 DESIGN OF PIPE SUPPORTING ELEMENTS

421.1 Supports, Braces, and Anchors

(a) Supports shall be designed to support the pipe without causing excessive local stresses in the pipe and without imposing excessive axial or lateral friction forces that might prevent the desired freedom of movement.

(b) Braces and damping devices may occasionally be required to prevent vibration of piping.

(c) All attachments to the pipe shall be designed to minimize the added stresses in the pipe wall because

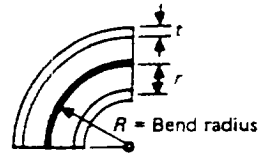
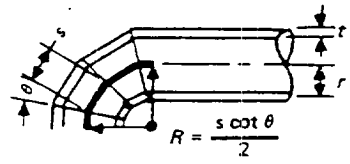
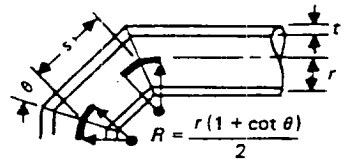
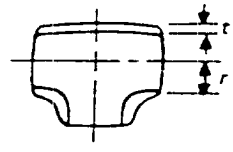
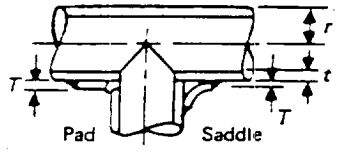
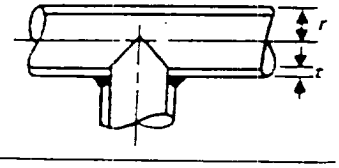
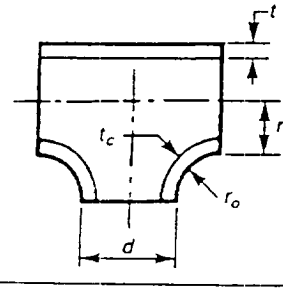
Description	Flexibility Factor k	Stress Intensification Factor i_i (1)	Stress Intensification Factor i_o (2)	Flexibility Characteristic h	Sketch
Welding elbow,[3, 4, 5, 6, 7] or pipe bend	$\frac{1.65}{h}$	$\frac{0.9}{h^{2/3}}$	$\frac{0.75}{h^{2/3}}$	$\frac{tR}{r^2}$	
Closely spaced miter bend,[3, 4, 5, 7] $s < r(1 + \tan\theta)$	$\frac{1.52}{h^{5/6}}$	$\frac{0.9}{h^{2/3}}$	$\frac{0.75}{h^{2/3}}$	$\frac{\cot\theta}{2}\frac{ts}{r^2}$	
Widely spaced miter bend,[3, 4, 7, 8] $s \geq r(1 + \tan\theta)$	$\frac{1.52}{h^{5/6}}$	$\frac{0.9}{h^{2/3}}$	$\frac{0.75}{h^{2/3}}$	$\frac{1 + \cot\theta}{2}\frac{t}{r}$	
Welding tee[3, 4] per ASME B16.9	1	$0.75i_o + 0.25$	$\frac{0.9}{h^{2/3}}$	$4.4\frac{t}{r}$	
Reinforced tee[3, 4, 9] with pad or saddle	1	$0.75i_o + 0.25$	$\frac{0.9}{h^{2/3}}$	$\frac{(t + 1/2\ T)^{5/2}}{t^{3/2}\ r}$	
Unreinforced fabricated tee[3, 4]	1	$0.75i_o + 0.25$	$\frac{0.9}{h^{2/3}}$	$\frac{t}{r}$	
Extruded welding tee[3, 4, 11] $r_o \geq 0.05d$ $t_c < 1.5t$	1	$0.75i_o + 0.25$	$\frac{0.9}{h^{2/3}}$	$\left(1 + \frac{r_o}{r}\right)\frac{t}{r}$	

FIG. 419.6.4(c) FLEXIBILITY FACTOR k AND STRESS INTENSIFICATION FACTOR i

Description	Flexibility Factor k	Stress Intensification Factor i_i (1)	Stress Intensification Factor i_o (2)	Flexibility Characteristic h	Sketch
Butt welded joint, reducer, or welding neck flange	1	1.0		...	...
Double welded slip-on flange	1	1.2		...	...
Fillet welded joint (single welded), or single welded slip-on flange	1	1.3		...	...
Lapped flange (with ANSI B16.9 lap-joint stub)	1	1.6		...	...
Threaded pipe joint, or threaded flange	1	2.3		...	...
Corrugated straight pipe, or corrugated or creased bend[10]	5	2.5		...	...

NOTES:

(1) In-plane.

(2) Out-of-plane.

(3) For fittings and miter bends, the flexibility factors k and stress intensification factors i in the Table apply to bending in any plane and shall not be less than unity; factors for torsion equal unity. Both factors apply over the effective arc length (shown by heavy center lines in the sketches) for curved and miter elbows, and to the intersection point for tees.

(4) The values of k and i can be read directly from Chart A by entering with the characteristic h computed from the equations given, where

R = bend radius of welding elbow or pipe bend, in. (mm)

T = pad or saddle thickness, in. (mm)

d = outside diameter of branch

r = mean radius of matching pipe, in. (mm)

r_o = see Note (11)

s = miter spacing at center line

t = nominal wall thickness of: part itself, for elbows and curved or mited bends; matching pipe, for welding tees; run or header, for fabricated tees (provided that if thickness is greater than that of matching pipe, increased thickness must be maintained for at least one run O.D. to each side of the branch O.D.).

t_c = the crotch thickness of tees

θ = one-half angle between adjacent miter axes, deg.

(5) Where flanges are attached to one or both ends, the values of k and i in the Table shall be corrected by the factors C_1 given below, which can be read directly from Chart B, entering with the computed h: one end flanged, $h^{1/6} \geq 1$; both ends flanged, $h^{1/3} \geq 1$.

(6) The engineer is cautioned that cast butt welding elbows may have considerably heavier walls than that of the pipe with which they are used. Large errors may be introduced unless the effect of these greater thicknesses is considered.

(7) In large diameter thin wall elbows and bends, pressure can significantly affect the magnitude of flexibility and stress intensification factors. To correct values obained from Table for the pressure effect, divide:

Flexibility factor k by $$1 + 6\frac{P}{E_c}\left(\frac{r}{t}\right)^{7/3}\left(\frac{R}{r}\right)^{1/3}$$

Stress intensification factor i by $$1 + 3.25\frac{P}{E_c}\left(\frac{r}{t}\right)^{5/2}\left(\frac{R}{r}\right)^{2/3}$$

where

E_c = cold modulus of elasticity

P = gage pressure

(8) Also includes single miter joint.

(9) When $T > 1\frac{1}{2}t$, use $h = 4.05\ t/r$.

(10) Factors shown apply to bending; flexibility factor for torsion equals 0.9.

FIG. 419.6.4(c) FLEXIBILITY FACTOR k AND STRESS INTENSIFICATION FACTOR i (CONT'D)

(11) Radius of curvature of external contoured portion of outlet measured in the plane containing the axes of the run and branch. This is subject to the following limitations:

(a) minimum radius r_o: the lesser of $0.05d$ or 38 mm (1.5 in.);

(b) maximum radius r_o shall not exceed:

(1) for branches DN200 (NPS 8) and larger, $0.10d + 13$ mm (0.50 in);

(2) for branches less than DN200 (NPS 8), 32 mm (1.25 in.);

(c) when the external contour contains more than one radius, the radius of any arc sector of approximately 45 deg. shall meet the requirements of (a) and (b) above;

(d) machining shall not be employed in order to meet the above requirements.

FIG. 419.6.4(c) FLEXIBILITY FACTOR k AND STRESS INTENSIFICATION FACTOR i (CONT'D)

of the attachment. Nonintegral attachments, such as pipe clamps and ring girders, are preferred where they will fulfill the supporting or anchoring functions.

(d) If pipe is designed to operate above 20% SMYS, all attachments welded to the pipe shall be made to a separate cylindrical member that completely encircles the pipe, and this encircling member shall be welded to the pipe by continuous circumferential welds.

(e) The applicable sections of MSS SP-58 for materials and design of pipe hangers and supports and of MSS SP-69 for their selection and application may be used.

PART 6
AUXILIARY AND OTHER SPECIFIC PIPING

422 DESIGN REQUIREMENTS

422.3 Instrument and Other Auxiliary Liquid Petroleum or Liquid Anhydrous Ammonia Piping

All instrument and other auxiliary piping connected to primary piping and which operates at a gage pressure exceeding 15 psi (1 bar) shall be constructed in accordance with the provisions of this Code.

422.6 Pressure Disposal Piping

Pressure disposal or relief piping between pressure origin point and relief device shall be in accordance with this Code.

422.6.1 A full area stop valve may be installed between origin point and relief device providing such valve can be locked or sealed in the open position.

422.6.2 Disposal piping from relief device shall be connected to a proper disposal facility, which may be a flare stack, suitable pit, sump, or tank. This disposal piping shall have no valve between relief device and disposal facility unless such valve can be locked or sealed in the open position.

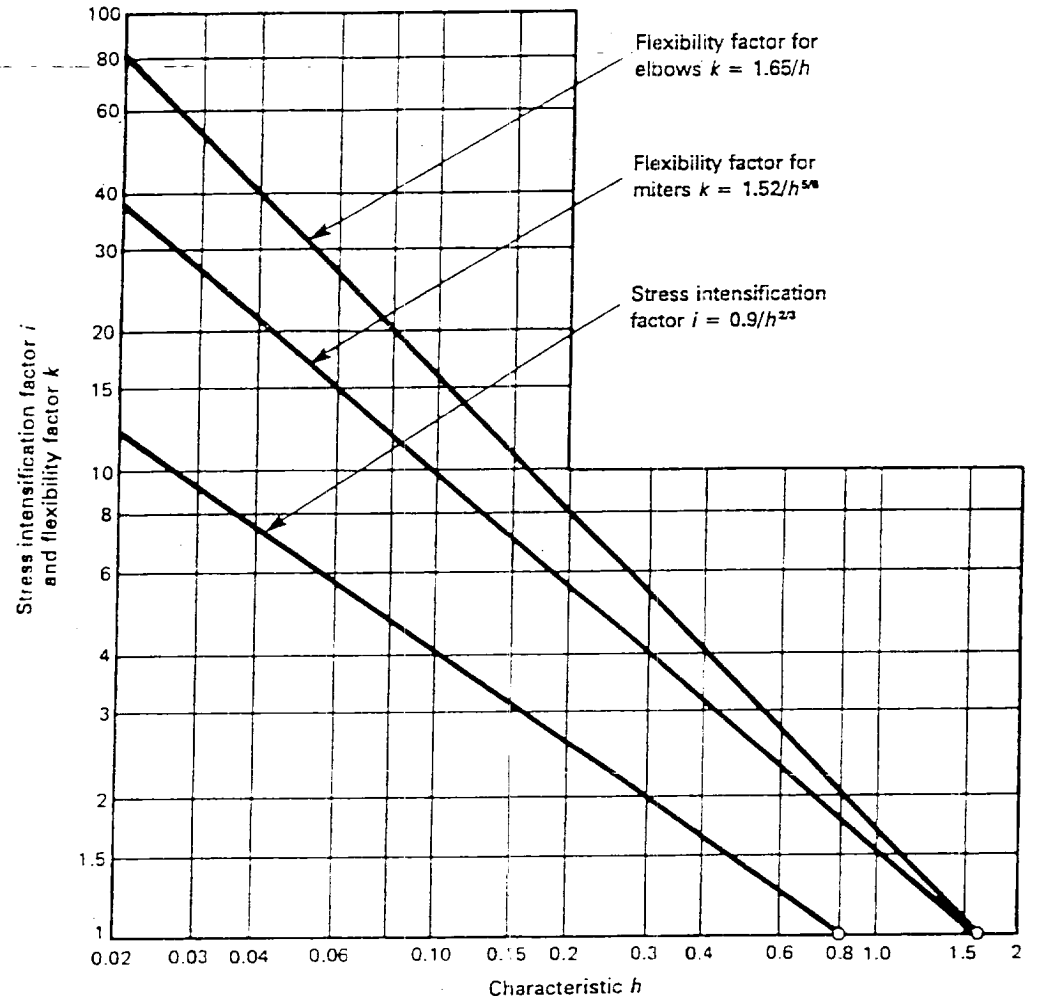


Chart A

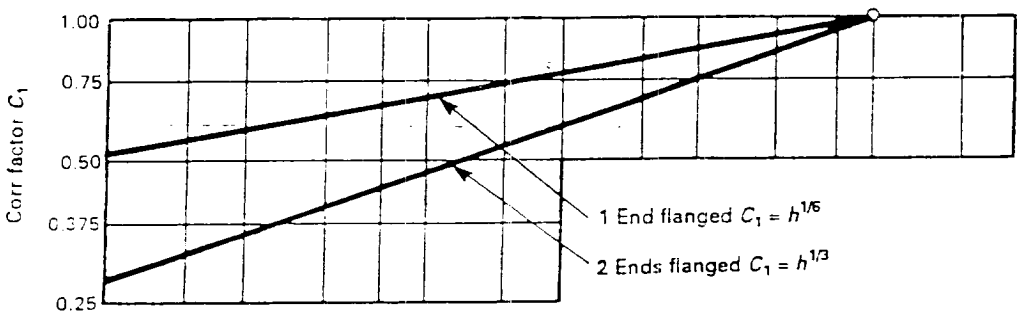


Chart B

FIG. 419.6.4(c) FLEXIBILITY FACTOR k AND STRESS INTENSIFICATION FACTOR i (CONT'D)

CHAPTER III
MATERIALS

423 MATERIALS — GENERAL REQUIREMENTS

423.1 Acceptable Materials and Specifications

(a) The materials used shall conform to the specifications listed in Table 423.1 or shall meet the requirements of this Code for materials not listed. Specific editions of standards incorporated in this Code by reference, and the names and addresses of the sponsoring organizations, are shown in Appendix A, since it is not practical to refer to a specific edition of each standard in Table 423.1 and throughout the Code text. Appendix A will be revised at intervals, as needed, and issued in Addenda to the Code. Materials and components conforming to a specification or standard previously listed in Table 423.1, or to a superseded edition of a listed specification or standard, may be used.

(b) Except as otherwise provided for in this Code, materials which do not conform to a listed specification or standard shall be qualified for use by petitioning the Code Committee for approval. Complete information shall be supplied to the Code Committee and the Code Committee approval shall be obtained before the material may be used.

423.2 Limitations on Materials

423.2.1 General

(a) The designer shall give consideration to the significance of temperature on the performance of the material.

(b) Selection of material to resist deterioration in service is not within the scope of this Code. It is the designer's responsibility to select materials suitable for the fluid service under the intended operating conditions. An example of a source of information on materials performance in corrosive environments is the *Corrosion Data Survey* published by the National Association of Corrosion Engineers.

423.2.3 Steel. Steels for pipe are shown in Table 423.1 (except as noted in para. 423.2.5).

423.2.4 Cast, Malleable, and Wrought Iron

(a) Cast, malleable, and wrought iron shall not be used for pressure containing parts except as provided in paras. 407.1(a), 407.1(b), and 423.2.4(b).

(b) Cast, malleable, and wrought iron are acceptable in pressure vessels and other equipment noted in para. 400.1.2(b) and in proprietary items [see para. 400.1.2(g)], except that pressure containing parts shall be limited to pressures not exceeding 250 psi (17 bar).

423.2.5 Materials for Liquid Anhydrous Ammonia Pipeline Systems. Only steel conforming to specifications listed in Appendix A shall be used for pressure containing piping components and equipment in liquid anhydrous ammonia pipeline systems. However, internal parts of such piping components and equipment may be made of other materials suitable for the service.

The longitudinal or spiral weld of electric resistance welded and electric induction welded pipe shall be normalized.

Cold formed fittings shall be normalized after fabrication.

Except for the quantities permitted in steels by individual specifications for steels listed in Appendix A, the use of copper, zinc, or alloys of these metals is prohibited for all pressure piping components subject to a liquid anhydrous ammonia environment.

423.2.6 Materials for Carbon Dioxide Piping Systems. Blow down and bypass piping in carbon dioxide pipelines shall be of a material suitable for the low temperatures expected.

425 MATERIALS APPLIED TO MISCELLANEOUS PARTS

425.3 Gaskets

Limitations on gasket materials are covered in para. 408.4.

425.4 Bolting

Limitations on bolting materials are covered in para. 408.5.

TABLE 423.1
MATERIAL STANDARDS

Standard or Specification	Designation
Pipe	
Pipe, Steel, Black & Hot-Dipped, Zinc-Coated Welded & Seamless	ASTM A 53
Seamless Carbon Steel Pipe for High-Temperature Service	ASTM A 106
Pipe, Steel, Electric-Fusion (Arc)-Welded (Sizes NPS 16 and Over)	ASTM A 134
Electric-Resistance-Welded Steel Pipe	ASTM A 135
Electric-Fusion (Arc)-Welded Steel Pipe (NPS 4 and Over)	ASTM A 139
Seamless and Welded Steel Pipe for Low Temperature Service	ASTM A 333
Metal-Arc-Welded Steel Pipe for Use with High-Pressure Transmission Systems	ASTM A 381
Seamless Carbon Steel Pipe for Atmospheric and Lower Temperatures	ASTM A 524
General Requirements for Specialized Carbon and Alloy Steel Pipe	ASTM A 530
Electric-Fusion-Welded Steel Pipe for Atmospheric and Lower Temperatures	ASTM A 671
Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures	ASTM A 672
Line Pipe	API 5L
Fittings, Valves, and Flanges	
Pipe Flanges and Flanged Fittings	ASME B16.5
Forgings, Carbon Steel, for Piping Components	ASTM A 105
Gray Iron Castings for Valves, Flanges, and Pipe Fittings	ASTM A 126
Forgings, Carbon Steel, for General-Purpose Piping	ASTM A 181
Forged or Rolled Alloy-Steel Pipe Flanges, Forged Fittings, and Valves and Parts for High-Temperature Service	ASTM A 182
Steel Castings, Carbon, Suitable for Fusion Welding, for High Temperature Service	ASTM A 216
Steel Castings, Martensitic Stainless and Alloy, for Pressure Containing Parts, Suitable for High-Temperature Service	ASTM A 217
Piping Fittings of Wrought Carbon Steel and Alloy Steel for Moderate and Elevated Temperatures	ASTM A 234
Forgings, Carbon and Low-Alloy Steel, Requiring Notch Toughness Testing for Piping Components	ASTM A 350
Ferritic Ductile Iron Pressure-Retaining Castings for Use at Elevated Temperatures	ASTM A 395
Piping Fittings of Wrought Carbon Steel and Alloy Steel for Low Temperature Service [Note (1)]	ASTM A 420
Steel Castings Suitable for Pressure Service	ASTM A 487
Forgings, Carbon and Alloy Steel, for Pipe Flanges, Fittings, Valves, and Parts for High-Pressure Transmission Service	ASTM A 694
Wellhead Equipment	API 6A
Pipeline Valves, End Closures, Connectors and Swivels	API 6D
Steel Gate Valves, Flanged and Buttwelding Ends	API 600
Compact Carbon Steel Gate Valves	API 602
Class 150, Corrosion Resistant Gate Valves	API 603
Quality Standard for Steel Castings for Valves, Flanges and Fittings and Other Piping Components	MSS SP-55
Specification For High Test Wrought Welding Fittings	MSS SP-75
Bolting	
Alloy-Steel and Stainless Steel Bolting Materials for High-Temperature Service	ASTM A 193
Carbon and Alloy Steel Nuts for Bolts for High-Pressure and High-Temperature Service	ASTM A 194
Carbon Steel Externally Threaded Standard Fasteners	ASTM A 307
Alloy Steel Bolting Materials for Low-Temperature Service	ASTM A 320
High-Strength Bolts for Structural Steel Joints	ASTM A 325
Quenched and Tempered Alloy Steel Bolts, Studs, and Other Externally Threaded Fasteners	ASTM A 354
Quenched and Tempered Steel Bolts and Studs	ASTM A 449

(continued)

TABLE 423.1
MATERIAL STANDARDS (CONT'D)

Standard or Specification	Designation
Bolting (Cont'd)	
Heat Treated Steel Structural Bolts, 150 ksi (1035 MPa) Minimum Tensile Strength	ASTM A 490
Structural Materials	
General Requirements for Rolled Steel Plates, Shapes, Sheet Piling, and Bars for Structural Use	ASTM A 6
General Requirements for Steel Plates for Pressure Vessels	ASTM A 20
General Requirements for Steel Bars, Carbon and Alloy, Hot-Wrought and Cold-Finished	ASTM A 29
Structural Steel	ASTM A 36
Pressure Vessel Plates, Alloy Steel, Manganese-Vanadium	ASTM A 225
High-Strength Low-Alloy Structural Steel	ASTM A 242
Low and Intermediate Tensile Strength Carbon Steel Plates, and Bars	ASTM A 283
Pressure Vessel Plates, Carbon Steel, Low- and Intermediate-Tensile Strength	ASTM A 285
High-Strength Low-Alloy Structural Manganese Vanadium Steel	ASTM A 441
Pressure Vessel Plates, Carbon Steel, Improved Transition Properties	ASTM A 442
General Requirements for Steel Sheet and Strip, Alloy, Hot-Rolled and Cold-Rolled	ASTM A 505
Steel Sheet and Strip, Alloy, Hot-Rolled and Cold-Rolled, Regular Quality	ASTM A 506
Steel Sheet and Strip, Alloy, Hot-Rolled and Cold-Rolled, Drawing Quality	ASTM A 507
High-Yield-Strength, Quenched and Tempered Alloy Steel Plate, Suitable for Welding	ASTM A 514
Pressure Vessel Plates, Carbon Steel, for Intermediate- and Higher-Temperature Service	ASTM A 515
Pressure Vessel Plates, Carbon Steel, for Moderate- and Lower-Temperature Service	ASTM A 516
Pressure Vessel Plates, Alloy Steel, High-Strength, Quenched and Tempered	ASTM A 517
Pressure Vessel Plates, Heat Treated, Carbon-Manganese-Silicon Steel	ASTM A 537
High-Strength Low-Alloy Columbium-Vanadium Steels of Structural Quality	ASTM A 572
Structural Carbon Steel Plates of Improved Toughness	ASTM A 573
Steel Bars, Carbon, Merchant Quality, M-Grades	ASTM A 575
Steel Bars, Carbon, Hot-Wrought, Special Quality	ASTM A 576
Normalized High-Strength Low-Alloy Structural Steel	ASTM A 633
Steel Bars, Carbon, Merchant Quality, Mechanical Properties	ASTM A 663
Steel Bars, Carbon, Hot-Wrought, Special Quality, Mechanical Properties	ASTM A 675
Miscellaneous	
Pipe Hangers and Support Materials, Design and Manufacture	MSS SP-58

GENERAL NOTE:
Specific editions of standards incorporated in this Code by reference, and the names and addresses of the sponsoring organizations, are shown in Appendix A, since it is not practical to refer to a specific edition of each standard in Table 423.1 and throughout the Code text. Appendix A will be revised at intervals as needed, and issued in Addenda to the Code.

NOTE:
(1) A 420 Grade WPL9 is not recommended for anhydrous ammonia due to copper content.

CHAPTER IV
DIMENSIONAL REQUIREMENTS

426 DIMENSIONAL REQUIREMENTS FOR STANDARD AND NONSTANDARD PIPING COMPONENTS

426.1 Standard Piping Components

Dimensional standards for piping components are listed in Table 426.1. Also, certain material specifications listed in Table 423.1 contain dimensional requirements which are requirements of para. 426. Dimensions of piping components shall comply with these standards and specifications unless the provisions of para. 426.2 are met.

426.2 Nonstandard Piping Components

The dimensions for nonstandard piping components shall be such as to provide strength and performance equivalent to standard components or as provided under para. 404. Wherever practical, these dimensions shall conform to those of comparable standard components.

426.3 Threads

The dimensions of all piping connection threads, not otherwise covered by a governing component standard or specification, shall conform to the requirements of the applicable standards listed in Table 426.1 (see para. 414.1).

TABLE 426.1
DIMENSIONAL STANDARDS

Standard or Specification	Designation
Pipe	
Welded and Seamless Wrought Steel Pipe	ASME B36.10M
Stainless Steel Pipe	ASME B36.19M
Line Pipe (*Combination of former API Spec. 5L, 5LS, and 5LX*)	API 5L
Fittings, Valves, and Flanges	
Pipe Flanges and Flanged Fittings	ASME B16.5
Factory-Made Wrought Steel Buttwelding Fittings	ASME B16.9
Face-to-Face and End-to-End Dimensions of Valves	ASME B16.10
Metallic Gaskets for Pipe Flanges — Ring Joint, Spiral-Wound, and Jacketed	ASME B16.20
Nonmetallic Flat Gaskets for Pipe Flanges	ASME B16.21
Buttwelding Ends	ASME B16.25
Wrought Steel Buttwelding Short Radius Elbows and Returns	ASME B16.28
Wellhead Equipment	API 6A
Pipeline Valves, End Closures, Connectors and Swivels	API 6D
Steel Gate Valves, Flanged and Buttwelding Ends	API 600
Compact Carbon Steel Gate Valves	API 602
Class 150, Corrosion Resistant Gate Valves	API 603
Standard Finishes for Contact Faces of Pipe Flanges and Connecting-End Flanges of Valves and Fittings	MSS SP-6
Standard Marking System for Valves, Fittings, Flanges and Unions	MSS SP-25
Steel Pipe Line Flanges	MSS SP-44
Pressure Testing of Steel Valves	MSS SP-61
Butterfly Valves	MSS SP-67
Cast Iron Gate Valves, Flanged and Threaded Ends	MSS SP-70
Cast Iron Swing Check Valves, Flanged and Threaded Ends	MSS SP-71
Specification for High Test Wrought Welding Fittings	MSS SP-75
Cast Iron Plug Valves, Flanged and Threaded Ends	MSS SP-78
Miscellaneous	
Unified Inch Screw Threads (UN and UNR Thread Form)	ASME B1.1
Pipe Threads, General Purpose (Inch)	ASME B1.20.1
Dry Seal Pipe Threads (Inch)	ASME B1.20.3
Threading, Gaging, and Thread Inspection of Casing, Tubing, and Line Pipe Threads	API 5B
Pipe Hangers and Supports—Selection and Application	MSS SP-69

GENERAL NOTE: Specific editions of standards incorporated in this Code by reference, and the names and addresses of the sponsoring organizations, are shown in Appendix A, since it is not practical to refer to a specific edition of each standard in Table 426.1 and throughout the Code text. Appendix A will be revised at intervals as needed, and issued in Addenda to the Code.

CHAPTER V
CONSTRUCTION, WELDING, AND ASSEMBLY

434 CONSTRUCTION

434.1 General

New construction and replacements of existing systems shall be in accordance with the requirements of this Chapter. Where written specifications are required, they shall be in sufficient detail to insure that the requirements of this Code shall be met. Such specifications shall include specific details on handling of pipe, equipment, materials, welding, and all construction factors which contribute to safety and sound engineering practice. It is not intended herein that all construction items be covered in full detail, since the specification should be all-inclusive. Whether covered specifically or not, all construction and materials shall be in accordance with good engineering, safety, and proven pipeline practice.

434.2 Inspection

The operating company shall make provision for suitable inspection of pipeline and related facilities by qualified inspectors to assure compliance with the construction specifications. Qualification of inspection personnel and the type and extent of inspection shall be in accordance with the requirements of para. 436. Repairs required during new construction shall be in accordance with paras. 434.5, 434.8, and 461.1.2.

434.3 Right of Way

434.3.1 Location. Right of way should be selected so as to minimize the possibility of hazard from future industrial or urban development or encroachment on the right of way.

434.3.2 Construction Requirements. Inconvenience to the landowner should be a minimum and safety of the public shall be given prime consideration.

(a) All blasting shall be in accordance with governing regulations and shall be performed by competent and qualified personnel, and performed so as to provide adequate protection to the general public, livestock, wildlife, buildings, telephone, telegraph, and power lines, underground structures, and any other property in the proximity of the blasting.

(b) In grading the right of way, every effort shall be made to minimize damage to the land and prevent abnormal drainage and erosive conditions. The land is to be restored to as nearly original condition as is practical.

(c) In constructing pipeline crossings of railroads, highways, streams, lakes, rivers, etc., safety precautions such as signs, lights, guard rails, etc., shall be maintained in the interest of public safety. The crossings shall comply with the applicable rules, regulations, and restrictions of regulatory bodies having jurisdiction.

434.3.3 Survey and Staking or Marking. The route shall be surveyed and staked, and such staking or marking should be maintained during construction, except route of pipeline offshore shall be surveyed and the pipeline shall be properly located within the right of way by maintaining survey route markers or by surveying during construction.

434.4 Handling, Hauling, Stringing, and Storing

Care shall be exercised in the handling or storing of pipe, casing, coating materials, valves, fittings, and other materials to prevent damage. When applicable, railroad transportation of pipe shall meet the requirements of API RP 5L1. In the event pipe is yard coated or mill coated, adequate precautions shall be taken to prevent damage to the coating when hauling, lifting, and placing on the right of way. Pipe shall not be allowed to drop and strike objects which will distort, dent, flatten, gouge, or notch the pipe or damage the coating, but shall be lifted or lowered by suitable and safe equipment.

434.5 Damage to Fabricated Items and Pipe

(a) Fabricated items such as scraper traps, manifolds, volume chambers, etc., shall be inspected before assembly into the mainline or manifolding and defects shall be repaired in accordance with provisions of the standard or specification applicable to their manufacture.

(b) Pipe shall be inspected before coating and before

assembly into the mainline or manifolding. Distortion, buckling, denting, flattening, gouging, grooves, or notches, and all defects of this nature, shall be prevented, repaired, or eliminated as specified herein.

(1) Injurious gouges, grooves, or notches shall be removed. These defects may be repaired by the use of welding procedures prescribed in API 5L or removed by grinding, provided the resulting wall thickness is not less than that permitted by the material specification.

(2) When conditions outlined in para. 434.5(b)(1) cannot be met, the damaged portion shall be removed as a cylinder. Insert patching is not permitted. Weld-on patching, other than complete encirclement, is not permitted in pipelines intended to operate at a hoop stress of more than 20% of the specified minimum yield strength of the pipe.

(3) Notches or laminations on pipe ends shall not be repaired. The damaged end shall be removed as a cylinder and the pipe end properly rebeveled.

(4) Distorted or flattened lengths shall be discarded.

(5) A dent (as opposed to a scratch, gouge, or groove) may be defined as a gross disturbance in the curvature of the pipe wall. A dent containing a stress concentrator, such as a scratch, gouge, groove, or arc burn, shall be removed by cutting out the damaged portion of the pipe as a cylinder.

(6) All dents which affect the curvature of the pipe at the seam or at any girth weld shall be removed as in para. 434.5(b)(5). All dents which exceed a maximum depth of ¼ in. (6 mm) in pipe NPS 4 and smaller, or 6% of the nominal pipe diameter in sizes greater than NPS 4, shall not be permitted in pipelines intended to operate at a hoop stress of more than 20% of the specified minimum yield strength of the pipe. Insert patching, overlay, or pounding out of dents shall not be permitted in pipelines intended to operate at a hoop stress of more than 20% of the specified minimum yield strength of the pipe.

(7) Buckled pipe shall be replaced as a cylinder.

434.6 Ditching

(a) Depth of ditch shall be appropriate for the route location, surface use of the land, terrain features, and loads imposed by roadways and railroads. All buried pipelines shall be installed below the normal level of cultivation and with a minimum cover not less than that shown in Table 434.6(a). Where the cover provisions of Table 434.6(a) cannot be met, pipe may be installed with less cover if additional protection is provided to withstand anticipated external loads and to minimize damage to the pipe by external forces.

(b) Width and grade of ditch shall provide for lowering of the pipe into the ditch to minimize damage to the coating and to facilitate fitting the pipe to the ditch.

(c) Location of underground structures intersecting the ditch route shall be determined in advance of construction activities to prevent damage to such structures. A minimum clearance of 12 in. (0.3 m) shall be provided between the outside of any buried pipe or component and the extremity of any other underground structures, except for drainage tile which shall have a minimum clearance of 2 in. (50 mm), and as permitted under para. 461.1.1(c).

(d) Ditching operations shall follow good pipeline practice and consideration of public safety. API RP 1102 will provide additional guidance.

434.7 Bends, Miters, and Elbows

Changes in direction, including sags or overbends required to conform to the contour of the ditch, may be made by bending the pipe or using miters, factory made bends, or elbows. [See limitations in para. 406.2.]

434.7.1 Bends Made From Pipe

(a) Bends shall be made from pipe having wall thicknesses determined in accordance with para. 404.2.1. When hot bends are made in pipe which has been cold worked in order to meet the specified minimum yield strength, wall thicknesses shall be determined by using the lower stress values in accordance with para. 402.3.1(d).

(b) Bends shall be made in such a manner as to preserve the cross-sectional shape of the pipe, and shall be free from buckling, cracks, or other evidence of mechanical damage. The pipe diameter shall not be reduced at any point by more than 2½% of the nominal diameter, and the completed bend shall pass the specified sizing pig.

(c) The minimum radius of field cold bends shall be as specified in para. 406.2.1(b).

(d) Tangents approximately 6 ft (2 m) in length are preferred on both ends of cold bends.

434.7.2 Mitered Bends

(a) Mitered bends are permitted subject to limitations in para. 406.2.2.

(b) Care shall be taken in making mitered joints to provide proper spacing and alignment and full penetration welds.

434.7.3 Factory Made Bends and Elbows

(a) Factory made wrought steel welding bends and

TABLE 434.6(a)
MINIMUM COVER FOR BURIED PIPELINES

Location	For Normal Excavation, in. (m) [Note (1)]	For Rock Excavation Requiring Blasting or Removal by Equivalent Means, in. (m)
Industrial, commercial, and residential areas	36 (0.9)	24 (0.6)
River and stream crossings	48 (1.2)	18 (0.45)
Drainage ditches at roadways and railroads	36 (0.9)	24 (0.6)
Any other area	30 (0.75)	18 (0.45)

NOTE:
(1) Minimum cover for pipelines transporting carbon dioxide, LPG, or liquid anhydrous ammonia shall be: 48 in. (1.2 m) for normal excavation in industrial, commercial, and residential areas, river and stream crossings, and drainage ditches at roadways and railroads; and 36 in. (0.9 m) for normal excavation in any other area.

factory made elbows may be used subject to limitations in para. 406.2.3,and transverse segments cut therefrom may be used for changes in direction provided the arc distance measured along the crotch is at least 2 in. (50 mm) on pipe size NPS 4 and larger.

(b) If the internal diameter of such fittings differs by more than $^3/_{16}$ in. (5 mm) from that of the pipe, the fitting shall be treated as indicated in Fig. 434.8.6(a)-(2) or use a transition nipple not less than one-half pipe diameter in length with acceptable joint designs as illustrated in Fig. 434.8.6(a)-(2).

02 **434.8 Welding**

434.8.1 General

(a) Scope. Welding herein applies to the arc and gas welding of pipe in both wrought and cast steel materials as applied in pipelines and connections to apparatus or equipment. This includes butt joints in the installation of pipe, valves, flanges, fittings, and other equipment, and fillet welded joints in pipe branches, slip-on flanges, etc. It does not apply to the welding of longitudinal or spiral joints in the manufacture of pipe, fittings, and valves, or to pressure vessels or assemblies manufactured in accordance with the ASME Boiler and Pressure Vessel Code, Section VIII, Division 1 or 2.

(b) Welding Terms. Definitions pertaining to welding as used in this Code conform to the standard definitions established by the American Welding Society and contained in ANSI/AWS A3.0, Section IX of the ASME Boiler and Pressure Vessel Code, and API 1104.

(c) Safe Practices in Cutting and Welding. Prior to cutting and welding in areas in which the possible leakage or presence of vapor or flammable liquid constitutes a hazard of fire or explosion, a thorough check shall be made to determine the presence of a combustible gas mixture or flammable liquid. Cutting and welding shall begin only when safe conditions are indicated.

434.8.2 Welding Processes and Filler Metal

(a) Welding shall be performed by a manual, semiautomatic, or automatic process or combination of processes that have been demonstrated to produce sound welds.

(b) Unless otherwise specified by the operating company, welding electrodes and consumables shall comply with the following:

(1) Filler metal and consumables shall be selected so that the strength of the completed weldment will equal or exceed the specified minimum tensile strength of the materials being joined.

(2) If base metals of different tensile strengths are to be joined, the nominal tensile strength of the weld metal shall equal or exceed the tensile strength of the weaker of the two.

(3) When filler metals of different strenghts are used in a single weld, the proportions shall be such that the completed weldment equals the specified minimum tensile strength of the base metal.

(4) For alloy steels, the nominal chemical analysis of the weld metal shall be the same as the nominal chemical analysis of the base metal. If base metals of different chemical analysis are being joined, the weld metal shall be the same as eitehr base metal, or of intermediate composition, except as specified below.

(5) When austenitic steels are joined to ferritic steels, the weld metal shall have an austenitic structure.

434.8.3 Welder and Welding Procedure Qualifications

(a) Welder and welding procedure qualifications for cross country pipelines shall be performed in accordance with API 1104. Welder and welding procedure qualifications for alloy steel and for shop fabricated piping assemblies, and welding at stations and terminals shall be performed in accordance with API 1104 or Section IX of the ASME Boiler and Pressure Vessel Code.

(b) Prior to any welding covered by this Code, a welding procedure specification shal be established and qualified by testing to demonstrate that welds having suitable mechanical properties and soundness can be produced. Welding procedure specifications and each welder or welding operator shall be qualified as required by API 1104, or Section IX of the ASME Boiler and Pressure Vessel Code, whichever is appropriate for the locations, materials, and type of welding to be performed. The welding procedure specification shall be adhered to during welding performed under this Code.

(c) The welding procedure specifications shall at a minimum include the information required by API 1104 or Section IX of the ASME Boiler and Pressure Vessel Code. When materials, welding consumables, mechanical restraint, service conditions and/or weather conditions make more details necessary to produce a sound weld, such as preheat, interpass temperature, and post-weld heat treatment, such details shall be provided. When joining materials with notch-toughness requirements, particularly for low temperature service, consideration shall be given to weld metal and heat-affected zone toughness requirements in the welding procedure specification. When applicable, the test method, temperature, specimen, and acceptance criteria shall be specified in the welding procedure specification.

(d) API 1104 and Section IX of the ASME Boiler and Pressure Vessel Code contain sections entitled "Essential Variables" applicable to welding procedure specifications, procedure qualification records, and welder qualifications. The classification of base materials and weld filler materials into groups does not imply that other materials within a particular group may be indiscriminately substituted for the base material or weld filler material used for the qualificaition test. Welding procedure qualification tests should be conducted with the highest strength base metal to be welded in the essential variable groups identified in the procedure specification.

(e) Welder requalification tests are required if there is some specific reason to question a welder's ability or if the welder is not engaged in a given process of welding for a period of six months or more.

(f) The operating company shall be responsible for qualifications of procedures and welders. The preparation of welding procedure specifications and/or performance of welding qualification tests may be delegated to others; however, each company that performs welding activities is responsible for the welding activities performed by its employees and contractors.

(g) Qualification Records. The welding procedure followed during the qualifying tests shall be recorded in detail. Records of the tests that establish the qualification of a welding procedure specification shall be retained as long as that procedure is in use. A record of the welders qualified, showing the date and results of the tests, shall be retained during the construction involved and for six months thereafter.

434.8.4 Welding Standards. All the welding done under this Code shall be performed under a specification which embodies the minimum requirements of this Code and shall encompass the requirements of API 1104 except as provided in paras. 434.8.3(a) and (b).

434.8.5 Required Inspection and Acceptance Criteria

(a) Required Inspection

(1) The quality of welding shall be checked by visual inspection and supplemental nondestructive methods or by removing completed welds as selected and designated by the inspector for destructive testing.

(2) All welds shall be visually inspected.

(3) When the pipeline is to be operated at a hoop stress of more than 20% of the specified minimum yield strength of the pipe, girth welds shall be inspected. A minimum of 10% of the girth welds completed each day shall be randomly selected by the operating company and inspected. The inspection shall be by radiographic or other accepted volumetric nondestructive methods. Each weld inspected shall be inspected completely around its circumference. In the following locations or conditions, all girth welds in the pipe shall be completely inspected; however, if some of the girth welds are inaccessible, a minimum of 90% of the welds are to be inspected.

(a) within populated areas such as residential subdivisions, shopping centers, and designated commercial and industrial areas;

(b) river, lake, and stream crossings within the area subject to frequent inundation; and river, lake, and stream crossings on bridges;

(c) railroad or public highway rights of way, including tunnels, bridges, and overhead railroad and road crossings;

(d) offshore and inland coastal waters;

(e) old girth welds in used pipe;

(f) tie-in girth welds not hydrostatically tested in accordance with para. 437.4.1.

(b) Inspection Methods and Acceptance Standards

(1) Nondestructive inspection shall consist of visual inspection and radiographic examination or other acceptable nondestructive methods, and shall be in

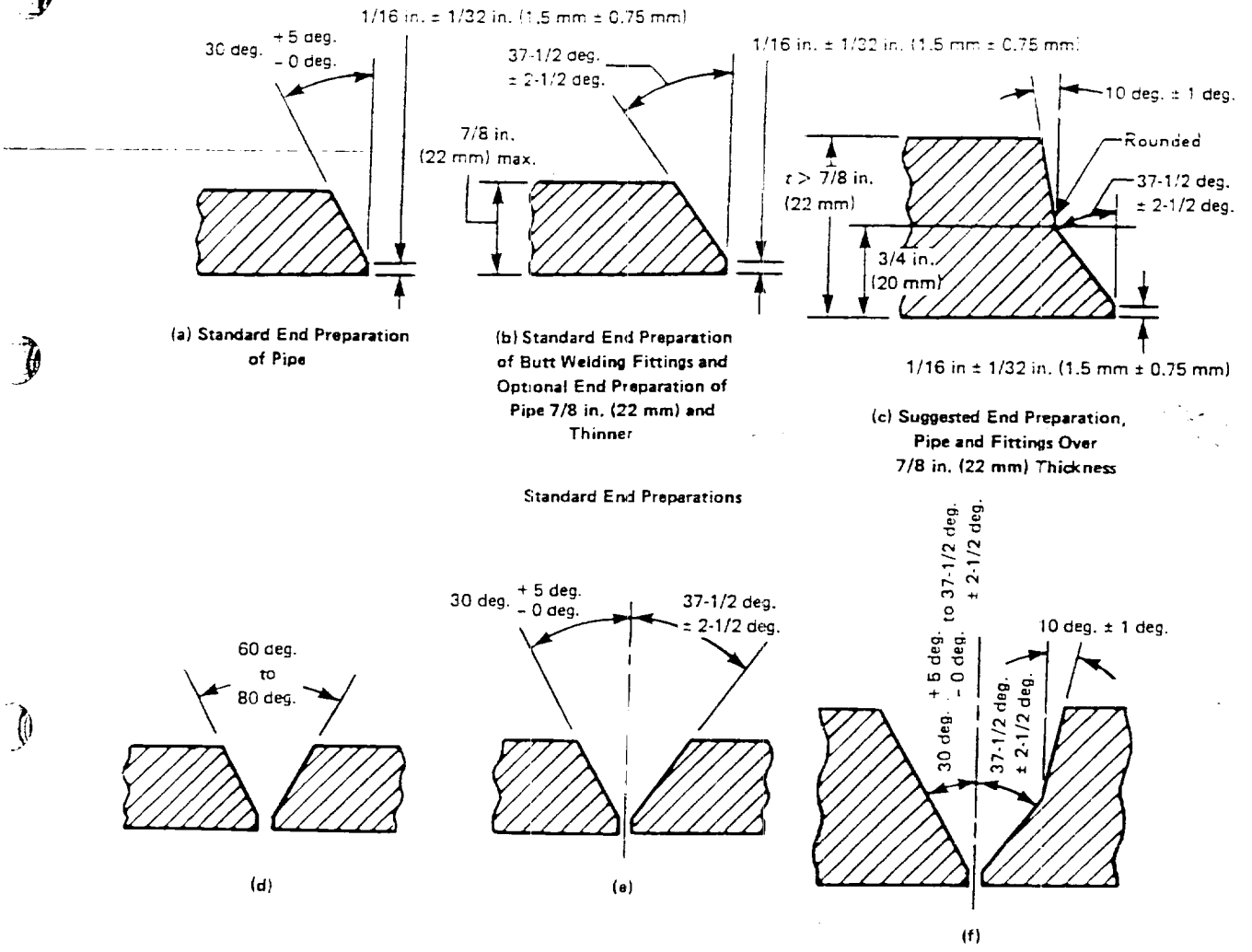


FIG. 434.8.6(a)-(1) ACCEPTABLE BUTT WELDED JOINT DESIGN FOR EQUAL WALL THICKNESSES

accordance with API 1104. The methods used shall be capable of producing indications of potential defects that can be accurately interpreted and evaluated. Welds shall meet the acceptance standards for discontinuities contained in API 1104, or the alternate acceptance standards for girth welds in Appendix A of API 1104.

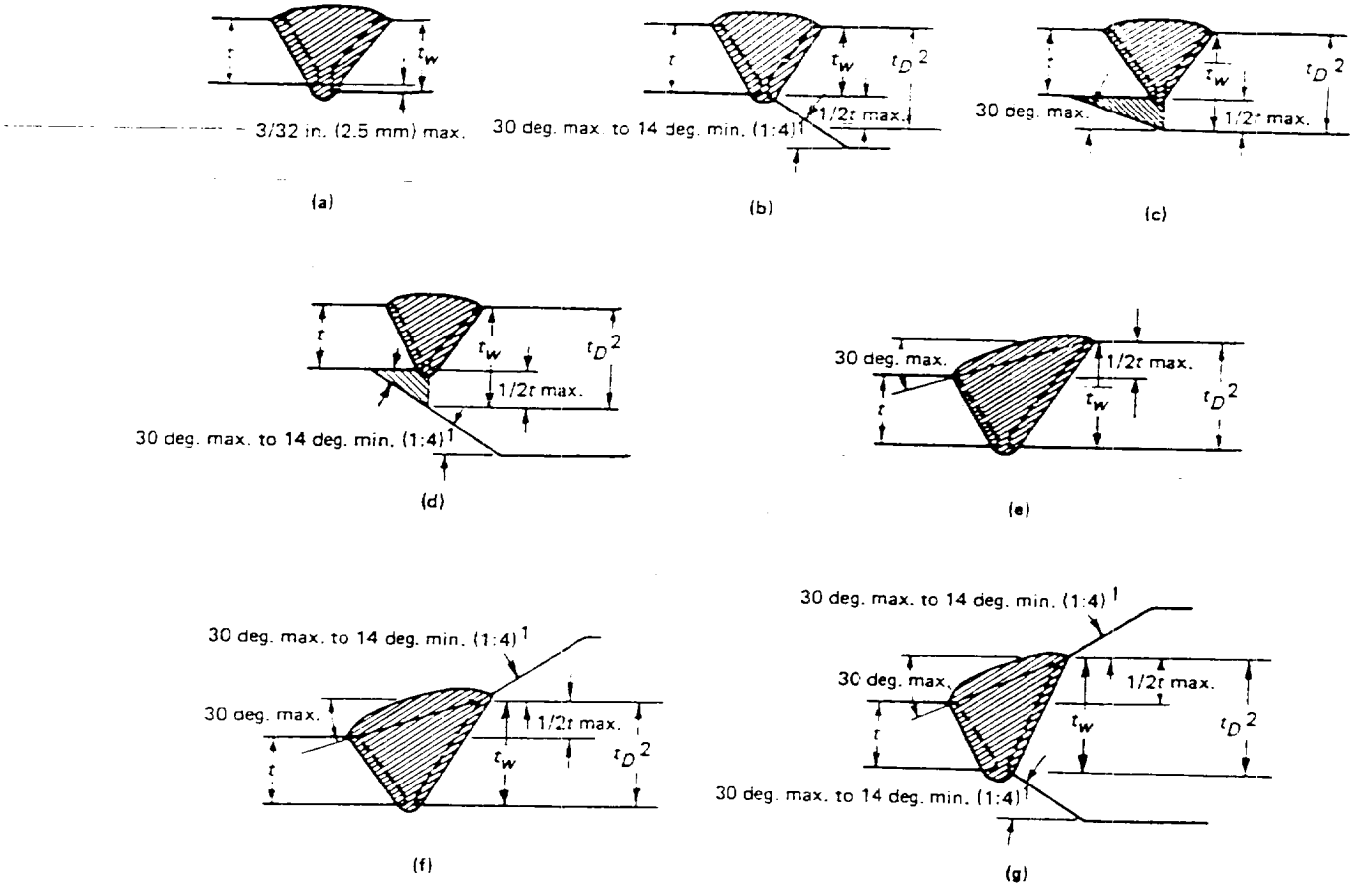
(2) Completed welds which have been removed for destructive examination shall meet the requirements of API 1104 for Welder Qualification by Destructive Testing. Trepanning methods of testing shall not be used.

434.8.6 Types of Welds, Joint Designs, and Transition Nipples

(a) Butt Welds. Butt welded joints may be of the single vee, double vee, or other suitable type of groove. Joint designs shown in Fig. 434.8.6(a)-(1) or applicable combinations of these joint design details are recommended for ends of equal thickness. The transition between ends of unequal thickness may be accomplished by taper or welding as shown in Fig. 434.8.6(a)-(2), or by means of a prefabricated transition nipple not less than one-half pipe diameter in length with acceptable joint designs as illustrated in Fig. 434.8.6(a)-(2).

(b) Fillet Welds. Fillet welds may be concave to slightly convex. The size of a fillet weld is stated as a leg length of the largest inscribed right isosceles triangle as shown in Fig. 434.8.6(b) covering recommended attachment details of flanges.

(c) Tack Welds. Tack welding shall be done by qualified welders, the same as all other welds.



Notes to follow on next page.

FIG. 434.8.6(a)-(2) ACCEPTABLE BUTT WELDED JOINT DESIGN FOR UNEQUAL WALL THICKNESSES

434.8.7 Removal or Repair of Defects

(a) Arc Burns. Arc burns can cause serious stress concentrations in pipelines and shall be prevented, removed, or repaired. The metallurgical notch caused by arc burns shall be removed by grinding, provided the grinding does not reduce the remaining wall thickness to less than the minimum permitted by the material specifications. Complete removal of the metallurgical notch created by an arc burn can be determined as follows. After visible evidence of the arc burn has been removed by grinding, swab the ground area with a minimum 10% solution of ammonium persulfate or a 5% solution of nital. A darkened spot is evidence of a metallurgical notch and indicates that additional grinding is necessary. If the resulting wall thickness after grinding is less than that permitted by the material specification, the portion of pipe containing the arc burn shall be removed or repaired in accordance with para. 451.6. Insert patching is prohibited.

(b) Weld Defects. Authorization for repair of welds, removal and repair of weld defects, and testing of weld repairs shall be in accordance with API 1104.

(c) Pipe Defects. Laminations, split ends, or other defects in the pipe shall be repaired or removed in accordance with para. 434.5(b).

434.8.8 Preheating and Interpass Temperature

(a) The welding procedure specification shall specify the minimum preheat temperature. When the welding procedure specification specifies preheating above ambient temperatures, the method of heating shall be specified. For heat treated and other high strength materials and impact tested materials, control of interpass temperatures may be necessary. The operating company shall

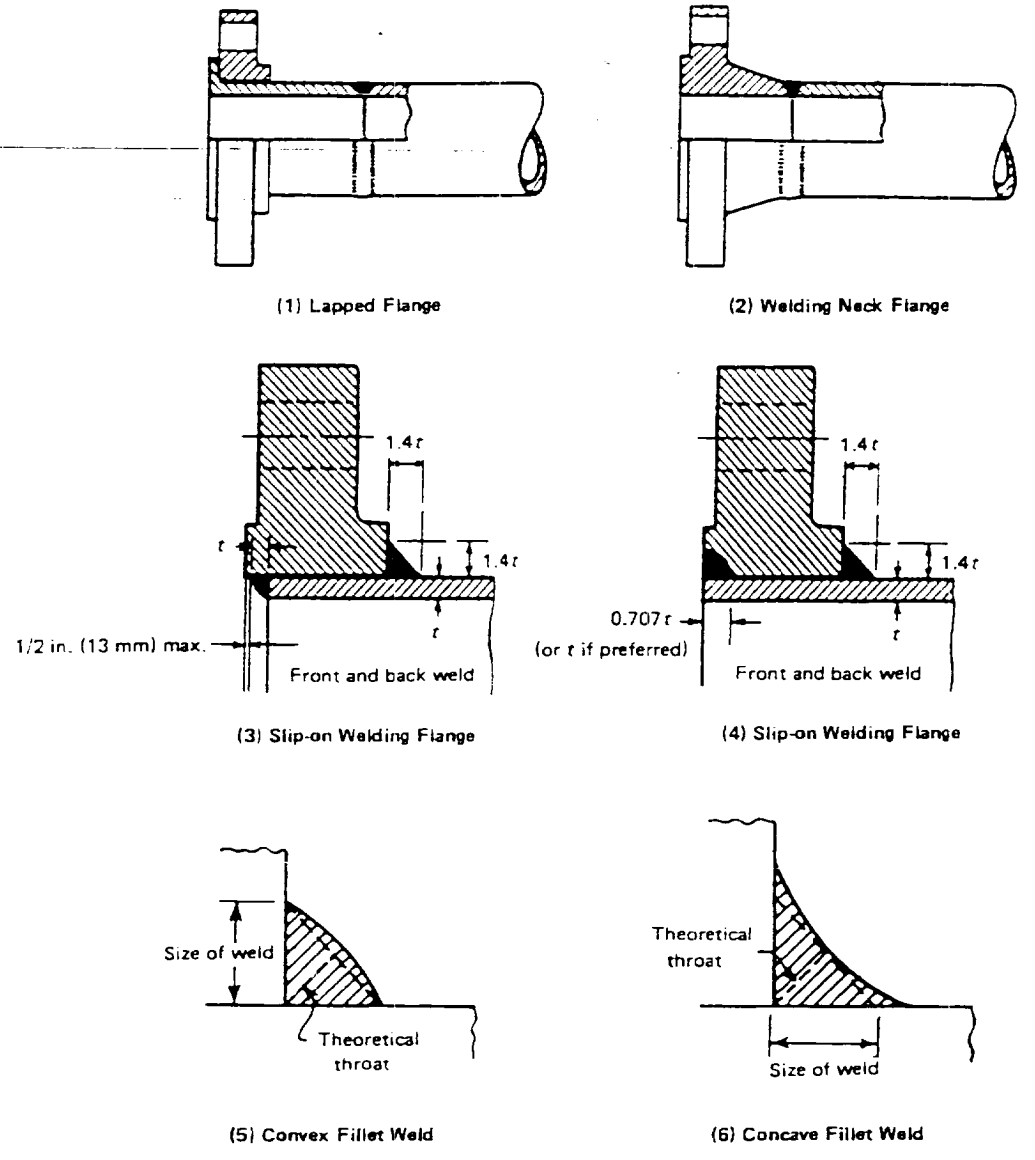


FIG. 434.8.6(b) RECOMMENDED ATTACHMENT DETAILS OF FLANGES

determine when interpass temperature limits are necessary, and, when required, the interpass temperatures shall be provided in the welding procedure specification.

(b) When welding dissimilar materials having different preheating requirements, the material requiring the higher preheat shall govern.

(c) The preheating temperature shall be checked by the use of temperature indicating crayons, thermocouple pyrometers, or other suitable method to assure that the required temperature is attained prior to and maintained during the welding operation.

434.8.9 Stress Relieving

(a) Welds shall be stress relieved when the effective weld throat [see Fig. 434.8.6(a)-(2)] exceeds 1¼ in. (32 mm), unless it can be demonstrated by welding procedure qualification tests, using materials of the same specification, type, and grade with an effective weld throat that is equal to or greater than the production weld, that stress relieving is not necessary.

Welds in carbon steels having an effective weld throat larger than 1¼ in. (32 mm) and not larger than 1½ in. (38 mm) may be exempted from stress relieving

if a minimum preheating temperature of 200°F (93°C) is used. The welding procedure specification shall specify when stress relieving and/or heat treatment are required due to composition, thickness, welding process, restraint of the weld joint, or service conditions. When required, the welding procedure qualification test shall include stress relieving and/or heat treatment of the completed test joint. The postweld stress relieving and heat treatment requirements in ASME B31.3 or Section VIII, Division 1 or 2 of the ASME Boiler and Pressure Vessel Code may be used as a guide for minimum stress relieving and heat treating requirements. The thickness to be used to determine the stress relieving requirements of branch connections or slip-on flanges shall be the thickness of the pipe or header.

The thickness to be used to determine the stress relieving requirements of branch connections or slip-on flanges shall be the thickness of the pipe or header.

(b) In welds between dissimilar materials, if either material requires stress relieving, the joint shall require stress relieving.

434.9 Tie-In

Gaps left in the continuous line construction at such points as river, canal, highway, or railroad crossings require special consideration for alignment and welding. Sufficient equipment shall be available and care exercised not to force or strain the pipe to proper alignment.

434.10 Installation of Pipe in the Ditch

It is very important that stresses induced into the pipeline by construction be minimized. The pipe shall fit the ditch without the use of external force to hold it in place until the backfill is completed. When the pipe is lowered into the ditch, care shall be exercised so as not to impose undue stress in the pipe. Slack loops may be used where laying conditions render their use advisable.

434.11 Backfilling

Backfilling shall be performed in a manner to provide firm support of the pipe. When there are large rocks in the backfill material, care shall be exercised to prevent damage to the pipe and coating by such means as the use of a rock shield material, or by making the initial fill with a rock-free material sufficient to prevent rock damage. Where the ditch is flooded, care shall be exercised so that the pipe is not floated from the bottom of the ditch prior to backfill completion.

434.12 Restoration of Right of Way and Cleanup

These operations shall follow good construction practices and considerations of private and public safety.

434.13 Special Crossings

Water, railroad, and highway crossings require specific considerations not readily covered in a general statement, since all involve variations in basic design. The pipeline company shall obtain required permits for such crossings. The design shall employ sound engineering and good pipeline practice with minimum hazard to the facility and due consideration of public safety. Construction shall be so organized as to result in minimal interference with traffic or the activities of adjacent property owners. Adequate efforts shall be made to determine the location of buried pipelines, utility lines, and other underground structures along and crossing the proposed right of way. The owners of any affected structures shall be given adequate prior notice of the proposed construction so that the owner may make operational preparations and provide a representative at the crossing.

434.13.1 Water Crossings. Crossings of rivers, streams, lakes, and inland bodies of water are individual problems, and the designer shall investigate composition of bottom, variation in banks, velocity of water, scouring, and special seasonal problems. The designer shall determine whether the crossing is to be underwater, overhead on a suspension bridge, or supported on an adjacent bridge. Continuity of operation and the safety of the general public shall be the controlling factors both in design and in construction. Where required, detailed plans and specifications shall be prepared taking into account these and any special considerations or limitations imposed by the regulatory body involved.

(a) Underwater Construction. Plans and specifications shall describe the position of the line, showing relationship of the pipeline to the natural bottom and the depth below mean low water level when applicable. To meet the conditions set out in para. 434.13.1, heavier wall pipe may be specified. Approach and position of the line in the banks is important, as is the position of the line across the bottom. Special consideration shall be given to depth of cover and other means of protecting the pipeline in the surf zone. Special consideration shall be given to protective coating and the use of concrete jacketing or the application of river weights. Complete inspection shall be provided. Precautions shall be taken during construction to limit stress below the level that would produce buckling

or collapse due to out-of-roundness of the completed pipeline.

434.13.2 Overhead Structures. Overhead structures used to suspend pipelines shall be designed and constructed on the basis of sound engineering and within the restrictions or regulations of the governing body having jurisdiction. Detailed plans and specifications shall be prepared where required and adequate inspection shall be provided to assure complete adherence thereto.

434.13.3 Bridge Attachments. Special requirements are involved in this type of crossing. The use of higher strength lightweight steel pipe, proper design and installation of hangers, and special protection to prevent damage by the elements or bridge and approach traffic shall be considered. Any agreed upon restrictions or precautions shall be contained in the detailed specifications. Inspectors shall assure themselves that these requirements are met.

02 **434.13.4 Railroad and Highway Crossings**

(a) The safety of the general public and the prevention of damage to the pipeline by reason of its location are primary considerations. The great variety of such crossings precludes standard design. The construction specifications shall cover the procedure for such crossings, based upon the requirements of the specific location.

(b) Installation of uncased carrier pipe is preferred. Installation of carrier pipe, or casing if used, shall be in accordance with API RP 1102. As specified in para. 461.1.2(f), if casing is used, coated carrier pipe shall be independently supported outside each end of the casing and insulated from the casing throughout the cased section, and casing ends shall be sealed using a durable, electrically nonconductive material.

(c) The total effective stress due to internal design pressure and external loads (including both live and dead loads) in pipe installed under railroads or highways without use of casing shall be calculated in accordance with API RP 1102 and shall not exceed the allowable effective stress noted in para. 402.3.2(e). Also, cyclic stress components shall be checked for fatigue.

434.14 Inland Coastal Water Construction

Plans and specifications shall describe alignment of the pipeline, depth below mean water level, and depth below bottom if ditched. Special consideration shall be given to depth of cover and other means of protecting the pipeline in the surf zone. Consideration shall be given to use of weight coating(s), anchors, or other means of maintaining position of the pipe under anticipated conditions of buoyance and water motion. Complete construction inspection shall be provided. Precautions shall be taken during construction to limit stress below the level that would produce buckling or collapse due to out-of-roundness of the completed pipeline.

434.15 Block and Isolating Valves

434.15.1 General

(a) Block and isolating valves shall be installed for limiting hazard and damage from accidental discharge and for facilitating maintenance of the piping system.

(b) Valves shall be at accessible locations, protected from damage or tampering, and suitably supported to prevent differential settlement or movement of the attached piping. Where an operating device to open or close the valve is provided, it shall be protected and accessible only to authorized persons.

(c) Submerged valves on pipelines shall be marked or spotted by survey techniques to facilitate quick location when operation is required.

434.15.2 Mainline Valves

(a) Mainline block valves shall be installed on the upstream side of major river crossings and public water supply reservoirs. Either a block or check valve shall be installed on the downstream side of major river crossings and public water supply reservoirs.

(b) A mainline block valve shall be installed at mainline pump stations, and a block or check valve (where applicable to minimize pipeline backflow) shall be installed at other locations appropriate for the terrain features. In industrial, commercial, and residential areas where construction activities pose a particular risk of external damage to the pipeline, provisions shall be made for the appropriate spacing and location of mainline valves consistent with the type of liquids being transported.

(c) A remotely operated mainline block valve shall be provided at remotely controlled pipeline facilities to isolate segments of the pipeline.

(d) On piping systems transporting LPG or liquid anhydrous ammonia, check valves shall be installed where applicable with each block valve to provide automatic blockage of reverse flow in the piping system.

(e) In order to facilitate operational control, limit the duration of an outage, and to expedite repairs, mainline block valves shall be installed at 7.5 mile (12 km) maximum spacing on piping systems transporting LPG or liquid anhydrous ammonia in industrial, commercial, and residential areas.

434.15.3 Pump Station, Tank Farm, and Terminal Valves

(a) Valves shall be installed on the suction and discharge of pump stations whereby the pump station can be isolated from the pipeline.

(b) Valves shall be installed on lines entering or leaving tank farms or terminals at convenient locations whereby the tank farm or terminal may be isolated from other facilities such as the pipeline, manifolds, or pump stations.

434.16 Connections to Main Lines

Where connections to the main line such as branch lines, jump-overs, relief valves, air vents, etc., are made to the main line, they shall be made in accordance with para. 404.3.1. When such connections or additions are made to coated lines, all damaged coating shall be removed and replaced with new coating material in accordance with para. 461.1.2(h). This protective coating should include the attachments.

434.17 Scraper Traps

434.17.1 Scraper traps are to be installed as deemed necessary for good operations. All pipe, valves, fittings, closures, and appurtenances shall comply with appropriate sections of this Code.

434.17.2 Scraper traps on mainline terminations and tied into connection piping or manifolding shall be anchored below ground with adequate concrete anchors when required and suitably supported above ground to prevent transmission of line stresses due to expansion and contraction to connecting facilities.

434.17.3 Scraper trap and its components shall be assembled in accordance with para. 435, and pressure tested to the same limits as the main line. See para. 437.4.

02 ### 434.18 Line Markers

(a) Except as provided in paragraph (d) of this section, adequate pipeline location markers for the protection of the pipeline, the public, and persons performing work in the area shall be placed over each buried pipeline in accordance with the following:

(1) Markers shall be located at each public road crossing, at each railroad crossing, at each navigable stream crossing, and in sufficient numbers along the remainder of the buried line so that the pipeline location including direction of the pipeline is adequately known. It is recommended that markers are installed on each side of each crossing whenever possible.

(2) Markers shall be installed at locations where the line is above ground in areas which are accessible to the public.

(b) The marker shall state at least the following on a background of sharply contrasting colors:

(1) The word "Warning," "Caution," or "Danger" followed by the words "Petroleum (or the name of the hazardous liquid transported) Pipeline" or "Carbon Dioxide Pipeline" all of which, except for markers in heavily developed urban areas, must be in letters at least one inch high with an approximate stroke of one-quarter inch.

(2) The name of the operator and a telephone number (including area code) where the operator can be reached at all times.

(c) API RP 1109 should be used for additional guidance.

(d) Unless required by applicable regulatory agencies, line markers are not required for buried pipelines located offshore or under waterways and other bodies of water, or in heavily developed urban areas such as downtown business centers where the placement of markers is impractical and would not serve the purpose for which markers are intended and the local government maintains substructure records.

434.19 Corrosion Control

Protection of ferrous pipe and components from external and internal corrosion shall be as prescribed in Chapter VIII.

434.20 Pump Station, Tank Farm, and Terminal Construction

434.20.1 General. All construction work performed on pump stations, tank farms, terminals, equipment installations, piping, and allied facilities shall be done under construction specifications. Such specifications shall cover all phases of the work under contract and shall be in sufficient detail to insure that the requirements of this Code shall be met. Such specifications shall include specific details on soil conditions, foundations and concrete work, steel fabrication and building erection, piping, welding, equipment and materials, and all construction factors contributing to safety and sound engineering practice.

434.20.2 Location. Pump stations, tank farms, and terminals should be located on the pipeline's fee or leased property in order to be assured that proper safety

precautions may be applied. The pump station, tank farm, or terminal shall be located at such clear distances from adjacent properties not under control of the company as to minimize the communication of fire from structures on adjacent properties. Similar consideration shall be given to its relative location from the station, manifolds, tankage, maintenance facilities, personnel housing, etc. Sufficient open space shall be left around the building and manifolds to provide access for maintenance equipment and fire fighting equipment. The station, tank farm, or terminal shall be fenced in such a manner as to minimize trespass, and roadways and gates should be located to give ready access to or egress from the facilities.

434.20.3 Building Installation. Buildings shall be located and constructed to comply with detailed plans and specifications. The excavation for and installation of foundations and erection of the building shall be done by craftsmen familiar with the respective phase of the work, and all work shall be done in a safe and workmanlike manner. Inspection shall be provided to assure that the requirements of the plans and specifications are met.

434.20.4 Pumping Equipment and Prime Movers. Installation of pumping equipment and prime movers shall be covered by detailed plans and specifications which have taken into account the variables inherent in local soil conditions, utilization, and arrangement of the equipment to provide the optimum in operating ease and maintenance access. Machinery shall be handled and mounted in accordance with recognized good millwright practice and be provided with such protective covers as to prevent damage during construction. Recommendations of installation details provided by manufacturers for auxiliary piping, setting, and aligning shall be considered as minimum requirements.

434.20.5 Pump Station, Tank Farm, and Terminal Piping. All piping, including but not limited to main unit interconnections, manifolds, scraper traps, etc., which can be subject to the mainline pressure shall be constructed in accordance with the welding standards (see para. 434.8), corrosion control requirements (see Chapter VIII), and other practices of this Code.

434.20.6 Controls and Protective Equipment. Pressure controls and protective equipment, including pressure limiting devices, regulators, controllers, relief valves, and other safety devices, as shown on the drawings or required by the specifications, shall be installed by competent and skilled workmen. Installation shall be accomplished with careful handling and minimum exposure of instruments and devices to inclement weather conditions, dust, or dirt to prevent damage. Also, piping, conduits, or mounting brackets shall not cause the instruments or devices to be distorted or in any strain. Instruments and devices shall be installed so that they can be checked without undue interruptions in operations. After installation, controls and protective equipment shall be tested under conditions approximating actual operations to assure their proper functioning.

434.20.7 Fire Protection. Fire protection when provided shall be in accordance with recommendations in NFPA 30. If the system installed requires the services of fire pumps, their motive power shall be separate from the station power so that their operation shall not be affected by emergency shutdown facilities.

434.21 Storage and Working Tankage

434.21.1 General. All construction work performed on storage and working tankage and allied equipment, piping, and facilities shall be done under construction specifications. Such specifications shall cover all phases of the work under contract, and shall be in sufficient detail to insure that the requirements of the Code shall be met. Such specifications shall include specific details on soil conditions, foundations and concrete work, tank fabrication and erection, piping, welding, equipment and materials, dikes, and all construction factors contributing to safety and sound engineering practice.

434.21.2 Location

(a) Tankage shall be located on the pipeline's fee or leased property in order to assure that proper safety precautions may be applied. Tank facilities shall be located at such clear distances from adjacent properties not under control of the company as to minimize the communication of fire from structures on adjacent properties. Similar consideration shall be given to relative locations between station manifolds, pumping equipment, maintenance facilities, personnel housing, etc. Sufficient open space shall be left around the tankage facilities and associated equipment to provide access for maintenance and fire fighting equipment. The tankage area shall be fenced so as to minimize trespass, and roadways and gates should be located to give ready ingress to and egress from the facilities.

(b) Spacing of tankage shall be governed by the requirements of NFPA 30.

434.21.3 Tanks and Pipe-Type Storage

(a) Tanks for storage or handling crude oil and liquid petroleum products and liquid alcohols having vapor pressures approximating atmospheric shall be

constructed in accordance with API 650, API 12B, API 12D, API 12F, or designed and constructed in accordance with accepted good engineering practices.

(b) Tanks for storage or handling liquid petroleum products and liquid alcohols having vapor gage pressures of 0.5 psi (0.035 bar) but not exceeding 15 psi (1 bar) shall be constructed in accordance with API 620.

(c) Tanks used for storage or handling liquids having vapor gage pressures greater than 15 psi (1 bar) shall be designed and constructed in accordance with the design of accredited tank builders and the ASME Boiler and Pressure Vessel Code, Section VIII, Division 1 or Division 2.

(d) Buried pipe-type holders used for storage and handling liquid petroleum, liquid alcohols, or liquid anhydrous ammonia shall be designed and constructed in accordance with the requirements of this Code for pipe and piping components.

434.21.4 Foundations. Tank foundations shall be constructed in accordance with plans and specifications which shall take into account local soil conditions, type of tank, usage, and general location.

434.21.5 Dikes or Firewalls. The protection of the pipeline's station, tank farm, terminal, or other facilities from damage by fire from adjacent facilities, as well as the protection of the general public, may dictate the need of dikes or firewalls around tankage or between tankage and station or terminal. Tank dikes or firewalls, where required, shall be constructed to meet the capacity requirements set out in NFPA 30.

434.22 Electrical Installations

434.22.1 General. Electrical installations for lighting, power, and control shall be covered by detailed plans and specifications, and installations shall be in accordance with codes applicable to the specific type of circuitry and classification of areas for electrical installation. Inspection shall be provided and all circuitry shall be tested before operation to assure that the installation was made in workmanlike manner to provide for the continuing safety of personnel and equipment. Installations shall be made in accordance with NFPA 70 and API RP 500C.

434.22.2 Care and Handling of Materials. All electrical equipment and instruments shall be carefully handled and properly stored or enclosed to prevent damage, deterioration, or contamination during construction. Packaged components are not to be exposed until installation. Equipment susceptible to damage or deterioration by exposure to humidity shall be adequately protected by using appropriate means such as plastic film enclosures, desiccants, or electric heating.

434.22.3 Installation. The installation of electrical materials shall be made by qualified personnel familiar with details of electrical aspects and code requirements for such installation. At all times care shall be exercised to prevent damage to the insulation of cable and wiring. All partial installations shall be protected from damage during construction. The installation design and specifications shall give consideration to the need for dust- and/or moisture-proof enclosures for such special gear as relays, small switches, and electronic components. In no case shall the frames of electric motors or other grounded electrical equipment be used as the ground connection for electrical welding.

434.23 Liquid Metering

434.23.1 Positive displacement meters, turbine meters, or equivalent liquid measuring devices and their proving facilities shall be designed and installed in accordance with the API Manual of Petroleum Measurement Standards.

434.23.2 Provisions shall be made to permit access to these facilities by authorized personnel only.

434.23.3 Assembly of the metering facility components shall be in accordance with para. 435.

434.24 Liquid Strainers and Filters

434.24.1 Strainers and filters shall be designed to the same pressure limitations and subjected to the same test pressures as the piping system in which they are installed, and supported in such a manner as to prevent undue loading to the connecting piping system.

434.24.2 Installation and design shall provide for ease of maintenance and servicing without interference with the station operation.

434.24.3 The filtering medium should be of such retention size and capacity as to fully protect the facilities against the intrusion of harmful foreign substances.

434.24.4 Assembly of strainers or filters and their components shall be in accordance with para. 435.

435 ASSEMBLY OF PIPING COMPONENTS

435.1 General

The assembly of the various piping components, whether done in a shop or as a field erection, shall be done so that the completely erected piping conforms

with the requirements of this Code and with the specific requirements of the engineering design.

435.2 Bolting Procedure

435.2.1 All flanged joints shall be fitted up so that the gasket contact faces bear uniformly on the gasket, and made up with uniform bolt stress.

435.2.2 In bolting gasketed flanged joints, the gasket shall be properly compressed in accordance with the design principles applicable to the type of gasket used.

435.2.3 All bolts or studs shall extend completely through their nuts.

435.3 Pumping Unit Piping

435.3.1 Piping to main pumping units shall be so designed and supported that when assembled to the pump flanges and valves it should be relatively free of stress and should not add stress or load to the pump frame.

435.3.2 The design and assembly shall take into account the forces of expansion and contraction to minimize their effect within the assembly.

435.3.3 All valves and fittings on pumping units shall carry the same pressure ratings as required for line operating pressures.

435.3.4 Welding shall be in accordance with para. 434.8 of the Code.

435.3.5 Bolting shall be in accordance with para. 435.2.

435.4 Manifolds

435.4.1 All components within a manifold assembly, including valves, flanges, fittings, headers, and special assemblies, shall withstand the operating pressures and specified loadings for the specific service piping to which it is connected.

435.4.2 Meter banks, prover loops, and scraper traps shall be subject to the same assembly requirements as manifolds.

435.4.3 Manifold headers with multiple outlets shall have outlets designed as covered in paras. 404.3.1(b) and 404.3.1(e) and illustrated in Figs. 404.3.1(b)(3) and 404.3.1(d)(2), respectively. Assembly may be with the use of jigs to assure alignment of outlets and flanges with other components. The fabricated unit shall be stress relieved before removal from the jig.

435.4.4 Manifold headers assembled from wrought tees, fittings, and flanges may be assembled with jigs to assure alignment of components. Stress relieving should be considered.

435.4.5 All welding on manifolds and headers shall conform to para. 434.8.

435.4.6 Final assembly of all components shall minimize locked-in stresses. The entire assembly shall be adequately supported to provide minimum unbalance and vibration.

435.5 Auxiliary Liquid Petroleum, Carbon Dioxide, Liquid Anhydrous Ammonia, or Liquid Alcohol Piping

435.5.1 All auxiliary piping between main units and auxiliary components shall be assembled in a workmanlike manner and in accordance with the applicable code.

435.5.2 All welded auxiliary lines shall be assembled in accordance with the requirements of this Code with special provisions as required for assembly to minimize locked-in stress, and for adequate support or restraint to minimize vibration.

CHAPTER VI
INSPECTION AND TESTING

436 INSPECTION

436.1 General

Construction inspection provisions for pipelines and related facilities shall be adequate to assure compliance with the material, construction, welding, assembly, and testing requirements of this Code.

436.2 Qualification of Inspectors

Inspection personnel shall be qualified by training and experience. Such personnel shall be capable of performing the following inspection services:

(a) right of way and grading;

(b) ditching;

(c) line up and pipe surface inspection;

(d) welding;

(e) coating;

(f) tie-in and lowering;

(g) backfilling and clean up;

(h) pressure testing;

(i) special services for testing and inspection of facilities, such as station construction, river crossings, electrical installation, radiography, corrosion control, etc., as may be required.

436.5 Type and Extent of Examination Required

436.5.1 Visual

(a) Material

(1) All piping components shall be visually inspected to insure that no mechanical damage has occurred during shipment and handling prior to being connected into the piping system.

(2) All pipe shall be visually inspected to discover any defects as described in paras. 434.5 and 434.8.7.

(3) On systems where pipe is telescoped by grade, wall thickness, or both, particular care shall be taken to insure proper placement of pipe. Permanent records shall be kept showing the location as installed of each grade, wall thickness, type, specification, and manufacturer of the pipe.

(b) Construction

(1) Visual inspection for detection of surface defects in the pipe shall be provided for each job just ahead of any coating operation and during the lowering-in and backfill operation.

(2) The pipe swabbing operation shall be inspected for thoroughness to provide a clean surface inside the pipe.

(3) Before welding, the pipe shall be examined for damage-free bevels and proper alignment of the joint.

(4) The stringer bead shall be inspected, particularly for cracks, before subsequent beads are applied.

(5) The completed weld shall be cleaned and inspected prior to coating operations, and irregularities that could protrude through the pipe coating shall be removed.

(6) When the pipe is coated, inspection shall be made to determine that the coating machine does not cause harmful gouges or grooves in the pipe surface.

(7) Lacerations of the pipe coating shall be inspected prior to repair of coating to see if the pipe surface has been damaged. Damaged coating and pipe shall be repaired before the pipe is lowered in the ditch.

(8) All repairs, changes, or replacements shall be inspected before they are covered up.

(9) The condition of the ditch shall be inspected before the pipe is lowered in to assure proper protection of pipe and coating. For underwater crossings the condition of the ditch and fit of the pipe to the ditch shall be inspected when feasible.

(10) The fit of the pipe to ditch shall be inspected before the backfilling operations.

(11) The backfilling operations shall be inspected for quality and compaction of backfill, placement of material for the control of erosion, and possible damage to the pipe coatings.

(12) Cased crossings shall be inspected during installation to determine that the carrier pipe is supported, sealed, and insulated from the casing.

(13) River crossings shall have thorough inspection, and shall be surveyed and profiled after construction.

(14) All piping components other than pipe shall be inspected to insure damage-free condition and proper installation.

436.5.2 Supplementary Types of Examination

(a) Testing of field and shop welds shall be made in accordance with para. 434.8.5.

(b) Radiographic inspection of welds shall be performed in accordance with para. 434.8.5.

(c) Coated pipe shall be inspected in accordance with para. 461.1.2.

436.6 Repair of Defects

436.6.1 Defects of fabricated items and in pipe wall shall be repaired or eliminated in accordance with para. 434.5.

436.6.2 Welding defects shall be repaired in accordance with para. 434.8.7.

436.6.3 Holidays or other damage to coating shall be repaired in accordance with para. 461.1.2.

437 TESTING

437.1 General

(a) In order to meet requirements of this Code, it is necessary that tests be made upon the completed system and upon component parts of the finished system. When reference in this Code is made to tests or portions of tests described in other codes and specifications, they shall be considered as a part of this Code.

(b) Should leaks occur on tests, the line section or component part shall be repaired or replaced and retested in accordance with this Code.

437.1.3 Testing of Fabricated Items

(a) Fabricated items such as scraper traps, manifolds, volume chambers, etc., shall be hydrostatically tested to limits equal to or greater than those required of the completed system. This test may be conducted separately or as a part of the completed system.

(b) In testing fabricated items before installation, the applicable paragraphs of specifications listed in Table 423.1 shall apply.

437.1.4 Testing After New Construction

(a) Systems or Parts of Systems

(1) All liquid transportation piping systems within the scope of this Code, regardless of stress, shall be tested after construction. Carbon dioxide systems shall be hydrostatically tested.

(2) Systems to be operated at a hoop stress of more than 20% of the specified minimum yield strength of the pipe shall be hydrostatically tested in accordance with para. 437.4.1.

(3) Systems to be operated at a hoop stress of 20% or less of specified minimum yield strength of the pipe may be subjected to a leak test in accordance with para. 437.4.3 in lieu of the hydrostatic test specified in para. 437.4.1.

(4) When testing piping, in no case shall the test pressure exceed that stipulated in the standards of material specifications (except pipe) incorporated in this Code by reference and listed in Table 423.1 for the weakest element in the system, or portion of system, being tested.

(5) Equipment not to be subjected to test pressure shall be disconnected from the piping or otherwise isolated. Valves may be used if valve, including closing mechanism, is suitable for the test pressure.

(b) Testing Tie-Ins. Because it is sometimes necessary to divide a pipeline into test sections and install test heads, connecting piping, and other necessary appurtenances for testing, or to install a pretested replacement section, it is not required that tie-in welds be tested; however, tie-in welds and girth welds joining lengths of pretested pipe shall be inspected by radiographic or other accepted nondestructive methods in accordance with para. 434.8.5(a)(4) if system is not pressure tested after tie-in. After such inspection, the joint shall be coated and inspected in accordance with para. 461.1.2 before backfilling.

(c) Testing Controls and Protective Equipment. All controls and protective equipment, including pressure limiting devices, regulators, controllers, relief valves, and other safety devices, shall be tested to determine that they are in good mechanical condition; of adequate capacity, effectiveness, and reliability of operation for the service in which they are employed; functioning at the correct pressure; and properly installed and protected from foreign materials or other conditions that might prevent proper operation.

437.4 Test Pressure

437.4.1 Hydrostatic Testing of Internal Pressure Piping

(a) Portions of piping systems to be operated at a hoop stress of more than 20% of the specified minimum yield strength of the pipe shall be subjected at any point to a hydrostatic proof test equivalent to not less than 1.25 times the internal design pressure at that point (see para. 401.2.2) for not less than 4 hr. When lines are tested at pressures that develop a hoop stress, based on nominal wall thickness, in excess of 90% of the specified minimum yield strength of the pipe, special care shall be used to prevent overstrain of the pipe.

(1) Those portions of piping systems where all of the pressured components are visually inspected during the proof test to determine that there is no leakage require no further test. This can include lengths of pipe that are pretested for use as replacement sections.

(2) On those portions of piping systems not visually inspected while under test, the proof test shall be followed by a reduced pressure leak test equivalent to not less than 1.1 times the internal design pressure for not less than 4 hr.

(b) API RP 1110 may be used for guidance for the hydrostatic test.

(c) The hydrostatic test shall be conducted with water, except liquid petroleum that does not vaporize rapidly may be used provided:

(1) the pipeline section under test is not offshore and is outside of cities and other populated areas, and each building within 300 ft (90 m) of the test section is unoccupied while the test pressure is equal to or greater than a pressure which produces a hoop stress of 50% of the specific minimum yield strength of the pipe;

(2) the test section is kept under surveillance by regular patrols during test; and

(3) communication is maintained along the test section.

(d) If the testing medium in the system will be subject to thermal expansion during the test, provisions shall be made for relief of excess pressure. Effects of temperature changes shall be taken into account when interpretations are made of recorded test pressures.

(e) After completion of the hydrostatic test, it is important in cold weather that the lines, valves, and fittings be drained completely of any water to avoid damage due to freezing.

(f) Carbon dioxide pipelines, valves, and fittings shall be dewatered and dried prior to placing in service to prevent the possibility of forming a corrosive compound from carbon dioxide and water.

437.4.3 Leak Testing. A 1 hr hydrostatic or pneumatic leak test may be used for piping systems to be operated at a hoop stress of 20% or less of the specified minimum yield strength of the pipe. The hydrostatic test pressure shall be not less than 1.25 times the internal design pressure. The pneumatic test gage pressure shall be 100 psi (7 bar) or that pressure which would produce a nominal hoop stress of 25% of the specified minimum yield strength of the pipe, whichever is less.

437.6 Qualification Tests

Where tests are required by other sections of this Code, the following procedures shall be used.

437.6.1 Visual Examination. Used or new pipe to be laid shall be visually examined in accordance with para. 436.5.1.

437.6.2 Bending Properties

(a) For pipe of unknown specification or ASTM A 120, bending properties are required if minimum yield strength used for design is above 24,000 psi (165 MPa), and after type of joint has been identified in accordance with para. 437.6.4. For pipe NPS 2 and smaller, bending test shall meet the requirements of ASTM A 53 or API 5L. For pipe larger than NPS 2 in nominal diameter, flattening tests shall meet the requirements in ASTM A 53, API 5L, or API 5LU.

(b) The number of tests required to determine bending properties shall be the same as required in para. 437.6.6 to determine yield strength.

437.6.3 Determination of Wall Thickness. When the nominal wall thickness is not known, it shall be determined by measuring the thickness at quarter points on one end of each piece of pipe. If the lot of pipe is known to be of uniform grade, size, and nominal thickness, measurement shall be made on not less than 5% of the individual lengths, but not less than 10 lengths; thickness of the other lengths may be verified by applying a gage set to the minimum thickness. Following such measurement, the nominal wall thickness shall be taken as the next nominal wall thickness below the average of all the measurements taken, but in no case greater than 1.14 times the least measured thickness for all pipe under NPS 20, and no greater than 1.11 times the least measured thickness for all pipe NPS 20 and larger.

437.6.4 Determination of Weld Joint Factor. If the type of longitudinal or spiral weld joint is known, the corresponding weld joint factor (Table 402.4.3) may be used. Otherwise, as noted in Table 402.4.3, the factor E shall not exceed 0.60 for pipe NPS 4 and smaller, or 0.80 for pipe over NPS 4.

437.6.5 Weldability. For steel pipe of unknown specification, weldability shall be determined as follows. A qualified welder shall make a girth weld in the pipe. This weld shall be tested in accordance with the requirements of para. 434.8.5. The qualifying weld shall be made under the most severe conditions under which welding will be permitted in the field and using the same procedure as to be used in the field. The pipe shall be considered weldable if the requirements set forth in para. 434.8.5 are met. At least one such test

weld shall be made for each number of lengths to be used as listed below.

Minimum Number of Test Welds

Nominal Pipe Size	Number of Lengths per Test
Less than 6	400
6 through 12	200
Larger than 12	100

All test specimens shall be selected at random.

437.6.6 Determination of Yield Strength. When the specified minimum yield strength, minimum tensile strength, or minimum percent of elongation of pipe is unknown, the tensile properties may be established as follows.

Perform all tensile tests prescribed by API 5L or 5LU, except that the minimum number of such tests shall be as follows.

Nominal Pipe Size	Number of Lengths per Test
Less than 6	200
6 through 12	100
Larger than 12	50

All test specimens shall be selected at random.

437.6.7 Minimum Yield Strength Value. For pipe of unknown specification, the minimum yield strength may be determined as follows.

Average the value of all yield strength tests for a test lot. The minimum yield strength shall then be taken as the lesser of the following:

(a) 80% of the average value of the yield strength tests;

(b) the minimum value of any yield strength test, except that in no case shall this value be taken as greater than 52,000 psi (358 MPa);

(c) 24,000 psi (165 MPa) if the average yield-tensile ratio exceeds 0.85.

437.7 Records

A record shall be maintained in the files of the operating company relative to design, construction, and testing of each mainline within the scope of this Code. These records shall include material specifications; route maps and alignments sheets for 'as-built' condition; location of each pipe size, grade, wall thickness, type of seam (if any), and manufacturer; coatings; test data; and, for carbon dioxide pipelines, toughness requirements. These records shall be kept for the life of the facility. See para. 436.5.1(a)(3).

CHAPTER VII
OPERATION AND MAINTENANCE PROCEDURES

450 OPERATION AND MAINTENANCE PROCEDURES AFFECTING THE SAFETY OF LIQUID TRANSPORTATION PIPING SYSTEMS

450.1 General

(a) It is not possible to prescribe in this Code a detailed set of operating and maintenance procedures that will encompass all cases. It is possible, however, for each operating company to develop operating and maintenance procedures based on the provisions of this Code, and the company's experience and knowledge of its facilities and conditions under which they are operated, which will be adequate from the standpoint of public safety.

(b) The methods and procedures set forth herein serve as a general guide, but do not relieve the individual or operating company from the responsibility for prudent action that current particular circumstances make advisable.

(c) It must be recognized that local conditions (such as the effects of temperature, characteristics of the line contents, and topography) will have considerable bearing on the approach to any particular maintenance and repair job.

(d) Suitable safety equipment shall be available for personnel use at all work areas and operating facilities where liquid anhydrous ammonia is transported. Such safety equipment shall include at least the following:

(1) full face gas mask with anhydrous ammonia refill canisters;

(2) independently supplied air mask;

(3) tight-fitting goggles or full face shield;

(4) protective gloves;

(5) protective boots;

(6) protective slicker and/or protective pants and jacket;

(7) easily accessible shower and/or at least 50 gal (190 liters) of clean water in an open top container.

Personnel shall be instructed in effective use of masks and limited shelf life of refill canisters. Protective clothing shall be of rubber fabric or other ammonia impervious material.

450.2 Operation and Maintenance Plans and Procedures

Each operating company having a transportation piping system within the scope of this Code shall:

(a) have written detailed plans and training programs for employees covering operating and maintenance procedures for the transportation piping system during normal operations and maintenance in accordance with the purpose of this Code; essential features recommended for inclusion in the plans for specific portions of the system are given in paras. 451 and 452.

(b) have a plan for external and internal corrosion control of new and existing piping systems, including requirements and procedures prescribed in para. 453 and Chapter VIII;

(c) have a written Emergency Plan as indicated in para. 454 for implementation in the event of system failures, accidents, or other emergencies; train appropriate operating and maintenance employees with regard to applicable portions of the plan, and establish liaison with appropriate public officials with respect to the plan;

(d) have a plan for reviewing changes in conditions affecting the integrity and safety of the piping system, including provisions for periodic patrolling and reporting of construction activity and changes in conditions, especially in industrial, commercial, and residential areas and at river, railroad, and highway crossings, in order to consider the possibility of providing additional protection to prevent damage to the pipeline in accordance with para. 402.1;

(e) establish liaison with local authorities who issue construction permits in urban areas to prevent accidents caused by excavators;

(f) establish procedures to analyze all failures and accidents for the purpose of determining the cause and to minimize the possibility of recurrence;

(g) maintain necessary maps and records to properly administer the plans and procedures, including records listed in para. 455;

(h) have procedures for abandoning piping systems, including the requirements in para. 457;

(i) in establishing plans and procedures, give particu-

lar attention to those portions of the system presenting the greatest hazard to the public in the event of emergencies or because of construction or extraordinary maintenance requirements;

(j) operate and maintain its piping system in conformance with these plans and procedures;

(k) modify the plans and procedures from time to time as experience dictates and as exposure of the system to the public and changes in operating conditions require.

451 PIPELINE OPERATION AND MAINTENANCE

451.1 Operating Pressure

(a) Care shall be exercised to assure that at any point in the piping system the maximum steady state operating pressure and static head pressure with the line in a static condition do not exceed at that point the internal design pressure and pressure ratings for the components used as specified in para. 402.2.3, and that the level of pressure rise due to surges and other variations from normal operation does not exceed the internal design pressure at any point in the piping system and equipment by more than 10% as specified in para. 402.2.4.

(b) A piping system shall be qualified for a higher operating pressure when the higher operating pressure will produce a hoop stress of more than 20% of the specified minimum yield strength of the pipe in accordance with para. 456.

(c) If a piping system is derated to a lower operating pressure in lieu of repair or replacement, the new maximum steady state operating pressure shall be determined in accordance with para. 451.7.

(d) For existing systems utilizing materials produced under discontinued or superseded standards or specifications, the internal design pressure shall be determined using the allowable stress and design criteria listed in the issue of the applicable code or specification in effect at the time of the original construction.

451.2 Communications

A communications facility shall be maintained to assure safe pipeline operations under both normal and emergency conditions.

C2 ### 451.3 Line Markers and Signs

(a) Line markers shall be installed and maintained over each line at each public road crossing, at each railroad crossing, at each navigable stream crossing, and in sufficient number along the remainder of the pipeline route to properly locate and identify the buried pipeline. See para. 434.18.

(b) Pipeline markers at crossings, aerial markers when used, and other signs shall be maintained so as to indicate the location of the line and to provide the required information on the pipeline. Additional pipeline markers shall be installed and maintained along the pipeline in areas of development and growth to protect the pipeline from encroachment.

451.4 Right of Way Maintenance

(a) The right of way should be maintained so as to have clear visibility and to give reasonable access to maintenance crews.

(b) Access shall be maintained to valve locations.

(c) Diversion ditches or dikes shall be maintained where needed to protect against washouts of the line and erosion of the landowner's property.

451.5 Patrolling

(a) Each operating company shall maintain a periodic pipeline patrol program to observe surface conditions on and adjacent to the pipeline right of way, indication of leaks, construction activity other than that performed by the company, and any other factors affecting the safety and operation of the pipeline. Special attention shall be given to such activities as road building, ditch cleanouts, excavations, and like encroachments to the pipeline system. Patrols shall be made at intervals not exceeding 2 weeks, except that piping systems transporting LPG or liquid anhydrous ammonia shall be patrolled at intervals not exceeding 1 week in industrial, commercial, or residential areas.

(b) Underwater crossings shall be inspected periodically for sufficiency of cover, accumulation of debris, or for any other condition affecting the safety and security of the crossings, and at any time it is felt that the crossings are in danger as a result of floods, storms, or suspected mechanical damage.

451.6 Pipeline Repairs

451.6.1 General

(a) Repairs shall be covered by a maintenance plan [see para. 450.2(a)] and shall be performed under qualified supervision by trained personnel aware of and familiar with the hazards to public safety, utilizing strategically located equipment and repair materials. The maintenance plan shall consider the appropriate

information contained in API Publ. 2200, API Pub. 2201, API Standard 1104, and API RP 1111. It is essential that all personnel working on pipeline repairs understand the need for careful planning of the job, be briefed as to the procedure to be followed in accomplishing the repairs, and follow precautionary measures and procedures outlined in API Publ. 2200. Personnel working on repairs to pipelines handling LPG, carbon dioxide, liquid alcohol, or liquid anhydrous ammonia shall also be informed on the specific properties, characteristics, and potential hazards associated with those liquids, precautions to be taken following detection of a leak, and safety repair procedures set forth for LPG pipelines in API Publ. 2200. Approvals, procedures, and special considerations described in API Publ. 2201 shall be observed for welding, as well as making hot taps on pipelines, vessels, or tanks which are under pressure. Piping in the vicinity of any repair shall be adequately supported during and after the repair.

(b) If an inert fluid is used to temporarily displace the liquid in a pipeline system for the purpose of a repair, a detailed written procedure shall be required. Because the potential energy of a gas presents special concerns, this procedure shall address, as a minimum, the factors related to the use of an inert gas:

(1) maximum flow rate;

(2) pressure;

(3) injection temperature;

(4) inert gas disposal;

(5) safety procedures.

The procedure shall be followed under the supervision required in para. 451.6.1(a).

451.6.2 Disposition of Defects

(a) Limits and Dispositions of Imperfections

(1) Gouges and grooves shall be removed or repaired in accordance with para. 451.6.2(b).

(2) Dents meeting any of the following conditions shall be removed or repaired:

(a) dents which affect the pipe curvature at the pipe seam or at any girth weld;

(b) dents containing a scratch, gouge, or groove;

(c) dents exceeding a depth of $\frac{1}{4}$ in. (6 mm) in pipe NPS 4 and smaller, or 6% of the nominal pipe diameter in sizes greater than NPS 4;

(d) dents containing external corrosion where the remaining wall thickness is less than 87.5% of that required for design.

(3) All arc burns shall be removed or repaired.

(4) All cracks shall be removed or repaired.

(5) All welds found to have defects as set forth in para. 434.8.5(b) or in the appropriate pipe specification shall be removed or repaired.

(6) General Corrosion. Pipe shall be replaced, or repaired if the area is small, or operated at a reduced pressure (see para. 451.7) if general corrosion has reduced the wall thickness to less than the design thickness calculated in accordance with para. 404.1.2 decreased by an amount equal to the manufacturing tolerance applicable to the pipe or component.

(7) Localized Corrosion Pitting. Pipe shall be repaired, replaced, or operated at a reduced pressure (see para. 451.7) if localized corrosion pitting has reduced the wall thickness to less than the design thickness calculated in accordance with para. 404.1.2 decreased by an amount equal to the manufacturing tolerance applicable to the pipe or component. This applies if the length of the pitted area is greater than permitted by the equation shown below. The following method applies only when the depth of the corrosion pit is less than 80% of the nominal wall thickness of the pipe. This method shall not be used to evaluate corrosion concentrated in electric resistance welded seams (ERW), electric induction welded seams or electric flash-welded seams, nor shall it be used to evaluate corrosion-caused metal loss which is circumferentially oriented along or in a girth weld or its heat-affected zone. The method may be used, however, to evaluate the longitudinal profile of corrosion-caused metal loss which crosses a girth weld or impinges on a submerged arc welded seam. The corroded area must be clean to bare metal. Care shall be taken in cleaning corroded areas of a pressurized pipeline when the degree of corrosion is significant.

$$L = 1.12B\sqrt{Dt_n}$$

where

$$B = \sqrt{\left(\frac{c/t_n}{1.1c/t_n - 0.15}\right)^2 - 1}$$

L = maximum allowable longitudinal extent of the corroded area as shown in Fig. 451.6.2(a)(7), in. (mm)

B = a value not to exceed 4.0 which may be determined from the above equation or Fig. 451.6.2(a)(7)

D = nominal outside diameter of the pipe, in. (mm)

t_n = nominal wall thickness of the pipe, in. (mm)

c = maximum depth of the corroded area, in. (mm)

(8) Areas where grinding has reduced the remaining wall thickness to less than the design thickness calculated in accordance with para. 404.1.2 decreased

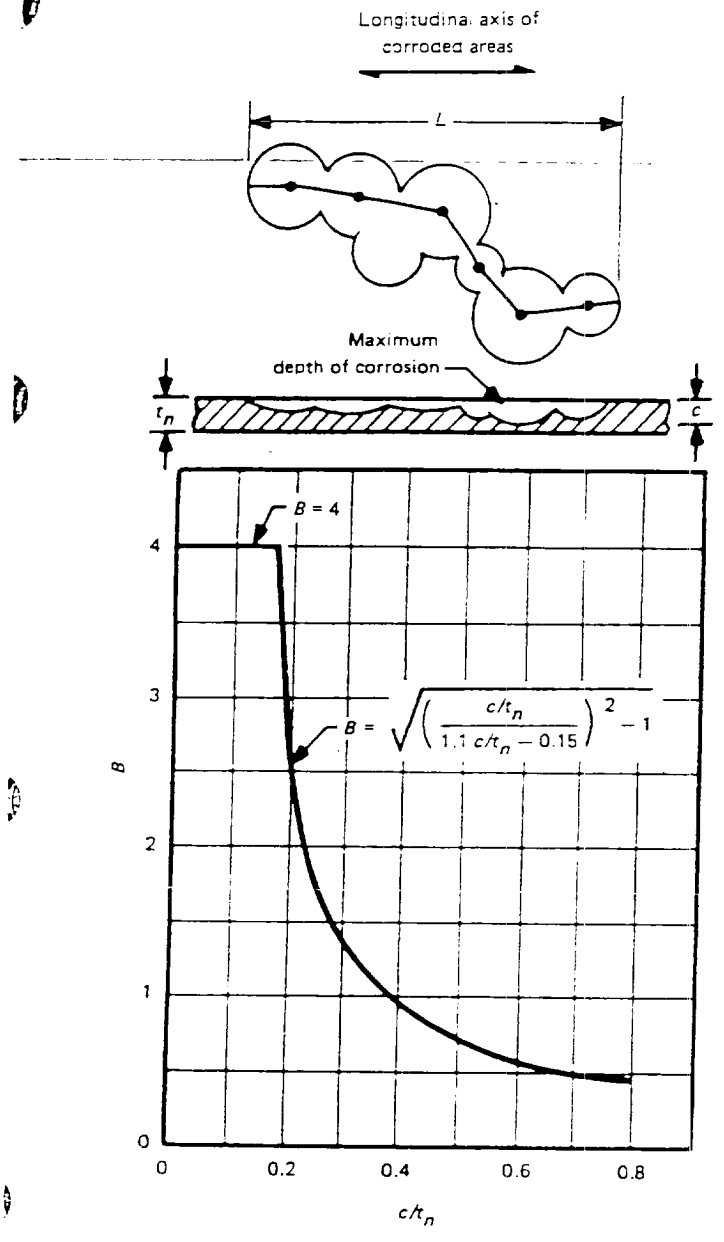


FIG. 451.6.2(a)(7) PARAMETERS USED IN ANALYSIS OF THE STRENGTH OF CORRODED AREAS

by an amount equal to the manufacturing tolerance applicable to the pipe or component, may be analyzed the same as localized corrosion pitting [see para. 451.6.2(a)(7)] to determine if ground areas need to be replaced, repaired, or the operating pressure reduced (see para. 451.7). ASME B31G may be used for guidance.

(9) All pipe containing leaks shall be removed or repaired.

(b) Allowable Pipeline Repairs

(1) If practical, the pipeline should be taken out of service and repaired by cutting out a cylindrical piece of pipe containing the defect and replacing the same with pipe meeting the requirements of para. 401.2.2 and having a length of not less than one-half diameter.

(2) If not practical to take the pipeline out of service, repairs may be made by the installation of a full encirclement welded or mechanically applied split sleeve in accordance with para. 451.6.2(c).

(a) For repairs of dents, or dents containing external corrosion where the remaining wall thickness is less than 87.5% of that required for design, either a hardenable filler material such as epoxy shall be used to fill the void between the sleeve and the pipe to restore the original contour of the pipe, or the carrier pipe shall be tapped through the sleeve or other means provided to equalize the internal pressures of the carrier pipe and the sleeve.

(b) For repairs to nonleaking cracks in materials that might be expected to behave in a brittle manner (e.g., a seam defect in a low-frequency welded ERW seam), an appropriately-designed fitting shall be installed on the sleeve through which the sleeve and carrier pipe will be tapped to equalize the internal pressures of the carrier pipe and the sleeve.

(3) If not practical to take the pipeline out of service, defects may be removed by grinding or hot tapping. Sharp imperfections may be rendered blunt by grinding, but the absence of a sharp imperfection must be verified by visual and nondestructive examination. When grinding, the ground areas shall be smoothly contoured and be in accordance with para. 451.6.2(a)(8). When hot tapping, the portion of piping containing the defect shall be completely removed.

(4) If not practical to take the pipeline out of service, minor leaks and small corroded areas, except for cracks, may be repaired by the installation of a patch or welded fitting in accordance with paras. 451.6.2(c)(5) and (8). Pipe containing arc burns, grooves, and gouges may be repaired with patches or welded fitting if the arc burn or notch is removed by grinding.

(5) If not practical to take the pipeline out of service, defects in welds produced with a filler metal, small corroded areas, gouges, grooves, and arc burns may be repaired by depositing weld metal in accordance with para. 451.6.2(c)(9). Weld imperfections, arc burns,

gouges, and grooves shall be removed by grinding prior to depositing the weld filler metal.

(6) If not practical to take the pipeline out of service, nonleaking corroded areas may be repaired by installation of a fully-welded, partial encirclement half sole in accordance with para. 451.6.2(c)(13).

(7) If not practical to take the pipeline out of service, nonleaking corroded areas may be repaired by installation of a mechanically applied composite material wrap used to reinforce the pipeline in accordance with para. 451.6.2(c)(14).

(c) Repair Methods

(1) All repair weld procedures and all welders performing repair work shall be qualified in accordance with para. 434.8.3 or API RP 1107. The welders shall also be familiar with safety precautions and other problems associated with cutting and welding on pipe that contains or has contained liquids within the scope of this Code. Cutting and welding shall commence only after compliance with para. 434.8.1(c).

(2) The qualification test for welding procedures to be used on pipe containing a liquid shall consider the cooling effects of the pipe contents on the soundness and physical properties of the weld. Welding procedures on pipe not containing liquid shall be qualified in accordance with para. 434.8.3.

(3) Materials used for pipeline repair shall be in accordance with at least one of the specifications or standards listed in Table 423.1, or as otherwise required by this Code.

(4) Temporary repairs may be necessitated for operating purposes and shall be made in a safe manner. Such temporary repairs shall be made permanent or replaced in a permanent manner as described herein as soon as practical.

(5) Welded patches shall have rounded corners and a maximum dimension of 6 in. (150 mm) along the pipe axis. The patch material shall be of a similar or higher grade with a wall thickness similar to the pipe being repaired. Patches shall be limited to pipe sizes NPS 12 and less and conforming to API 5L, Grade X42 and lower. Patches shall be attached by fillet welds. Insert patching is prohibited. Special consideration shall be given to minimize stress concentrations resulting from the repair.

(6) Full encirclement welded split sleeves installed to repair leaks or otherwise to contain internal pressure shall have a design pressure of not less than the pipe being repaired and shall be fully welded, both circumferentially and longitudinally. Length of full encirclement split sleeves shall not be less than 4 in. (100 mm). If the sleeve is thicker than the pipe being repaired, the circumferential ends shall be chamfered (at approximately 45 deg.) down to the thickness of the pipe. For full encirclement split sleeves installed for repair by reinforcement only and not internal pressure containment, circumferential welding is optional. Special consideration shall be given to minimize stress concentrations resulting from the repair.

(7) Mechanically applied full encirclement repair fittings shall meet the design requirements of paras. 401.2 and 418.

(8) Welded fittings used to cover pipeline defects shall not exceed NPS 3 and shall have a design pressure of not less than the pipe being repaired.

(9) For repairs involving only deposition of a weld filler metal, welding processes shall be in accordance with the requirements of the appropriate pipe specification for the grade and type being repaired. Welding procedure qualifications shall be in accordance with para. 451.6.2(c)(2).

(10) Where repairs are made to a coated pipe, all damaged coating shall be removed and new coating applied in accordance with para. 461.1.2. Replacement pieces of pipe, welded patches, and full encirclement welded split sleeves used in making repairs shall also be coated when installed in a coated line.

(11) Pipe containing liquid shall be examined to determine that the material is sound and of adequate thickness in the areas to be affected by grinding, welding, cutting, or hot tapping operations.

(12) If the pipeline is not taken out of service, the operating pressure shall be reduced to a level which will provide safety during the repair operations.

(13) Fully welded partial encirclement half soles may be used to repair corroded areas only on pipe and shall not be used to repair leaks, gouges, dents, or other defects. The use of half soles shall be limited to pipe sizes NPS 12 or less and may only be used on pipe made prior to 1942 with a specified minimum yield strength not exceeding 40,000 psi (276 MPa). The half sole material shall be of a similar or higher grade with a wall thickness not less than 87.5% or more than 125% of that of the pipe being repaired. Half soles shall have rounded corners and a maximum length of 10 ft (3 m) along the pipe axis. Half soles shall not be used across girth welds and the minimum clearance between the end of half soles or the ends of half soles and girth welds shall be 2 in. Combinations of a half sole and patches shall not be used in parallel around a given circumference. To ensure optimum performance of half soles, the annular space between

the corroded pipe and the half sole may be filled with a hardenable filler material such as epoxy. Special consideration shall be given to ensuring a close fit between the edges of the half sole and the pipe being repaired and to minimizing stress concentrations resulting from the repair.

(14) Mechanically applied composite material wrap may be used to reinforce the pipeline provided that design and installation methods are proven for the intended service prior to application. The user is cautioned that a qualified written procedure performed by trained personnel is a requirement and records shall be retained in accordance with para. 455.

02 **451.6.3 Testing Repairs to Pipelines Operating at a Hoop Stress of More Than 20% of the Specified Minimum Yield Strength of the Pipe**

(a) Testing of Replacement Pipe Sections. When a scheduled repair to a pipeline is made by cutting out a section of the pipe as a cylinder and replacing it with another section of pipe, the replacement section of pipe shall be subjected to a pressure test. The replacement section of pipe shall be tested as required for a new pipeline in accordance with para. 437.4.1. The tests may be made on the pipe prior to installation provided radiographic or other acceptable nondestructive tests (visual inspection excepted) are made on all tie-in butt welds after installation.

(b) Examination of Repair Welds. Welds made during pipeline repairs shall be visually examined by a qualified inspector. Welds should also be examined by at least one other nondestructive examination method.

451.7 Derating a Pipeline to a Lower Operating Pressure

(a) Corroded pipe or pipe containing areas repaired by grinding may be derated to a lower operating pressure in lieu of replacement or repair or further repair. Except as provided in para. 451.7(b), the lower operating pressure shall be based on para. 404.1.2 and the actual remaining wall thickness of the pipe at the point of deepest corrosion or grinding.

(b) For pipe containing localized corrosion pitting or areas repaired by grinding where the remaining material in the pipe does not meet the depth and length limits in para. 451.6.2(a)(7), the lower operating pressure may be determined by the following equation, provided the corrosion or grinding is not in the girth or longitudinal weld or related heat affected zones.

$$P_d = 1.1P_i \left[\frac{1 - 0.6^{-}\left(\frac{c}{t_n}\right)}{1 - \frac{0.57c}{t_n\sqrt{G^2 + 1}}} \right]$$

where

G = $0.893\, L/\sqrt{Dt_n}$
= a value not to exceed 4.0 in the above analysis and which may be determined from the above equation

P_d = derated internal design gage pressure, psi (bar)

P_i = original internal design gage pressure, based on specified nominal wall thickness of the pipe (see para. 404.1), psi (bar)

L = longitudinal extent of the corroded area as shown in Fig. 451.6.2(a)(7), in. (mm)

For t_n, c, and D, see para. 451.6.2(a)(7).

For values of G greater than 4.0,

$$P_d = 1.1P_i\,(1 - c/t_n)$$

except p_d shall not exceed p_i.

451.8 Valve Maintenance

Pipeline block valves shall be inspected, serviced where necessary, and partially operated at least once each year to assure proper operating conditions.

451.9 Railroads and Highways Crossing Existing Pipelines 02

(a) When an existing pipeline is to be crossed by a new road or railroad, the operating company shall analyze the pipeline in the area to be crossed in terms of the new anticipated external loads. If the sum of the circumferential stresses caused by internal pressure and newly imposed external loads (including both live and dead loads) exceeds 0.90 SMYS (specified minimum yield strength), the operating company shall install mechanical reinforcement, structural protection, or suitable pipe to reduce the stress to 0.90 SMYS or less, or redistribute the external loads acting on the pipeline. API RP 1102 provides methods that may be used to determine the total stress caused by internal pressure and external loads. API RP 1102 also provides methods to check cyclic stress components for fatigue.

(b) Installation of uncased carrier pipe is preferred. Adjustments of existing pipelines in service at a proposed railroad or highway crossing shall conform to details contained in API RP 1102. As specified in para. 461.1.2(f), if casing is used, coated carrier pipe shall

be independently supported outside each end of the casing and insulated from the casing throughout the cased section, and casing ends shall be sealed using a durable, electrically nonconductive material.

(c) Testing and inspection of replaced pipe sections shall conform to requirements of para. 451.6.3. All new girth welds in the carrier pipe shall be radiographed or inspected by other acceptable nondestructive methods (visual inspection excepted).

451.10 Inland Waters Platform Risers

Riser installations shall be visually inspected annually for physical damage and corrosion in the splash zone and above. The extent of any observed damage shall be determined, and, if necessary, the riser installation shall be repaired or replaced.

452 PUMP STATION, TERMINAL, AND TANK FARM OPERATION AND MAINTENANCE

452.1 General

(a) Starting, operating, and shutdown procedures for all equipment shall be established and the operating company shall take appropriate steps to see that these procedures are followed. These procedures shall outline preventive measures and systems checks required to ensure the proper functioning of all shutdown, control, and alarm equipment.

(b) Periodic measurement and monitoring of flow and recording of discharge pressures shall be provided for detection of deviations from the steady state operating conditions of the system.

452.2 Controls and Protective Equipment

(a) Controls and protective equipment, including pressure limiting devices, regulators, controllers, relief valves, and other safety devices, shall be subjected to systematic periodic inspections and tests, at least annually, except as provided in para. 452.2(b), to determine that they are:

(1) in good mechanical condition;

(2) adequate from the standpoint of capacity and reliability of operation for the service in which they are employed;

(3) set to function at the correct pressure;

(4) properly installed and protected from foreign materials or other conditions that might prevent proper operation.

(b) Relief valves on pressure storage vessels containing LPG, carbon dioxide, or liquid anhydrous ammonia shall be subjected to tests at least every 5 years.

452.3 Storage Vessels

(a) Storage vessels, including atmospheric and pressure tanks, handling the liquid or liquids being transported shall be periodically inspected and pertinent records maintained. Points to be covered include:

(1) stability of foundation;

(2) condition of bottom, shell, stairs, roof;

(3) venting or safety valve equipment;

(4) condition of firewalls or tank dikes.

(b) Storage vessels and tanks shall be cleaned in accordance with API Publ. 2015.

452.4 Storage of Combustible Materials

All flammable or combustible materials in quantities beyond those required for everyday use or other than those normally used in pump houses shall be stored in a separate structure built of noncombustible material located a suitable distance from the pump house. All aboveground oil or gasoline storage tanks shall be protected in accordance with NFPA 30.

452.5 Fencing

Station, terminal, and tank farm areas shall be maintained in a safe condition, and shall be fenced and locked, or attended, for the protection of the property and the public.

452.6 Signs

(a) Suitable signs shall be posted to serve as warnings in hazardous areas.

(b) Classified and high voltage areas shall be adequately marked and isolated.

(c) Caution signs shall be displayed indicating name of the operating company and, where possible, an emergency telephone contact.

452.7 Prevention of Accidental Ignition

(a) Smoking shall be prohibited in all areas of a pump station, terminal, or tank farm in which the possible leakage or presence of vapor constitutes a hazard of fire or explosion.

(b) Flashlights or hand lanterns, when used, shall be of the approved type.

(c) Welding shall commence only after compliance with para. 434.8.1(c).

(d) Consideration should be given to the prevention

of other means of accidental ignition. See NACE RP-01-77 for additional guidance.

453 CORROSION CONTROL

Protection of ferrous pipe and components from external and internal corrosion, including tests, inspections, and appropriate corrective measures, shall be as prescribed in Chapter VIII.

454 EMERGENCY PLAN

(a) A written Emergency Plan shall be established for implementation in the event of system failures, accidents, or other emergencies, and shall include procedures for prompt and expedient remedial action providing for the safety of the public and operating company personnel, minimizing property damage, protecting the environment, and limiting accidental discharge from the piping system.

(b) The Plan shall provide for acquainting and training of personnel responsible for the prompt execution of emergency action. Personnel shall be informed concerning the characteristics of the liquid in the piping systems and the safe practices in the handling of accidental discharge and repair of the facilities, with emphasis on the special problems and additional precautions in the handling of leaks and repair of systems transporting LPG, carbon dioxide, or liquid anhydrous ammonia. The operating company shall establish scheduled reviews with personnel of procedures to be followed in emergencies at intervals not exceeding 6 months, and reviews shall be conducted such that they establish the competence of the Emergency Plan.

(c) Procedures shall cover liaison with state and local civil agencies such as fire departments, police departments, sheriff's offices, and highway patrols, to provide prompt intercommunications for coordinated remedial action; dissemination of information on location of system facilities; characteristics of the liquids transported, including additional precautions necessary with leaks from piping systems transporting LPG, carbon dioxide, or liquid anhydrous ammonia; and joint preparation of cooperative action as necessary to assure the safety of the public in the event of emergencies.

(d) A line of communications shall be established with residents along the piping system to recognize and report a system emergency to the appropriate operating company personnel. This could include supplying a card, sticker, or equivalent with names, addresses, and telephone numbers of operating company personnel to be contacted.

(e) In the formulation of emergency procedures for limiting accidental discharge from the piping system, the operating company shall give consideration to:

(1) formulating and placing in operation procedures for an area cooperative pipeline leak notification emergency action system between operating companies having piping systems in the area;

(2) reduction of pipeline pressure by ceasing pumping operations on the piping system, opening the system to delivery storage on either side of the leak site, and expeditious closing of block valves on both sides of the leak site, and in the case of systems transporting LPG, continuation of pumping until LPG has been replaced at point of leak by a less volatile product if vapors are not accumulating to an extent that a serious hazard appears imminent;

(3) interim instructions to local authorities prior to arrival of qualified operating company personnel at the leak site;

(4) rapid transportation of qualified personnel to the leak site;

(5) minimization of public exposure to injury and prevention of accidental ignition by evacuation of residents and the halting of traffic on roads, highways, and railroads in the affected area;

(6) in the case of systems transporting LPG, assessment of extent and coverage of the LPG vapor cloud and determination of hazardous area with portable explosimeters; ignition of vapors at leak site to prevent the uncontrolled spread of vapors; utilization of temporary flares or blowdowns on either side of the leak site; and utilization of internal plugging equipment where it is anticipated that vaporization of LPG entrapped in pipeline segment will continue over a prolonged period;

(7) in the case of systems transporting liquid anhydrous ammonia, assessment of the extent and coverage of the ammonia vapor cloud and utilization of internal plugging equipment where it is anticipated that vaporization of liquid anhydrous ammonia entrapped in the pipeline segment will continue over a prolonged period;

(8) In the case of systems transporting carbon dioxide, assessment of the carbon dioxide released, it effects, and the use of existing means to blow down and control the spread of it at the leak site.

455 RECORDS

For operation and maintenance purposes, the following records shall be properly maintained:

(a) necessary operational data;

(b) pipeline patrol records;

(c) corrosion records as required under para. 465;

(d) leak and break records;

(e) records pertaining to routine or unusual inspections, such as external or internal line conditions;

(f) pipeline repair records.

456 QUALIFYING A PIPING SYSTEM FOR A HIGHER OPERATING PRESSURE

(a) In the event of up-rating an existing piping system when the higher operating pressure will produce a hoop stress of more than 20% of the specified minimum yield strength of the pipe, the following investigative and corrective measures shall be taken:

(1) the design and previous testing of the piping system and the materials and equipment in it be reviewed to determine that the proposed increase in maximum steady state operating pressure is safe and in general agreement with the requirements of this Code;

(2) the conditions of the piping system be determined by leakage surveys and other field inspections, examination of maintenance and corrosion control records, or other suitable means;

(3) repairs, replacements, or alterations in the piping system disclosed to be necessary by steps (1) and (2) be made.

(b) The maximum steady state operating pressure may be increased after compliance with (a) above and one of the following provisions.

(1) If the physical condition of the piping system as determined by (a) above indicates that the system is capable of withstanding the desired increased maximum steady state operating pressure in accordance with the design requirement of this Code, and the system has previously been tested for a duration and to a pressure equal to or greater than required in paras. 437.4.1(a) and (c) for a new piping system for the proposed higher maximum steady state operating pressure, the system may be operated at the increased maximum steady state operating pressure.

(2) If the physical condition of the piping system as determined by (a) above indicates that the ability of the system to withstand the increased maximum steady state operating pressure has not been satisfactorily verified, or the system has not been previously tested to the levels required by this Code for a new piping system for the proposed higher maximum steady state operating pressure, the system may be operated at the increased maximum steady state operating pressure if the system shall successfully withstand the test required by this Code for a new system to operate under the same conditions.

(c) In no case shall the maximum steady state operating pressure of a piping system be raised to a value higher than the internal design pressure permitted by this Code for a new piping system constructed of the same materials. The rate of pressure increase to the higher maximum allowable steady state operating pressure should be gradual so as to allow sufficient time for periodic observations of the piping system.

(d) Records of such investigations, work performed, and pressure tests conducted shall be preserved as long as the facilities involved remain in service.

457 ABANDONING A PIPING SYSTEM

In the event of abandoning a piping system, it is required that:

(a) facilities to be abandoned in place shall be disconnected from all sources of the transported liquid, such as other pipelines, meter stations, control lines, and other appurtenances;

(b) facilities to be abandoned in place shall be purged of the transported liquid and vapor with an inert material and the ends sealed.

CHAPTER VIII
CORROSION CONTROL

460 GENERAL

(a) This Chapter prescribes minimum requirements and procedures for protection of ferrous pipe and components from external and internal corrosion, and is applicable to new piping installations and existing piping systems.

(b) External and internal corrosion shall be controlled consistent with condition of the piping system and the environment in which the system is located by application of these corrosion control requirements and procedures. Application of some corrosion control practices requires a significant amount of competent judgment in order to be effective in mitigating corrosion, and deviation from the provisions of this Chapter is permissible in specific situations, provided the operating company can demonstrate that the objectives expressed herein have been achieved. For carbon dioxide systems, it shall be recognized that water can combine with carbon dioxide to form a compound that may be corrosive under pipeline conditions.

(c) Corrosion control requirements and procedures may in many instances require measures in addition to those shown herein. Therefore, each operating company shall establish procedures to implement the requirements of this Chapter. Procedures, including those for design, installation, and maintenance of cathodic protection systems, shall be prepared and carried out by, or under the direction of, persons qualified by training or experience in corrosion control methods. NACE RP-01-69 or NACE RP-06-75 provides a guide for procedures to implement requirements herein and to monitor and maintain cathodic protection systems.

(d) Corrosion personnel shall be provided equipment and instrumentation necessary to accomplish the work.

(e) Coating crews and inspectors shall be suitably instructed and provided with equipment necessary to coat and inspect the pipe and components.

461 EXTERNAL CORROSION CONTROL FOR BURIED OR SUBMERGED PIPELINES

461.1 New Installations

461.1.1 General

(a) Control of external corrosion of new buried or submerged piping systems shall be provided for each component in the system except where the operating company can demonstrate by tests, investigations, or experience in the area of application that a detrimental corrosive environment does not exist. However, within 12 months after installation, the operating company shall electrically inspect the buried or submerged system. If the electrical inspection indicates that a corrosive condition exists, the piping system shall be cathodically protected. If cathodic protection is not installed, the piping system shall be electrically inspected at intervals not exceeding 5 years, and the system shall be cathodically protected if electrical inspection indicates that a corrosive condition exists.

(b) Control of external corrosion of buried or submerged pipe and components in new installations (including new pump stations, tank farms, and terminals, and relocating, replacing, or otherwise changing existing piping systems) shall be accomplished by the application of an effective protective coating supplemented with cathodic protection and suitable drainage bonds in stray current areas. Materials shall be selected with due regard to the type of supplemental corrosion protection and to the environment.

(c) Where impractical, and where adequate provisions for corrosion control have been made, the minimum clearance of 12 in. (300 mm) between the outside of any pipe installed underground and the extremity of any other underground structure specified in para. 434.6(c) may be reduced.

461.1.2 Protective Coating

(a) Protective coatings used on buried or submerged pipe and components shall have the following characteristics:

(1) mitigate corrosion;

(2) have sufficient adhesion to the metal surface to effectively resist underfilm migration of moisture;

(3) be ductile enough to resist cracking;

(4) have strength sufficient to resist damage due to handling and soil stress;

(5) have properties compatible with any supplemental cathodic protection.

(b) Welds shall be inspected for irregularities that could protrude through the pipe coating, and any such irregularities shall be removed.

(c) Pipe coating shall be inspected, both visually and by an electric holiday detector, just prior to: lowering pipe into ditch, applying a weight coating if used, or submerging the pipe if no weight coating is used. Any holiday or other damage to the coating detrimental to effective corrosion control shall be repaired and reinspected.

(d) Insulating type coating, if used, shall have low moisture absorption characteristics and provide high electrical resistance. Insulating coatings shall be inspected in accordance with established practices at the time of application and just prior to lowering pipe into ditch, and defects shall be repaired and reinspected.

(e) Pipe shall be handled and lowered into ditch or submerged so as to prevent damage after the electrical inspection. Pipe coating shall be protected from lowering-in damage in rough or detrimental environment by use of rock shield, ditch padding, or any other suitable protective measures.

(f) If coated pipe is installed by boring, driving, or other similar method, precautions shall be taken to minimize damage to the coating during installation. If casing is used (see paras. 434.13.4 and 451.9), carrier pipe shall be independently supported outside each end of the casing and insulated from the casing throughout the length of cased section, and casing ends shall be sealed using a durable, electrically nonconductive material.

(g) The backfilling operation shall be inspected for quality, compaction, and placement of material to prevent damage to pipe coating.

(h) Where a connection is made to a coated pipe, all damaged coating shall be removed and new coating applied on the attachments as well as on the pipe.

461.1.3 Cathodic Protection System

(a) A cathodic protection system provided by a galvanic anode or impressed current anode system shall be installed that will mitigate corrosion and contain a method of determining the degree of cathodic protection achieved on the buried or submerged piping system.

(b) A cathodic protection system shall be installed not later than 1 year after completion of construction.

(c) Cathodic protection shall be controlled so as not to damage the protective coating, pipe, or components.

(d) Owners of known underground structures which may be affected by installation of a cathodic protection system shall be notified of said installation, and, where necessary, joint bonding surveys shall be conducted by parties involved.

(e) Electrical installations shall be made in accordance with the National Electrical Code, NFPA 70, API RP 500C, and applicable local codes.

461.1.4 Electrical Isolation

(a) Buried or submerged coated piping systems shall be electrically isolated at all interconnections with foreign systems, except where arrangements are made for mutual cathodic protection or where underground metallic structures are electrically interconnected and cathodically protected as a unit.

(b) An insulating device shall be installed where electrical isolation of a portion of a piping system from pump stations, storage tanks, and similar installations is necessary to facilitate the application of corrosion control. The insulating device shall not be installed where a combustible atmosphere is anticipated unless precautions are taken to prevent arcing.

(c) Consideration shall be given to the prevention of damage to piping systems due to lightning or fault currents when installed in close proximity to electric transmission tower footings, ground cables, or counterpoise. See NACE RP-01-77 for guidance when ac interference problems are suspected. Studies in collaboration with the operator of such electric transmission systems shall be made on common problems of corrosion and electrolysis.

(d) Electrical tests shall be made to locate any unintentional contacts with underground metallic structures, and, if such contacts exist, each one shall be corrected.

(e) When a pipeline is separated, a bonding conductor of sufficient current carrying capacity shall be installed across the points of separation and retained during the period of separation.

461.1.5 Test Leads

(a) Except where impractical in wet marsh areas, sufficient test leads shall be installed on all buried or submerged coated piping systems for taking electrical measurements to indicate adequacy of the cathodic protection.

(b) Test leads shall be installed as follows.

(1) Special attention shall be given to the manner of installation of test leads used for corrosion control or testing, and leads shall be attached to the pipe in such manner as to minimize stress and prevent surface

cracks in the pipe. Leads may be attached directly on the pipe with the low temperature welding process using aluminum powder and copper oxide and limiting the charge to a 15 g cartridge, or with soft solders or other materials that do not involve temperatures exceeding those for soft solders.

(2) Slack shall be provided to prevent test leads from being broken or damaged during backfilling.

(3) Leads shall be insulated from the conduit in which they are contained.

(4) Bond points shall be made watertight, and bared test lead wires, pipe, and components shall be protected by electrical insulating material compatible with original wire insulation and pipe coating.

461.1.6 Electrical Interference

(a) If an impressed current type cathodic protection system is used, the anodes shall be located so as to minimize adverse effect on existing underground metallic structures.

(b) The possibility of external corrosion induced by stray electrical currents in the earth shall be recognized. See NACE RP-01-69 and NACE RP-01-77 for additional guidance. These stray currents are generated by sources remote from, and independent of, the piping system, and are more predominant in highly industrialized areas, mining regions, and locales containing high voltage dc electrical power ground beds. Foreign company pipeline cathodic protection systems are also a common source of stray earth currents. The protection of the piping system against stray current induced corrosion shall be provided by metallic bonds, increased cathodic protection, supplemental protective coatings, insulating flanges, or galvanic anodes.

461.2 Existing Piping Systems

The operating company shall establish procedures for determining the external condition of its existing buried or submerged piping systems and take action appropriate for the conditions found, including, but not limited to, the following.

(a) Examine and study records available from previous inspections and conduct additional inspections where the need for additional information is indicated. The type, location, number, and frequency of such inspections shall be determined by consideration of such factors as knowledge of the condition of the piping system and environment, and public or employee safety in the event of leakage. Corrective measures shall be in accordance with para. 464.

(b) Install cathodic protection on all buried or submerged piping systems that are coated with an effective external surface coating material, except at pump stations, tank farms, and terminals. All buried or submerged piping at pump stations, tank farms, and terminals shall be electrically inspected and cathodic protection installed or augmented where necessary.

(c) Operating pressures on bare piping systems shall not be increased until they are electrically inspected and other appropriate actions are taken regarding condition of pipe and components. The requirements of para. 456 shall also be complied with in the event of uprating.

461.3 Monitoring

(a) Cathodic protection facilities for new or existing piping systems shall be maintained in a serviceable condition, and electrical measurements and inspections of cathodically protected buried or submerged piping systems, including tests for stray electrical currents, shall be conducted at least each calendar year, but with intervals not exceeding 15 months, to determine that the cathodic protection system is operating properly and that all buried or submerged piping is protected in accordance with applicable criteria. Appropriate corrective measures shall be taken where tests indicate that adequate protection does not exist.

(b) Evidence of adequate level of cathodic protection shall be by one or more of the criteria listed in Criteria for Cathodic Protection, Section 6 in NACE RP-01-69, or Section 5 in NACE RP-06-75.

(c) The type, number, location, and frequency of tests shall be adequate to establish with reasonable accuracy the degree of protection provided on all piping within the limits of each cathodic protection system, and shall be determined by considering:

(1) age of the piping system and operating experience, including bell hole inspections and leakage survey data;

(2) condition of pipe at time of application of cathodic protection and method of applying protection;

(3) corrosiveness of environment;

(4) probability of loss of protection due to activity of other construction, reconstruction, or other causes in the area;

(5) method of applying cathodic protection and design life of cathodic protection installation;

(6) public and employee safety.

(d) Test leads required for cathodic protection shall be maintained so that electrical measurements can be obtained to insure adequate protection.

(e) Cathodic protection rectifiers or other impressed

current power source shall be inspected at intervals not exceeding 2 months.

(f) All connected protective devices, including reverse current switches, diodes, and interference bonds, failure of which would jeopardize structure protection, shall be checked at intervals not exceeding 2 months. Other interference bonds shall be checked at least each calendar year but at intervals not exceeding 15 months.

(g) Bare components in a piping system that are not protected by cathodic protection shall be electrically inspected at intervals not exceeding 5 years. The results of this inspection and leak records for the piping components inspected shall be analyzed to determine the location of localized active corrosion areas. Cathodic protection shall be applied at such areas. Inspections and analysis of leak and repair records shall be repeated at intervals not exceeding 5 years.

(h) Buried or submerged piping components exposed for any reason shall be examined for indications of external corrosion. Discovery of active corrosion, general pitting of the component's surface, or a leak caused by corrosion shall be investigated further to determine the cause and extent of the corrosion and whether cathodic protection shall be installed or augmented to mitigate corrosion or whether piping system or portion thereof shall be treated as indicated in paras. 464(b), (c), and (d).

462 INTERNAL CORROSION CONTROL

462.1 New Installations

(a) Internal corrosion is recognized in the operation of liquid pipelines, and a commodity that will corrode the internal surfaces of pipe and components in a piping system shall not be transported unless the corrosive effect of the commodity has been investigated and adequate steps taken to mitigate internal corrosion. It is usually necessary to control internal corrosion in petroleum products and liquefied petroleum gas pipelines to protect product quality, preserve high line efficiencies, and prevent corrosion of internal surfaces. NACE RP-01-75 provides guidance. Frequent scraping, pigging, or sphering, dehydration, inhibition, or internal coating may be used to limit internal corrosion.

(b) If dehydration or inhibitors are used to control internal corrosion, sufficient coupon holders or other types of monitoring techniques shall be utilized to adequately determine the effectiveness of the internal corrosion control program. Inhibitors shall be selected of a type that will not cause deterioration of any piping component and shall be used in sufficient quantity and proper quality necessary to mitigate internal corrosion.

(c) If internal coatings are used to control corrosion, they shall meet the quality specifications and minimum dry film thickness established in the industry and be inspected in accordance with industry recommended practices. Internal coatings shall include provisions for joint protection on piping joined by welding or other methods exposing parent metal at the joints, such as the use of a suitable corrosion inhibitor.

(d) For purposes of this Code, liquid anhydrous ammonia shall contain a minimum of 0.2% water by weight to inhibit stress corrosion cracking. Any added water must be made using steam condensate, deionized, or distilled water.

462.2 Existing Piping Systems

The operating company shall establish procedures for determining the corrosive effect of the commodity being transported, and the internal condition of its existing piping systems, and take appropriate action for the conditions found, including, but not limited to, the following.

Examine and study records available from previous inspections and conduct additional inspections and investigations where the need for additional information is indicated. Corrective measures shall be in accordance with para. 464.

462.3 Monitoring

(a) If scraping, pigging, or sphering, dehydration, inhibitors, or internal coating are used to control internal corrosion in new or existing piping systems, coupons shall be examined or other monitoring techniques utilized at intervals not exceeding 6 months to determine the effectiveness of the protective measures or the extent of any corrosion. Appropriate corrective measures shall be taken where examinations or monitoring techniques indicate that adequate protection does not exist.

(b) Whenever any pipe or component in a piping system can be visually examined internally, or pipe or component is removed from a piping system for any reason, the internal surfaces shall be inspected for evidence of corrosion, and if corrosion is found, the adjacent pipe or component shall be examined. Discovery of active corrosion, general pitting of the pipe or component surface, or a leak caused by corrosion shall be investigated further to determine the cause and extent of the corrosion and whether steps shall be taken or augmented to mitigate corrosion or whether system or

portion thereof shall be treated as indicated in paras. 464(b), (c), and (d).

463 EXTERNAL CORROSION CONTROL FOR PIPING EXPOSED TO ATMOSPHERE

463.1 New Installations

Pipe and components that are exposed to the atmosphere shall be protected from external corrosion by use of corrosion resistant steel or application of protective coating or paint unless the operating company can demonstrate by test, investigation, or experience in area of application that a corrosive atmosphere does not exist. Protective coating or paint shall be applied to a clean surface and shall be suitable material to provide adequate protection from the environment.

463.2 Existing Piping Systems

Pipe and components in existing piping systems that are exposed to the atmosphere shall be inspected in accordance with a planned schedule and corrective measures shall be taken in accordance with para. 464.

463.3 Monitoring

Protective coating or paint used to prevent corrosion of pipe and components exposed to the atmosphere shall be maintained in a serviceable condition, and such protective coating or paint, as well as bare pipe and components not coated or painted as permitted under para. 463.1, shall be inspected at intervals not exceeding 3 years. Appropriate corrective measures shall be taken in accordance with para. 464 where inspections indicate that adequate protection does not exist.

464 CORRECTIVE MEASURES

(a) Criteria on corrosion limits and disposition of corroded pipe are specified in paras. 451.6.2(a)(6) and 451.6.2(a)(7).

(b) Where inspections or leakage history indicate that active corrosion of metal is taking place in any portion of a piping system to the extent that a safety hazard is likely to result, that portion of the system shall be treated as specified in para. 451.6.2(a)(6) or (7), and:

(1) in the case of external corrosion of buried or submerged piping, cathodic protection shall be installed or augmented to mitigate the external corrosion;

(2) in the case of internal corrosion of piping, steps indicated in para. 462.1 shall be taken or augmented to mitigate the internal corrosion;

(3) in the case of external corrosion of piping exposed to the atmosphere, protective coating or paint shall be repaired or applied to mitigate the external corrosion.

(c) Pipe that is replaced because of external corrosion shall be replaced with coated pipe if buried or submerged, and with corrosion resistant steel pipe or coated or painted pipe if exposed to the atmosphere.

(d) If a portion of the piping system is repaired, reconditioned, or replaced, or operating pressure is reduced because of external or internal corrosion, the need for protection of that portion from such corrosion deterioration shall be considered, and any indicated steps taken to control the corrosion.

465 RECORDS

(a) Records and maps showing the location of cathodically protected piping, cathodic protection facilities, and neighboring structures affected by or affecting the cathodic protection system shall be maintained and retained for as long as the piping system remains in service.

(b) Results of tests, surveys and inspections required by this Chapter shall be retained as needed to indicate the adequacy of corrosion control measures. The minimum retention period shall be 2 years or until the results of subsequent inspections, tests, or surveys are received, whichever is longer.

CHAPTER IX
OFFSHORE LIQUID PIPELINE SYSTEMS

A400 GENERAL STATEMENTS

(a) Chapter IX pertains only to offshore pipeline systems as defined in para. A400.1.

(b) This Chapter is organized to parallel the numbering and content of the first eight chapters of the Code. Paragraph designations are the same as those in the first eight chapters, with the prefix "A."

(c) All provisions of the first eight chapters of the Code are also requirements of this Chapter unless specifically modified herein. If the text in this Chapter adds requirements, the requirements in the original Chapter with the same title and number also apply. If a provision in this Chapter is in conflict with one or more provisions in other chapters, the provision in this Chapter shall apply.

(d) It is the intent of this Chapter to provide requirements for the safe and reliable design, installation, and operation of offshore liquid pipeline systems. It is not the intent of this Chapter to be all inclusive. Engineering judgment must be used to identify special considerations which are not specifically addressed. API RP 1111 may be used as a guide. It is not the intent of this Chapter to prevent the development and application of new equipment and technology. Such activity is encouraged as long as the safety and reliability requirements of the Code are satisfied.

A400.1 Scope

This Chapter covers the design, material requirements, fabrication, installation, inspection, testing, and safety aspects of the operation and maintenance of offshore pipeline systems. For purposes of this Chapter, offshore pipeline systems include offshore liquid pipelines, pipeline risers, offshore liquid pumping stations, pipeline appurtenances, pipe supports, connectors, and other components as addressed specifically in the Code. See Fig. 400.1.2.

A400.2 Definitions

Some of the more common terms relating to offshore liquid pipelines are defined below.

buckle arrestor: any device attached to, or made a part of, the pipe for the purpose of arresting a propagating buckle.

buckle detector: any means for detecting dents, excessive ovalization, or buckles in a pipeline.

external hydrostatic pressure: pressure acting on any external surface resulting from its submergence in water.

flexible pipe: pipe which is

(a) manufactured as a composite from both metal and nonmetal components;

(b) capable of allowing large deflections without adversely affecting the pipe's integrity; and

(c) intended to be an integral part of the permanent liquid transportation system.

Flexible pipe does not include solid metallic pipe, plastic pipe, fiber reinforced plastic pipe, rubber hose, or metallic pipes lined with nonmetallic linings or coatings.

hyperbaric weld: a weld performed at ambient hydrostatic pressure.

offshore: the area beyond the line of ordinary high water along that portion of the coast that is in direct contact with the open seas and beyond the line marking the seaward limit of inland coastal waters.

offshore pipeline riser: the vertical or near-vertical portion of an offshore pipeline between the platform piping and the pipeline at or below the seabed, including a length of pipe of at least five pipe diameters beyond the bottom elbow, bend, or fitting. Because of the wide variety of configurations, the exact location of transition among pipeline, pipeline riser, and platform piping must be selected on a case-by-case basis.

offshore pipeline system: includes all components of a pipeline installed offshore for the purpose of transporting liquid, other than production facility piping. Tanker or barge loading hoses are not considered part of the offshore pipeline system.

offshore platform: any fixed or permanently anchored structure or artificial island located offshore.

pipe collapse: flattening deformation of the pipe resulting in loss of cross-sectional strength and circular shape, which is caused by excessive external hydrostatic pressure acting alone.

platform piping: on offshore platforms producing hydrocarbons, platform piping is all liquid transmission piping and appurtenances between the production facility and the offshore pipeline riser(s). On offshore platforms not producing hydrocarbons, platform piping is all liquid transmission piping and appurtenances between the risers. Because of a wide variety of configurations, the exact location of the transition between the offshore pipeline riser(s), platform piping, and production facility must be selected on a case-by-case basis.

propagating buckle: a buckle which progresses rapidly along a pipeline caused by the effect of external hydrostatic pressure on a previously formed buckle, local collapse, or other cross-sectional deformation.

pull tube: a conduit attached to an offshore platform through which a riser can be installed.

pull-tube riser: riser pipe or pipes installed through a pull tube (e.g., J tube or I tube).

return interval: statistically determined time interval between successive events of design environmental conditions being equaled or exceeded.

riser: see *offshore pipeline riser.*

sea floor bathymetry: refers to water depths along the pipeline route.

splash zone: the area of the pipeline riser or other pipeline components that is intermittently wet and dry due to wave and tidal action.

trawl board: a structure that is attached to the bottom of commercial fishing nets and is dragged along the sea floor.

vortex shedding: the periodic shedding of fluid vortices and resulting unsteady flow patterns downstream of a pipeline span.

A401 DESIGN CONDITIONS

A401.1 General

A401.1.1 Offshore Design Conditions. A number of physical parameters, henceforth referred to as design conditions, govern design of the offshore pipeline system so that it meets installation, operation, and other post-installation requirements. Some of the conditions which may influence the safety and reliability of an offshore pipeline system are

- pressure,
- temperature,
- waves,
- current,
- seabed,
- wind,
- ice,
- seismic activity,
- platform motion,
- water depth,
- support settlement,
- accidental loads,
- marine vessel activity, and
- fishing/recreational activities.

The design of an offshore pipeline system is often controlled by installation considerations rather than by operating load conditions.

A401.9 Installation Design Considerations

A401.9.1 Loads for Installation Design. The design of an offshore pipeline system suitable for safe installation and the development of offshore pipeline construction procedures shall be based on consideration of the parameters listed in paras. A401.9.2 and A401.9.3. These parameters shall be considered to the extent that they are significant to the proposed system and applicable to the method of installation being considered.

All parts of the offshore pipeline system shall be designed for the most critical combinations of installation and environmental loads, acting concurrently, to which the system may be subjected.

A401.9.2 Installation Loads. Installation loads which shall be considered are those imposed on the pipeline system under anticipated installation conditions, excluding those resulting from environmental conditions.

Loads which should be considered as installation loads include:

(a) weight, including (as appropriate) the weight of:

(1) pipe;

(2) coatings and their absorbed water;

(3) attachments to the pipe; and

(4) fresh water or sea water content (if pipe is flooded during installation);

(b) buoyancy;

(c) external pressure; and

(d) static loads imposed by construction equipment.

When considering the effect of pipe and/or pipeline component weights (in air and submerged) on installa-

tion stresses and strains, the variability due to weight coating, manufacturing tolerances, and water absorption shall also be considered.

A401.9.3 Environmental Loads During Installation. Environmental loads which shall be considered are those imposed on the pipeline system by environmental conditions. Loads which should be considered under this category include, as appropriate, those arising due to:

(a) waves;

(b) current;

(c) wind;

(d) tides;

(e) ice; and

(f) dynamic loads imposed by construction equipment and vessel motions.

The effects of large tidal changes and water depth variations on construction equipment shall be considered.

An appropriate design return interval storm shall be selected for the anticipated installation duration. This design return interval shall not be less than three times the expected exposure period for the pipeline during installation, or 1 year, whichever is longer.

Direction of waves, wind, and currents shall be considered to determine the most critical expected combination of the environmental loads to be used with the installation loads, as described in para. A401.9.1.

Loads imposed by construction equipment and vessel motions vary with the construction method and construction vessel selected. The limitations and behavioral characteristics of installation equipment shall be considered in the installation design. The effect of vessel motions on the pipe and its coating shall be considered.

Local environmental forces are subject to radical change in offshore areas. As a result, those potential changes should be considered during installation contingency planning as well as during installation design.

A401.9.4 Bottom Soils. Soil characteristics shall be considered in on-bottom stability analysis during the installation period, span analysis, and when installation procedures are developed for the following:

(a) riser installation in pull tubes;

(b) laying horizontal curves in the pipeline routing;

(c) pipeline bottom tows; and

(d) trenching and backfilling.

A401.10 Operational Design Considerations

A401.10.1 Loads for Operational Design. The design of an offshore pipeline system suitable for safe operation shall be based on considerations of the parameters listed in paras. A401.10.2 and A401.10.3. These parameters shall be considered to the extent that they are significant to the proposed system.

All parts of the offshore pipeline system shall be designed for the most critical combinations of operational and environmental loads, acting concurrently, to which the system may be subjected. The most critical combination will depend upon operating criteria during storm conditions. If full operations are to be maintained during storm conditions, then the system shall be designed for concurrent action of full operational and design environmental loads. If operations are to be reduced or discontinued during storm conditions, then the system shall be designed for both:

(a) full operational loads, plus maximum coincidental environmental loads; and

(b) design environmental loads, plus appropriate reduced operational loads.

A401.10.2 Operational Loads. Operational loads which shall be considered are those imposed on the pipeline system during its operation, excluding those resulting from environmental conditions.

Loads which should be considered operational loads include:

(a) weight, including (as appropriate) the weight of:

(1) pipe;

(2) coatings and their absorbed water;

(3) attachments to the pipe; and

(4) transported contents;

(b) buoyancy;

(c) internal and external pressure;

(d) thermal expansion and contraction;

(e) residual loads; and

(f) overburden.

Anticipated impact loads, such as those caused by trawl boards, should be considered as an operational load.

A401.10.3 Environmental Loads During Operation. Environmental loads which shall be considered are those imposed on the pipeline system by environmental conditions. Loads which should be considered under this category include, as appropriate, those arising due to:

(a) waves;

(b) current;

(c) wind;

(d) tides;

(e) ice loads (e.g., weight, floating impacts, scouring);

(f) seismic events; and

(g) dynamically induced soil loads (e.g., mud slides, soil liquefaction).

An appropriate design return interval storm shall be selected for the anticipated operational life of the offshore pipeline system but shall not be less than 100 years.

Direction of waves, wind, and currents shall be considered to determine the most critical expected combination of the environmental loads to be used with the operations loads, as described in para. A401.10.1.

A401.10.4 Bottom Soils. When establishing on-bottom stability requirements and maximum allowable spans for irregular seabeds, consideration shall be given to seabed soil characteristics.

A401.11 Hydrostatic Test Design Considerations

A401.11.1 Loads for Hydrostatic Test Design. The design of an offshore pipeline system suitable for safe hydrostatic testing and the development of offshore pipeline hydrostatic test procedures shall be based on consideration of the parameters listed in paras. A401.11.2 and A401.11.3. These parameters shall be considered to the extent that they are significant to the proposed test.

All parts of the offshore pipeline system shall be designed for the most critical combinations of hydrostatic test and environmental loads, acting concurrently, to which the system may be subjected.

A401.11.2 Hydrostatic Test Loads. Hydrostatic test loads which shall be considered are those imposed on the offshore pipeline system under anticipated test conditions, excluding those resulting from environmental conditions.

Loads which should be considered hydrostatic test loads include:

(a) weight, including (as appropriate) the weight of:

(1) pipe;

(2) coatings and their absorbed water;

(3) attachments to the pipe; and

(4) fresh water or sea water used for hydrostatic test;

(b) buoyancy;

(c) internal and external pressure;

(d) thermal expansion and contraction;

(e) residual loads; and

(f) overburden.

A401.11.3 Environmental Loads During Hydrostatic Test. Environmental loads which shall be considered are those imposed on the pipeline system by environmental conditions. Loads which should be considered under this category include, as appropriate, those arising due to:

(a) waves;

(b) current;

(c) wind; and

(d) tides.

An appropriate design return interval storm shall be selected for the anticipated hydrostatic test duration but shall not be less than 1 year.

Direction of waves, wind, and currents shall be considered to determine the most critical expected combination of the environmental loads to be used with the hydrostatic test loads, as described in para. A401.11.1.

A401.11.4 Bottom Soils. When establishing on-bottom stability requirements and maximum allowable spans for irregular seabeds, consideration shall be given to seabed soil characteristics.

A401.12 Route Selection Considerations

(a) Offshore pipeline routes shall be selected to minimize the adverse effects of:

(1) installation and related environmental loads (see para. A401.9);

(2) operational and related environmental loads (see para. A401.10); and

(3) hydrostatic test and related environmental loads (see para. A401.11).

(b) Selection of offshore pipeline routes shall consider the capabilities and limitations of anticipated construction equipment.

(c) Surveys of the pipeline route shall be conducted to identify:

(1) seabed materials;

(2) subsea (including sub-bottom) and surface features which may represent potential hazards to the pipeline construction and operations;

(3) subsea (including sub-bottom) and surface features which may be adversely affected by pipeline construction and operations, including archaeological and sensitive marine areas;

(4) turning basins;

(5) anchorage areas;

(6) shipping lanes; and

(7) foreign pipeline and other utility crossings.

(d) Routing shall be selected to avoid, to the extent practical, the identified hazards.

A402 DESIGN CRITERIA

A402.3 Allowable Stresses and Other Stress Limits

The allowable stresses and other stress limits given in para. 402.3 are superseded by the provisions of paras. A402.3.4 and A402.3.5.

Design and installation analyses shall be based upon accepted engineering methods, material strengths, and applicable design conditions.

A402.3.4 Strength Criteria During Installation and Testing

(a) Allowable Stress Values. The maximum longitudinal stress due to axial and bending loads during installation shall be limited to a value that prevents pipe buckling and that will not impair the serviceability of the installed pipeline system. Other stresses resulting from pipeline installation activities, such as spans, shall be limited to the same criteria. Instead of a stress criterion, an allowable installation strain limit may be used.

(b) Design Against Buckling. The offshore pipeline system shall be designed and installed in a manner to prevent local buckling of the pipe wall, collapse, and column buckling during installation. Design and installation procedures shall consider the effect of external hydrostatic pressure; bending, axial, and torsional loads; impact; mill tolerances in the wall thickness; out-of-roundness; and other applicable factors. Consideration shall also be given to mitigation of propagation buckling which may follow local buckling or denting. The pipe wall thickness shall be selected to resist collapse due to external hydrostatic pressure.

(c) Design Against Fatigue. The pipeline shall be designed and installed to limit anticipated stress fluctuations to magnitudes and frequencies which will not impair the serviceability of the installed pipeline. Loads which may cause fatigue include wave action and vibrations induced by vortex shedding. Pipelines and riser spans shall be designed to prevent vortex-induced resonant vibrations, when practical. When vibrations must be tolerated, the resulting stresses due to vibration shall be considered. If alternative acceptance standards for girth welds in API Standard 1104 are used, the cyclic stress analysis shall include the determination of a predicted fatigue spectrum to which the pipeline is exposed over its design life.

(d) Design Against Fracture. Prevention of fractures during installation shall be considered in material selection in accordance with the requirements of para. A423.2. Welding procedures and weld defect acceptance criteria shall consider the need to prevent fractures during installation. See paras. 434.8.5 and A434.8.5.

(e) Design Against Loss of In-Place Stability. Design against loss of in-place stability shall be in accordance with the provisions of para. A402.3.5(e), except that the installation design wave and current conditions shall be based upon the provisions of para. A401.9.3. If the pipeline is to be trenched, it shall be designed for stability during the period prior to trenching.

(f) Impact. During the period when the pipe is susceptible to impact damage during installation and testing, consideration shall be given to impacts due to:

(1) anchors;
(2) trawl boards;
(3) vessels;
(4) ice keels; and
(5) other foreign objects.

(g) Residual Stresses. The pipeline system shall normally be installed in a manner so as to minimize residual stresses. The exception shall be when the designer purposefully plans for residual stresses (e.g., reeled pipe, cold springing of risers, pull-tube risers).

(h) Flexible Pipe. The manufacturer's recommended installation procedures should be adhered to during installation. Flexible pipe shall be designed or selected to prevent failure due to the combined effects of external pressure, internal pressure, torsional forces, axial forces, and bending. (See API RP 17B.)

A402.3.5 Strength Criteria During Operations

(a) Allowable Stress Values. Allowable stress values for steel pipe during operation shall not exceed those calculated by the equations in para. A402.3.5(a), (1) through (3).

(1) Hoop Stress. For offshore pipeline systems, the tensile hoop stress due to the difference between internal and external pressures shall not exceed the values given below.

NOTE: Sign convention is such that tension is positive and compression is negative.

$$S_h \le F_1\,(S_y)$$

$$S_h = (P_i - P_e)\frac{D}{2t} \qquad \left(S_h = (P_i - P_e)\frac{D}{20t}\right)$$

where

S_h = hoop stress, psi (MPa)
P_i = internal design pressure, psi (bar)
P_e = external pressure, psi (bar)

TABLE A402.3.5(a)
DESIGN FACTORS FOR OFFSHORE PIPELINE SYSTEMS

Location	Hoop Stress F_1	Longitudinal Stress F_2	Combined Stress F_3
Pipeline	0.72	0.80	0.90
Riser and Platform Piping [Note (1)]	0.60	0.80	0.90

GENERAL NOTE: In the setting of design factors, due consideration has been given to, and allowance has been made for, the underthickness tolerance and maximum allowable depth of imperfections provided for in the specifications approved by the Code.

NOTE:
(1) Platform piping does not include production facility piping on a platform; see definitions para. A400.2.

D = nominal outside diameter of pipe, in. (mm)
t = nominal wall thickness, in. (mm)
F_1 = hoop stress design factor from Table A402.3.5(a)
S_y = specified minimum yield strength, psi (MPa)

(2) Longitudinal Stress. For offshore pipeline systems, the longitudinal stress shall not exceed values found from

$$|S_L| \le F_2(S_y)$$

where
S_L = maximum longitudinal stress, psi (positive tensile or negative compressive) (MPa)
= $S_a + S_b$ or $S_a - S_b$, whichever results in the larger stress value
S_a = axial stress, psi (positive tensile or negative compressive) (MPa)
= F_a/A
F_a = axial force, lb (N)
A = cross-sectional area of pipe material, in.^{2} (mm^2)
S_b = maximum resultant bending stress, psi (MPa)
= $\pm\sqrt{(i_iM_i)^2 + (i_oM_o)^2}/Z$
M_i = in-plane bending moment, in.-lb (N·m)
M_o = out-of-plane bending moment, in.-lb (N·m)
i_i = in-plane stress intensification factor from Fig. 419.6.4(c)
i_o = out-of-plane stress intensification factor from Fig. 419.6.4(c)
Z = section modulus of the pipe, in.^{3} (cm^3)
F_2 = longitudinal stress design factor from Table A402.3.5(a)
S_y = specified minimum yield strength, psi (MPa)
$|\ |$ = absolute value

(3) Combined Stress. For offshore pipeline systems, the combined stress shall not exceed the value given by the Maximum Shear Stress Equation (Tresca Combined Stress):

$$2\left[\sqrt{\left(\frac{S_L - S_h}{2}\right)^2 + S_t^2}\right] \le F_3(S_y)$$

where
S_L = maximum longitudinal stress, psi (positive tensile or negative compressive) (MPa)
= $S_a + S_b$ or $S_a - S_b$, whichever results in the larger stress value
S_a = axial stress, psi (positive tensile or negative compressive) (MPa)
= F_a/A
F_a = axial force, lb (N)
A = pipe cross-sectional area, in.^{2} (mm^2)
S_b = maximum resultant bending stress, psi (MPa)
= $\pm\sqrt{(i_iM_i)^2 + (i_oM_o)^2}/Z$
M_i = in-plane bending moment, in.-lb (N·m)
M_o = out-of-plane bending moment, in.-lb (N·m)
i_i = in-plane stress intensification factor from Fig. 419.6.4(c)
i_o = out-of-plane stress intensification factor from Fig. 419.6.4(c)
Z = section modulus of the pipe, in.^{3} (cm^3)
S_h = hoop stress, psi (MPa)
S_y = specified minimum yield strength, psi (MPa)
S_t = torsional stress, psi (MPa)
= $M_t/2Z$
M_t = torsional moment, in.-lb (N·m)
F_3 = combined stress design factor from Table A402.3.5(a)

Alternatively, the Maximum Distortional Energy Theory (Von Mises Combined Stress) may be used for limiting combined stress values. Accordingly, the combined stress should not exceed values given by:

$$\sqrt{S_h^2 - S_L S_h + S_L^2 + 3S_t^2} \le F_3(S_y)$$

(4) Strain. When the pipeline experiences a predictable noncyclic displacement of its support (e.g., fault movement along the pipeline route or differential subsidence along the line) or pipe sag before support contact, the longitudinal and combined stress limits may be replaced with an allowable strain limit, so long as the consequences of yielding do not impair the serviceability of the installed pipeline. The permissible maximum longitudinal strain depends upon the ductility of the material, any previously experienced plastic strain, and the buckling behavior of the pipe. Where plastic strains are anticipated, the pipe eccentricity, pipe out-of-roundness, and the ability of the weld to undergo such strains without detrimental effect should be considered. These same criteria may be applied to pull tube or bending shoe risers or pipe installed by the reel method.

(b) Design Against Buckling. The pipeline shall be designed with an adequate margin of safety to prevent local buckling of the pipewall, collapse, and column buckling during operations. Design and operating procedures shall consider the effect of external hydrostatic pressure; bending, axial, and torsional loads; impact; mill tolerances in the wall thickness, out-of-roundness, and other applicable factors. Consideration shall also be given to mitigation of propagation buckling which may follow local buckling or denting. The pipe wall thickness shall be selected to resist collapse due to external hydrostatic pressure.

(c) Design Against Fatigue. The pipeline shall be designed and operated to limit anticipated stress fluctuations to magnitudes and frequencies which will not impair the serviceability of the pipeline. Loads which may cause fatigue include internal pressure variations, wave action, and pipe vibration, such as that induced by vortex shedding. Pipe and riser spans shall be designed so that vortex-induced resonant vibrations are prevented, whenever practical. When vibrations must be tolerated, the resulting stresses due to vibration shall be considered in the combined stress calculations in para. A402.3.5(a). In addition, calculated fatigue failure shall not result during the design life of the pipeline and risers.

(d) Design Against Fracture. Prevention of fractures during operation shall be considered in material selection in accordance with the requirements of para. A423.2. Welding procedures and weld defect acceptance criteria shall consider the need to prevent fractures during operation. See paras. 434.8.5 and A434.8.5.

(e) Design Against Loss of In-Place Stability

(1) General. Pipeline design for lateral and vertical on-bottom stability is governed by permanent features such as sea floor bathymetry and soil characteristics and by transient events, such as hydrodynamic, seismic, and soil behavior events, having a significant probability of occurrence during the life of the system. Design conditions to be considered are provided in para. A402.3.5(e), (2) through (4).

The pipeline system shall be designed to prevent horizontal and vertical movements or shall be designed so that any movements will be limited to values not causing allowable stresses and strains to be exceeded. Typical factors to be considered in the stability design include

- wave and current forces,
- soil properties,
- scour and resultant spanning,
- soil liquefaction, and
- slope failure.

Stability may be obtained by such means as, but not limited to

- adjusting pipe submerged weight,
- trenching and or covering of pipe, and
- anchoring.

When calculating hydrodynamic forces, the fact that wave forces vary spatially along the length of the pipeline may be taken into account.

Two on-bottom stability design conditions that shall be considered are installation and operational.

(2) Design Wave and Current Conditions. Operational design wave and current conditions shall be based upon an event having a minimum return interval of not less than 100 years. The most unfavorable expected combination of wave and current conditions shall be used. Maximum wave and maximum current conditions do not necessarily occur simultaneously. When selecting the most unfavorable condition, consideration must be given to the timing of occurrence of the wave and current direction and magnitude.

(3) Stability Against Waves and Currents. The submerged weight of the pipe shall be designed to resist or limit movement to amounts which do not cause the longitudinal and combined stresses, as calculated by the equations in para. A402.3.5(a), to exceed the limits specified in para. A402.3.5(a). The submerged weight may be adjusted by weight coating and/or increasing pipe wall thickness. Hydrodynamic forces shall be based on the wave and current values for the design condition at the location. See para. A402.3.5(e)(2).

Wave and current direction and concurrence shall be considered.

The pipeline and its appurtenances may be lowered below bottom grade to provide stability.

Backfill or other protective covering options shall use materials and procedures which preclude damage to the pipeline and coatings.

Anchoring may be used alone or in conjunction with other options to maintain stability. The anchors shall be designed to withstand lateral and vertical loads expected from the design wave and current condition. Anchors shall be spaced to prevent excessive stresses in the pipe. Scour shall be considered in the design of the anchoring system. The effect of anchors on the cathodic protection system shall be considered.

Intermittent block type, clamp-on, or set-on weights (river weights) shall not be used on offshore pipelines where there is a potential for the weight to become unsupported because of scour.

(4) Shore Approaches. Pipe in the shore approach zone shall be installed on a suitable above-water structure or lowered or bored to the depth necessary to prevent scouring, spanning, or stability problems which affect integrity and safe operation of the pipeline during its anticipated service life. Seasonal variation in the near-shore thickness of sea floor sediments and shoreline erosion over the pipeline service life shall be considered.

(5) Slope Failure and Soil Liquefaction. The pipelines shall be designed for slope failure in zones where they are expected (mud slide zones, steep slopes, areas of seismic slumping). If it is not practical to design the pipeline system to survive the event, the pipeline shall be designed for controlled breakaway with provisions to minimize loss of the pipeline contents.

Design for the effects of liquefaction shall be performed for areas of known or expected occurrence. Soil liquefaction normally results from cyclic wave overpressures or seismic loading of susceptible soils. The bulk specific gravity of the pipeline shall be selected, or alternative methods shall be selected to ensure both horizontal and vertical stability.

Seismic design conditions used to predict the occurrence of bottom liquefaction or slope failure shall be at least as severe as those used for the operating design strength calculations for the pipeline. Occurrence of soil liquefaction due to wave overpressures shall be based on a storm interval of not less than 100 years.

(6) Bottom Soils. The pipe-soil interaction factors that are used shall be representative of the bottom conditions at the site.

(f) Impact. During operations, consideration shall be given to impacts due to:

(1) anchors;

(2) trawl boards;

(3) vessels;

(4) ice keels; and

(5) other foreign objects.

A402.3.6 Design for Expansion and Flexibility. Unburied subsea pipeline systems and platform piping shall be considered as "aboveground piping" [see para. 419.1(a), (b), and (d)] where such definition is applicable.

Thermal expansion and contraction calculations shall consider the effects of fully saturated backfill material on soil restraint.

Allowable strength criteria shall be in accordance with para. A402.3.5 in lieu of the allowables listed in para. 419.6.4. Equations in para. 419.6.4 are valid for calculating the indicated stresses. See paras. A401.10 and A401.11 for loads which must be considered in design. Where appropriate, allowable strain criteria in para. A402.3.5(a)(4) may be used in lieu of allowable stress criteria.

When an offshore pipeline is to be laid across a known fault zone or in an earthquake-prone area, consideration shall be given to the need for flexibility in the pipeline system and its components to minimize the possibility of damage due to seismic activity. Flexibility in the pipeline system may be provided by installation of the pipeline on or above the seabed and/or by use of breakaway couplings, slack loops, flexible pipe sections, or other site-specific solutions.

A402.3.7 Design of Clamps and Supports. Clamps and supports shall be designed such that a smooth transfer of loads is made from the pipeline or riser to the supporting structure without highly localized stresses due to stress concentrations. When clamps are to be welded to the pipe, they shall fully encircle the pipe and be welded to the pipe by a full encirclement weld. The support shall be attached to the encircling member and not the pipe.

All welds to the pipe shall be nondestructively tested. Clamps and supports shall be designed in accordance with the requirements of API RP 2A-WSD.

Clamps and support design shall consider the corrosive effects of moisture-retaining gaps and crevices and galvanically dissimilar metals.

A402.3.8 Design of Connectors and Flanges. Connectors and flanges shall be designed or selected to provide the smooth transfer of loads and prevent excessive deformation of the attached pipe.

A402.3.9 Design of Structural Pipeline Riser Protectors. Where pipeline risers are installed in locations subject to impact from marine traffic, protective devices shall be installed in the zone subject to damage to protect the pipe and coating.

A402.3.10 Design and Protection of Special Assemblies. Design of special assemblies, such as connections, subsea tie-in assemblies, subsea valves, expansion loops, seabed riser connections, and subsea pipeline manifolds, shall consider the additional forces and effects imposed by a subsea environment. Such additional considerations include design storm currents and potential for seabed movement in soft sediments, soil liquefaction, increased potential for corrosion, thermal expansion and contraction, and stress due to installation procedures.

Appropriate measures shall be taken to protect special assemblies in areas where the assemblies are subject to damage by outside forces, such as fishing and marine construction activities.

A402.3.11 Design of Flexible Pipe. Due to its composite makeup, the mechanical behavior of flexible pipe is significantly different from that of steel pipe. Flexible pipe may be used for offshore pipelines if calculations and/or test results verify that the pipe can safely withstand loads considered in paras. A401.9, A401.10, and A401.11. Careful consideration should be given to the use of flexible pipe due to its permeable nature and possible rapid decompression failure of the liner material and collapse of the inner liner due to residual gas pressure in the annulus upon pipeline depressurization. (See API RP 17B.)

A402.3.12 Design of Pipeline Crossings. Subsea pipeline crossings shall be designed to provide a minimum 12 in. (300 mm) separation between the two lines. Dielectric separation of the two pipelines shall be considered in design of pipeline crossings. Soil settlement, scour, and cyclical loads shall be considered in the design of pipeline crossings in order to ensure that the separation is maintained for the design life of both lines.

When two liquid pipelines cross, the longitudinal stress and combined stress, as calculated by the equations in para. A402.3.5(a), shall not exceed the limits specified in Table A402.3.5(a). Where appropriate, allowable strain criteria in para. A402.3.5(a)(4) may be used in lieu of allowable stress criteria. Where crossing pipelines are governed by different codes, the allowable stress limits shall be in accordance with the provisions of the applicable code.

A402.4 Allowances

A402.4.3 Weld Joint Factors. Pipe with a weld joint factor less than 1 (Table 402.4.3) shall not be used in offshore pipeline systems.

A404 PRESSURE DESIGN OF COMPONENTS

A404.1 Straight Pipe

A404.1.1 General

(b) For offshore pipeline systems, the applicable allowable stress value specified and defined in para. 404.1.1(b) shall be as follows:

$$S = F_1 (S_y)$$

where F_1 and S_y are defined in para. A402.3.5.

A404.3 Intersections

A404.3.1 Branch Connections

(d) Reinforcement of Single Openings

(1) Pipe that has been cold-worked solely for the purpose of increasing the yield strength to meet the specified minimum yield strength is prohibited in offshore liquid pipeline systems. This does not preclude the use of pipe that has been cold-worked specifically for the purpose of meeting dimensional requirements.

(e) Reinforcement of Multiple Openings

(4) Pipe that has been cold-worked solely for the purpose of increasing the yield strength to meet the specified minimum yield strength is prohibited in offshore liquid pipeline systems. This does not preclude the use of pipe that has been cold-worked specifically for the purpose of meeting dimensional requirements.

A405 PIPE

A405.2 Metallic Pipe

A405.2.1 Steel Pipe

(a) The provisions of para. 405.2.1(a) are superseded by the following. New pipe of the specifications listed in Table 423.1 may be used in accordance with the design equations of para. 404.1.2 subject to para A404.1.1 and to the testing requirements of paras. 437.1.4(a)(1), 437.1.4(a)(2), 437.1.4(a)(4), 437.1.4(a)(5), 437.1.4(b), 437.1.4(c), 437.4.1, and A437.1.4.

(c) Para. 405.2.1(c) does not apply.

(d) Pipe that has been cold-worked solely for the purpose of increasing the yield strength to meet the specified minimum yield strength is prohibited in off-

shore liquid pipeline systems. This does not preclude the use of pipe that has been cold-worked specifically for the purpose of meeting dimensional requirements.

A405.3 Flexible Pipe

Selection of flexible pipe shall be in accordance with API RP 17B. (See also para. A402.3.11.)

A406 FITTINGS, ELBOWS, BENDS, AND INTERSECTIONS

A406.2 Bends, Miters, and Elbows

A406.2.2 Mitered Bends. Mitered bends are prohibited in offshore liquid pipeline systems.

A406.4 Reductions

A406.4.2 Orange Peel Swages. Orange peel swages are prohibited in offshore liquid pipeline systems, other than temporary construction components or other non-pressure-containing components.

A406.6 Closures

A406.6.4 Fabricated Closures. Orange peel bull plugs and fishtails are prohibited in offshore liquid pipeline systems, other than temporary construction components or other non-pressure-containing components.

A407 VALVES

A407.1 General

Paragraph 407.1(b) does not apply. Cast iron or ductile iron valves are prohibited for applications in offshore liquid pipeline systems.

A408 FLANGES, FACINGS, GASKETS, AND BOLTING

A408.1 Flanges

A408.1.1 General. Paragraph 408.1.1(c) does not apply. Cast iron or ductile iron flanges are prohibited for applications in offshore liquid pipeline systems.

A408.3 Flange Facings

A408.3.1 General

(c) Ring joint-type flanges are preferred in offshore liquid pipeline systems.

A409 USED PIPING COMPONENTS AND EQUIPMENT

Used piping components, such as fittings, elbows, bends, intersections, couplings, reducers, closures, flanges, valves, and equipment, may be reused as noted in para. 409, except that the reuse of piping components of unknown specification is prohibited in offshore liquid pipeline systems.

A410 OTHER DESIGN CONSIDERATIONS

A410.1 Pigs and Internal Inspection Tools

When specifying in-line piping components for offshore pipelines, consideration shall be given to the need for running pipeline pigs and internal inspection tools. Selection of bend radius, launcher and receiver traps, bend configuration, internal diameter variations (including ovality), and other internal obstructions shall allow the passage of such devices, except where not practical.

A410.2 Special Components

System components which are not specifically covered in this Code shall be validated for fitness by either:

(a) documented full-scale prototype testing of the components or special assemblies; or

(b) a documented history of successful usage of these components or special assemblies produced by the same design method.

Documentation shall include design and installation methods which have been proven for the service for which the component is intended.

Care should be exercised in any new application of existing designs to ensure suitability for the intended service.

A414 THREADED JOINTS

A414.1 General

Threaded connections for in-line piping component sizes, NPS 2 (60.3 mm) or larger, are prohibited in offshore pipeline systems, except as permitted in para. A410.2.

A419 EXPANSION AND FLEXIBILITY

See para. A402.3.6 for additional provisions.

A421 DESIGN OF PIPE-SUPPORTING ELEMENTS

See para. A402.3.7 for additional provisions.

A423 MATERIALS — GENERAL REQUIREMENTS

A423.1 Acceptable Materials and Specifications

Concrete weight coating materials (cement, aggregate, reinforcing steel) shall meet or exceed the requirements of applicable ASTM standards.

Flexible pipe shall be manufactured from materials meeting the requirements of API RP 17B and ASTM or ASME standards applicable to the materials selected by the designer.

A423.2 Limitations on Materials

"Unidentified" pipe, plastic pipe, ASTM A 120 pipe, plastic pipe with nonmetallic reinforcement, cast iron pipe, ductile iron pipe, and pipe that has been cold-worked in order to meet the specified minimum yield strength are prohibited in offshore liquid pipeline systems. This does not preclude the use of pipe that has been cold-worked specifically for the purpose of meeting dimensional requirements.

In addition to the requirements contained in referenced standards, certain other requirements may be considered for components used offshore, depending on water depth, water temperature, internal pressure, product composition, product temperature, installation method and/or other loading conditions. For example, consideration of additional limitations or requirements for pipe may include one or more of the following:

(a) wall thickness tolerance;

(b) outside diameter tolerance;

(c) out-of-roundness tolerance;

(d) maximum and minimum yield and tensile strengths;

(e) pipe chemistry limitations;

(f) fracture toughness;

(g) hardness; and

(h) pipe mill hydrostatic testing and other nondestructive testing.

For sour service (H_2S), refer to NACE MR-01-75.

A434 CONSTRUCTION

A434.2 Inspection

Repairs required during new construction shall also be in accordance with paras. A434.8 and A461.1.2.

A434.3 Right-of-Way

A434.3.3 Survey and Staking or Marking. The route of the offshore pipeline shall be surveyed, and the pipeline shall be properly located within the right-of-way by maintaining survey route markers or by surveying during installation.

A434.4 Handling, Hauling, Stringing, and Storing

Transportation by truck or other road vehicles, rail cars, and marine vessels shall be performed in such a manner as to avoid damage to the pipe and any preapplied coatings. Transportation of line pipe shall conform to the requirements of API RP 5LW or API RP 5L1, as applicable.

A434.6 Ditching

The provisions of para. 434.6 are not applicable for offshore pipelines. Offshore pipelines should be trenched where necessary for stability, mechanical protection, or prevention of interference with maritime activities.

The methods and details of the pipeline trenching and lowering operations shall be based on site-specific conditions. Methods and details shall be selected to prevent damage to the pipe, coating, and pipeline appurtenances.

A434.7 Bends, Miters, and Elbows

Miter bends shall not be used in offshore liquid pipeline systems.

A434.7.1 Bends Made From Pipe

(a) Pipe that has been cold-worked solely for the purpose of increasing the yield strength to meet the specified minimum yield strength is prohibited in offshore liquid pipeline systems. This does not preclude the use of pipe that has been cold-worked specifically for the purpose of meeting dimensional requirements.

A434.8 Welding

A434.8.3 Welding Qualifications. Welding procedures and welders performing hyperbaric welding on offshore pipeline systems shall be qualified in accor-

dance with the testing provisions of either API Std. 1104 or ASME Section IX, as supplemented by AWS D3.6 for Type "O" welds.

A434.8.5 Welding Quality

(a) Inspection Methods

(2) Welds in offshore pipeline systems may also be evaluated on the basis of para. A434.8.5(b).

(4) The requirements of para. 434.8.5(a)(4) are superseded by the following provisions. All circumferential welds on offshore pipeline systems shall meet the requirements in para. 434.8.5(a) for a pipeline which would operate at a hoop stress of more than 20% of the specified minimum yield strength of the pipe. One hundred percent of the total number of circumferential butt welds on offshore pipeline systems shall be nondestructively inspected, if practical; but in no case shall less than 90% of such welds be inspected. The inspection shall cover 100% of the length of such inspected weld.

(b) Standards of Acceptability. For girth welds in offshore pipeline systems, alternative flaw acceptance limits may be based upon fracture mechanics analysis and fitness-for-purpose criteria as described by API Std. 1104. Such alternative acceptance standards shall be supported by appropriate stress analyses, supplementary welding procedure test requirements, and nondestructive examinations beyond the minimum requirements specified herein. The accuracy of the nondestructive techniques for flaw depth measurement shall be verified.

A434.8.9 Stress Relieving

(a) On offshore pipeline systems, the demonstration specified in para. 434.8.9(a) shall be conducted on materials and under conditions which simulate, as closely as practical, the actual production welding.

A434.11 Backfilling

Backfilling of trenched offshore pipelines is not normally required but may sometimes be utilized to provide additional stability or protection.

A434.13 Special Crossings

A434.13.1 Water Crossings. See para. A402.3.5(e)(3) concerning the use of river weights.

A434.14 Offshore Pipeline Construction

A434.14.1 Pipe Depth and Alignment. Plans and specifications shall describe alignment of the pipeline, its design depth below mean water level, and the depth below the sea bottom, if trenching is prescribed. Special consideration shall be given to depth of cover and other means of protecting the pipeline in the surf zone and other areas of potential hazards such as near platforms, anchorage areas, and shipping fairways.

A434.14.2 Installation Procedures and Equipment Selection. Installation procedures shall be prepared prior to beginning construction. Installation procedures shall address the design considerations in para. A401.9 and strength considerations in para. A402.3.4.

A434.14.3 Movement of Existing Pipelines. Consideration should be given to reducing operating pressures in the existing pipelines to obtain the lowest practical stress levels prior to movement of the existing lines. Whether the pipeline pressure is reduced or not, the following steps should be taken prior to movement of the existing lines:

(a) perform a physical survey to determine the actual position of the pipeline;

(b) determine wall thickness and mechanical properties of the existing pipeline section to be moved;

(c) investigate possible pipe stress that may exist in the pipeline in its present condition.

(d) calculate additional stresses imposed by the proposed movement operation; and

(e) prepare a detailed procedure for the proposed movement.

Investigation of the possible pipe stresses that may be induced in the existing pipeline during the relocation should be performed regardless of the anticipated internal pressure. This investigation should consider appropriate elevation tolerances for the lowering. Pipe stresses resulting from the relocation should not exceed the criteria in para. A402.3.4, and pipe stresses resulting from existing pipeline operation after lowering should not exceed the criteria in para. A402.3.5.

A434.15 Block and Isolating Valves

A434.15.1 General

(a) Block and isolating valves shall be selected to provide timely closure and to limit both property and environmental damage and provide safety under emergency conditions.

(b) On offshore platforms, consideration shall be given to locating block and isolating valves, or valve operator controls where used, in areas that are readily accessible under emergency conditions.

(c) Submerged valves shall be marked or spotted by survey techniques and recorded on permanently retained as-built records to facilitate location when operation is required.

A434.18 Line Markers

Line markers are not required on offshore pipeline systems.

A436 INSPECTION

A436.2 Qualification of Inspectors

In addition to the requirements of para. 436.2 offshore inspection personnel shall be capable of inspecting the following, as applicable:

- offshore vessel positioning systems;
- diving operations;
- remotely operated vehicle (ROV) operations;
- pipeline trenching and burial operations;
- special services for testing and inspection of offshore pipeline facilities, such as subsea pipeline lateral tie-ins, and subsea pipeline crossings as may be required; and
- pipelay parameters.

A436.5 Type and Extent of Examination Required

A436.5.1 Visual

(b) Construction

(9) When offshore pipelines are trenched, the condition of the trench, trench depth, and fit of the pipe to the trench shall be inspected when feasible.

(11) When offshore pipelines are to be backfilled, the backfilling operations shall be inspected for quality of backfill, possible damage to the pipe coating, and depth of cover.

(12) Pipelines shall be inspected for spans.

(13) Pipeline crossings shall be inspected for specified separation.

(15) Where specified, special assemblies and protection measures as described in A402.3.10 shall be inspected for protection against damage by outside forces, such as fishing and other marine activities.

A437 TESTING

A437.1 General

A437.1.4 Testing After New Construction

(a) Systems or Parts of Systems

(3) Provisions of para. 437.1.4(a)(3) are superseded by the following. All pipe and pressure-containing piping components shall be tested in accordance with the provisions of para. 437.1.4(a)(2).

(b) Testing Tie-Ins. Nonwelded tie-in connections shall be observed for leaks at operating pressure. Tie-in welds and girth welds joining lengths of pretested pipe shall be inspected by radiographic or other accepted nondestructive methods in accordance with para. A434.8.5(a)(4), if system is not pressure-tested after tie-in.

(d) Hydrostatic Test Medium. The hydrostatic test medium for all offshore pipeline systems shall be water, except in arctic areas. Additives to mitigate the effects of corrosion, biofouling, and freezing should be considered. Such additives should be suitable for the methods of disposal of the test medium.

In arctic areas where freezing of water is a restraint, the use of air, inert gas, or glycol is allowable, provided appropriate detail considerations are addressed.

Disposal of all materials shall be done in an environmentally safe manner.

(e) Diameter Restrictions. Testing for buckles, dents, and other diameter restrictions shall be performed after installation. Testing shall be accomplished by passing a deformation detection device through the pipeline section, or by other methods capable of detecting a change in pipe cross-section. Pipe having deformation which affects the serviceability of the pipeline facilities shall be repaired or replaced. Consideration should also be given to repairing ovality which may interfere with pigging operations or internal inspections.

A437.4 Test Pressure

A437.4.3 Leak Testing. Provisions of para. 437.4.3 are not applicable for offshore pipeline systems.

A437.6 Qualification Tests

Pipe of unknown specification and ASTM A 120 specification pipe are not allowed in offshore pipeline systems. See para. A423.1.

A437.7 Records

"As-built" records shall also include the location of anodes and buckle arrestors (if used) by pipe joint installation sequence. Subsea valve, tie-in, and other special assembly locations shall be recorded by coordinates.

A450 OPERATION AND MAINTENANCE PROCEDURES AFFECTING THE SAFETY OF LIQUID TRANSPORTATION PIPING SYSTEMS

A450.2 Operation and Maintenance Plans and Procedures

The provisions of paras. 450.2(d), 450.2(e), and 450.2(i) are superseded by the following:

(d) Have a plan for reviewing conditions affecting the integrity and safety of the pipeline system, including provisions for periodic patrolling and reporting of construction activity and changes in conditions.

(e) Establish and maintain liaisons with local offshore authorities who issue permits in order to prevent accidents caused by new construction. Establish and maintain liaisons with available offshore firefighting and pollution control entities.

(i) In establishing plans and procedures, give particular attention to those portions of the system presenting the greatest hazard to the public and to the environment in the event of emergencies or because of construction or extraordinary maintenance requirements.

A451 PIPELINE OPERATION AND MAINTENANCE

A451.3 Markers

The provisions of para. 451.3 do not apply to offshore pipeline systems.

A451.4 Right-of-Way Maintenance

The provisions of para. 451.4 do not apply to offshore pipeline systems.

A451.5 Patrolling

(a) The provisions of para. 451.5(a) and (b) are superseded by the following. Each offshore pipeline system operator shall maintain a periodic pipeline patrol program to observe surface conditions on, and adjacent to, the pipeline right-of-way, indication of leaks, construction activity other than that performed by the operator, and any other factors affecting the safety and operation of the pipeline. Consideration should be given to increased patrols in areas more susceptible to damage by outside forces. Such areas are listed in A451.11.

A451.6 Pipeline Repairs

A451.6.1 General. Additional requirements for repairs to offshore pipeline systems are as follows:

• Repair operations shall not result in imposed deformations which would impair the integrity of the pipe materials, and weight or protective coating.

• Subsea equipment used in the repair of offshore pipeline systems shall be carefully controlled and monitored to avoid damaging the pipeline, external coating, or cathodic protection system.

• When lifting or supporting pipe during repairs, the curvature of a pipe sag bend and overbend shall be controlled to prevent overstressing, denting, or buckling the pipe or damaging the coating. Lifting equipment shall be selected to comply with this requirement.

• Wave and current loads shall be considered in determining total imposed stresses and cyclical loadings in both surface and subsurface repairs.

• When pipe is repaired damaged coating shall be repaired.

• Replacement pipe and components shall be protected from corrosion.

Consideration should be given to obtaining pipe-to-water potentials during the repair operations to verify conformance to cathodic protection requirements.

A451.6.2 Disposition of Defects

(b) Allowable Pipeline Repairs

(4) Patches shall not be used on offshore pipeline systems.

(6) Partial encirclement half soles shall not be used on offshore pipeline systems.

(c) Repair Methods

(5) Patches shall not be used on offshore pipeline systems.

(8) Welded fittings allowed by para. 451.6.2(c)(8) to cover defects shall not be used in offshore pipeline systems.

(13) Half soles for repairs in offshore pipeline systems are prohibited.

A451.6.4 Repair of Flexible Pipe

(a) Major Structural Damage. If the serviceability of the flexible pipe is impaired, the damaged pipe section shall be replaced.

(b) Surface Cuts. In the event of surface cuts and abrasions which do not expose the load-carrying members to potential corrosion, the repair shall be performed in a manner recommended by the manufacturer.

A451.7 Derating a Pipeline to a Lower Operating Pressure

(c) If a component is installed during the repair that has a maximum pressure rating less than the allowable operating pressure of the pipeline, the pipeline shall be derated to the pressure rating of the component, analyzed in accordance with 451.1(a).

A451.8 Valve Maintenance

Provisions of para. 451.8 do not apply to offshore pipeline systems. Pipeline block valves that would be required by the Emergency Plan (see paras. 454 and A454) to be operated during an emergency shall be

inspected periodically, and fully or partially operated at least once a year.

A451.9 Railroads and Highways Crossing Existing Pipelines

The provisions of para. 451.9 do not apply to offshore pipeline systems.

A451.10 Offshore Pipeline Risers

The provisions of para. 451.10 do not apply to offshore pipeline systems.

A451.11 Inspection

As a means of maintaining the integrity of its pipeline system, each operating company shall establish and implement procedures for continuing surveillance of its facilities. Studies shall be initiated and appropriate action taken when unusual operating and maintenance conditions occur, such as failures, leakage history, unexplained changes in flow or pressure, or substantial changes in cathodic protection requirements.

Consideration should be given to inspection of pipelines and pipeline protection measures in areas most susceptible to damage by outside forces. Such areas may include shore crossings, areas near platforms, shipping fairways, pipeline crossings, span rectifications, subsea assemblies, and shallow water areas. If the operating company discovers that the cover or other conditions do not meet the original design, it shall determine whether the existing conditions are unacceptable. If unacceptable, the operating company shall provide additional protection by replacing cover, lowering the line, installing temporary or permanent warning markers or buoys, or using other suitable means.

When such studies indicate the facility is in an unsatisfactory condition, a planned program shall be initiated to abandon, replace, or repair. If such a facility cannot be repaired or abandoned, the maximum allowable operating pressure shall be reduced commensurate with the requirements described in paras. 451.7 and A451.7.

Offshore pipeline risers shall be visually inspected annually for physical damage and corrosion in the splash zone and above. Consideration should also be given to periodic visual inspection of the submerged zone of the riser. The extent of any observed damage shall be determined, and if the serviceability of the riser is affected, the riser shall be repaired or replaced.

Consideration should be given to the periodic use of internal or external inspection tools to monitor external and internal pipeline corrosion and to detect other unsafe conditions.

A452 OFFSHORE PLATFORM, PUMP STATION, TERMINAL, AND TANK FARM OPERATION AND MAINTENANCE

A452.5 Fencing

Fencing is not applicable for offshore facilities.

A452.7 Prevention of Accidental Ignition

Smoking shall be prohibited in all areas of offshore facilities in which the possible leakage or presence of vapor constitutes a fire or explosion hazard.

A454 EMERGENCY PLAN

(d) The provisions of para. 454(d) do not apply to offshore pipeline systems.

(e)

(5) The provisions of para. 454(e)(5) do not apply to offshore pipeline systems. To minimize public exposure to injury and to prevent accidental ignition, provisions for halting or diverting marine vessel traffic shall be included in the Emergency Plan.

A460 GENERAL

(a) In addition to the provisions of para. 460(a), special considerations shall be given to corrosion control of offshore pipeline systems because they cannot easily be inspected after installation and there is the possibility of damage to the coating system. Special attention shall be given to the selection, design, and application of corrosion control coatings, the cathodic protection system, and other corrosion design elements.

(c) NACE RP-06-75 provides a guide for procedures to implement requirements herein and to monitor and maintain cathodic protection systems for offshore pipeline systems.

A461 EXTERNAL CORROSION CONTROL FOR OFFSHORE SUBMERGED PIPELINES

A461.1 New Installations

A461.1.1 General

(a) The provisions of para. 461.1.1(a) do not apply to offshore pipeline systems. All submerged steel pipe,

valves, and related fittings shall be externally coated and cathodically protected.

(c) Provisions of para. 461.1.1(c) do not apply to offshore pipeline systems. A minimum clearance of 12 in. (300 mm) shall be maintained between the outside of any offshore pipeline and any other structure that may affect the cathodic protection of the offshore pipeline, except where impractical (e.g., bundled pipelines) and where adequate provisions for corrosion control have been made.

A461.1.2 Protective Coating

(a) In addition to the provisions of para. 461.1.2(a), the coating systems for offshore pipeline systems shall be selected for the type of environment in which the facility is to be installed and shall have the following additional characteristics:

- low water absorption;
- compatibility with system operating temperature;
- compatibility with weight coating application method, if applicable;
- sufficient toughness to withstand damage during installation and operation;
- resistance to future deterioration in a submerged environment;
- ease of repair; and
- resistance to cathodic disbondment.

The coating selected shall be applied in accordance with established specifications and the manufacturer's recommendations.

(f) The provisions of para. 461.1.2(f) do not apply to offshore pipeline systems. If coated pipe is installed by boring, driving, or other similar method, precautions shall be taken to minimize damage to the coating during installation. Consideration should be given to insulating the carrier pipe from the casing pipe when the carrier pipe is pulled into directionally drilled crossings or pull-tube risers. Consideration should also be given to preventing oxygen replenishment in the water in the annulus between carrier pipe and casing by sealing at least one end of pull-tube risers and directionally drilled crossings, or other measures to prevent corrosion.

(g) The provisions of para. 461.1.2(g) do not apply to offshore pipeline systems. In the event that backfilling is required, measures shall be taken to prevent damage to pipeline coating.

A461.1.3 Cathodic Protection System

(a) In addition to the provisions of para. 461.1.3(a), an offshore pipeline is considered to be cathodically protected when it meets one or more of the criteria established in NACE RP-06-75. Where impressed current systems are used, the system shall be designed to minimize outages. The design formula for galvanic anode systems shall include the percentage of exposed pipe, current output of the anodes, design life of the system, anode material, and utilization efficiency. Anodes should be compatible with the operating temperature of the pipeline and the marine environment. Consideration should be given to the effects on cathodic protection of variations in oxygen content, temperature, and water/soil resistivity of the particular offshore environment in which the pipeline is installed.

For installations containing flexible pipe, consideration shall be given to the need for galvanic anodes or impressed current at the end connections.

(b) Provisions of para. 461.1.3(b) do not apply to offshore pipeline systems. A cathodic protection system shall be installed at the time of pipeline installation or as soon as practical after pipeline installation.

(d) Provisions of para. 461.1.3(d) do not apply to offshore pipeline systems. Owners of other offshore pipelines or facilities which may be affected by installation of a cathodic protection system shall be notified of said installation.

A461.1.4 Electrical Isolation

(a) In addition to the provisions of para. 461.1.4, consideration shall be given to electrically isolating supporting devices, such as clamps and pipe supports, from the riser on platforms. Wiring and piping connections to an electrically isolated pipeline shall also be insulated from devices grounded to the platform.

A461.1.5 Test Leads

(a) It is considered impractical to locate test leads on submerged portions of offshore pipeline systems. Consideration should be given to installing test leads on platform risers, platform piping, and pipeline shore crossings.

A461.1.6 Electrical Interference

(c) When new pipeline are laid in the vicinity of existing lines, measures shall be taken to minimize electrical interference.

A461.3 Monitoring

(b) Evidence of adequate level of cathodic protection shall be by one or more of the criteria listed in NACE RP-06-75.

(h) If repairs are made to offshore pipelines below water, inspection for evidence of external corrosion or coating deterioration shall be made; and necessary corrective action shall be taken to maintain the corrosion protection of the pipeline.

When an offshore pipeline is lifted above water for maintenance or repair purpose, the operating company shall visually inspect for evidence of coating deterioration, external corrosion, and where possible, the condition of any exposed anode. If excessive corrosion is present, remedial action shall be taken as necessary.

(i) Consideration should be given to the periodic use of internal inspection tools to monitor external pipeline corrosion.

A463 EXTERNAL CORROSION CONTROL FOR OFFSHORE PIPING SYSTEMS EXPOSED TO ATMOSPHERIC CONDITIONS

A463.1 New Installations

The option of demonstrating "by test, investigation, or experience in area of application that a corrosive atmosphere does not exist," does not apply to offshore pipeline systems. The type of protective coating selected shall be resistant to the environment existing in offshore locations. The surface preparation and coating application shall be performed in accordance with established specifications and the manufacturer's recommendations. The selected coating should have the following characteristics:

- low water absorption,
- resistance to water action,
- compatibility with system operating temperature,
- resistance to atmospheric deterioration,
- resistance to mechanical damage, and
- ease of repair.

The splash zone area of the offshore pipeline system shall be designed with additional protection against corrosion. This shall be accomplished by one or more of the following:

- special coating;
- special protective systems and techniques; and
- other suitable measures, including selection of pipe material.

APPENDIX A
REFERENCED STANDARDS

Specific editions of standards incorporated in this Code by reference, and the names and addresses of the sponsoring organizations, are shown in this Appendix. It is not practical to refer to a specific edition of each standard throughout the Code text; instead, the specific edition reference dates are shown here. Appendix A will be revised at intervals as needed, and issued in Addenda to this Code. An asterisk (*) is used to indicate those standards that have been accepted as American National Standards by the American National Standards Institute (ANSI).

ASTM Specifications

A 6/A 6M-99b
A 20/A 20M-99a
A 29/A 29M-99
A 36/A 36M-00

A 53-99b

A 105/A 105M-98
A 106-99ε1 [Note (1)]
A 126-95ε1
A 134-96
A 135-97c [Note (1)]
A 139-96ε1

A 181/A 181M-95b
A 182/A 182M-99
A 193/A 193M-99a
A 194/A 194M-99

A 216/A 216M-93 (1998)
A 217/A 217M-99
A 225/A 225M-93 (1999)
A 234/A 234M-99
A 242/A 242M-00

A 283/A 283M-00
A 285/A 285M-90ε1 (1996)

A 307-97
A 320/A 320M-99
A 325-97
A 333/A 333M-99
A 350/A 350M-99

A 354-98
A 381-96
A 395-99

A 420/A 420M-99 [Note (4)]

A 449-93

A 487/A 487M-93 (1998)
A 490-97/A 490M-93

ASTM Specifications (Cont'd)

A 505-00
A 506-93 (1998)
A 507-93 (1998)
A 514/A 514M-00
A 515/A 515M-92 (1997)
A 516/A 516M-90ε1 (1996)
A 517/A 517M-93 (1999)
A 524-96 [Note (1)]
A 530/A 530M-99

A 572/A 572M-00
A 573/A 573M-93a (1998)
A 575-96
A 576-90b ε1 (1995)

A 633/A 633M-00

A 663/A 663M-89ε1 (1994)
A 671-96
A 672-96
A 675/A 675M-90a ε1 (1995)
A 694/A 694M-00

NFPA Codes

*30-1996
*70-1999

AWS Standards

*A3.0-1994
*D3.6M-1999

NACE Standards and Other Publications

MR-01-75 (2000 Rev.)
RP-01-69 (1996 Rev.)
RP-01-75
RP-01-77 (1995 Rev.)
RP-06-75
Corrosion Data Survey — Metals Section, 6th Ed., 1985

MSS Standard Practices

SP-6-1996
SP-25-1998
SP-44-1996
SP-55-1996
*SP-58-1993
SP-61-1992
SP-67-1995
SP-69-1996
SP-70-1998
SP-71-1997
SP-75-1998
SP-78-1998

API Standards and Other Publications

RP 2A-WSD, 20th Ed., 1993 & Supp. 1-1996

*Spec. 5B, 14th Ed., 1996
*Spec. 5L, 42nd Ed., 2000 [Note (2)]
*RP 5L1, 5th Ed., 1996
*RP 5LW, 2nd Ed., 1996 (Incorporates 5L1, 5L5, and 5L6)
*Spec. 6A, 18th Ed., 1999
Spec. 6D, 21st Ed., 1994
*Spec. 12B, 14th Ed., 1995
*Spec. 12D, 10th Ed., 1994
*Spec. 12F, 11th Ed., 1994

RP 17B, 2nd Ed., 1998
*RP 500, 2nd Ed., 1997

Std. 600, 10th Ed., 1997

Std. 602, 7th Ed., 1998
*Std. 603, 5th Ed., 1991
*Std. 620, 9th Ed., 1996
Std. 650, 10th Ed., 1998

RP 1102, 6th Ed., 1993
*Std. 1104, 19th Ed., 1999
RP 1109, 2nd Ed., 1993

REFERENCED STANDARDS (CONT'D)

API Standards and Other Publications (Cont'd)	ASME Codes and Standards	ASME Codes and Standards (Cont'd)
RP 1110, 4th Ed., 1997	*ASME Boiler and Pressure Vessel Code, 1998 Ed. and 1999 Addenda	*B16.20-1998 & Addenda 2000
RP 1111, 3rd Ed., 1999		*B16.21-1992
RP 1117, 2nd Ed., 1996		*B16.25-1997
	*B1.1-1998	*B16.28-1994
Publ. 2015, 5th Ed., 1994	*B1.20.1-1983 (R1992)	*B31G-1991
Publ. 2200, 3rd Ed., 1994	*B1.20.3-1976 (R1998)	*B31.5-1992 & Addenda-1994
Publ. 2201, 4th Ed., 1995		*B36.10M-1996
	*B16.5-1996 [Note (3)]	*B36.19M-1985 (R1994)
API Manual of Petroleum Measurement Standards	*B16.9-1993	
	*B16.10-1992	

GENERAL NOTE: The issue date shown immediately following the number of the standard (e.g., A 53-96, B1.1-1998, and SP-6-1996 is the effective date of issue (edition) of the standard.

NOTES:

(1) Approved only if mill hydrostatic test is performed.
(2) Use of bell and spigot line pipe not permitted.
(3) Limited as set forth in para. 402.2.1.
(4) A 420/A 420M Grade WPL9 is not suitable for anhydrous ammonia due to copper content.

Titles of standards and specifications listed above which are referenced in the text but do not appear in Table 423.1 — Material Standards or Table 426.1 — Dimensional Standards are as follows:

API	...	Manual of Petroleum Measurement Standards
API	2A-WSD	Recommended Practice for Planning, Designing, and Constructing Fixed Platforms — Working Stress Design
API	5L1	Recommended Practice for Railroad Transportation of Line Pipe
API	5LW	Recommended Practice for Tansportation of Line Pipe on Barges and Marine Vessels
API	12B	Specification for Bolted Tanks for Storage of Production Liquids
API	12D	Specification for Field Welded Tanks for Storage of Production Liquids
API	12F	Specification for Shop Welded Tanks for Storage of Production Liquids
API	17B	Recommended Practice for Flexible Pipe
API	500	Classification of Locations for Electrical Installations at Petroleum Facilities
API	620	Design and Construction of Large, Welded, Low-Pressure Storage Tanks
API	650	Welded Steel Tanks for Oil Storage
API	1102	Recommended Practice for Liquid Petroleum Pipelines Crossing Railroads and Highways
API	1104	Standard for Welding Pipelines and Related Facilities
API	1109	Recommended Practice for Marking Liquid Petroleum Pipeline Facilities
API	1110	Recommended Practice for Pressure Testing of Liquid Petroleum Pipelines
API	1111	Recommended Practice for Design, Construction, Operation and Maintenance of Offshore Hydrocarbon Pipelines
API	2015	Cleaning Petroleum Storage Tanks
API	2200	Repairing Crude Oil, Liquefied Petroleum Gas, and Product Pipelines
API	2201	Procedures for Welding or Hot Tapping on Equipment in Service
ASME	...	Boiler and Pressure Vessel Code, Section VIII Division 1 Pressure Vessels, Section VIII Division 2 Alternative Rules for Pressure Vessels, and Section IX Welding and Brazing Qualifications
ASME	B31G	Manual for Determining the Remaining Strength of Corroded Pipelines: A Supplement to B31, Code for Pressure Piping
ASME	B31.5	Refrigeration Piping
AWS	A3.0	Welding Terms and Definitions
AWS	D3.6	Specification for Underwater Welding
NACE	...	Corrosion Data Survey — Metals Section
NACE	MR-01-75	Sulfide Stress Cracking Resistant Metallic Materials for Oil Field Equipment
NACE	RP-01-69	Recommended Practice — Control of External Corrosion on Underground or Submerged Metallic Piping Systems
NACE	RP-01-75	Recommended Practice: Control of Internal Corrosion in Steel Pipelines Systems
NACE	RP-01-77	Mitigation of Alternating Current and Lightning Effects on Metallic Structures and Corrosion Control Systems
NACE	RP-06-75	Recommended Practice: Control of Corrosion on Offshore Steel Pipelines

REFERENCED STANDARDS (CONT'D)

NFPA	30	Flammable and Combustible Liquids Code
NFPA	70	National Electrical Code

Specifications and standards of the following organizations appear in Appendix A:

ANSI American National Standards Institute, Inc.
11 West 42nd Street
New York, NY 10036
212 642-4900

API American Petroleum Institute
Order Desk
1220 L Street, N.W.
Washington, DC 20005-4070
202 682-8375

ASME The American Society of Mechanical Engineers
Three Park Avenue
New York, NY 10016-5990
212 591-8500

ASME Order Department
22 Law Drive
Box 2900
Fairfield, NJ 07007-2900
800 843-2763
201 882-1167

ASTM American Society for Testing and Materials
100 Bar Harbor Drive
West Conshohocken, PA 19428-2959
610 832-9500

AWS American Welding Society
P.O. Box 351040
550 N.W. LeJeune Road
Miami, FL 33126
305 443-9353

MSS Manufacturers Standardization Society of the Valve and Fittings Industry, Inc.
127 Park Street, N.E.
Vienna, VA 22180
703 281-6613

NACE National Association of Corrosion Engineers
1440 South Creek Drive
P.O. Box 218340
Houston, TX 77218-8340
713 492-0535

NFPA National Fire Protection Association
1 Batterymarch Park
Quincy, MA 02269-9101
617 770-3000

APPENDIX B
SUBMITTAL OF TECHNICAL INQUIRIES TO THE B31 PRESSURE PIPING COMMITTEE

B-1 INTRODUCTION

The ASME B31 Pressure Piping Committee and its Section Committees meet regularly to consider revisions of the Code rules, new Code rules as dictated by technological development, Code Cases, and Code interpretations. This Appendix provides guidance to Code users for submitting technical inquiries to the Committee. Technical inquiries include requests for revisions or additions to the Code rules, requests for Code Cases, and requests for Code interpretations.

Code Cases may be issued by the Committee when the need is urgent. Code Cases clarify the intent of existing Code requirements or provide alternative requirements. Code Cases are written as a question and a reply and are usually intended to be incorporated into the Code at a later date. Code interpretations provide the meaning of or the intent of existing rules in the Code and are also presented as a question and a reply. Both Code Cases and Code interpretations are published by the Committee.

The Code rules, Code Cases, and Code interpretations established by the Committee are not to be considered as approving, recommending, certifying, or endorsing any proprietary or specific design or as limiting in any way the freedom of manufacturers or constructors to choose any method of design or any form of construction that conforms to the Code rules.

As an alternative to the requirements of this Appendix, members of the Committee and its Section Committees may introduce requests for Code revisions or additions, Code Cases, and Code interpretations at their respective Committee meetings or may submit such requests to the secretary of a Section Committee.

Inquiries that do not comply with the provisions of this Appendix or that do not provide sufficient information for the Committee's full understanding may result in the request being returned to the inquirer with no action.

B-2 INQUIRY FORMAT

Submittals to the Committee shall include:

(a) Purpose. Specify one of the following:

(1) revision of present Code rule(s);

(2) new or additional Code rule(s);

(3) Code Case;

(4) Code interpretation.

(b) Background. Provide the information needed for the Committee's understanding of the inquiry, being sure to include reference to the applicable Code Section, Edition, Addenda, paragraphs, figures, and tables. Preferably, provide a copy of the specific referenced portions of the Code.

(c) Presentations. The inquirer may desire or be asked to attend a meeting of the Committee to make a formal presentation or to answer questions from the Committee members with regard to the inquiry. Attendance at a Committee meeting shall be at the expense of the inquirer. The inquirer's attendance or lack of attendance at a meeting shall not be a basis for acceptance or rejection of the inquiry by the Committee.

B-3 CODE REVISIONS OR ADDITIONS

Requests for Code revisions or additions shall provide the following:

(a) Proposed Revision(s) or Additions(s). For revisions, identify the rules of the Code that require revision and submit a copy of the appropriate rules as they appear in the Code marked up with the proposed revision. For additions, provide the recommended wording referenced to the existing Code rules.

(b) Statement of Need. Provide a brief explanation of the need for the revision(s) or addition(s).

(c) Background Information. Provide background information to support the revision(s) or addition(s) including any data or changes in technology that form the basis for the request that will allow the Committee to adequately evaluate the proposed revision(s) or addition(s). Sketches, tables, figures, and graphs should be submitted as appropriate. When applicable, identify any pertinent paragraph in the Code that would be affected by the revision(s) or addition(s) and paragraphs in the

Code that reference the paragraphs that are to be revised or added.

B-4 CODE CASES

Requests for Code Cases shall provide a statement of need and background information similar to that defined in B-3(b) and B-3(c), respectively, for Code revisions or additions. The proposed Code Case should identify the Code Section and be written as a question and a reply in the same format as existing Code Cases.

B-5 CODE INTERPRETATIONS

Requests for Code interpretations shall provide the following:

(a) Inquiry. Provide a condensed and precise question, omitting superfluous background information, and, when possible, composed in such a way that a "yes" or a "no" reply, possibly with brief provisos, is acceptable. The question should be technically and editorially correct.

(b) Reply. Provide a proposed reply that will clearly and concisely answer the inquiry question. Preferably, the reply should be "yes" or "no" possibly with brief provisos.

(c) Background Information. Provide any background information that will assist the Committee in understanding the proposed inquiry and reply.

B-6 SUBMITTAL AND RESPONSE

Submittals to and responses from the Committee shall meet the following:

(a) Submittal. Inquiries from Code users shall preferably be submitted in typewritten form; however, legible handwritten inquiries will also be considered. They shall include the name, address, telephone number, and fax number, if available, of the inquirer and be mailed to the following address:

Secretary
ASME B31 Committee
Three Park Avenue
New York, NY 10016-5990

(b) Response. The Secretary of the appropriate Section Committee shall acknowledge receipt of each properly prepared inquiry and shall provide a written response to the inquirer upon completion of the requested action by the appropriate Section Committee.

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ASME B31.4

INTERPRETATIONS NO. 7

Replies to Technical Inquiries
January 1, 2001 Through December 31, 2001

It has been agreed to publish intepretations issued by the B31 Committee concerning B31.4 as part of the update service to the Code. The interpretations have been asssigned numbers in chronological order. Each interpretation applies either to the latest Edition or Addenda at the time of issuance of the interpretation or the Edition or Addenda stated in the reply. Subsequent revisions to the Code may have superseded the reply.

These replies are taken verbatim from the original letters, except for a few typographical and editorial corrections made for the purpose of improved clarity. In some instances, a review of the interpretation revealed a need for corrections of a technical nature. In these cases, a revised reply bearing the original interpretation number with the suffix R is presented. In the case where an interpretation is corrected by Errata, the original interpretation number with the suffix E is used.

ASME procedures provide for reconsideration of these interpretations when or if additional information is available which the inquirer believes might affect the interpretation. Further, persons aggrieved by an interpretation may appeal to the cognizant ASME committee or subcommittee. As stated in the Statement of Policy in the Code documents, ASME does not "approve," "certify," "rate," or "endorse" any item, construction, proprietary device, or activity.

For detailed instructions on preparations of technical inquiries to the B31 Committee, refer to Appendix B.

Interpretations No. 1 was included with ANSI/ASME B31.4c-1986. Interpretations No. 2 was included with ASME B31.4a-1987. Interpretations No. 3 was included with ASME B31.4a-1991. Interpretations No. 4 was included with ASME B31.4a-1994. Interpretations No. 5 was included with ASME B31.4-1998. Interpretations No. 6 was included with B31.4a-2001.

Interpretations No. 7 contains interpretations inadvertently omitted from Interpretations No. 6.

B31.4

Subject	Interpretation	File No.
434.7.1, Bends, Miters, and Elbows, and 437.4.1, Hydrostatic Testing of Internal Pressure Piping	4-73	B31-01-006
401.2.2, Internal Design Pressure	4-74	B31-01-007
409, Used Piping Components and Equipment	4-75	B31-01-008

Interpretation: 4-73

Subject: ASME B31.4-1998 Edition, Paras. 434.7.1 and 437.4.1

Date Issued: March 22, 2001

File: B31-01-006

Question: If a section of pipe meets the following requirements: pretested for use as a replacement pipe in accordance with section 437.4.1 of B31.4; then cold bent in accordance with section 434.7.1 of B31.4; and complies with the quality requirements of section 434.7.1 of B31.4; does the pipe bend need to be retested in accordance with section 437.4.1 of B31.4 after completion of the bend?

Reply: No.

Interpretation: 4-74

Subject: ASME B31.4-1998 Edition, Para. 401.2.2, Internal Design Pressure

Date Issued: March 23, 2001

File: B31-01-007

Question: May a piece of pipe that has been subjected to a hydrostatic test by a manufacturer to a pressure level less than or equal to 1.25 times its design pressure as per paragraph 401.2.2 for a period of less than 4 hr be subjected to a hydrostatic test in the field to a pressure level of 1.25 times its design pressure for a period of 4 hr or more?

Reply: Yes.

Interpretation: 4-75

Subject: ASME B31.4-1998 Edition, Para. 409, Used Piping Components and Equipment

Date Issued: March 22, 2001

File: B31-01-008

Question: May B31.4 be interpreted to consider an existing pipeline built per B31.8 as "used" in accordance with para. 405.2.1(b) or (c) and para. 409 of B31.4 and then operated at an operating pressure established in accordance with paragraph 451.1 of B31.4?

Reply: Yes.

ASME CODE FOR PRESSURE PIPING, B31

B31.1	Power Piping	2001
B31.2[1]	Fuel Gas Piping	1968
B31.3	Process Piping	2002
B31.4	Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids	2002
B31.5	Refrigeration Piping and Heat Transfer Components	2001
B31.8	Gas Transmission and Distribution Piping Systems	1999
B31.9	Building Services Piping	1996
B31.11	Slurry Transportation Piping Systems	1989 (R1998)
B31G-1991	Manual for Determining the Remaining Strength of Corroded Pipelines: A Supplement to ASME B31 Code for Pressure Piping	

NOTE:

(1) USAS B31.2-1968 was withdrawn as an American National Standard on February 18, 1988. ASME will continue to make available USAS B31.2-1968 as a historical document for a period of time.

ASME Code for Pressure Piping, B31
An American National Standard

ASME B31G-1991
(REVISION OF ANSI/ASME B31G-1984)

Manual for Determining the Remaining Strength of Corroded Pipelines

A Supplement to ASME B31 Code for Pressure Piping

The American Society of Mechanical Engineers

AN AMERICAN NATIONAL STANDARD

ASME CODE FOR PRESSURE PIPING, B31

Manual for Determining the Remaining Strength of Corroded Pipelines

A Supplement to ASME B31 Code for Pressure Piping

ASME B31G-1991

(REVISION OF ANSI/ASME B31G-1984)

The American Society of Mechanical Engineers

345 East 47th Street, New York, N.Y. 10017

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The 1991 edition of this Manual will be revised when public comment or Committee actions necessitate the issuance of a new edition, or it will be reviewed and reaffirmed 5 years from the date of approval of this edition. No addenda service is provided with this publication. Written interpretations of the requirements of this Manual will not be issued to the current edition.

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FOREWORD

(This Foreword is not a part of ASME B31G-1991.)

It is recognized by pipeline companies that some sections of high pressure pipelines, particularly those installed a number of years ago, have experienced some corrosion. Where corrosion is found, pipeline operators have been deeply concerned about the need for a method of determining the remaining strength of these corroded areas. If the corrosion does not penetrate the pipe wall, what is the pressure containing capability of the remaining pipe metal in terms of its ability to continue to operate safely at the maximum allowable operating pressure (MAOP) of the pipeline system? Thus, one of the needs of the pipeline industry has been a procedure that will help operators, particularly field personnel, make decisions on existing pipelines, when exposed for any purpose, as to whether any corroded region may be left in service or whether it needs to be repaired or replaced. Such determinations must be based upon sound research and extensive testing in order to provide safe and conservative guidelines on which to base field decisions. The Manual provides procedures to assist in this determination.

Parts 2, 3, and 4 are based on Appendices G-6, G-7, and G-8 of the ASME Guide for Gas Transmission and Distribution Piping Systems, 1983 Edition. They are included in this Manual for use by field operators to determine the remaining strength of corroded pipe. The technology is based on research done in the Columbus laboratories of the Battelle Memorial Institute; specifically, their report *Summary of Research to Determine the Strength of Corroded Areas in Line Pipe,* July 10, 1971.

A revision to the 1984 edition of the Manual was undertaken in 1989. The revision includes a number of clarifications and corrections. The computer program presented in Appendix B and used to produce a printed table of maximum acceptable corrosion lengths for a given pipe diameter, and up to ten wall thicknesses of that diameter, was upgraded.

This Manual was approved by ASME and subsequently by the American National Standards Institute on May 20, 1991.

ASME CODE FOR PRESSURE PIPING, B31

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PART 1
INTRODUCTION

1.1 SCOPE

The scope of this Manual includes all pipelines within the scope of the pipeline codes that are part of ASME B31 Code for Pressure Piping, i.e., ASME B31.4, Liquid Transportation Systems for Hydrocarbons, Liquid Petroleum Gas, Anhydrous Ammonia, and Alcohols; ASME B31.8, Gas Transmission and Distribution Piping Systems; and ASME B31.11, Slurry Transportation Piping Systems. Parts 2, 3, and 4 are based on material included in ASME Guide for Gas Transmission and Distribution Piping Systems, 1983 Edition.

This Manual is not applicable to new construction covered under the B31 Code Sections. That is, it is not intended that this Manual be used to establish acceptance standards for pipe that may have become corroded prior to or during fabrication and/or installation.

This Manual is intended solely for the purpose of providing guideline information for the designer/owner/operator. Thus, the specific use of this Manual is the responsibility of the designer/owner/operator.

1.2 LIMITATIONS

(a) This Manual is limited to corrosion on weldable pipeline steels categorized as carbon steels or high strength low alloy steels. Typical of these materials are those described in ASTM A 53, A 106, and A 381, and API 5L. (The current API 5L includes all Grades formerly in API 5LX and 5LS.)

(b) This Manual applies only to defects in the body of line pipe which have relatively smooth contours and cause low stress concentration (e.g., electrolytic or galvanic corrosion, loss of wall thickness due to erosion).

(c) This procedure should not be used to evaluate the remaining strength of corroded girth or longitudinal welds or related heat affected zones, defects caused by mechanical damage, such as gouges and grooves, and defects introduced during pipe or plate manufacture, such as seams, laps, rolled ends, scabs, or slivers.

(d) The criteria for corroded pipe to remain in service presented in this Manual are based only upon the ability of the pipe to maintain structural integrity under internal pressure. It should not be the sole criterion when the pipe is subject to significant secondary stresses (e.g., bending), particularly if the corrosion has a significant transverse component.

(e) This procedure does not predict leaks or rupture failures.

1.3 INITIAL DEVELOPMENT

In the late 1960s, a major long-lines gas transmission pipeline company in conjunction with the Battelle Memorial Institute in Columbus, Ohio, began a research effort to examine the fracture initiation behavior of various kinds of corrosion defects in line pipe. This included determining the relationship between the size of a defect and the level of internal pressure that would cause the defect to leak or rupture. The testing by the gas pipeline company and Battelle demonstrated that there was indeed a possibility of developing methodology and procedures to analyze varying degrees of corrosion of existing pipelines. From this, an operator could make a valid determination as to whether the pipelines could safely remain in service or should be repaired or replaced. As the awareness of this research program grew, other transmission companies began to express considerable interest.

Beginning in the early 1970s, the American Gas Association (AGA) Pipeline Research Committee assumed responsibility for this activity and began developing methods for predicting the pressure strength of line pipe containing various sizes of corrosion defects.

The overall objective of these experiments 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.

1.4 METHODOLOGY AND RESEARCH PROCEDURES

The procedure contained in this Manual is based upon pressuring actual corroded pipe to failure in an extensive series of full-size tests. Since there was pipe available that had been removed from service and that had sustained corrosion damage, it seemed more logical to test these full-size, actual field specimens, either in place or in a large, full-scale test cell, rather than base these guidelines upon purely laboratory tests using machined defects. Several hundred full-scale pipe tests were conducted on all types of defects to establish general defect behavior. Mathematical expressions to calculate the pressure strength of corroded pipe materials were developed on the basis of these extensive tests. These mathematical expressions, although semiempirical, were founded upon well established principles of fracture mechanics. The basis principle of fracture mechanics is that the resistance of the material to unstable fracturing in the presence of a defect is related to the size of the defect and an inherent metal property called toughness. The tougher the material, the larger the flaw that can be tolerated before failure will occur. Also, the bigger the defect, the lower the pressure at which a leak or rupture will occur. These two features may seem obvious, but they form the basis of fracture mechanics in terms of determining the real strength of pipe containing defects.

During 1970 and 1971, 47 pressure tests were conducted on several pipe sizes to evaluate the effectiveness of the mathematical expressions in determining the strength of corroded areas. The diameter of the pipe material examined ranged from 16 in. through 30 in. and wall thickness varied from 0.312 in. through 0.375 in. The pipe materials have ranged in yield strength from about 25,000 psi for API 5L Grade A-25 to about 52,000 psi for 5LX Grade X-52.

The mathematical expressions developed from the earlier experiments have been modified based on later test results and now provide reliable estimates of the failure pressures for corrosion defects over the range of materials covered in this study. The experiments

on corroded pipe indicated that line pipe steels have adequate toughness and that the toughness is not a significant factor. The failure of blunt corrosion flaws is controlled by their size and the flow stress or yield stress of the material.

Figure 1-1 shows the relationship between the full-size test failures and the criterion for acceptance of corrosion pits in line pipe. The criterion is that they shall withstand a pressure equal to a stress level of 100% of the specified minimum yield stress (SMYS). The Figure is based on an assured parabolic profile of the corroded regions and presents the maximum corrosion depth, divided by the pipe wall thickness, plotted against the corrosion length, divided by the square root of the pipe radius times wall thickness. Each of the data points plotted represents one full-size pipe experiment on corroded pipe, and the number next to the data point represents the stress at failure pressure expressed as percent SMYS. There are only 3 data points (experiments) that failed at pressure levels below 100% SMYS, indicating the lack of severity of corrosion defects in general (note that all three would be rejected by this criterion). The solid line shown on the Figure is the line that identifies failure pressures of less than 100% SMYS. There are a number of data points that are below this line, but all of them represent failures above 100% SMYS. The fact that these are above 100% SMYS simply indicates that the criterion is very conservative.

The acceptable region in the plot is the shaded region below and to the left of the solid line. The Tables in Part 3 are based on corrosion depths and lengths determined by this solid line. Corrosion pits that have depths and lengths that fall above the curve are not acceptable, in accordance with the criteria presented herein, and the operating pressure either has to be reduced, or the corrosion pit removed or repaired.

1.5 HOW TO USE THE MANUAL

Part 2, Determination of Maximum Allowable Longitudinal Extent of Corrosion, sets forth the equations for determining the severity of the corroded areas. It tells the operator how to measure the longitudinal extent and maximum depth of the corroded areas. One can then use Eq. (2) of Part 2 to determine if the corroded area is serious.

However, it is recognized that most field operators will prefer a simpler method of evaluating a corroded area. Therefore, Part 3, Tables for Corrosion Limits, evaluates Eq. (2) and places the results in tabular form. This allows the field operator to make decisions simply by going to a table after measuring the longitudinal extent and maximum depth of the corroded area and making a choice.

Locate the table appropriate for the pipe O.D. and wall thickness. Look down the left column and find the depth of corrosion that is equal to or the next number larger than the measured maximum depth of the corroded area. Read across to the column headed by the wall thickness or next number lower than the pipe's nominal wall thickness to determine the maximum allowable longitudinal extent of the corroded area for the depth of corrosion. If the measured longitudinal extent of the corroded area is equal to or less than the maximum allowable longitudinal extent of the corroded area determined from the Table, the pipe strength is suitable for the present MAOP[1] and is capable of containing a test pressure that will produce a stress of 100% SMYS of the pipe material.

[1]As used in this manual, the term MAOP shall represent maximum steady state operating pressure for pipelines within the scope of ASME B31.4 and ASME B31.11 and maximum allowable operating pressure for pipelines within the scope of ASME B31.8.

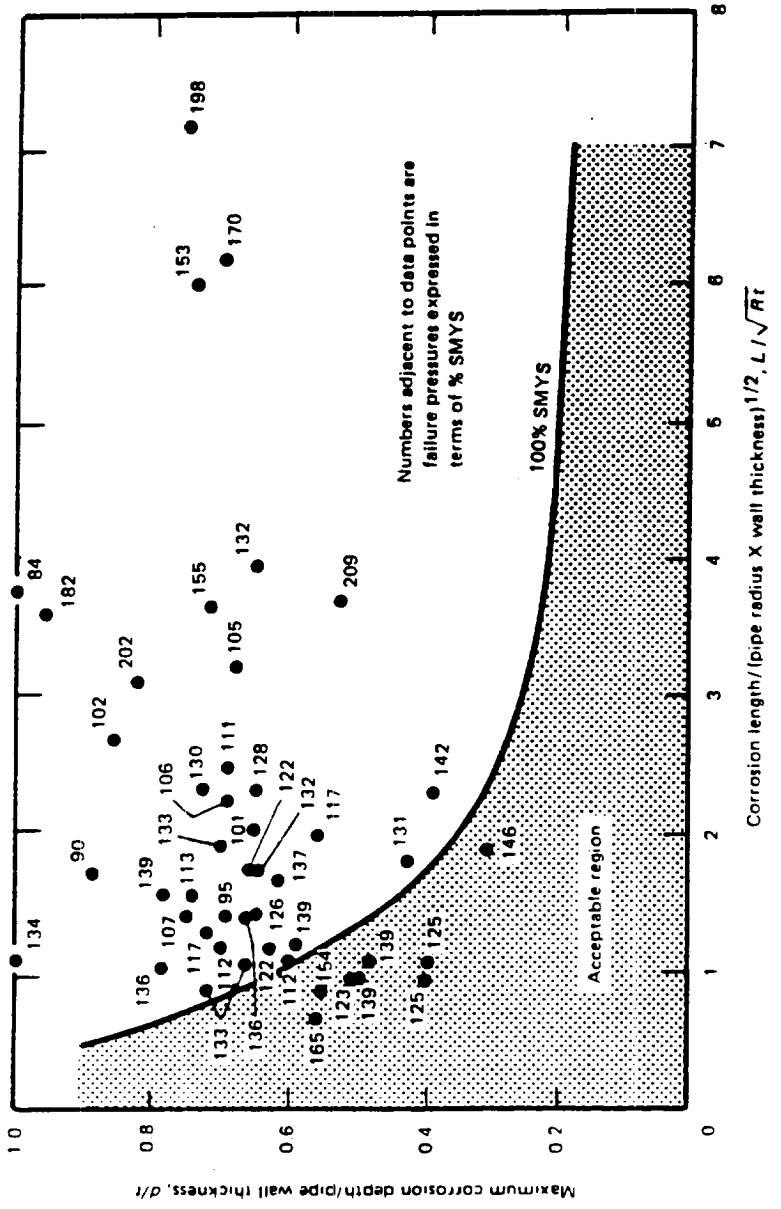

FIG. 1-1 PARABOLIC CRITERIA FOR CLASSIFYING CORROSION DEFECTS ACCORDING TO PREDICTED FAILURE STRESS

The tables produce results which may be more conservative than Eq. (2) of Part 2. The tables could show that the corroded area is unsuitable for the current MAOP, but Eq. (2) may show that it is. Therefore, it is possible for the corroded region to be rejected by the tables, but found suitable by using Eq. (2).

If the tables and Eq. (2) both show the corroded region to be unsuitabe, it may still be possible to establish suitability by one of the methods mentioned in para. 1.7. Another alternative would be to lower the MAOP of the pipeline, if permitted by operating conditions. Part 4 can be used to determine a lower MAOP that has the same safety factor provided by Parts 2 and 3.

Regardless of which alternative is chosen, in all cases where the corroded region is to be left in service, measures should be taken to arrest further corrosion. Such measures should include coating the corroded region and, if indicated, increasing the cathodic protection level.

Figure 1-2 , Procedure for Analysis of Corroded Pipe Strength, shows the steps necessary to proceed through the evaluation of a corroded area on a pipeline in order to determine if any corrective action is needed. The steps shown in the dashed boxes are valid means of determining a safe operating pressure (or MAOP), but the procedures for conducting these steps or the acceptance levels are not in this Manual.

1.6 THE MEANING OF ACCEPTANCE

(a) Any corroded region indicated as acceptable by the criteria of this Manual for service at the established MAOP is capable of withstanding a hydrostatic pressure test that will produce a stress of 100% of the pipe SMYS.

(b) Any corroded region indicated as acceptable for service at a reduced MAOP is capable of withstanding a hydrostatic pressure test at a ratio above the MAOP equal to the ratio of a 100% SMYS test to 72% SMYS operation (1.39:1). If a larger ratio is desired, the reduced MAOP can be adjusted accordingly.

1.7 OTHER MEANS OF DETERMINING SAFE PIPELINE OPERATING PRESSURE

(a) The operator can make a more rigorous analysis of the corroded area to determine the remaining strength by performing a fracture mechanics analysis based upon established principles and practices using the actual profile of the corroded region.

(b) The operator can reestablish the MAOP by a complete hydrostatic pressure test that produces a minimum stress of 100% SMYS, or establish a lower MAOP based on the pressure of a successful test conducted at a lower pressure.

(c) The procedures and acceptance criteria for conducting these alternative acceptance tests, either fracture mechanics analysis or hydrostatic tests, are not included in this Manual.

1.8 COMPUTER PROGRAMS

Appendix A is a BASIC computer program, CRVL.BAS, developed by Mr. Richard L. Seifert and is based on the equations in Parts 2 and 4. It can be used to expedite the evaluation procedure. Several examples of the program output are shown.

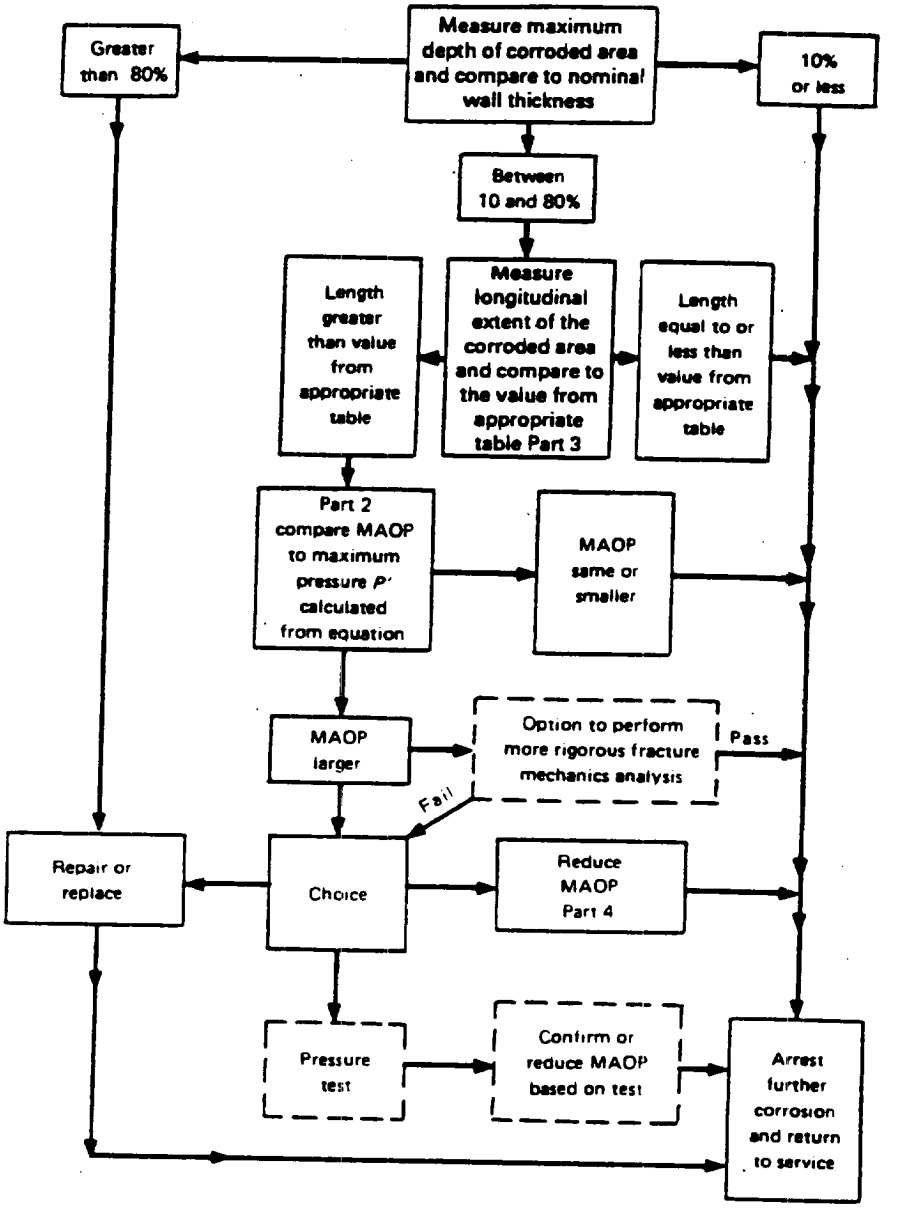

FIG. 1-2 PROCEDURE FOR ANALYSIS OF CORRODED PIPE STRENGTH

Appendix B is a BASIC computer program, CRLGTHU.BAS by Mr. Seifert, which is an upgrade of CRLGTH.BAS, which was contained in the first printing of this Manual. CRLGTH.BAS was used to produce some of the tables in Part 3. It required that the BASIC program be modified slightly each time it was used. The new program CRLGTHU.BAS does not require modification. It will produce a printed table of maximum acceptable corrosion lengths for a given pipe diameter, and up to ten wall thicknesses of that diameter. An example of a printed table by this program is included at the end of Appendix B.

Both CRVL.BAS and CRLGTHU.BAS were written in BASIC for a specific computer/. printer combination and can be utilized by most state-of- the-art microprocessors. However, minor modifications may be necessary for use on other equipment or for other purposes.

These computer programs are reproduced herein solely for the convenience of the Manual user, and ASME and the auther make no claims as to their accuracy or effectiveness.

PART 2
DETERMINATION OF MAXIMUM ALLOWABLE LONGITUDINAL EXTENT OF CORROSION

The depth of a corrosion pit may be expressed as a percent of the nominal wall thickness of the pipe by:

$$\% \text{ pit depth} = 100d/t \tag{1}$$

where

d = measured maximum depth of the corroded area, in., as shown in Fig. 2-1

t = nominal wall thickness of the pipe, in. Additional wall thickness required for concurrent external loads shall not be included in the calculations.

A contiguous corroded area having a maximum depth of more than 10% but less than 80% of the nominal wall thickness of the pipe should not extend along the longitudinal axis of the pipe for a distance greater than that calculated from:

$$L = 1.12B\sqrt{Dt} \tag{2}$$

(L may also be determined from Tables 3-1 through 3-12 in Part 3.)

where

L = maximum allowable longitudinal extent of the corroded area, in., collinear with L_M in Fig. 2-1

D = nominal outside diameter of the pipe, in.

B = a value which may be determined from the curve in Fig. 2-2 or from:

$$B = \sqrt{\left(\frac{d/t}{1.1\,d/t - 0.15}\right)^2 - 1} \tag{3}$$

except that B may not exceed the value 4. If the corrosion depth is between 10% and 17.5%, use $B = 4.0$ in Eq. (2).

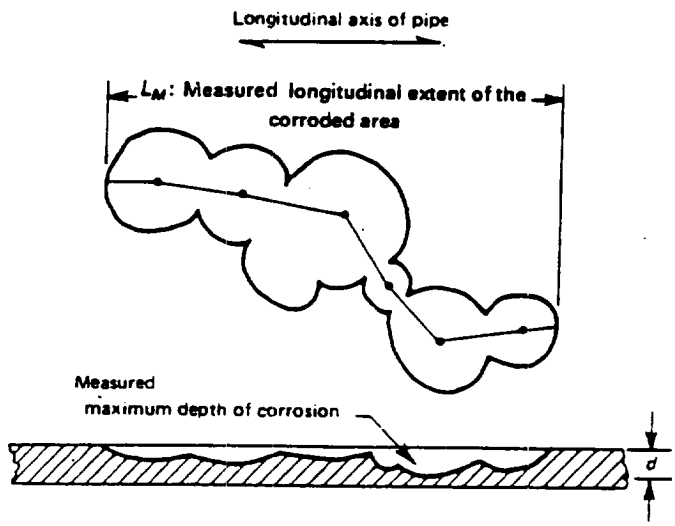

FIG. 2-1 CORROSION PARAMETERS USED IN ANALYSIS

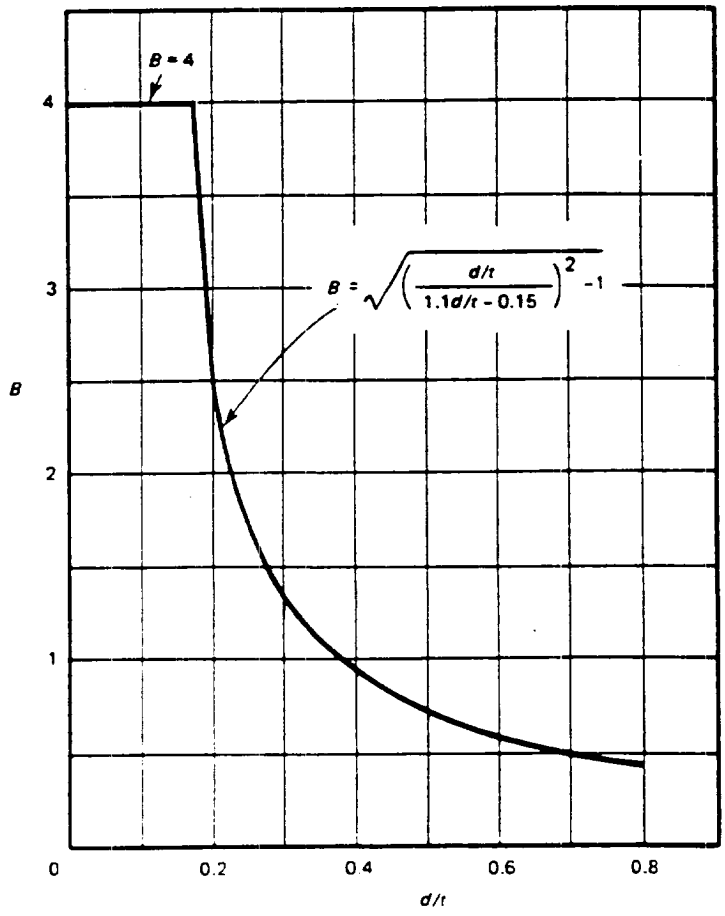

FIG. 2-2 CURVE FOR DETERMINING THE VALUE *B*

PART 3
TABLES FOR CORROSION LIMITS

The tables in this Part are calculated from the equations in Part 2. They provide a ready reference of maximum corrosion lengths for a spectrum of pipe diameters, wall thicknesses, and pit depths. These Tables may be used to determine the maximum allowable longitudinal extent of a contiguous area of corrosion as given in Part 2.

(a) The corroded area must be clean to bare metal. Care should be taken when cleaning corroded areas of a pressurized pipeline.

(b) Measure the maximum depth of the corroded area d and the longitudinal extent of the corroded area as shown in Fig. 2-1.

(c) Determine the size (NPS) of the pipe and nominal wall thickness.

(d) Turn to the page in the Table corresponding to the size (NPS) of the pipe.

(e) Locate the row showing a depth equal to the measured maximum depth of the corroded area. If the exact measured value is not listed, choose the row showing the NEXT GREATER DEPTH.

(f) Scan across to the column showing the wall thickness of the pipe. If the nominal wall thickness is not listed, use the column for the NEXT THINNER WALL. The value L found at the intersection of the wall thickness column and depth row is the maximum allowable longitudinal extent of such a corroded area.

(g) The tables in Part 3 produce results which may be more conservative than those obtained from the equations in Part 2. Therefore, the tables could show that a given corroded area is unsuitable for the current MAOP, but the use of the equations in Part 2 may show that it is acceptable.

TABLE 3-1 VALUES OF *L* FOR PIPE SIZES ≥ NPS 2 AND < NPS 6

Depth, *d*, in.	Wall Thickness, *t*, in. 0.083	0.109	0.125	0.141	0.154	0.172	0.188	0.218
0.01	2	.....	.....	.....	.....	.....	.....	.....
0.02	15/16	1 13/16	2 7/16	2 9/16	2 11/16	2 7/8	3	.....
0.03	1/2	7/8	1 1/8	1 1/2	1 15/16	2 7/8	3	3 1/4
0.04	3/8	5/8	3/4	15/16	1 1/8	1 3/8	1 3/4	2 3/4
0.05	5/16	7/16	9/16	11/16	13/16	1	1 5/16	1 3/8
0.06	1/4	3/8	1/2	9/16	11/16	13/16	15/16	1 3/16
0.07	.....	5/16	7/16	1/2	9/16	11/16	3/4	1
0.08	.....	5/16	3/8	7/16	1/2	9/16	11/16	13/16
0.09	.....	.....	5/16	3/8	7/16	1/2	9/16	3/4
0.10	.....	.....	1/4	5/16	3/8	7/16	1/2	11/16
0.11	.....	.....	.....	5/16	3/8	7/16	1/2	5/8
0.12	.....	.....	.....	.....	5/16	3/8	7/16	9/16
0.13	.....	.....	.....	.....	.....	5/16	3/8	1/2
0.14	.....	.....	.....	.....	.....	.....	3/8	7/16
0.15	.....	.....	.....	.....	.....	.....	5/16	7/16
0.16	.....	.....	.....	.....	.....	.....	.....	3/8
0.17	.....	.....	.....	.....	.....	.....	.....	3/8

TABLE 3-2 VALUES OF *L* FOR PIPE SIZES ≥ NPS 6 AND < NPS 10

Depth, *d*, in.	Wall Thickness, *t*, in. 0.083	0.125	0.156	0.188	0.203	0.219	0.250	0.312
0.010	3 5/16	.....	.....	.....	.....	.....	.....	.....
0.020	1 1/2	4 1/16	4 9/16	5	.....	.....	.....	.....
0.030	7/8	1 7/8	3 3/8	5	5 3/16	5 3/8	5 3/4	.....
0.040	5/8	1 1/4	1 7/8	2 15/16	3 3/8	4 3/8	5 3/4	6 7/16
0.050	1/2	15/16	1 3/8	1 15/16	2 5/16	2 3/4	3 7/8	6 7/16
0.060	7/16	13/16	1 1/8	1 9/16	1 3/4	2 1/16	2 11/16	4 3/4
0.070	.....	11/16	15/16	1 5/16	1 7/16	1 11/16	2 1/8	3 3/8
0.080	.....	9/16	13/16	1 1/8	1 1/4	1 7/16	1 3/4	2 11/16
0.090	.....	1/2	3/4	1	1 1/8	1 1/4	1 9/16	2 1/4
0.100	.....	7/16	11/16	7/8	1	1 1/8	1 3/8	2
0.110	.....	.....	9/16	13/16	7/8	1	1 1/4	1 3/4
0.120	.....	.....	9/16	3/4	13/16	15/16	1 1/8	1 5/8
0.130	.....	.....	.....	11/16	3/4	7/8	1 1/16	1 7/16
0.140	.....	.....	.....	5/8	11/16	13/16	15/16	1 1/8
0.150	.....	.....	.....	9/16	5/8	3/4	7/8	1 1/4
0.160	.....	.....	.....	.....	9/16	11/16	13/16	1 3/16
0.170	.....	.....	.....	.....	.....	5/8	3/4	1 1/8
0.180	.....	.....	.....	.....	.....	.....	3/4	1 1/16
0.190	.....	.....	.....	.....	.....	.....	11/16	1
0.200	.....	.....	.....	.....	.....	.....	5/8	15/16
0.210	.....	.....	.....	.....	.....	.....	.....	7/8
0.220	.....	.....	.....	.....	.....	.....	.....	11/16
0.230	.....	.....	.....	.....	.....	.....	.....	13/16
0.240	.....	.....	.....	.....	.....	.....	.....	3/4

TABLE 3-3 VALUES OF *L* FOR PIPE SIZES ≥ NPS 10 AND < NPS 16

Depth, *d*, in.	Wall Thickness, *t*, in. 0.156	0.219	0.250	0.307	0.344	0.365	0.438	0.500
0.020	5 13/16	.....	.....	.....	.....	.....	.....	.....
0.030	4 5/16	6 7/8	7 3/8	.....	.....	.....	.....	.....
0.040	2 7/16	5 15/16	7 3/8	8 1/8	8 3/8	8 7/8	.....	.....
0.050	1 3/4	3 1/2	4 15/16	8 1/8	8 3/8	8 7/8	.....	.....
0.060	1 7/16	2 9/16	3 3/8	5 3/4	8 3/8	8 7/8	9 1/4	10 3/8
0.070	1 3/16	2 1/8	2 11/16	4 1/8	5 1/2	6 3/8	9 1/4	10 3/8
0.080	1 1/16	1 13/16	2 1/4	3 5/16	4 3/16	4 7/8	8 1/8	10 3/8
0.090	15/16	1 9/16	1 15/16	2 13/16	3 1/2	3 13/16	6 1/8	9 3/8
0.100	13/16	1 7/16	1 3/4	2 7/16	3	3 3/8	4 15/16	6 15/16
0.110	3/4	1 3/16	1 9/16	2 1/16	2 5/8	2 15/16	4 3/8	5 3/8
0.120	11/16	1 1/16	1 7/16	2	2 3/8	2 3/8	3 11/16	4 13/16
0.130	.....	1	1 5/16	1 13/16	2 1/16	2 3/8	3 5/16	4 1/4
0.140	.....	15/16	1 1/4	1 11/16	2	2 1/16	3	3 13/16
0.150	.....	7/8	1 1/8	1 9/16	1 7/8	2 1/16	2 1/4	3 7/16
0.160	.....	13/16	1 1/16	1 7/16	1 3/4	1 15/16	2 9/16	3 3/16
0.170	.....	3/4	1	1 3/8	1 5/8	1 13/16	2 1/8	2 15/16
0.180	.....	.....	15/16	1 5/16	1 9/16	1 11/16	2 1/16	2 3/4
0.190	.....	.....	7/8	1 1/4	1 7/16	1 5/8	2 1/8	2 5/8
0.200	.....	.....	13/16	1 1/8	1 3/8	1 1/2	2	2 7/16
0.210	.....	.....	.....	1 1/8	1 5/16	1 7/16	1 7/8	2 3/16
0.220	.....	.....	.....	1 1/16	1 1/4	1 3/8	1 13/16	2 1/4
0.230	.....	.....	.....	1	1 1/16	1 5/16	1 3/4	2 1/8
0.240	.....	.....	.....	15/16	1 1/8	1 1/4	1 11/16	2 1/16
0.250	.....	.....	.....	.....	1 1/16	1 3/16	1 9/16	1 15/16
0.260	.....	.....	.....	.....	1 1/16	1 1/8	1 1/2	1 7/8
0.270	.....	.....	.....	.....	1	1 1/16	1 7/16	1 13/16
0.280	.....	.....	.....	.....	.....	1 1/16	1 7/16	1 3/4
0.290	.....	.....	.....	.....	.....	1	1 3/8	1 11/16
0.300	.....	.....	.....	.....	.....	.....	1 5/16	1 5/8
0.310	.....	.....	.....	.....	.....	.....	1 1/4	1 9/16
0.320	.....	.....	.....	.....	.....	.....	1 3/16	1 1/2
0.330	.....	.....	.....	.....	.....	.....	1 1/16	1 7/16
0.340	.....	.....	.....	.....	.....	.....	1 1/8	1 3/8
0.350	.....	.....	.....	.....	.....	.....	1 1/16	1 3/8
0.360	.....	.....	.....	.....	.....	.....	.....	1 5/16
0.370	.....	.....	.....	.....	.....	.....	.....	1 1/4
0.380	.....	.....	.....	.....	.....	.....	.....	1 1/4
0.390	.....	.....	.....	.....	.....	.....	.....	1 1/16
0.400	.....	.....	.....	.....	.....	.....	.....	1 1/16
0.410	.....	.....	.....	.....	.....	.....	.....	.....

TABLE 3-4 VALUES OF *L* FOR PIPE SIZES ≥ NPS 16 AND < NPS 20

Depth, *d*, in.	Wall Thickness, *t*, in. 0.188	0.250	0.312	0.344	0.375	0.438	0.500	0.625
0.020	7¾	.....	.....	.....	.....	.....	.....	.....
0.030	7¾	8 15/16	.....	.....	.....	.....	.....	.....
0.040	4½	8 13/16	10	10½	11	.....	.....	.....
0.050	3 1/16	6	10	10½	11	11⅞	12 11/16	.....
0.060	2⅜	4⅛	7 7/16	10½	11	11⅞	12 11/16	.....
0.070	2	3¼	5¼	6¾	8 13/16	11⅞	12 11/16	14 9/16
0.080	1¾	2¾	4 3/16	5⅛	6⅛	10 9/16	12 11/16	14 9/16
0.090	1½	2⅜	3½	4¼	5 1/16	7 7/16	11 7/16	14 9/16
0.100	1⅜	2⅛	3 1/16	3⅝	4 9/16	6	8½	14 9/16
0.110	1¼	1 15/16	2¾	3¼	3¾	5⅛	6⅞	13⅞
0.120	1⅛	1¾	2½	2 15/16	3⅜	4½	5⅞	10 9/16
0.130	1 1/16	1⅝	2¼	2 11/16	3 1/16	4	5 3/16	8⅛
0.140	15/16	1½	2⅛	2 7/16	2 13/16	3⅝	4⅝	7 7/16
0.150	⅞	1⅜	1 15/16	2¼	2⅝	3⅜	4¼	6 5/16
0.160	.....	1 5/16	1 13/16	2⅛	2 7/16	3⅛	3⅞	5 15/16
0.170	.....	1 3/16	1 11/16	2	2¼	2 15/16	3⅜	5⅛
0.180	.....	1⅛	1⅝	1⅞	2⅛	2¾	3⅛	5
0.190	.....	1 1/16	1½	1¾	2	2 9/16	3 3/16	4⅝
0.200	.....	1	1 7/16	1 11/16	1 15/16	2 7/16	3	4⅜
0.210	.....	.....	1⅜	1⅝	1 13/16	2 5/16	2⅞	4⅛
0.220	.....	.....	1 5/16	1½	1¾	2 3/16	2 11/16	3⅞
0.230	.....	.....	1¼	1 7/16	1 11/16	2⅛	2 9/16	3 11/16
0.240	.....	.....	1 3/16	1⅜	1 9/16	2	2½	3½
0.250	.....	.....	.....	1 5/16	1½	1 15/16	2⅜	3⅜
0.260	.....	.....	.....	1¼	1 7/16	1⅞	2¼	3¼
0.270	.....	.....	.....	1 3/16	1⅜	1 13/16	2 3/16	3⅛
0.280	.....	.....	.....	.....	1 5/16	1 11/16	2⅛	3
0.290	.....	.....	.....	.....	1 3/16	1⅝	2 1/16	2⅞
0.300	.....	.....	.....	.....	1¼	1 9/16	1 15/16	2¾
0.310	.....	.....	.....	.....	.....	1 9/16	1⅞	2 11/16
0.320	.....	.....	.....	.....	.....	1½	1 13/16	2 9/16
0.330	.....	.....	.....	.....	.....	1 7/16	1¾	2½
0.340	.....	.....	.....	.....	.....	1⅜	1 11/16	2 7/16
0.350	.....	.....	.....	.....	.....	1 3/16	1 11/16	2⅜
0.360	.....	.....	.....	.....	.....	.....	1⅝	2 3/16
0.370	.....	.....	.....	.....	.....	.....	1 9/16	2¼
0.380	.....	.....	.....	.....	.....	.....	1½	2 3/16
0.390	.....	.....	.....	.....	.....	.....	1 7/16	2⅛
0.400	.....	.....	.....	.....	.....	.....	1 3/16	2 1/16
0.410	.....	.....	.....	.....	.....	.....	.....	2
0.420	.....	.....	.....	.....	.....	.....	.....	1 15/16
0.430	.....	.....	.....	.....	.....	.....	.....	1⅞
0.440	.....	.....	.....	.....	.....	.....	.....	1⅞
0.450	.....	.....	.....	.....	.....	.....	.....	1 13/16
0.460	.....	.....	.....	.....	.....	.....	.....	1¾
0.470	.....	.....	.....	.....	.....	.....	.....	1 11/16
0.480	.....	.....	.....	.....	.....	.....	.....	1 11/16
0.490	.....	.....	.....	.....	.....	.....	.....	1⅝
0.500	.....	.....	.....	.....	.....	.....	.....	1 9/16
0.510	.....	.....	.....	.....	.....	.....	.....	.....

TABLE 3-5 VALUES OF *L* FOR PIPE SIZES ≥ NPS 20 AND < NPS 24

Depth, *d*, in.	Wall Thickness, *t*, in. 0.219	0.250	0.344	0.406	0.469	0.500	0.562	0.625
0.030	9⅛	10	.....	.....	.....	.....	.....	.....
0.040	8 1/16	10	11¾	.....	.....	.....	.....	.....
0.050	4¾	6 11/16	11¾	12¾	13¾	14 3/16	.....	.....
0.060	3 9/16	4⅝	11¾	12¾	13¾	14 3/16	15	.....
0.070	2⅞	3 11/16	7 9/16	12¾	13¾	14 3/16	15	15 13/16
0.080	2 7/16	3 1/16	5¾	8⅞	13¾	14 3/16	15	15 13/16
0.090	2 3/16	2 11/16	4¾	6 13/16	10 3/16	12 13/16	15	15 13/16
0.100	1 15/16	2⅜	4 1/16	5 11/16	7 15/16	9½	14⅛	15 13/16
0.110	1¾	2⅛	3⅝	4⅞	6⅝	7 11/16	10⅝	15½
0.120	1⅝	1 15/16	3¼	4 5/16	5¾	6 9/16	8 11/16	11¾
0.130	1½	1 13/16	3	3 15/16	5 1/16	5¾	7 7/16	9 11/16
0.140	1⅜	1 11/16	2¾	3 9/16	4⅝	5 5/16	6 9/16	8 5/16
0.150	1¼	1 9/16	2 9/16	3 3/16	4 3/16	4¾	5⅞	7 5/16
0.160	1 3/16	1 7/16	2⅜	3 1/16	3⅞	4⅜	5 3/16	6⅝
0.170	1 1/16	1⅜	2¼	2⅞	3⅝	4 1/16	4 15/16	6 1/16
0.180	.....	1¼	2⅛	2 11/16	3 7/16	3 13/16	4⅜	5 5/16
0.190	.....	1 3/16	2	2 9/16	3 3/16	3 9/16	4 5/16	5 3/16
0.200	.....	1⅛	1⅞	2 7/16	3 1/16	3⅜	4 1/16	4⅞
0.210	.....	.....	1 13/16	2 5/16	2⅞	3 1/16	3⅞	4 9/16
0.220	.....	.....	1 11/16	2 3/16	2¾	3 1/16	3⅝	4 5/16
0.230	.....	.....	1⅝	2⅛	2⅝	2⅞	3½	4⅛
0.240	.....	.....	1 9/16	2	2½	2¾	3 5/16	3 15/16
0.250	.....	.....	1½	1 15/16	2 7/16	2 11/16	3 3/16	3¾
0.260	.....	.....	1 7/16	1⅞	2 5/16	2 9/16	3 1/16	3⅝
0.270	.....	.....	1⅜	1¾	2¼	2 7/16	2 15/16	3 7/16
0.280	.....	.....	.....	1 11/16	2⅛	2⅜	2 13/16	3 5/16
0.290	.....	.....	.....	1⅝	2 1/16	2¼	2¾	3 1/16
0.300	.....	.....	.....	1 9/16	2	2 3/16	2⅝	3⅛
0.310	.....	.....	.....	1½	1 15/16	2⅛	2 9/16	3
0.320	.....	.....	.....	1 7/16	1⅞	2 1/16	2 7/16	2⅞
0.330	.....	.....	.....	.....	1 13/16	2	2⅜	2 13/16
0.340	.....	.....	.....	.....	1¾	1 15/16	2 5/16	2¾
0.350	.....	.....	.....	.....	1 11/16	1⅞	2¼	2⅝
0.360	.....	.....	.....	.....	1⅝	1 13/16	2 1/16	2 9/16
0.370	.....	.....	.....	.....	1 9/16	1¾	2⅛	2½
0.380	.....	.....	.....	.....	.....	1 11/16	2 1/16	2 7/16
0.390	.....	.....	.....	.....	.....	1⅝	2	2⅜
0.400	.....	.....	.....	.....	.....	1 5/16	1 15/16	2 5/16
0.410	.....	.....	.....	.....	.....	.....	1⅞	2¼
0.420	.....	.....	.....	.....	.....	.....	1 13/16	2 1/16
0.430	.....	.....	.....	.....	.....	.....	1¾	2⅛
0.440	.....	.....	.....	.....	.....	.....	1⅝	2 1/16
0.450	.....	.....	.....	.....	.....	.....	.....	2
0.460	.....	.....	.....	.....	.....	.....	.....	1 15/16
0.470	.....	.....	.....	.....	.....	.....	.....	1 15/16
0.480	.....	.....	.....	.....	.....	.....	.....	1⅞
0.490	.....	.....	.....	.....	.....	.....	.....	1 13/16
0.500	.....	.....	.....	.....	.....	.....	.....	1¾
0.510	.....	.....	.....	.....	.....	.....	.....	.....

TABLE 3-6 VALUES OF *L* FOR PIPE SIZES ≥ NPS 24 AND < NPS 30

Depth, *d*, in.	Wall Thickness, *t*, in. 0.250	0.312	0.375	0.438	0.469	0.500	0.562	0.625
0.030	11	.....	.....	.....	.....	.....	.....	.....
0.040	11	12¼	13 7/16	.....	.....	.....	.....	.....
0.050	7 5/16	12¼	13 7/16	14½	15	15½	.....	.....
0.060	5 1/16	9 1/16	13 7/16	14½	15	15½	16 7/16	.....
0.070	4	6 7/16	10 13/16	14½	15	15½	16 7/16	17⅜
0.080	3⅜	5⅛	7¾	12½	15	15½	16 7/16	17⅜
0.090	2 15/16	4 3/16	6¼	9⅛	11 3/16	14	16 7/16	17⅜
0.100	2⅝	3¾	5¼	7⅜	8 11/16	10⅝	15 7/16	17⅜
0.110	2⅜	3⅜	4⅝	6¼	7¼	8 7/16	11⅝	16 13/16
0.120	2⅛	3 1/16	4⅛	5½	6¼	7 3/16	9½	12⅞
0.130	2	2 13/16	3¾	4 15/16	5 9/16	6 9/16	8⅛	10⅝
0.140	1 13/16	2 9/16	3 7/16	4 7/16	5 1/16	5 11/16	7 3/16	9⅛
0.150	1 11/16	2⅜	3 3/16	4⅛	4⅝	5 3/16	6 7/16	8 1/16
0.160	1 5/16	2¼	3	3 13/16	4¼	4¾	5⅞	7¼
0.170	1½	2⅛	2 13/16	3 9/16	4	4 7/16	5 7/16	6⅝
0.180	1⅜	2	2⅝	3⅜	3¾	4⅛	5⅛	6⅛
0.190	1 5/16	1⅞	2½	3 3/16	3½	3⅞	4¾	5 11/16
0.200	1¼	1¾	2⅜	3	3 5/16	3 11/16	4 7/16	5 5/16
0.210	.....	1 11/16	2¼	2⅞	3 3/16	3½	4 1/16	5
0.220	.....	1 9/16	2⅛	2 11/16	3	3 3/16	4 .	4¾
0.230	.....	1½	2 1/16	2 9/16	2⅞	3 1/16	3 13/16	4½
0.240	.....	1 7/16	1 15/16	2½	2¾	3 1/16	3⅜	4 9/16
0.250	.....	.....	1⅞	2⅜	2⅝	2 15/16	3½	4⅛
0.260	.....	.....	1¾	2¼	2½	2 13/16	3⅜	3 15/16
0.270	.....	.....	1 11/16	2 3/16	2 7/16	2 11/16	3 3/16	3 13/16
0.280	.....	.....	1⅝	2⅛	2 5/16	2 9/16	3⅛	3⅝
0.290	.....	.....	1 9/16	2	2¼	2½	3	3½
0.300	.....	.....	1½	1 15/16	2 1/16	2⅜	2⅞	3⅜
0.310	.....	.....	.....	1⅞	2⅛	2 5/16	2 13/16	3¼
0.320	.....	.....	.....	1 13/16	2	2¼	2 11/16	3 3/16
0.330	.....	.....	.....	1¾	1 15/16	2 1/16	2⅝	3 1/16
0.340	.....	.....	.....	1 11/16	1⅞	2⅛	2½	3
0.350	.....	.....	.....	1⅝	1 13/16	2 1/16	2 7/16	2⅞
0.360	.....	.....	.....	.....	1¾	2	2⅜	2 13/16
0.370	.....	.....	.....	.....	1 11/16	1 15/16	2 5/16	2¾
0.380	.....	.....	.....	.....	.....	1⅞	2¼	2⅝
0.390	.....	.....	.....	.....	.....	1 13/16	2 3/16	2 9/16
0.400	.....	.....	.....	.....	.....	1¾	2⅛	2½
0.410	.....	.....	.....	.....	.....	.....	2 1/16	2 7/16
0.420	.....	.....	.....	.....	.....	.....	2	2⅜
0.430	.....	.....	.....	.....	.....	.....	1 15/16	2 3/16
0.440	.....	.....	.....	.....	.....	.....	1⅞	2¼
0.450	.....	.....	.....	.....	.....	.....	.....	2 1/16
0.460	.....	.....	.....	.....	.....	.....	.....	2⅛
0.470	.....	.....	.....	.....	.....	.....	.....	2⅛
0.480	.....	.....	.....	.....	.....	.....	.....	2 1/16
0.490	.....	.....	.....	.....	.....	.....	.....	2
0.500	.....	.....	.....	.....	.....	.....	.....	1 15/16
0.510	.....	.....	.....	.....	.....	.....	.....	.....

TABLE 3-7 VALUES OF L FOR PIPE SIZES ≥ NPS 30 AND < NPS 36

Depth, d, in.	Wall Thickness, t, in. 0.250	0.312	0.375	0.438	0.500	0.625	0.688
0.030	12¼	.....	.....	.....	.....	.....	.....
0.040	12¼	13 11/16	15	.....	.....	.....	.....
0.050	8 3/16	13 11/16	15	16¼	17⅜	.....	.....
0.060	5 11/16	10⅛	15	16¼	17⅜	.....	.....
0.070	4½	7 3/16	12⅛	16¼	17⅜	19⅜	20⅜
0.080	3¼	5 11/16	8 11/16	14	17⅜	19⅜	20⅜
0.090	3¼	4 13/16	6 15/16	10 1/16	15 11/16	19⅜	20⅜
0.100	2 15/16	4 3/16	5⅞	8 9/16	11⅜	19⅜	20⅜
0.110	2⅜	3¼	5 9/16	7	9 7/16	18 15/16	20⅜
0.120	2⅜	3⅜	4⅜	6⅛	8 1/16	14 7/16	20⅜
0.130	2 3/16	3⅛	4 3/16	5½	7 1/16	11⅞	15 13/16
0.140	2 1/16	2⅞	3⅞	5	6⅜	10 9/16	13 1/16
0.150	1⅞	2 11/16	3 9/16	4⅜	5 13/16	9	11¼
0.160	1¾	2½	3 5/16	4¼	5 5/16	8 1/16	9 15/16
0.170	1 11/16	2⅜	3⅛	4	4 15/16	7⅜	9
0.180	1 9/16	2 3/16	2 15/16	3¾	4⅝	6 13/16	8 5/16
0.190	1 7/16	2 1/16	2¾	3 9/16	4⅜	6⅜	7 9/16
0.200	1⅜	2	2⅝	3⅜	4⅛	5 15/16	7 1/16
0.210	.....	1⅞	2½	3 3/16	3 13/16	5⅝	6⅝
0.220	.....	1 13/16	2⅜	3	3¾	5 5/16	6¼
0.230	.....	1 11/16	2¼	2⅞	3 9/16	5 1/16	5 15/16
0.240	.....	1⅝	2 3/16	2¾	3⅜	4 15/16	5⅝
0.250	.....	.....	2 1/16	2⅝	3¼	4⅝	5⅝
0.260	.....	.....	2	2 9/16	3⅛	4 7/16	5⅛
0.270	.....	.....	1 15/16	2 7/16	3	4¼	4 15/16
0.280	.....	.....	1 13/16	2⅜	2⅞	4 1/16	4¾
0.290	.....	.....	1¾	2¼	2 15/16	3 15/16	4 9/16
0.300	.....	.....	1 11/16	2 1/16	2 11/16	3 11/16	4⅜
0.310	.....	.....	.....	2⅛	2⅜	3 11/16	4¼
0.320	.....	.....	.....	2	2½	3 5/16	4⅛
0.330	.....	.....	.....	1 15/16	2 7/16	3 7/16	4
0.340	.....	.....	.....	1⅞	2⅜	3 5/16	3⅞
0.350	.....	.....	.....	1 11/16	2¼	3¼	3¾
0.360	.....	.....	.....	.....	2 1/16	3⅛	3⅝
0.370	.....	.....	.....	.....	2⅛	3 1/16	3 9/16
0.380	.....	.....	.....	.....	2 1/16	2 15/16	3 7/16
0.390	.....	.....	.....	.....	2	2⅞	3⅜
0.400	.....	.....	.....	.....	1 15/16	2 11/16	3¼
0.410	.....	.....	.....	.....	.....	2½	3 1/16
0.420	.....	.....	.....	.....	.....	2 3/16	3⅛
0.430	.....	.....	.....	.....	.....	2 9/16	3
0.440	.....	.....	.....	.....	.....	2½	2 15/16
0.450	.....	.....	.....	.....	.....	2 7/16	2⅞
0.460	.....	.....	.....	.....	.....	2⅜	2 11/16
0.470	.....	.....	.....	.....	.....	2 5/16	2¾
0.480	.....	.....	.....	.....	.....	2 3/16	2 11/16
0.490	.....	.....	.....	.....	.....	2¼	2⅝
0.500	.....	.....	.....	.....	.....	2 1/16	2 9/16
0.510	.....	.....	.....	.....	.....	.....	2½
0.520	.....	.....	.....	.....	.....	.....	2 7/16
0.530	.....	.....	.....	.....	.....	.....	2⅜
0.540	.....	.....	.....	.....	.....	.....	2 5/16
0.550	.....	.....	.....	.....	.....	.....	2¼
0.560	.....	.....	.....	.....	.....	.....	.....

TABLE 3-8 VALUES OF L FOR PIPE SIZES ≥ NPS 36 AND < NPS 42

Depth, d, in.	Wall Thickness, t, in. 0.250	0.281	0.312	0.375	0.406	0.469	0.562	0.688
0.030	13 7/16	14 1/2	.....	.....	.....	.....	.....	.....
0.040	13 7/16	14 1/2	15	16 7/16	.....	.....	.....	.....
0.050	9	13 1/8	15	16 7/16	17 1/8	18 7/16	.....	.....
0.060	6 1/2	8 1/2	11 1/8	16 7/16	17 1/8	18 7/16	20 1/8	.....
0.070	4 11/16	6 9/16	7 7/8	13 1/4	17 1/8	18 7/16	20 1/8	22 9/16
0.080	4 1/8	5 9/16	6 1/2	9 1/2	11 7/8	18 7/16	20 1/8	22 9/16
0.090	3 9/16	4 1/8	5 1/2	7 1/8	9 9/16	13 11/16	20 1/8	22 9/16
0.100	3 9/16	3 7/8	4 1/8	6 7/16	7 1/8	10 1/8	18 13/16	22 9/16
0.110	2 7/8	3 7/16	4 1/8	5 1/8	6 9/16	8 7/8	14 1/2	22 9/16
0.120	2 1/8	3 1/8	3 1/2	5 1/16	5 13/16	7 11/16	11 1/8	22 9/16
0.130	2 7/16	2 7/8	3 7/16	4 9/16	5 1/2	6 13/16	9 13/16	17 9/16
0.140	2 1/4	2 11/16	3 1/8	4 1/4	4 13/16	6 9/16	8 3/4	14 9/16
0.150	2 1/16	2 1/2	2 15/16	3 15/16	4 7/16	5 11/16	7 7/8	12 9/16
0.160	1 15/16	2 3/16	2 1/2	3 1/8	4 1/8	5 1/4	7 1/16	10 13/16
0.170	1 11/16	2 1/16	2 9/16	3 7/16	3 7/8	4 7/8	6 1/8	9 13/16
0.180	1 11/16	2 1/16	2 7/16	3 1/4	3 1/8	4 9/16	6 1/16	9
0.190	1 1/8	1 15/16	2 1/16	3 1/16	3 7/16	4 3/16	5 11/16	8 9/16
0.200	1 1/2	1 11/16	2 1/16	2 7/8	3 1/4	4 1/16	5 7/16	7 1/4
0.210	.....	1 1/4	2 1/16	2 1/2	3 1/8	3 7/8	5 1/16	7 1/2
0.220	.....	1 1/8	1 15/16	2 1/8	2 15/16	3 11/16	4 7/8	6 7/8
0.230	.....	.....	1 7/8	2 1/2	2 15/16	3 1/2	4 11/16	6 1/2
0.240	.....	.....	1 3/4	2 1/8	2 11/16	3 1/8	4 7/16	6 1/16
0.250	.....	.....	.....	2 1/4	2 9/16	3 1/4	4 1/2	5 7/8
0.260	.....	.....	.....	2 1/16	2 1/2	3 1/16	4 1/16	5 1/8
0.270	.....	.....	.....	2 1/16	2 1/8	3	3 15/16	5 7/16
0.280	.....	.....	.....	2	2 9/16	2 7/8	3 11/16	5 1/16
0.290	.....	.....	.....	1 15/16	2 1/16	2 3/4	3 9/16	5
0.300	.....	.....	.....	1 7/8	2 1/8	2 11/16	3 1/2	4 15/16
0.310	.....	.....	.....	.....	2	2 9/16	3 7/16	4 11/16
0.320	.....	.....	.....	.....	1 15/16	2 1/2	3 3/16	4 1/2
0.330	.....	.....	.....	.....	.....	2 3/8	3 1/16	4 1/8
0.340	.....	.....	.....	.....	.....	2 3/16	3 1/8	4 1/4
0.350	.....	.....	.....	.....	.....	2 1/4	3	4 1/8
0.360	.....	.....	.....	.....	.....	2 1/16	2 15/16	4
0.370	.....	.....	.....	.....	.....	2 1/8	2 11/16	3 7/8
0.380	.....	.....	.....	.....	.....	.....	2 1/2	3 1/4
0.390	.....	.....	.....	.....	.....	.....	2 11/16	3 11/16
0.400	.....	.....	.....	.....	.....	.....	2 9/16	3 9/16
0.410	.....	.....	.....	.....	.....	.....	2 1/2	3 1/2
0.420	.....	.....	.....	.....	.....	.....	2 7/16	3 3/8
0.430	.....	.....	.....	.....	.....	.....	2 3/8	3 7/16
0.440	.....	.....	.....	.....	.....	.....	2 7/16	3 3/8
0.450	.....	.....	.....	.....	.....	.....	.....	3 3/8
0.460	.....	.....	.....	.....	.....	.....	.....	3 3/16
0.470	.....	.....	.....	.....	.....	.....	.....	3
0.480	.....	.....	.....	.....	.....	.....	.....	2 15/16
0.490	.....	.....	.....	.....	.....	.....	.....	2 7/8
0.500	.....	.....	.....	.....	.....	.....	.....	2 11/16
0.510	.....	.....	.....	.....	.....	.....	.....	2 1/2
0.520	.....	.....	.....	.....	.....	.....	.....	2 9/16
0.530	.....	.....	.....	.....	.....	.....	.....	2 7/8
0.540	.....	.....	.....	.....	.....	.....	.....	2 7/16
0.550	.....	.....	.....	.....	.....	.....	.....	2 1/2
0.560	.....	.....	.....	.....	.....	.....	.....	.....

TABLE 3-9 VALUES OF *L* FOR PIPE SIZES ≥ NPS 42 AND < NPS 48

Depth, *d*, in.	Wall Thickness, *t*, in. 0.344	0.406	0.438	0.469	0.500	0.562	0.625	0.688	0.750
0.030	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.040	17	.....	.....	.....	.....	.....	.....	.....	.....
0.050	17	18½	19 3/16	19⅞	20½	.....	.....	.....	.....
0.060	17	18½	19 3/16	19⅞	20½	21¾	.....	.....	.....
0.070	10 15/16	18½	19 3/16	19⅞	20½	21¾	22 15/16	24 1/16	.....
0.080	8 5/16	12⅞	16 9/16	19⅞	20½	21¾	22 15/16	24 1/16	25⅛
0.090	6⅞	9⅞	12 1/16	14 13/16	18 9/16	21¾	22 15/16	24 1/16	25⅛
0.100	5 15/16	8 3/16	9¾	11½	13¾	20 7/16	22 15/16	24 1/16	25⅛
0.110	5¼	7 1/16	8¼	9 9/16	11⅛	15⅜	22 7/16	24 1/16	25⅛
0.120	4 11/16	6 5/16	7¼	8 5/16	9½	12 9/16	17 1/16	24 1/16	25⅛
0.130	4 5/16	5 11/16	6½	7⅜	8⅜	10¾	14	18¾	25⅛
0.140	4	5 3/16	5 15/16	6 11/16	7½	9½	12 1/16	15 7/16	20¼
0.150	3 11/16	4 13/16	5 7/16	6⅛	6 13/16	8½	10⅝	13 9/16	16 13/16
0.160	3 7/16	4 7/16	5 1/16	5⅝	6 5/16	7¾	9 9/16	11 13/16	14 9/16
0.170	3¼	4 3/16	4 11/16	5¼	5⅞	7 5/16	8¾	10⅝	12⅞
0.180	3 1/16	3 15/16	4 7/16	4 15/16	5½	6 11/16	8 1/16	9 11/16	11⅝
0.190	2⅞	3 11/16	4 1/16	4 13/16	5 3/16	6¼	7½	9	10 11/16
0.200	2¾	3½	3 15/16	4⅞	4⅞	5⅞	7 1/16	8⅜	9⅞
0.210	2 9/16	3⅜	3¾	4 3/16	4⅝	5 9/16	6⅝	7⅞	9 1/16
0.220	2 7/16	3 1/16	3 9/16	4	4⅛	5 5/16	6 5/16	7⅛	8⅝
0.230	2⅜	3 1/16	3 7/16	3 13/16	4 3/16	5 1/16	6	7	8⅛
0.240	2¼	2 15/16	3¼	3⅝	4	4 13/16	5 11/16	6 11/16	7¾
0.250	2⅛	2 13/16	3⅛	3½	3⅞	4⅝	5 7/16	6⅛	7⅜
0.260	2 1/16	2 11/16	3	3⅜	3 11/16	4 7/16	5¼	6 1/16	7
0.270	1 15/16	2 9/16	2⅞	3 3/16	3 9/16	4¼	5	5 13/16	6 11/16
0.280	.....	2 7/16	2 13/16	3⅛	3 7/16	4⅛	4 13/16	5⅝	6 7/16
0.290	.....	2⅜	2 11/16	3	3 5/16	3 15/16	4⅝	5⅜	6 3/16
0.300	.....	2¼	2 9/16	2⅞	3 1/16	3 13/16	4½	5 3/16	6
0.310	.....	2 3/16	2½	2¾	3 1/16	3 11/16	4 5/16	5 1/16	5¾
0.320	.....	2⅛	2⅜	2 11/16	2 15/16	3 9/16	4 1/16	4⅞	5 5/16
0.330	.....	.....	2 5/16	2 9/16	2⅞	3 7/16	4 1/16	4 13/16	5⅛
0.340	.....	.....	2¼	2½	2¾	3 5/16	3 15/16	4 9/16	5¼
0.350	.....	.....	2 1/16	2 7/16	2 11/16	3¼	3 13/16	4 7/16	5 1/16
0.360	.....	.....	.....	2 5/16	2⅝	3⅛	3 11/16	4 3/16	4 15/16
0.370	.....	.....	.....	2¼	2½	3 1/16	3⅝	4 1/16	4¾
0.380	.....	.....	.....	.....	2 7/16	2 15/16	3½	4 1/16	4⅝
0.390	.....	.....	.....	.....	2⅛	2⅞	3 7/16	3 15/16	4½
0.400	.....	.....	.....	.....	2 5/16	2 13/16	3 5/16	3⅞	4 7/16
0.410	.....	.....	.....	.....	.....	2¾	3¼	3¾	4 5/16
0.420	.....	.....	.....	.....	.....	2⅝	3⅛	3 11/16	4 3/16
0.430	.....	.....	.....	.....	.....	2 9/16	3 1/16	3 9/16	4 1/16
0.440	.....	.....	.....	.....	.....	2½	3	3½	4
0.450	.....	.....	.....	.....	.....	.....	2 15/16	3⅜	3⅞
0.460	.....	.....	.....	.....	.....	.....	2 13/16	3 5/16	3 11/16
0.470	.....	.....	.....	.....	.....	.....	2¾	3¼	3¾
0.480	.....	.....	.....	.....	.....	.....	2 11/16	3 1/16	3⅜
0.490	.....	.....	.....	.....	.....	.....	2⅝	3⅛	3 9/16
0.500	.....	.....	.....	.....	.....	.....	2 9/16	3	3½
0.510	.....	.....	.....	.....	.....	.....	.....	2 15/16	3⅜
0.520	.....	.....	.....	.....	.....	.....	.....	2⅞	3 5/16

TABLE 3-9 VALUES OF *L* FOR PIPE SIZES ≥ NPS 42 AND < NPS 48

Wall Thickness, *t*, in.								Depth, *d*, in.
0.812	0.875	0.938	1.000	1.062	1.125	1.188	1.250	
.....	.....	.....	.....	.....	.....	.....	.....	0.030
.....	.....	.....	.....	.....	.....	.....	.....	0.040
.....	.....	.....	.....	.....	.....	.....	.....	0.050
.....	.....	.....	.....	.....	.....	.....	.....	0.060
.....	.....	.....	.....	.....	.....	.....	.....	0.070
.....	.....	.....	.....	.....	.....	.....	.....	0.080
26 3/16	27 3/16	.....	.....	.....	.....	.....	.....	0.090
26 3/16	27 3/16	28 1/8	.....	.....	.....	.....	.....	0.100
26 3/16	27 3/16	28 1/8	29 1/16	29 15/16	.....	.....	.....	0.110
26 3/16	27 3/16	28 1/8	29 1/16	29 15/16	30 13/16	31 5/8	.....	0.120
26 3/16	27 3/16	28 1/8	29 1/16	29 15/16	30 13/16	31 5/8	32 7/16	0.130
26 3/16	27 3/16	28 1/8	29 1/16	29 15/16	30 13/16	31 5/8	32 7/16	0.140
21 3/4	27 3/16	28 1/8	29 1/16	29 15/16	30 13/16	31 5/8	32 7/16	0.150
18 3/16	23 5/16	28 1/8	29 1/16	29 15/16	30 13/16	31 5/8	32 7/16	0.160
15 3/4	19 9/16	24 15/16	29 1/16	29 15/16	30 13/16	31 5/8	32 7/16	0.170
14	17	20 15/16	26 1/4	29 15/16	30 13/16	31 5/8	32 7/16	0.180
12 11/16	15 1/8	18 1/4	22 1/4	27 5/8	30 13/16	31 5/8	32 7/16	0.190
11 5/8	13 11/16	16 1/4	19 7/16	23 1/2	29 1/16	31 1/8	32 3/16	0.200
10 3/4	12 5/16	14 3/4	17 3/8	20 9/16	24 13/16	30 7/16	32 7/16	0.210
10	11 5/8	13 9/16	15 3/4	18 7/16	21 13/16	26 1/8	31 1/4	0.220
9 7/16	10 7/8	12 9/16	14 1/2	16 3/4	19 9/16	23	27 5/16	0.230
8 7/8	10 1/4	11 3/4	13 7/16	15 7/16	17 13/16	20 11/16	24 1/8	0.240
8 7/16	9 11/16	11 1/16	12 9/16	14 5/16	16 3/8	18 13/16	21 1/4	0.250
8	9 3/16	10 7/16	11 13/16	13 3/8	15 1/4	17 1/8	19 13/16	0.260
7 11/16	8 3/4	9 7/8	11 3/16	12 5/8	14 1/4	16 1/8	18 5/16	0.270
7 3/8	8 5/16	9 7/16	10 5/8	11 15/16	13 7/16	15 1/8	17	0.280
7 1/16	8	9	10 1/8	11 3/16	12 11/16	14 1/4	15 15/16	0.290
6 13/16	7 11/16	8 5/8	9 11/16	10 13/16	12 1/16	13 1/2	15 1/16	0.300
6 9/16	7 3/8	8 5/16	9 1/4	10 5/16	11 1/2	12 13/16	14 1/4	0.310
6 3/16	7 1/8	8	8 15/16	9 15/16	11	12 1/4	13 9/16	0.320
6 1/8	6 7/8	7 11/16	8 7/16	9 9/16	10 9/16	11 11/16	12 15/16	0.330
5 13/16	6 11/16	7 7/16	8 5/16	9 3/16	10 3/16	11 1/4	12 3/8	0.340
5 3/4	6 7/16	7 3/16	8	8 7/8	9 13/16	10 13/16	11 7/8	0.350
5 9/16	6 1/4	7	7 3/4	8 9/16	9 7/16	10 7/16	11 7/16	0.360
5 3/8	6 1/16	6 3/4	7 1/2	8 5/16	9 1/8	10 1/16	11	0.370
5 1/4	5 7/8	6 9/16	7 5/16	8 1/16	8 7/8	9 3/4	10 5/8	0.380
5 1/8	5 3/4	6 3/8	7 1/16	7 13/16	8 9/16	9 7/16	10 5/16	0.390
5	5 5/16	6 1/4	6 7/8	7 5/8	8 3/8	9 1/8	10	0.400
4 7/8	5 7/16	6 1/16	6 11/16	7 3/8	8 1/8	8 7/8	9 11/16	0.410
4 3/4	5 3/16	5 15/16	6 9/16	7 1/16	7 7/8	8 5/8	9 3/8	0.420
4 5/8	5 3/16	5 3/4	6 3/8	7	7 11/16	8 3/8	9 1/8	0.430
4 1/2	5 1/16	5 5/8	6 1/4	6 13/16	7 1/2	8 3/16	8 7/8	0.440
4 7/16	4 15/16	5 1/2	6 1/16	6 11/16	7 5/16	8	8 11/16	0.450
4 5/16	4 13/16	5 3/8	5 15/16	6 1/2	7 1/8	7 13/16	8 7/16	0.460
4 3/16	4 3/4	5 1/4	5 13/16	6 3/8	7	7 5/8	8 1/4	0.470
4 1/8	4 5/8	5 1/8	5 11/16	6 1/4	6 13/16	7 7/16	8 1/16	0.480
4	4 1/2	5 1/16	5 5/16	6 1/8	6 11/16	7 1/4	7 7/8	0.490
3 15/16	4 7/16	4 15/16	5 7/16	6	6 9/16	7 1/8	7 11/16	0.500
3 7/8	4 5/16	4 13/16	5 5/16	5 7/8	6 3/8	6 15/16	7 5/16	0.510
3 3/4	4 1/4	4 3/4	5 1/4	5 3/4	6 1/4	6 13/16	7 3/8	0.520

(table continues)

TABLE 3-9 VALUES OF *L* FOR PIPE SIZES ≥ NPS 42 AND < NPS 48 (CONT'D)

Depth, *d*, in.	Wall Thickness, *t*, in. 0.344	0.406	0.438	0.469	0.500	0.562	0.625	0.688	0.750
0.530	.....	.....	.....	.....	.....	.....	.....	2 13/16	3 1/4
0.540	.....	.....	.....	.....	.....	.....	.....	2 3/4	3 3/16
0.550	.....	.....	.....	.....	.....	.....	.....	2 11/16	3 1/8
0.560	.....	.....	.....	.....	.....	.....	.....	.....	3 1/16
0.570	.....	.....	.....	.....	.....	.....	.....	.....	3
0.580	.....	.....	.....	.....	.....	.....	.....	.....	2 15/16
0.590	.....	.....	.....	.....	.....	.....	.....	.....	2 7/8
0.600	.....	.....	.....	.....	.....	.....	.....	.....	2 13/16
0.610	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.620	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.630	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.640	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.650	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.660	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.670	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.680	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.690	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.700	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.710	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.720	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.730	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.740	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.750	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.760	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.770	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.780	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.790	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.800	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.810	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.820	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.830	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.840	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.850	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.860	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.870	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.880	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.890	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.900	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.910	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.920	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.930	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.940	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.950	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.960	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.970	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.980	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.990	.....	.....	.....	.....	.....	.....	.....	.....	.....
1.000	.....	.....	.....	.....	.....	.....	.....	.....	.....
1.010	.....	.....	.....	.....	.....	.....	.....	.....	.....

TABLE 3-9 VALUES OF *L* FOR PIPE SIZES ≥ NPS 42 AND < NPS 48 (CONT'D)

Wall Thickness, *t*, in.								Depth, *d*, in.
0.812	0.875	0.938	1.000	1.062	1.125	1.188	1.250	
3 11/16	4 3/16	4 5/8	5 1/8	5 5/8	6 1/8	6 11/16	7 1/4	0.530
3 3/8	4 1/16	4 9/16	5	5 1/2	6	6 9/16	7 1/8	0.540
3 9/16	4	4 7/16	4 15/16	5 7/16	5 15/16	6 7/16	6 15/16	0.550
3 1/2	3 15/16	4 3/8	4 13/16	5 5/16	5 13/16	6 5/16	6 13/16	0.560
3 7/16	3 7/8	4 5/16	4 3/4	5 3/16	5 11/16	6 3/16	6 11/16	0.570
3 3/8	3 3/4	4 1/4	4 11/16	5 1/8	5 9/16	6 1/16	6 9/16	0.580
3 5/16	3 11/16	4 1/8	4 9/16	5	5 1/2	6	6 7/16	0.590
3 1/4	3 5/8	4 1/16	4 1/2	4 15/16	5 3/8	5 7/8	6 3/8	0.600
3 3/16	3 9/16	4	4 7/16	4 7/8	5 5/16	5 3/4	6 1/4	0.610
3 1/8	3 1/2	3 15/16	4 3/8	4 3/4	5 3/16	5 11/16	6 1/8	0.620
3 1/16	3 7/16	3 7/8	4 1/4	4 11/16	5 1/8	5 9/16	6 1/16	0.630
3	3 3/8	3 13/16	4 3/16	4 5/8	5 1/16	5 1/2	5 15/16	0.640
.....	3 5/16	3 3/4	4 1/8	4 9/16	4 15/16	5 3/8	5 13/16	0.650
.....	3 1/4	3 11/16	4 1/16	4 7/16	4 7/8	5 5/16	5 3/4	0.660
.....	3 3/16	3 5/8	4	4 3/8	4 13/16	5 1/4	5 11/16	0.670
.....	3 1/8	3 9/16	3 15/16	4 5/16	4 3/4	5 1/8	5 9/16	0.680
.....	3 1/8	3 1/2	3 7/8	4 1/4	4 11/16	5 1/16	5 1/2	0.690
.....	3 1/16	3 7/16	3 13/16	4 3/16	4 9/16	5	5 7/16	0.700
.....	.....	3 3/8	3 3/4	4 1/8	4 1/2	4 15/16	5 3/16	0.710
.....	.....	3 5/16	3 11/16	4 1/16	4 7/16	4 7/8	5 1/4	0.720
.....	.....	3 1/4	3 5/8	4	4 3/8	4 3/4	5 3/16	0.730
.....	.....	3 3/16	3 9/16	3 15/16	4 5/16	4 11/16	5 1/8	0.740
.....	.....	3 1/8	3 1/2	3 7/8	4 1/4	4 5/8	5	0.750
.....	.....	.....	3 7/16	3 13/16	4 3/16	4 9/16	4 15/16	0.760
.....	.....	.....	3 7/16	3 3/4	4 1/8	4 1/2	4 7/8	0.770
.....	.....	.....	3 3/8	3 11/16	4 1/16	4 7/16	4 13/16	0.780
.....	.....	.....	3 5/16	3 11/16	4	4 3/8	4 3/4	0.790
.....	.....	.....	3 1/4	3 5/8	3 15/16	4 5/16	4 11/16	0.800
.....	.....	.....	.....	3 9/16	3 15/16	4 1/4	4 5/8	0.810
.....	.....	.....	.....	3 1/2	3 7/8	4 3/16	4 9/16	0.820
.....	.....	.....	.....	3 7/16	3 13/16	4 1/8	4 1/2	0.830
.....	.....	.....	.....	3 3/8	3 3/4	4 1/8	4 7/16	0.840
.....	.....	.....	.....	.....	3 11/16	4 1/16	4 3/8	0.850
.....	.....	.....	.....	.....	3 5/8	4	4 5/16	0.860
.....	.....	.....	.....	.....	3 5/8	3 15/16	4 1/4	0.870
.....	.....	.....	.....	.....	3 9/16	3 7/8	4 1/4	0.880
.....	.....	.....	.....	.....	3 1/2	3 13/16	4 3/16	0.890
.....	.....	.....	.....	.....	3 7/16	3 11/16	4 1/8	0.900
.....	.....	.....	.....	.....	.....	3 3/4	4 1/16	0.910
.....	.....	.....	.....	.....	.....	3 11/16	4	0.920
.....	.....	.....	.....	.....	.....	3 5/8	3 15/16	0.930
.....	.....	.....	.....	.....	.....	3 5/8	3 13/16	0.940
.....	.....	.....	.....	.....	.....	3 9/16	3 7/8	0.950
.....	.....	.....	.....	.....	.....	.....	3 13/16	0.960
.....	.....	.....	.....	.....	.....	.....	3 3/4	0.970
.....	.....	.....	.....	.....	.....	.....	3 3/4	0.980
.....	.....	.....	.....	.....	.....	.....	3 11/16	0.990
.....	.....	.....	.....	.....	.....	.....	3 5/8	1.000
.....	.....	.....	.....	.....	.....	.....	.....	1.010

TABLE 3-10 VALUES OF *L* FOR PIPE SIZES ≥ NPS 48 AND < NPS 52

Depth, *d*, in.	Wall Thickness, *t*, in. 0.344	0.406	0.438	0.469	0.500	0.562	0.625	0.688	0.750
0.030	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.040	18 3/16	.....	.....	.....	.....	.....	.....	.....	.....
0.050	18 3/16	19 3/4	20 9/16	21 1/4	21 15/16	.....	.....	.....	.....
0.060	18 3/16	19 3/4	20 9/16	21 1/4	21 15/16	23 1/4	.....	.....	.....
0.070	11 11/16	19 3/4	20 9/16	21 1/4	21 15/16	23 1/4	24 9/16	25 3/4	.....
0.080	8 15/16	13 3/4	17 11/16	21 1/4	21 15/16	23 1/4	24 9/16	25 3/4	26 7/8
0.090	7 3/8	10 9/16	12 7/8	15 13/16	19 13/16	23 1/4	24 9/16	25 3/4	26 7/8
0.100	6 5/16	8 3/4	10 3/8	12 5/16	14 11/16	21 7/8	24 9/16	25 3/4	26 7/8
0.110	5 5/8	7 9/16	8 13/16	10 1/4	11 15/16	16 7/16	24	25 3/4	26 7/8
0.120	5 1/16	6 3/4	7 3/4	8 7/8	10 3/16	13 7/16	18 1/4	25 3/4	26 7/8
0.130	4 5/8	6 1/16	6 15/16	7 7/8	8 15/16	11 1/2	15	20	26 7/8
0.140	4 1/4	5 9/16	6 9/16	7 1/8	8	10 1/8	12 7/8	16 1/2	21 5/8
0.150	3 15/16	5 1/8	5 13/16	6 9/16	7 5/16	9 1/8	11 3/8	14 1/4	18
0.160	3 11/16	4 3/4	5 3/8	6 1/16	6 3/4	8 5/16	10 1/4	12 3/8	15 5/16
0.170	3 7/16	4 1/2	5 1/16	5 5/8	6 1/4	7 11/16	9 1/8	11 1/8	13 13/16
0.180	3 1/4	4 3/16	4 3/4	5 5/16	5 7/8	7 1/8	8 3/8	10 3/8	12 7/16
0.190	3 1/16	4	4 1/2	5	5 1/2	6 11/16	8 1/16	9 5/8	11 3/8
0.200	2 15/16	3 3/4	4 1/4	4 11/16	5 3/16	6 5/16	7 9/16	8 15/16	10 9/16
0.210	2 3/4	3 9/16	4	4 1/2	4 15/16	5 15/16	7 1/8	8 3/8	9 13/16
0.220	2 5/8	3 7/16	3 13/16	4 1/4	4 11/16	5 11/16	6 3/4	7 15/16	9 1/4
0.230	2 1/2	3 1/4	3 11/16	4 1/16	4 1/2	5 3/8	6 3/8	7 1/2	8 11/16
0.240	2 3/8	3 1/8	3 1/2	3 7/8	4 5/16	5 1/8	6 1/8	7 1/8	8 1/4
0.250	2 5/16	3	3 3/8	3 3/4	4 1/8	4 15/16	5 13/16	6 13/16	7 7/8
0.260	2 3/16	2 7/8	3 1/4	3 9/16	3 15/16	4 3/4	5 9/16	6 1/2	7 1/2
0.270	2 1/16	2 3/4	3 1/16	3 7/16	3 13/16	4 9/16	5 3/8	6 1/4	7 3/16
0.280	.....	2 5/8	3	3 3/16	3 11/16	4 3/8	5 3/16	6	6 7/8
0.290	.....	2 9/16	2 7/8	3 3/16	3 1/2	4 1/4	5	5 3/4	6 5/8
0.300	.....	2 7/16	2 3/4	3 1/16	3 3/8	4 1/16	4 13/16	5 9/16	6 3/8
0.310	.....	2 3/8	2 11/16	2 15/16	3 5/16	3 15/16	4 5/8	5 3/8	6 3/16
0.320	.....	2 1/4	2 9/16	2 7/8	3 3/16	3 13/16	4 1/2	5 3/16	5 15/16
0.330	.....	.....	2 1/2	2 3/4	3 1/16	3 11/16	4 3/8	5 1/16	5 3/4
0.340	.....	.....	2 3/8	2 11/16	3	3 9/16	4 3/16	4 7/8	5 9/16
0.350	.....	.....	2 5/16	2 9/16	2 7/8	3 7/16	4 1/16	4 3/4	5 7/16
0.360	.....	.....	.....	2 1/2	2 13/16	3 3/8	4	4 5/8	5 1/4
0.370	.....	.....	.....	2 7/16	2 11/16	3 1/4	3 7/8	4 1/2	5 1/8
0.380	.....	.....	.....	.....	2 5/8	3 1/16	3 3/4	4 3/8	5
0.390	.....	.....	.....	.....	2 9/16	3 1/16	3 5/8	4 1/4	4 13/16
0.400	.....	.....	.....	.....	2 7/16	3	3 9/16	4 1/8	4 11/16
0.410	.....	.....	.....	.....	.....	2 15/16	3 7/16	4	4 9/16
0.420	.....	.....	.....	.....	.....	2 13/16	3 3/8	3 15/16	4 1/2
0.430	.....	.....	.....	.....	.....	2 3/4	3 1/4	3 11/16	4 3/8
0.440	.....	.....	.....	.....	.....	2 11/16	3 3/16	3 3/4	4 1/4
0.450	.....	.....	.....	.....	.....	.....	3 1/8	3 5/8	4 1/16
0.460	.....	.....	.....	.....	.....	.....	3 1/16	3 9/16	4 1/16
0.470	.....	.....	.....	.....	.....	.....	2 15/16	3 7/16	4
0.480	.....	.....	.....	.....	.....	.....	2 7/8	3 3/8	3 7/8
0.490	.....	.....	.....	.....	.....	.....	2 13/16	3 5/16	3 13/16
0.500	.....	.....	.....	.....	.....	.....	2 3/4	3 1/4	3 11/16
0.510	.....	.....	.....	.....	.....	.....	.....	3 3/16	3 5/8
0.520	.....	.....	.....	.....	.....	.....	.....	3 1/16	3 9/16

TABLE 3-10 VALUES OF *L* FOR PIPE SIZES ≥ NPS 48 AND < NPS 52

Wall Thickness, *t*, in.								Depth, *d*, in.
0.812	0.875	0.938	1.000	1.062	1.125	1.188	1.250	
.....	.....	.....	.....	.....	.....	.....	.....	0.030
.....	.....	.....	.....	.....	.....	.....	.....	0.040
.....	.....	.....	.....	.....	.....	.....	.....	0.050
.....	.....	.....	.....	.....	.....	.....	.....	0.060
.....	.....	.....	.....	.....	.....	.....	.....	0.070
.....	.....	.....	.....	.....	.....	.....	.....	0.080
28	29 1/16	.....	.....	.....	.....	.....	.....	0.090
28	29 1/16	30 1/16	.....	.....	.....	.....	.....	0.100
28	29 1/16	30 1/16	31 1/16	32	.....	.....	.....	0.110
28	29 1/16	30 1/16	31 1/16	32	32 15/16	33 13/16	.....	0.120
28	29 1/16	30 1/16	31 1/16	32	32 15/16	33 13/16	34 11/16	0.130
28	29 1/16	30 1/16	31 1/16	32	32 15/16	33 13/16	34 11/16	0.140
23 1/4	29 1/16	30 1/16	31 1/16	32	32 15/16	33 13/16	34 11/16	0.150
19 7/16	24 15/16	30 1/16	31 1/16	32	32 15/16	33 13/16	34 11/16	0.160
16 13/16	20 15/16	26 9/16	31 1/16	32	32 15/16	33 13/16	34 11/16	0.170
14 15/16	18 1/16	22 3/8	28 1/16	32	32 15/16	33 13/16	34 11/16	0.180
13 9/16	16 1/16	19 1/2	23 3/4	29 1/2	32 15/16	33 13/16	34 11/16	0.190
12 3/8	14 11/16	17 3/8	20 3/4	25 1/8	31 1/16	33 13/16	34 11/16	0.200
11 1/2	13 7/16	15 3/4	18 9/16	22	26 1/2	32 9/16	34 11/16	0.210
10 3/4	12 7/16	14 1/2	16 7/8	19 11/16	23 3/16	27 13/16	33 15/16	0.220
10 1/16	11 3/8	13 7/16	15 1/2	17 15/16	20 15/16	24 9/16	29 7/16	0.230
9 1/2	10 15/16	12 9/16	14 1/8	16 1/2	19 1/16	22 1/8	25 13/16	0.240
9	10 5/16	11 13/16	13 7/16	15 5/16	17 1/2	20 1/8	23 1/4	0.250
8 9/16	9 13/16	11 1/8	12 5/8	14 5/16	16 5/16	18 9/16	21 3/16	0.260
8 3/16	9 5/16	10 9/16	11 15/16	13 1/2	15 1/4	17 1/4	19 5/16	0.270
7 7/8	8 13/16	10 1/16	11 3/8	12 3/4	14 3/8	16 3/16	18 3/16	0.280
7 9/16	8 9/16	9 5/8	10 13/16	12 1/8	13 9/16	15 1/4	17 1/16	0.290
7 1/4	8 1/16	9 1/4	10 3/8	11 9/16	12 15/16	14 7/16	16 1/16	0.300
7	7 7/8	8 7/8	9 15/16	11 1/16	12 5/16	13 11/16	15 1/4	0.310
6 3/4	7 5/8	8 9/16	9 9/16	10 5/8	11 13/16	13 1/16	14 1/2	0.320
6 1/2	7 3/8	8 1/4	9 3/16	10 3/16	11 3/16	12 1/2	13 13/16	0.330
6 3/16	7 1/8	7 15/16	8 7/8	9 13/16	10 7/8	12	13 1/4	0.340
6 1/8	6 7/8	7 11/16	8 9/16	9 1/2	10 1/2	11 9/16	12 11/16	0.350
5 15/16	6 11/16	7 1/2	8 5/16	9 3/16	10 1/8	11 1/8	12 1/16	0.360
5 3/4	6 1/2	7 1/4	8 1/16	8 7/8	9 3/4	10 3/4	11 3/4	0.370
5 5/8	6 5/16	7 1/16	7 13/16	8 5/8	9 1/2	10 1/8	11 1/8	0.380
5 1/2	6 1/8	6 7/8	7 9/16	8 3/8	9 3/16	10 1/16	11	0.390
5 3/16	6	6 11/16	7 1/8	8 1/8	8 15/16	9 3/4	10 11/16	0.400
5 1/16	5 13/16	6 1/2	7 3/16	7 7/8	8 11/16	9 1/2	10 5/16	0.410
5 1/16	5 11/16	6 3/16	7	7 11/16	8 7/16	9 1/4	10 1/16	0.420
4 15/16	5 5/16	6 1/16	6 13/16	7 1/2	8 1/4	9	9 3/4	0.430
4 13/16	5 1/16	6	6 5/8	7 3/16	8	8 3/4	9 1/2	0.440
4 11/16	5 3/16	5 7/8	6 1/2	7 1/8	7 13/16	8 5/16	9 1/4	0.450
4 5/8	5 1/16	5 3/4	6 1/8	7	7 5/8	8 3/16	9 1/16	0.460
4 1/2	5 1/16	5 5/8	6 3/16	6 11/16	7 7/16	8 1/8	8 13/16	0.470
4 1/8	4 15/16	5 1/2	6 1/16	6 11/16	7 3/16	7 13/16	8 1/8	0.480
4 3/16	4 13/16	5 3/8	5 15/16	6 1/2	7 1/8	7 3/4	8 3/16	0.490
4 3/16	4 3/4	5 1/4	5 11/16	6 3/8	7	7 5/8	8 1/4	0.500
4 1/8	4 5/8	5 1/16	5 11/16	6 1/4	6 11/16	7 7/16	8 1/16	0.510
4 1/16	4 9/16	5 1/16	5 9/16	6 1/8	6 11/16	7 3/16	7 7/8	0.520

(table continues)

TABLE 3-10 VALUES OF L FOR PIPE SIZES ≥ NPS 48 AND < NPS 52 (CONT'D)

Depth, d, in.	Wall Thickness, t, in. 0.344	0.406	0.438	0.469	0.500	0.562	0.625	0.688	0.750
0.530	.....	.....	.....	.....	.....	.....	.....	3	3½
0.540	.....	.....	.....	.....	.....	.....	.....	2 15/16	3 7/16
0.550	.....	.....	.....	.....	.....	.....	.....	2¾	3 5/16
0.560	.....	.....	.....	.....	.....	.....	.....	.....	3¼
0.570	.....	.....	.....	.....	.....	.....	.....	.....	3 3/16
0.580	.....	.....	.....	.....	.....	.....	.....	.....	3⅛
0.590	.....	.....	.....	.....	.....	.....	.....	.....	3 1/16
0.600	.....	.....	.....	.....	.....	.....	.....	.....	3
0.610	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.620	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.630	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.640	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.650	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.660	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.670	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.680	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.690	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.700	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.710	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.720	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.730	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.740	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.750	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.760	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.770	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.780	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.790	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.800	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.810	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.820	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.830	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.840	.....	.....	.....	.....	.....	.....	.....	.....	.....
0.850	.....	.....	.....	.....	.....	.....	.....	.....	.....

TABLE 3-10 VALUES OF *L* FOR PIPE SIZES ≥ NPS 48 AND < NPS 52 (CONT'D)

Wall Thickness, *t*, in.								Depth, *d*, in.
0.812	0.875	0.938	1.000	1.062	1.125	1.188	1.250	
3 15/16	4 7/16	4 15/16	5 1/2	6	6 9/16	7 1/8	7 1/4	0.530
3 7/8	4 3/8	4 7/8	5 3/8	5 7/8	6 7/16	7	7 9/16	0.540
3 13/16	4 1/4	4 3/4	5 1/4	5 13/16	6 3/16	6 7/8	7 7/16	0.550
3 3/4	4 1/16	4 11/16	5 3/16	5 11/16	6 1/16	6 3/4	7 3/16	0.560
3 5/8	4 1/8	4 5/8	5 1/16	5 9/16	6 1/16	6 5/8	7 1/16	0.570
3 9/16	4 1/16	4 1/2	5	5 1/2	6	6 1/2	7 1/16	0.580
3 1/2	3 15/16	4 7/16	4 7/8	5 3/8	5 7/8	6 3/8	6 15/16	0.590
3 7/16	3 7/8	4 3/8	4 13/16	5 1/4	5 3/4	6 1/4	6 13/16	0.600
3 3/8	3 13/16	4 1/4	4 3/4	5 3/16	5 11/16	6 3/16	6 11/16	0.610
3 5/16	3 3/4	4 3/16	4 5/8	5 1/8	5 9/16	6 1/16	6 9/16	0.620
3 1/4	3 11/16	4 1/8	4 9/16	5	5 1/2	5 15/16	6 7/16	0.630
3 3/16	3 5/8	4 1/16	4 1/2	4 15/16	5 3/8	5 7/8	6 3/8	0.640
.....	3 9/16	4	4 7/16	4 7/8	5 5/16	5 3/4	6 1/4	0.650
.....	3 1/2	3 15/16	4 5/16	4 3/4	5 1/4	5 11/16	6 1/8	0.660
.....	3 7/16	3 7/8	4 1/4	4 11/16	5 1/8	5 5/8	6 1/16	0.670
.....	3 3/8	3 13/16	4 3/16	4 5/8	.....	.....	.....	0.680
.....	3 5/16	3 3/4	4 1/8	4 9/16	.....	.....	.....	0.690
.....	3 1/4	3 11/16	4 1/16	4 1/2	.....	.....	.....	0.700
.....	.....	3 5/8	4	4 7/16	.....	.....	.....	0.710
.....	.....	3 9/16	3 15/16	4 5/16	.....	.....	.....	0.720
.....	.....	3 1/2	3 7/8	4 1/4	.....	.....	.....	0.730
.....	.....	3 7/16	3 13/16	4 3/16	.....	.....	.....	0.740
.....	.....	3 3/8	3 3/4	4 1/8	.....	.....	.....	0.750
.....	.....	.....	3 11/16	4 1/16	.....	.....	.....	0.760
.....	.....	.....	3 5/8	4	.....	.....	.....	0.770
.....	.....	.....	3 9/16	3 15/16	.....	.....	.....	0.780
.....	.....	.....	3 9/16	3 15/16	.....	.....	.....	0.790
.....	.....	.....	3 1/2	3 7/8	.....	.....	.....	0.800
.....	.....	.....	.....	3 13/16	.....	.....	.....	0.810
.....	.....	.....	.....	3 3/4	.....	.....	.....	0.820
.....	.....	.....	.....	3 11/16	.....	.....	.....	0.830
.....	.....	.....	.....	3 5/8	.....	.....	.....	0.840
.....	.....	.....	.....	.....	.....	.....	.....	0.850

TABLE 3-11 VALUES OF *L* FOR PIPE SIZES ≥ NPS 52 AND < NPS 56

Depth, *d*, in.	Wall Thickness, *t*, in. 0.406	0.438	0.469	0.500	0.562	0.625	0.688	0.750
0.040	.....	.....	.....	.....	.....	.....	.....	.....
0.050	20 9/16	21 1/8	22 1/8	22 11/16	.....	.....	.....	.....
0.060	20 9/16	21 1/8	22 1/8	22 13/16	24 3/16	.....	.....	.....
0.070	20 9/16	21 1/8	22 1/8	22 13/16	24 3/16	25 9/16	26 11/16	.....
0.080	14 5/16	18 7/16	22 1/8	22 13/16	24 3/16	25 9/16	26 11/16	28
0.090	11	13 7/16	16 1/2	20 5/8	24 3/16	25 9/16	26 11/16	28
0.100	9 1/8	10 13/16	12 13/16	15 5/16	22 1/4	25 9/16	26 11/16	28
0.110	7 7/8	9 3/16	10 11/16	12 1/8	17 1/8	25	26 11/16	28
0.120	7	8 1/16	9 1/4	10 9/16	14	19	26 11/16	28
0.130	6 5/16	7 1/4	8 1/16	9 5/16	11 15/16	15 5/8	20 13/16	28
0.140	5 3/4	6 9/16	7 7/16	8 1/8	10 9/16	13 1/8	17 5/16	22 9/16
0.150	5 5/16	6 1/16	6 13/16	7 5/8	9 1/2	11 13/16	14 13/16	18 3/4
0.160	5	5 5/8	6 5/16	7	8 11/16	10 1/8	13 1/8	16 3/16
0.170	4 5/8	5 1/4	5 7/8	6 1/2	8	9 1/4	11 13/16	14 1/8
0.180	4 3/8	4 15/16	5 1/2	6 1/8	7 7/16	9	10 13/16	12 15/16
0.190	4 1/8	4 1/8	5 3/16	5 3/4	6 15/16	8 1/8	10	11 7/8
0.200	3 15/16	4 7/16	4 7/8	5 7/16	6 9/16	7 7/8	9 5/16	11
0.210	3 3/4	4 3/16	4 11/16	5 1/8	6 3/16	7 1/8	8 3/4	10 1/4
0.220	3 9/16	4	4 7/16	4 7/8	5 7/8	7	8 1/4	9 5/8
0.230	3 3/8	3 13/16	4 1/4	4 11/16	5 5/8	6 5/8	7 13/16	9 1/16
0.240	3 1/4	3 5/8	4 1/16	4 1/2	5 1/8	6 1/8	7 1/16	8 9/16
0.250	3 1/8	3 1/2	3 7/8	4 5/16	5 1/8	6 1/16	7 1/16	8 1/16
0.260	3	3 3/8	3 3/4	4 1/8	4 15/16	5 13/16	6 3/4	7 13/16
0.270	2 7/8	3 3/16	3 9/16	3 15/16	4 3/4	5 9/16	6 1/2	7 1/2
0.280	2 3/4	3 1/8	3 7/16	3 13/16	4 9/16	5 1/8	6 1/4	7 3/16
0.290	2 5/8	3	3 5/16	3 11/16	4 3/8	5 1/16	6	6 7/8
0.300	2 9/16	2 7/8	3 3/16	3 9/16	4 1/4	5	5 13/16	6 5/8
0.310	2 7/16	2 3/4	3 1/16	3 7/16	4 1/8	4 15/16	5 5/8	6 7/16
0.320	2 3/8	2 11/16	3	3 5/16	3 15/16	4 11/16	5 7/16	6 3/16
0.330	.....	2 9/16	2 7/8	3 3/16	3 13/16	4 1/2	5 1/4	6
0.340	.....	2 1/2	2 13/16	3 1/16	3 3/4	4 3/8	5 1/16	5 11/16
0.350	.....	2 3/8	2 11/16	3	3 5/8	4 1/4	4 15/16	5 5/8
0.360	.....	.....	2 5/8	2 7/8	3 1/2	4 1/8	4 13/16	5 1/2
0.370	.....	.....	2 1/2	2 13/16	3 3/8	4	4 11/16	5 5/16
0.380	.....	.....	.....	2 3/4	3 5/16	3 7/8	4 1/2	5 3/16
0.390	.....	.....	.....	2 5/8	3 3/16	3 13/16	4 7/16	5 1/16
0.400	.....	.....	.....	2 9/16	3 1/8	3 11/16	4 3/16	4 7/8
0.410	.....	.....	.....	.....	3	3 5/8	4 3/16	4 3/4
0.420	.....	.....	.....	.....	2 15/16	3 1/2	4 1/16	4 11/16
0.430	.....	.....	.....	.....	2 7/8	3 7/16	4	4 9/16
0.440	.....	.....	.....	.....	2 13/16	3 3/16	3 7/8	4 7/16
0.450	.....	.....	.....	.....	.....	3 1/4	3 13/16	4 3/16
0.460	.....	.....	.....	.....	.....	3 3/16	3 11/16	4 1/4
0.470	.....	.....	.....	.....	.....	3 1/16	3 5/8	4 1/8
0.480	.....	.....	.....	.....	.....	3	3 1/2	4 1/16
0.490	.....	.....	.....	.....	.....	2 15/16	3 7/16	3 15/16
0.500	.....	.....	.....	.....	.....	2 7/8	3 3/8	3 7/8
0.510	.....	.....	.....	.....	.....	.....	3 5/16	3 13/16
0.520	.....	.....	.....	.....	.....	.....	3 3/16	3 11/16
0.530	.....	.....	.....	.....	.....	.....	3 1/8	3 5/8

TABLE 3-11 VALUES OF *L* FOR PIPE SIZES ≥ NPS 52 AND < NPS 56

Wall Thickness, *t*, in.								Depth, *d*, in.
0.812	0.875	0.938	1.000	1.062	1.125	1.188	1.250	
.....	.....	.....	.....	.....	.....	.....	.....	0.040
.....	.....	.....	.....	.....	.....	.....	.....	0.050
.....	.....	.....	.....	.....	.....	.....	.....	0.060
.....	.....	.....	.....	.....	.....	.....	.....	0.070
.....	.....	.....	.....	.....	.....	.....	.....	0.080
29⅛	30¼	.....	.....	.....	.....	.....	.....	0.090
29⅛	30¼	31 5/16	.....	.....	.....	.....	.....	0.100
29⅛	30¼	31 5/16	32 5/16	33 5/16	.....	.....	.....	0.110
29⅛	30¼	31 5/16	32 5/16	33 5/16	34¼	35 1/16	.....	0.120
29⅛	30¼	31 5/16	32 5/16	33 5/16	34¼	35 1/16	36⅛	0.130
29⅛	30¼	31 5/16	32 5/16	33 5/16	34¼	35 1/16	36⅛	0.140
24 3/16	30¼	31 5/16	32 5/16	33 5/16	34¼	35 1/16	36⅛	0.150
20 3/16	25 15/16	31 5/16	32 5/16	33 5/16	34¼	35 1/16	36⅛	0.160
17½	21¾	27⅜	32 5/16	33 5/16	34¼	35 1/16	36⅛	0.170
15 9/16	18 15/16	23 5/16	29 5/16	33 5/16	34¼	35 1/16	36⅛	0.180
14 1/16	16⅞	20 5/16	24¾	30 11/16	34¼	35 1/16	36⅛	0.190
12 15/16	15¼	18⅛	21⅝	26⅛	32 5/16	35 1/16	36⅛	0.200
11 15/16	14	16 7/16	19 5/16	22 15/16	27⅜	33⅞	36⅛	0.210
11 3/16	12 15/16	15 1/16	17 9/16	20½	24¼	29 1/16	35 3/16	0.220
10½	12⅛	14	16⅛	18 11/16	21¾	25⅝	30⅜	0.230
9⅞	11⅜	13 1/16	14 15/16	17 5/16	19 11/16	23	26⅞	0.240
9⅜	10¾	12 3/16	14	15 13/16	18¼	20 15/16	24 1/16	0.250
8 15/16	10 3/16	11⅝	13 3/16	14 13/16	16 15/16	19 5/16	22 1/16	0.260
8 9/16	9 11/16	11	12 7/16	14 1/16	15⅞	17 15/16	20⅛	0.270
8 1/16	9 5/16	10½	11 11/16	13¼	14 15/16	16 13/16	18 15/16	0.280
7⅞	8⅞	10 1/16	11¼	12⅝	14⅛	15⅞	17¾	0.290
7 9/16	8 9/16	9⅝	10¾	12	13 7/16	15	16¾	0.300
7¼	8¼	9¼	10 5/16	11½	12 11/16	14¼	15 13/16	0.310
7	7 15/16	8⅞	9 15/16	11 1/16	12¼	13⅝	15 1/16	0.320
6 13/16	7 11/16	8 5/16	9 9/16	10⅝	11¾	13	14⅜	0.330
6 9/16	7 1/16	8 3/16	9¼	10¼	11 5/16	12½	13¾	0.340
6⅜	7 1/16	8	8 15/16	9⅞	10⅞	12	13 3/16	0.350
6 3/16	6 13/16	7¾	8⅝	9 9/16	10½	11 9/16	12 11/16	0.360
6	6¾	7 9/16	8⅜	9¼	10 1/16	11 1/16	12¼	0.370
5⅞	6 9/16	7 5/16	8⅛	8 15/16	9⅞	10 13/16	11 13/16	0.380
5 13/16	6⅜	7⅛	7⅞	8 11/16	9 9/16	10½	11 3/16	0.390
5 9/16	6¼	6 15/16	7 11/16	8 7/16	9 1/16	10 3/16	11⅛	0.400
5⅜	6 1/16	6¾	7½	8¼	9	9⅞	10¾	0.410
5¼	5 15/16	6 9/16	7¼	8	8 13/16	9⅝	10 7/16	0.420
5⅛	5¾	6 7/16	7⅛	7 13/16	8 5/16	9⅛	10 1/16	0.430
5	5⅝	6¼	6 15/16	7⅝	8 1/16	9⅛	9⅞	0.440
4⅞	5½	6⅛	6¾	7 7/16	8⅛	8⅞	9⅝	0.450
4 13/16	5⅜	6	6⅝	7¼	7 15/16	8 11/16	9 7/16	0.460
4 11/16	5¼	5⅞	6 7/16	7⅛	7¾	8 7/16	9 1/16	0.470
4 9/16	5⅛	5¾	6 5/16	6 15/16	7 9/16	8¼	9	0.480
4½	5 1/16	5⅝	6 1/16	6 11/16	7 3/16	8 1/16	8¾	0.490
4⅜	4 15/16	5½	6 1/16	6⅝	7¼	7 15/16	8 9/16	0.500
4 3/16	4 11/16	5⅜	5 15/16	6½	7⅛	7¾	8⅜	0.510
4 1/16	4¼	5¼	5 11/16	6⅜	7	7 9/16	8¼	0.520
4⅛	4⅜	5 1/16	5 11/16	6¼	6 15/16	7 3/16	8 1/16	0.530

(table continues)

TABLE 3-11 VALUES OF L FOR PIPE SIZES ≥ NPS 52 AND < NPS 56 (CONT'D)

Depth, d, in.	Wall Thickness, t, in. 0.406	0.438	0.469	0.500	0.562	0.625	0.688	0.750
0.540	.....	.....	.....	.....	.....	.....	3 1/16	3 5/16
0.550*	.....	.....	.....	.....	.....	.....	3	3 1/2
0.560	.....	.....	.....	.....	.....	.....	.....	3 3/8
0.570	.....	.....	.....	.....	.....	.....	.....	3 5/16
0.580	.....	.....	.....	.....	.....	.....	.....	3 1/4
0.590	.....	.....	.....	.....	.....	.....	.....	3 3/16
0.600	.....	.....	.....	.....	.....	.....	.....	3 1/8
0.610	.....	.....	.....	.....	.....	.....	.....	.....
0.620	.....	.....	.....	.....	.....	.....	.....	.....
0.630	.....	.....	.....	.....	.....	.....	.....	.....
0.640	.....	.....	.....	.....	.....	.....	.....	.....
0.650	.....	.....	.....	.....	.....	.....	.....	.....
0.660	.....	.....	.....	.....	.....	.....	.....	.....
0.670	.....	.....	.....	.....	.....	.....	.....	.....
0.680	.....	.....	.....	.....	.....	.....	.....	.....
0.690	.....	.....	.....	.....	.....	.....	.....	.....
0.700	.....	.....	.....	.....	.....	.....	.....	.....
0.710	.....	.....	.....	.....	.....	.....	.....	.....
0.720	.....	.....	.....	.....	.....	.....	.....	.....
0.730	.....	.....	.....	.....	.....	.....	.....	.....
0.740	.....	.....	.....	.....	.....	.....	.....	.....
0.750	.....	.....	.....	.....	.....	.....	.....	.....
0.760	.....	.....	.....	.....	.....	.....	.....	.....
0.770	.....	.....	.....	.....	.....	.....	.....	.....
0.780	.....	.....	.....	.....	.....	.....	.....	.....
0.790	.....	.....	.....	.....	.....	.....	.....	.....
0.800	.....	.....	.....	.....	.....	.....	.....	.....
0.810	.....	.....	.....	.....	.....	.....	.....	.....
0.820	.....	.....	.....	.....	.....	.....	.....	.....
0.830	.....	.....	.....	.....	.....	.....	.....	.....
0.840	.....	.....	.....	.....	.....	.....	.....	.....
0.850	.....	.....	.....	.....	.....	.....	.....	.....
0.860	.....	.....	.....	.....	.....	.....	.....	.....
0.870	.....	.....	.....	.....	.....	.....	.....	.....
0.880	.....	.....	.....	.....	.....	.....	.....	.....
0.890	.....	.....	.....	.....	.....	.....	.....	.....
0.900	.....	.....	.....	.....	.....	.....	.....	.....
0.910	.....	.....	.....	.....	.....	.....	.....	.....
0.920	.....	.....	.....	.....	.....	.....	.....	.....
0.930	.....	.....	.....	.....	.....	.....	.....	.....
0.940	.....	.....	.....	.....	.....	.....	.....	.....
0.950	.....	.....	.....	.....	.....	.....	.....	.....
0.960	.....	.....	.....	.....	.....	.....	.....	.....
0.970	.....	.....	.....	.....	.....	.....	.....	.....
0.980	.....	.....	.....	.....	.....	.....	.....	.....
0.990	.....	.....	.....	.....	.....	.....	.....	.....
1.000	.....	.....	.....	.....	.....	.....	.....	.....
1.010	.....	.....	.....	.....	.....	.....	.....	.....

TABLE 3-11 VALUES OF L FOR PIPE SIZES ≥ NPS 52 AND < NPS 56 (CONT'D)

Wall Thickness, t, in.								Depth,
0.812	0.875	0.938	1.000	1.062	1.125	1.188	1.250	d, in.
4 1/16	4 9/16	5 1/16	5 9/16	6 1/8	6 11/16	7 3/16	7 7/8	0.540
3 15/16	4 7/16	4 15/16	5 1/2	6	6 9/16	7 1/8	7 3/4	0.550
3 7/8	4 3/8	4 7/8	5 3/8	5 7/8	6 7/16	7	7 5/8	0.560
3 13/16	4 5/16	4 13/16	5 5/16	5 13/16	6 3/16	6 7/8	7 7/16	0.570
3 3/4	4 3/16	4 11/16	5 3/16	5 11/16	6 1/4	6 3/4	7 5/16	0.580
3 11/16	4 1/8	4 5/8	5 1/8	5 5/16	6 1/8	6 5/8	7 1/16	0.590
3 9/16	4 1/16	4 1/2	5	5 1/2	6	6 9/16	7 1/16	0.600
3 1/2	4	4 7/16	4 15/16	5 3/8	5 7/8	6 7/16	6 15/16	0.610
3 7/16	3 7/8	4 3/8	4 13/16	5 5/16	5 13/16	6 5/16	6 13/16	0.620
3 3/8	3 13/16	4 5/16	4 3/4	5 1/4	5 11/16	6 3/16	6 11/16	0.630
3 5/16	3 3/4	4 3/16	4 11/16	5 1/8	5 5/8	6 1/8	6 5/8	0.640
.....	3 11/16	4 1/8	4 5/8	5 1/16	5 1/2	6	6 1/2	0.650
.....	3 5/8	4 1/16	4 1/2	4 15/16	5 7/16	5 15/16	6 1/8	0.660
.....	3 9/16	4	4 7/16	4 7/8	5 3/8	5 13/16	6 3/16	0.670
.....	3 1/2	3 15/16	4 3/8	4 13/16	5 1/4	5 3/4	6 1/16	0.680
.....	3 7/16	3 7/8	4 5/16	4 3/4	5 1/16	5 5/8	6 1/8	0.690
.....	3 3/8	3 13/16	4 1/4	4 11/16	5 1/8	5 9/16	6	0.700
.....	.....	3 3/4	4 3/16	4 9/16	5	5 1/2	5 15/16	0.710
.....	.....	3 11/16	4 1/8	4 1/2	4 15/16	5 3/8	5 13/16	0.720
.....	.....	3 5/8	4 1/16	4 7/16	4 7/8	5 5/16	5 3/4	0.730
.....	.....	3 9/16	4	4 3/8	4 13/16	5 1/4	5 11/16	0.740
.....	.....	3 1/2	3 15/16	4 5/16	4 3/4	5 1/16	5 5/8	0.750
.....	.....	.....	3 7/8	4 1/4	4 11/16	5 1/8	5 1/2	0.760
.....	.....	.....	3 13/16	4 3/16	4 5/8	5	5 7/16	0.770
.....	.....	.....	3 3/4	4 1/8	4 9/16	4 15/16	5 3/8	0.780
.....	.....	.....	3 11/16	4 1/16	4 1/2	4 7/8	5 5/16	0.790
.....	.....	.....	3 5/8	4	4 7/16	4 13/16	5 1/4	0.800
.....	.....	.....	.....	3 15/16	4 3/8	4 3/4	5 1/8	0.810
.....	.....	.....	.....	3 7/8	4 5/16	4 11/16	5 1/16	0.820
.....	.....	.....	.....	3 13/16	4 1/4	4 5/8	5	0.830
.....	.....	.....	.....	3 13/16	4 3/16	4 9/16	4 15/16	0.840
.....	.....	.....	.....	.....	4 1/8	4 1/2	4 7/8	0.850
.....	.....	.....	.....	.....	4 1/16	4 7/16	4 13/16	0.860
.....	.....	.....	.....	.....	4	4 3/8	4 3/4	0.870
.....	.....	.....	.....	.....	3 15/16	4 5/16	4 11/16	0.880
.....	.....	.....	.....	.....	3 7/8	4 1/4	4 5/8	0.890
.....	.....	.....	.....	.....	3 13/16	4 3/16	4 9/16	0.900
.....	.....	.....	.....	.....	.....	4 1/16	4 1/2	0.910
.....	.....	.....	.....	.....	.....	4 1/8	4 1/2	0.920
.....	.....	.....	.....	.....	.....	4 1/16	4 7/16	0.930
.....	.....	.....	.....	.....	.....	4	4 3/8	0.940
.....	.....	.....	.....	.....	.....	3 15/16	4 3/16	0.950
.....	.....	.....	.....	.....	.....	.....	4 1/4	0.960
.....	.....	.....	.....	.....	.....	.....	4 3/16	0.970
.....	.....	.....	.....	.....	.....	.....	4 1/8	0.980
.....	.....	.....	.....	.....	.....	.....	4 1/8	0.990
.....	.....	.....	.....	.....	.....	.....	4 1/16	1.000
.....	.....	.....	.....	.....	.....	.....	.....	1.010

TABLE 3-12 VALUES OF *L* FOR PIPE SIZES ≥ NPS 56 AND < NPS 60

Depth, *d*, in.	Wall Thickness, *t*, in. 0.406	0.438	0.469	0.500	0.562	0.625	0.688	0.750
0.040	.....	.....	.....	.....	.....	.....	.....	.....
0.050	21⅛	22 9/16	22 15/16	23 11/16	.....	.....	.....	.....
0.060	21⅛	22 9/16	22 15/16	23 11/16	25⅛	.....	.....	.....
0.070	21⅛	22 9/16	22 15/16	23 11/16	25⅛	26½	27 13/16	.....
0.080	14 13/16	19⅛	22 15/16	23 11/16	25⅛	26½	27 13/16	29 1/16
0.090	11 7/16	13 15/16	17 9/16	21 7/16	25⅛	26½	27 13/16	29 1/16
0.100	9½	11½	13 9/16	15⅞	23⅜	26½	27 13/16	29 1/16
0.110	8 3/16	9 9/16	11 1/16	12⅞	17¾	25 15/16	27 13/16	29 1/16
0.120	7¼	8⅜	9 9/16	11	14½	19 11/16	27 13/16	29 1/16
0.130	6 9/16	7½	8½	9 11/16	12 7/16	16 3/16	21⅜	29 1/16
0.140	6	6 13/16	7 11/16	8 11/16	10 15/16	13⅞	17⅞	23⅜
0.150	5 9/16	6¼	7 1/16	7⅞	9⅞	12¼	15⅜	19 7/16
0.160	5 1/16	5 13/16	6½	7 5/16	9	11 1/16	13⅜	16 13/16
0.170	4 13/16	5 7/16	6 1/16	6¾	8 5/16	10⅛	12¼	14⅞
0.180	4 9/16	5⅛	5 11/16	6 5/16	7 11/16	9 5/16	11¼	13 7/16
0.190	4 5/16	4 13/16	5⅛	5 15/16	7¼	8 11/16	10⅜	12 5/16
0.200	4 1/16	4 9/16	5 1/16	5⅝	6 13/16	8⅛	9 11/16	11⅜
0.210	3⅞	4⅜	4 13/16	5 5/16	6 7/16	7 11/16	9 1/16	10⅝
0.220	3 11/16	4⅛	4⅝	5 1/16	6⅛	7¼	8 9/16	9 15/16
0.230	3½	3 15/16	4⅛	4⅞	5 13/16	6⅞	8⅛	9 7/16
0.240	3⅜	3 13/16	4 3/16	4⅝	5 9/16	6 9/16	7 13/16	8 15/16
0.250	3¼	3⅝	4	4 7/16	5 5/16	6 5/16	7⅛	8½
0.260	3 1/16	3½	3⅞	4¼	5⅛	6 1/16	7 1/16	8⅛
0.270	2 15/16	3 5/16	3 11/16	4⅛	4 15/16	5 13/16	6¾	7¾
0.280	2⅞	3 1/16	3 9/16	3 15/16	4¾	5 9/16	6½	7 7/16
0.290	2¾	3 1/16	3 7/16	3 13/16	4 9/16	5⅜	6¼	7 3/16
0.300	2⅝	3	3 5/16	3 11/16	4⅜	5 3/16	6	6⅞
0.310	2 9/16	2⅞	3 3/16	3 9/16	4¼	5	5 13/16	6⅝
0.320	2 7/16	2¾	3⅛	3 7/16	4⅛	4⅞	5⅝	6 7/16
0.330	.....	2 11/16	3	3 5/16	4	4 11/16	5 7/16	6¼
0.340	.....	2 9/16	2⅞	3 1/16	3⅞	4 9/16	5¼	6 1/16
0.350	.....	2½	2 13/16	3⅛	3¾	4 7/16	5⅛	5⅞
0.360	.....	.....	2 11/16	3	3⅝	4 5/16	5	5 11/16
0.370	.....	.....	2⅝	2 15/16	3½	4 3/16	4 13/16	5½
0.380	.....	.....	.....	2 13/16	3 7/16	4 1/16	4 11/16	5⅜
0.390	.....	.....	.....	2¾	3 3/16	3 15/16	4 9/16	5¼
0.400	.....	.....	.....	2 11/16	3¼	3 13/16	4 7/16	5 1/16
0.410	.....	.....	.....	.....	3⅛	3¾	4 5/16	4 15/16
0.420	.....	.....	.....	.....	3 1/16	3⅝	4¼	4 13/16
0.430	.....	.....	.....	.....	3	3 5/16	4⅛	4¼
0.440	.....	.....	.....	.....	2⅞	3 1/16	4	4⅛
0.450	.....	.....	.....	.....	.....	3⅛	3 15/16	4½
0.460	.....	.....	.....	.....	.....	3¼	3 13/16	4⅛
0.470	.....	.....	.....	.....	.....	3 1/16	3¾	4 5/16
0.480	.....	.....	.....	.....	.....	3⅛	3 11/16	4 1/16
0.490	.....	.....	.....	.....	.....	3 1/16	3 9/16	4⅛
0.500	.....	.....	.....	.....	.....	3	3½	4
0.510	.....	.....	.....	.....	.....	.....	3 7/16	3 15/16
0.520	.....	.....	.....	.....	.....	.....	3 5/16	3⅞
0.530	.....	.....	.....	.....	.....	.....	3¼	3¾

TABLE 3-12 VALUES OF L FOR PIPE SIZES ≥ NPS 56 AND < NPS 60

Wall Thickness, t, in.								Depth, d, in.
0.812	0.875	0.938	1.000	1.062	1.125	1.188	1.250	
.....	.....	.....	.....	.....	.....	.....	.....	0.040
.....	.....	.....	.....	.....	.....	.....	.....	0.050
.....	.....	.....	.....	.....	.....	.....	.....	0.060
.....	.....	.....	.....	.....	.....	.....	.....	0.070
.....	.....	.....	.....	.....	.....	.....	.....	0.080
30 3/16	31 1/8	.....	.....	.....	.....	.....	.....	0.090
30 3/16	31 1/8	32 1/2	.....	.....	.....	.....	.....	0.100
30 3/16	31 1/8	32 1/2	33 1/2	34 9/16	.....	.....	.....	0.110
30 3/16	31 1/8	32 1/2	33 1/2	34 9/16	35 5/16	36 9/16	.....	0.120
30 3/16	31 1/8	32 1/2	33 1/2	34 9/16	35 5/16	36 9/16	37 1/2	0.130
30 3/16	31 1/8	32 1/2	33 1/2	34 9/16	35 5/16	36 9/16	37 1/2	0.140
25 1/8	31 1/8	32 1/2	33 1/2	34 9/16	35 5/16	36 9/16	37 1/2	0.150
21	26 15/16	32 1/2	33 1/2	34 9/16	35 5/16	36 9/16	37 1/2	0.160
18 3/16	22 9/16	28 11/16	33 1/2	34 9/16	35 5/16	36 9/16	37 1/2	0.170
16 3/16	19 5/8	24 3/16	30 5/16	34 9/16	35 5/16	36 9/16	37 1/2	0.180
14 5/8	17 1/2	21 1/16	25 11/16	31 7/8	35 5/16	36 9/16	37 1/2	0.190
13 3/8	15 13/16	18 13/16	22 7/16	27 1/8	33 9/16	36 9/16	37 1/2	0.200
12 1/8	14 1/2	17 1/16	20 1/16	23 3/4	28 5/8	35 3/16	37 1/2	0.210
11 9/16	13 7/16	15 5/8	18 3/16	21 5/16	25 3/16	30 1/8	36 5/8	0.220
10 7/8	12 9/16	14 1/2	16 3/4	19 3/8	22 9/16	26 9/16	31 9/16	0.230
10 1/4	11 13/16	13 9/16	15 1/2	17 13/16	20 9/16	23 7/8	27 7/8	0.240
9 3/4	11 1/8	12 3/4	14 1/2	16 9/16	18 15/16	21 3/4	25 1/16	0.250
9 1/4	10 9/16	12 1/16	13 11/16	15 1/2	17 3/8	20 1/16	22 7/8	0.260
8 7/8	10 1/16	11 7/16	12 15/16	14 9/16	16 1/2	18 5/8	21 1/8	0.270
8 1/2	9 5/8	10 7/8	12 1/4	13 3/4	15 1/2	17 1/16	19 5/8	0.280
8 1/8	9 1/4	10 7/16	11 11/16	13 1/16	14 11/16	16 7/16	18 7/16	0.290
7 13/16	8 7/8	10	11 3/16	12 1/2	13 15/16	15 9/16	17 1/8	0.300
7 9/16	8 5/16	9 9/16	10 11/16	11 15/16	13 3/16	14 13/16	16 7/16	0.310
7 5/16	8 1/4	9 1/4	10 3/16	11 7/16	12 3/4	14 1/8	15 3/8	0.320
7 1/16	7 15/16	8 7/8	9 15/16	11	12 3/16	13 1/2	14 15/16	0.330
6 13/16	7 11/16	8 1/8	9 9/16	10 5/8	11 3/4	12 13/16	14 5/16	0.340
6 5/8	7 7/16	8 5/16	9 1/4	10 1/4	11 5/16	12 1/2	13 11/16	0.350
6 7/16	7 1/4	8 1/16	8 15/16	9 7/8	10 15/16	12	13 3/16	0.360
6 1/4	7	7 13/16	8 11/16	9 9/16	10 9/16	11 5/8	12 11/16	0.370
6 1/16	6 13/16	7 5/8	8 7/16	9 5/16	10 1/4	11 1/4	12 5/16	0.380
5 15/16	6 5/8	7 3/8	8 3/16	9	9 15/16	10 7/8	11 7/8	0.390
5 3/4	6 7/16	7 3/16	7 15/16	8 1/4	9 1/8	10 9/16	11 1/2	0.400
5 5/8	6 5/16	7	7 3/4	8 1/2	9 1/8	10 1/4	11 3/16	0.410
5 7/16	6 1/8	6 13/16	7 9/16	8 5/16	9 1/8	9 15/16	10 7/8	0.420
5 5/16	6	6 11/16	7 3/8	8 1/8	8 7/8	9 11/16	10 5/16	0.430
5 3/16	5 7/8	6 1/2	7 1/16	7 7/8	8 5/8	9 7/16	10 1/4	0.440
5 1/16	5 11/16	6 1/8	7	7 11/16	8 7/16	9 3/16	10	0.450
5	5 9/16	6 3/16	6 7/8	7 9/16	8 1/4	9	9 3/4	0.460
4 7/8	5 7/16	6 1/16	6 11/16	7 3/8	8 1/16	8 13/16	9 9/16	0.470
4 3/4	5 5/16	5 15/16	6 5/16	7 3/16	7 7/8	8 5/16	9 5/16	0.480
4 5/8	5 1/8	5 13/16	6 7/16	7 1/16	7 11/16	8 1/8	9 1/8	0.490
4 9/16	5 1/8	5 11/16	6 5/16	6 7/8	7 9/16	3 1/16	8 7/8	0.500
4 7/16	5	5 5/16	6 3/16	6 3/4	7 3/8	8 1/16	8 11/16	0.510
4 3/8	4 15/16	5 3/16	6 1/16	6 5/8	7 1/4	7 7/8	8 5/16	0.520
4 1/4	4 13/16	5 1/8	5 15/16	6 1/2	7 1/8	7 3/4	8 3/8	0.530

(table continues)

TABLE 3-12 VALUES OF L FOR PIPE SIZES ≥ NPS 56 AND < NPS 60 (CONT'D)

Depth, d, in.	Wall Thickness, t, in. 0.406	0.438	0.469	0.500	0.562	0.625	0.688	0.750
0.540	.....	.....	.....	.....	.....	.....	3 3/16	3 11/16
0.550	.....	.....	.....	.....	.....	.....	3 1/8	3 3/8
0.560	.....	.....	.....	.....	.....	.....	.....	3 9/16
0.570	.....	.....	.....	.....	.....	.....	.....	3 7/16
0.580	.....	.....	.....	.....	.....	.....	.....	3 3/8
0.590	.....	.....	.....	.....	.....	.....	.....	3 5/16
0.600	.....	.....	.....	.....	.....	.....	.....	3 1/4
0.610	.....	.....	.....	.....	.....	.....	.....	.....
0.620	.....	.....	.....	.....	.....	.....	.....	.....
0.630	.....	.....	.....	.....	.....	.....	.....	.....
0.640	.....	.....	.....	.....	.....	.....	.....	.....
0.650	.....	.....	.....	.....	.....	.....	.....	.....
0.660	.....	.....	.....	.....	.....	.....	.....	.....
0.670	.....	.....	.....	.....	.....	.....	.....	.....
0.680	.....	.....	.....	.....	.....	.....	.....	.....
0.690	.....	.....	.....	.....	.....	.....	.....	.....
0.700	.....	.....	.....	.....	.....	.....	.....	.....
0.710	.....	.....	.....	.....	.....	.....	.....	.....
0.720	.....	.....	.....	.....	.....	.....	.....	.....
0.730	.....	.....	.....	.....	.....	.....	.....	.....
0.740	.....	.....	.....	.....	.....	.....	.....	.....
0.750	.....	.....	.....	.....	.....	.....	.....	.....
0.760	.....	.....	.....	.....	.....	.....	.....	.....
0.770	.....	.....	.....	.....	.....	.....	.....	.....
0.780	.....	.....	.....	.....	.....	.....	.....	.....
0.790	.....	.....	.....	.....	.....	.....	.....	.....
0.800	.....	.....	.....	.....	.....	.....	.....	.....
0.810	.....	.....	.....	.....	.....	.....	.....	.....
0.820	.....	.....	.....	.....	.....	.....	.....	.....
0.830	.....	.....	.....	.....	.....	.....	.....	.....
0.840	.....	.....	.....	.....	.....	.....	.....	.....
0.850	.....	.....	.....	.....	.....	.....	.....	.....
0.860	.....	.....	.....	.....	.....	.....	.....	.....
0.870	.....	.....	.....	.....	.....	.....	.....	.....
0.880	.....	.....	.....	.....	.....	.....	.....	.....
0.890	.....	.....	.....	.....	.....	.....	.....	.....
0.900	.....	.....	.....	.....	.....	.....	.....	.....
0.910	.....	.....	.....	.....	.....	.....	.....	.....
0.920	.....	.....	.....	.....	.....	.....	.....	.....
0.930	.....	.....	.....	.....	.....	.....	.....	.....
0.940	.....	.....	.....	.....	.....	.....	.....	.....
0.950	.....	.....	.....	.....	.....	.....	.....	.....
0.960	.....	.....	.....	.....	.....	.....	.....	.....
0.970	.....	.....	.....	.....	.....	.....	.....	.....
0.980	.....	.....	.....	.....	.....	.....	.....	.....
0.990	.....	.....	.....	.....	.....	.....	.....	.....
1.000	.....	.....	.....	.....	.....	.....	.....	.....
1.010	.....	.....	.....	.....	.....	.....	.....	.....

TABLE 3-12 VALUES OF *L* FOR PIPE SIZES ≥ NPS 56 AND < NPS 60 (CONT'D)

Wall Thickness, *t*, in.								Depth,
0.812	0.875	0.938	1.000	1.062	1.125	1.188	1.250	*d*, in.
4 1/16	4 11/16	5 1/4	5 13/16	6 1/8	6 15/16	7 9/16	8 3/16	0.540
4 1/8	4 3/8	5 1/8	5 11/16	6 1/4	6 13/16	7 7/16	8 1/16	0.550
4	4 9/16	5 1/16	5 9/16	6 1/8	6 11/16	7 3/16	7 7/8	0.560
3 15/16	4 7/16	4 15/16	5 1/2	6	6 9/16	7 1/8	7 3/4	0.570
3 7/8	4 1/8	4 7/8	5 3/8	5 15/16	6 7/16	7	7 5/8	0.580
3 13/16	4 5/16	4 13/16	5 5/16	5 13/16	6 3/8	6 7/8	7 7/16	0.590
3 3/4	4 3/16	4 11/16	5 3/16	5 11/16	6 1/4	6 3/4	7 3/16	0.600
3 5/8	4 1/8	4 5/8	5 1/8	5 5/8	6 1/8	6 11/16	7 3/16	0.610
3 9/16	4 1/16	4 9/16	5	5 1/2	6	6 9/16	7 1/16	0.620
3 1/2	4	4 7/16	4 15/16	5 7/16	5 15/16	6 7/16	7	0.630
3 7/16	3 15/16	4 3/8	4 7/8	5 3/16	5 13/16	6 3/16	6 7/8	0.640
.....	3 13/16	4 5/16	4 3/4	5 1/4	5 3/4	6 1/4	6 3/4	0.650
.....	3 3/4	4 1/4	4 11/16	5 1/8	5 5/8	6 1/8	6 5/8	0.660
.....	3 11/16	4 3/16	4 5/8	5 1/16	5 9/16	6 1/16	6 9/16	0.670
.....	3 5/8	4 1/16	4 9/16	5	5 7/16	5 15/16	6 7/16	0.680
.....	3 9/16	4	4 7/16	4 15/16	5 3/8	5 7/8	6 5/16	0.690
.....	3 1/2	3 15/16	4 3/8	4 13/16	5 5/16	5 3/4	6 1/4	0.700
.....	.....	3 7/8	4 5/16	4 3/4	5 1/4	5 11/16	6 1/8	0.710
.....	.....	3 13/16	4 1/4	4 11/16	5 1/8	5 5/8	6 1/16	0.720
.....	.....	3 3/4	4 3/16	4 5/8	5 1/16	5 1/2	6	0.730
.....	.....	3 11/16	4 1/8	4 9/16	5	5 7/16	5 7/8	0.740
.....	.....	3 5/8	4 1/16	4 1/2	4 15/16	5 3/8	5 13/16	0.750
.....	.....	.....	4	4 7/16	4 7/8	5 5/16	5 3/4	0.760
.....	.....	.....	3 15/16	4 3/8	4 3/4	5 1/16	5 5/8	0.770
.....	.....	.....	3 7/8	4 5/16	4 11/16	5 1/8	5 9/16	0.780
.....	.....	.....	3 13/16	4 1/4	4 5/8	5 1/16	5 1/2	0.790
.....	.....	.....	3 3/4	4 3/16	4 9/16	5	5 7/16	0.800
.....	.....	.....	.....	4 1/8	4 1/2	4 15/16	5 3/8	0.810
.....	.....	.....	.....	4 1/16	4 7/16	4 7/8	5 1/4	0.820
.....	.....	.....	.....	4	4 3/8	4 13/16	5 3/16	0.830
.....	.....	.....	.....	3 15/16	4 5/16	4 3/4	5 1/8	0.840
.....	.....	.....	.....	.....	4 1/4	4 11/16	5 1/16	0.850
.....	.....	.....	.....	.....	4 3/16	4 5/8	5	0.860
.....	.....	.....	.....	.....	4 1/8	4 9/16	4 15/16	0.870
.....	.....	.....	.....	.....	4 1/8	4 1/2	4 7/8	0.880
.....	.....	.....	.....	.....	4 1/16	4 7/16	4 13/16	0.890
.....	.....	.....	.....	.....	4	4 3/8	4 3/4	0.900
.....	.....	.....	.....	.....	.....	4 5/16	4 11/16	0.910
.....	.....	.....	.....	.....	.....	4 1/4	4 5/8	0.920
.....	.....	.....	.....	.....	.....	4 3/16	4 9/16	0.930
.....	.....	.....	.....	.....	.....	4 1/8	4 1/2	0.940
.....	.....	.....	.....	.....	.....	4 1/8	4 7/16	0.950
.....	.....	.....	.....	.....	.....	.....	4 7/16	0.960
.....	.....	.....	.....	.....	.....	.....	4 3/8	0.970
.....	.....	.....	.....	.....	.....	.....	4 5/16	0.980
.....	.....	.....	.....	.....	.....	.....	4 1/4	0.990
.....	.....	.....	.....	.....	.....	.....	4 1/16	1.000
.....	.....	.....	.....	.....	.....	.....	.....	1.010

PART 4
EVALUATION OF MAOP IN CORRODED AREAS

4.1 COMPUTATION OF *A*

If the measured maximum depth of the corroded area is greater than 10% of the nominal wall thickness but less than 80% of the nominal wall thickness and the measured longitudinal extent of the corroded area is greater than the value determined by Eq. (2) of Part 2, calculate

$$A = 0.893\left(\frac{L_m}{\sqrt{Dt}}\right)$$

where

L_m = measured longitudinal extent of the corroded area, in.

D = nominal outside diameter of the pipe, in.

t = nominal wall thickness of the pipe, in. Additional wall thickness required for concurrent external loads shall not be included in the calculations.

4.2 COMPUTATION OF *P'*

(a) For Values of A Less Than or Equal to 4.0. A and d/t determine a unique point on Fig. 4-1 corresponding to an acceptable pressure level P'. P' is obtained by interpolation between the curves for P, $0.95P$, $0.90P$, $0.85P$, $0.80P$, $0.75P$, $0.70P$, $0.65P$, $0.60P$.

d = measured maximum depth of corroded area, in.

P' = the safe maximum pressure for the corroded area. Curves for various values of P' are given in Fig. 4-1 per

$$P' = 1.1P\left[\frac{1 - \frac{2}{3}\left(\frac{d}{t}\right)}{1 - \frac{2}{3}\left(\frac{d}{t\sqrt{A^2 + 1}}\right)}\right]$$

except that P' may not exceed P.

P = the greater of either the established MAOP or

$$P = 2StFT/D$$

where

S = specified minimum yield strength (SMYS), psi

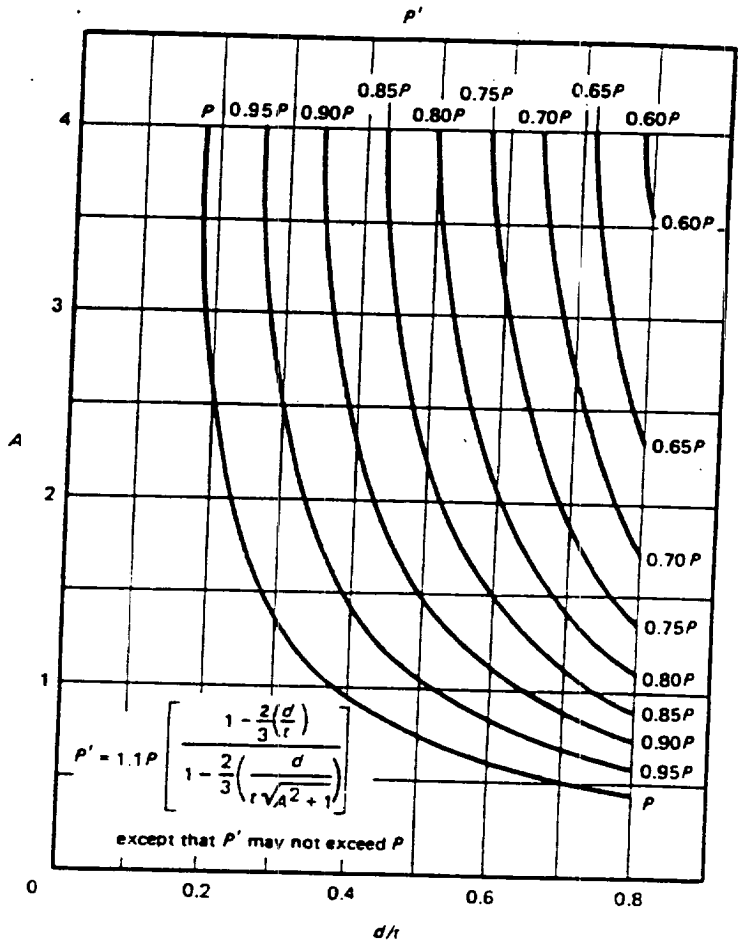

FIG. 4-1 CURVE FOR OBTAINING P' AS A FUNCTION OF d/t FOR VALUES OF A LESS THAN OR EQUAL TO 4.0

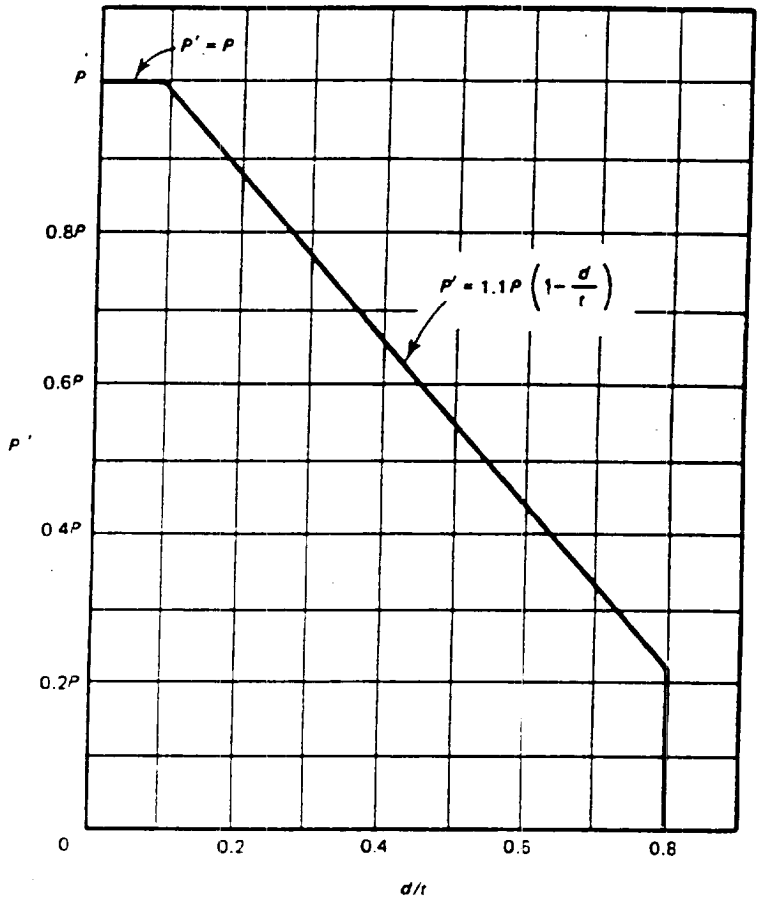

FIG. 4-2 P' AS A FUNCTION OF d/t FOR VALUES OF A GREATER THAN 4.0

F = appropriate design factor from ASME B31.4, ASME B31.8, or ASME B31.11

T = temperature derating factor from the appropriate B31 Code (if none listed, $T = 1$)

D = nominal outside diameter of the pipe, in.

t = nominal wall thickness of the pipe, in. Additional wall thickness required for concurrent external loads shall not be included in the calculations.

(b) For Values of A Greater Than 4.0

P' = the safe maximum pressure for the corroded area. Curves for various values of P' are given in Fig. 4-2 per

$$P' = 1.1P\left[1 - \frac{d}{t}\right]$$

except that P' may not exceed P.

4.3 MAOP AND P'

If the established MAOP is equal to or less than P', the corroded region may be used for service at that MAOP. If it is greater than P', then a lower MAOP should be established not to exceed P', or the corroded region should be repaired or replaced.

APPENDIX A
BASIC Computer Program, CRVL.BAS, for Determining Allowable Length *L* (Part 2) or Alternative Maximum Allowable Operating Pressure (Part 4)

Enter program and input as indicated. The examples should be used to verify correct entry of the program.

PROGRAM LISTING FOR CRVL.BAS BY R.L.SEIFERT

```
10 'PROGRAM WRITTEN BY R.L.SEIFERT, TENNESSEE GAS PIPELINE COMPANY,IN MICROSOFT
BASIC AND OPERABLE ON VARIOUS PERSONAL COMPUTERS, FEBRUARY 6, 1982, MODIFIED SEP
TEMBER 1984.
20 'EVALUATE EXTERNALLY CORRODED HIGH PRESSURE GAS PIPING TO DETERMINE THE MAXIM
UM PRESSURE THAT IT CAN SAFELY CONTAIN.
25 'THIS SYSTEM WAS DEVELOPED AT BATTELLE MEMORIAL INSTITUTE, COLUMBUS OHIO.
26 '***** PLEASE NOTE, THAT IF THE CORRODED SURFACE AREA EXTENDS ONTO OR ACROSS
A WELD, THEN THIS METHOD IS NOT VALID.  THE CORROSION MUST THEN BE EVALUATED BY
COMPANY-DESIGNATED SPECIALISTS.*****
30 'COMPUTER WILL DISPLAY AN "ILLEGAL FUNCTION ERROR" IF MAOP IS SET HIGHER THAN
 1.1 X P, BECAUSE AN ATTEMPT TO FIND THE SQUARE ROOT OF A NEGATIVE NUMBER WILL R
ESULT.  IN PRACTICE, THE MAOP WOULD NEVER BE SET THAT HIGH.
40 ' IF MAOP IS SET SLIGHTLY BELOW 1.1 X P, AND CORROSION DEPTH IS ALMOST 10% OF
 WALL THICKNESS, COMPUTER MAY CALL FOR A REDUCTION OF PRESSURE, BUT IT WILL ALSO
 STATE THAT THERE IS NO RESTRICTION OF OPERATION DUE TO d < .1t.
50 'MAOP IS NEVER SET THAT HIGH IN PRACTICE, SO THIS SHOULD BE NO PROBLEM.  THE
10% ALLOWABLE DEPTH WITH NO OPERATING RESTRICTIONS SHOULD APPLY.
60 'IF DEPTH OR LENGTH ARE SET TO ZERO, A RESPECTIVE SAFE LENGTH OR SAFE DEPTH W
ILL BE DETERMINED, EVEN THOUGH THAT IS AN IMPOSSIBILITY.  REGARD THE ZEROS AS IN
FINITESIMALS RATHER THAN ZEROS. (0 = .000001, FOR EXAMPLE)
70 'IF CORROSION DEPTH (d) IS ENTERED >1.5 X WALL THICKNESS (t), THEN THE EXPRES
SION (2/3 X (t/d) WILL BE =>1.  THIS WILL CAUSE A "DIVISION BY ZERO" ERROR IN TH
E CALCULATIONS.  DEPTH OF CORROSION CAN NEVER BE > WALL THICKNESS ANYWAY..
72 SCREEN 0,0,0:WIDTH 80:COLOR 14,1,0
75 DEFDBL A-Z
80 CLS:INPUT"MAXIMUM ALLOWABLE PRESSURE (MAOP) #/Sq.In.                    ";M
90 INPUT"ENTER OUTSIDE DIAMETER OF PIPE (D) Inches                        ";D
100 INPUT"ENTER PIPE WALL THICKNESS (t) Inch(es)                          ";T
110 INPUT"ENTER STRENGTH OF STEEL (SMYS) Lbs/sq.in.                       ";S
120 INPUT"ENTER DESIGN FACTOR (F) (.72,.60,.50,.40)                       ";F
130 INPUT"ENTER MAXIMUM CORROSION DEPTH (d)  Inch                         ";DE
140 INPUT"MAX.LONGITDNAL.LGTH OF CORRODED AREA (L) Inches                 ";L
150 PRINT:IF DE>.8*T THEN INPUT"DEPTH OF CORROSION EXCEEDS 80% OF PIPEWALL. PIPE
 MUST BE REPLACED.                    PRESS <ENTER> FOR FURTHER EVALUATION.";EN
160 IF DE=<.1*T THEN INPUT"CORROSION DEPTH IS LESS THAN 10% OF PIPE WALL. NO RES
TRICTIONS ON OPERATION.     PRESS <ENTER> FOR FURTHER EVALUATION.";EN
170 P=INT((2*S*T*F/D)+.5):A=(.893*L)/(D*T)^.5:A=(INT(1000*A))*.001
180 IF A<=4 THEN PS=INT(1.1*P*((1-((2*DE)/(3*T)))/(1-((2/3)*(DE/(T*(A^2+1)^.5)))
))+.5)
190 IF A>4 THEN PS=INT(1.1*P*(1-(DE/T))+.5)
195 IF PS>P THEN PS=P
200 CLS:PRINT"                                  -- INPUTTED DATA --"
210 PRINT"PIPE DIAMETER (D)="D"In.";TAB(30)"DESIGN FACTOR(F)="F
220 PRINT"WALL THICKNESS(t) ="T"In.";TAB(30)"MAX.COR.DPTH(d) ="DE"In.
230 PRINT"SMYS     ="S"PSI";TAB(30)"MAX.COR.LGTH(L) ="L"In.
240 PRINT"                                MAOP  ="M"PSI
250 PRINT"                                -- CALCULATED DATA --"
260 PRINT"                        INTERMEDIATE FACTOR (A)= ";:PRINT USING "##.###";(INT(10
00*A))*.001
270 PRINT"DESIGN PRESS.(P)="P"PSI";TAB(30)"SAFE PRESS.(P') ="PS"PSI"
```

** LISTING CONTINUES **

PROGRAM LISTING FOR CRVL.BAS BY R.L.SEIFERT - CONTINUED

```
280 IF DE>.8*T THEN PRINT"REPAIR OR REPLACE PIPE BECAUSE CORROSION DEPTH EXC
EEDS .8t."
290 IF PS=>M THEN PRINT"PIPE MAY BE OPERATED SAFELY AT MAOP,"M"PSI"
300 IF M>P THEN PRINT"MAOP EXCEEDS DESIGN PRESSURE (P). VERIFY THAT THIS VAR
IANCE IS VALID."
310 IF M>PS THEN PRINT"REDUCE OPERATING PRESSURE SO IT WILL NOT EXCEED"PS"PS
I, SO THAT PIPE":PRINT"WILL OPERATE LEGALLY AND SAFELY."
330 IF A=<4 THEN DP=((M-(1.1*P))*((3*T)*((A^2+1)^.5)))/(2*(M-((1.1*P)*((A^2+
1)^.5))))):DP=(INT(1000*DP))*.001
340 IF DP>.8*T THEN DP=.8*T
350 IF A=<4 THEN PRINT"WITH CORR.LNGTH."L"In., MAX. DEPTH IS "::PRINT USING
"#.####":(INT((1000*DP)+.5))*.001::PRINT" Inch.  A = "::PRINT USING "##.###"
:(INT((A*1000)+.5))*.001
360 IF A>4 THEN DP=((M/(1.1*P))-1)*(-T)
370 IF DP>.8*T THEN DP=.8*T
380 IF A>4 THEN PRINT"WITH CORR.LNGTH."L"In., MAX.DEPTH IS "::PRINT USING "#
.####":(INT((1000*DP)+.5))*.001::PRINT" Inch.  A = "::PRINT USING"###.###":(
INT((A*1000)+.5))*.001
390 AP=5:PS=INT(1.1*P*(1-(DE/T))+.5):IF PS>P THEN PS=P
400 IF M>PS THEN 420
410 PRINT"WITH CORR.DEPTH"DE"In., MAX. LENGTH IS INFINITY.  A = "::PRINT USI
NG "###.###":AP: GOSUB 530:GOTO 470
420 J=(2*DE)/(3*T):AP=(((J/(1-(((1.1*P)*(1-J))/M)))^2)-1)^.5:AP=INT((1000*AP
)+.5)*.001:PS=INT(1.1*P*((1-J)/(1-((2/3)*(DE/(T*AP^2+1)^.5))))+.5):LP=INT((1
000*((D*T)^.5)*1.12*AP))*.001:IF PS>P THEN PS=P
430 IF PS>M OR AP>4 THEN 450
440 PRINT"WITH CORR.DEPTH"DE"In., MAX. LENGTH IS "::PRINT USING "###.###":IN
T(1000*((D*T)^.5)*1.12*AP)*.001::PRINT" In. A = "::PRINT USING"###.###":(INT
(AP*1000))*.001:GOSUB 530:GOTO 470
450 AP=4:PS=1.1*P*((1-((2*DE)/(3*T))))/(1-((2/3)*(DE/(T*(AP^2+1)^.5)))))):PS=I
NT(PS+.5):IF PS>P THEN PS=P
460 GOTO 440
470 PRINT:INPUT"PRESS <1> FOR MORE CORROSION EVALUATIONS ON SAME PIPE.
                    OR <2> FOR CORROSION EVALUATIONS ON DIFFERENT PIPE.":
EN:IF EN>1 THEN 20
480 CLS:PRINT"MAXIMUM ALLOWABLE OPERATING PRESSURE (MAOP) =  "M"#/sq.in.
490 PRINT"OUTSIDE DIAMETER OF PIPE (D) =                    ":D"Inches
500 PRINT"PIPE WALL THICKNESS (t) =                         ":T"Inch
510 PRINT"SPECIFIED MIN.YIELD STRENGTH OF PIPE (SMYS) =     "S"#/sq.in.
520 PRINT"DESIGN FACTOR (F) =                               ":F:GOTO 130
530 IF DE>.8*T THEN PRINT"*** BUT"DE"Inch EXCEEDS ALLOWABLE CORROSION DEPTH
***"
540 RETURN
```

END OF PROGRAM LISTING

FOLLOWING ARE SOME EXAMPLES OF THE USE OF THE COMPUTER PROGRAM 'CRVL.BAS' BY R.L.SEIFERT, TENNESSEE GAS PIPELINE COMPANY.

THE PROGRAM PROMPTS THE USER ONE LINE AT A TIME FOR INPUT AS FOLLOWS:

EXAMPLE #1

```
MAXIMUM ALLOWABLE PRESSURE (MAOP) #/Sq.In.                  ? 910
ENTER OUTSIDE DIAMETER OF PIPE (D) Inches                   ? 30
ENTER PIPE WALL THICKNESS (t) Inch(es)                      ? .438
ENTER STRENGTH OF STEEL (SMYS) Lbs/sq.in.                   ? 52000
ENTER DESIGN FACTOR (F) (.72,.60,.50,.40)                   ? .72
ENTER MAXIMUM CORROSION DEPTH (d)  Inch                     ? .1
MAX.LONGITDNAL.LGTH OF CORRODED AREA (L) Inches             ? 7.5
```

AFTER THE USER HAS INPUTTED THE 7.5 IN THE LAST LINE (ABOVE), HE PRESSES THE <ENTER> KEY AND THE FOLLOWING READOUT RESULTS:

```
                    -- INPUTTED DATA --
PIPE DIAMETER (D)= 30 In.      DESIGN FACTOR(F)= .72
WALL THICKNESS(t) = .438 In.   MAX.COR.DPTH(d) = .1 In.
SMYS     = 52000 PSI           MAX.COR.LGTH(L) = 7.5 In.
                    MAOP  = 910 PSI
                    -- CALCULATED DATA --
                INTERMEDIATE FACTOR (A)=  1.847
DESIGN PRESS.(P)= 1093 PSI    SAFE PRESS.(P') = 1093 PSI
PIPE MAY BE OPERATED SAFELY AT MAOP, 910 PSI
WITH CORR.LNGTH. 7.5 In., MAX. DEPTH IS 0.2490 Inch.  A =  1.847
WITH CORR.DEPTH .1 In., MAX. LENGTH IS INFINITY.  A =   5.000

PRESS <1> FOR MORE CORROSION EVALUATIONS ON SAME PIPE,
   OR <2> FOR CORROSION EVALUATIONS ON DIFFERENT PIPE.?
```

FOLLOWING ARE MORE EXAMPLES OF PRINTOUTS OF VARIOUS CORROSION EVALUATIONS, SEVERAL OF WHICH REQUIRE REDUCTION OF PRESSURE, OR REPAIR, TO ALLOW RESUMPTION OF PIPELINE OPERATION.

EXAMPLE #2

```
                    -- INPUTTED DATA --
PIPE DIAMETER (D)= 20 In.      DESIGN FACTOR(F)= .5
WALL THICKNESS(t) = .25 In.    MAX.COR.DPTH(d) = .18 In.
SMYS     = 35000 PSI           MAX.COR.LGTH(L) = 10 In.
                    MAOP  = 400 PSI
                    -- CALCULATED DATA --
                INTERMEDIATE FACTOR (A)=  3.993
DESIGN PRESS.(P)= 438 PSI     SAFE PRESS.(P') = 284 PSI
REDUCE OPERATING PRESSURE SO IT WILL NOT EXCEED 284 PSI. SO THAT PIPE
WILL OPERATE LEGALLY AND SAFELY.
WITH CORR.LNGTH. 10 In., MAX. DEPTH IS 0.0790 Inch.  A =  3.993
WITH CORR.DEPTH .18 In., MAX. LENGTH IS   2.018 In. A =  0.806

PRESS <1> FOR MORE CORROSION EVALUATIONS ON SAME PIPE,
   OR <2> FOR CORROSION EVALUATIONS ON DIFFERENT PIPE.?
```

```
EXAMPLE #3              -- INPUTTED DATA --
PIPE DIAMETER (D)= 24 In.     DESIGN FACTOR(F)= .72
WALL THICKNESS(t) = .432 In. MAX.COR.DPTH(d) = .13 In.
SMYS     = 52000 PSI          MAX.COR.LGTH(L) = 30 In.
                        MAOP   = 910 PSI
                      -- CALCULATED DATA --
                INTERMEDIATE FACTOR (A)=  8.320
DESIGN PRESS.(P)= 1348 PSI    SAFE PRESS.(P') = 1037 PSI
PIPE MAY BE OPERATED SAFELY AT MAOP, 910 PSI
WITH CORR.LNGTH. 30 In., MAX.DEPTH IS 0.167 Inch.  A =   8.320
WITH CORR.DEPTH .13 In., MAX. LENGTH IS INFINITY.  A =   5.000

PRESS <1> FOR MORE CORROSION EVALUATIONS ON SAME PIPE,
   OR <2> FOR CORROSION EVALUATIONS ON DIFFERENT PIPE.?

EXAMPLE #4              -- INPUTTED DATA --
PIPE DIAMETER (D)= 24 In.     DESIGN FACTOR(F)= .72
WALL THICKNESS(t) = .432 In. MAX.COR.DPTH(d) = .3 In.
SMYS     = 52000 PSI          MAX.COR.LGTH(L) = 30 In.
                        MAOP   = 910 PSI
                      -- CALCULATED DATA --
                INTERMEDIATE FACTOR (A)=  8.320
DESIGN PRESS.(P)= 1348 PSI    SAFE PRESS.(P') = 453 PSI
REDUCE OPERATING PRESSURE SO IT WILL NOT EXCEED 453
PSI,          SO THAT PIPE WILL OPERATE LEGALLY AND SAFELY.
WITH CORR.LNGTH. 30 In., MAX.DEPTH IS 0.167 Inch.  A =   8.320
WITH CORR.DEPTH .3 In., MAX. LENGTH IS  12.867 In. A =   3.568

PRESS <1> FOR MORE CORROSION EVALUATIONS ON SAME PIPE,
   OR <2> FOR CORROSION EVALUATIONS ON DIFFERENT PIPE.?


EXAMPLE #5

                        -- INPUTTED DATA --
PIPE DIAMETER (D)= 24 In.     DESIGN FACTOR(F)= .72
WALL THICKNESS(t) = .281 In. MAX.COR.DPTH(d) = .08 In.
SMYS     = 52000 PSI          MAX.COR.LGTH(L) = 15 In.
                        MAOP   = 731 PSI
                      -- CALCULATED DATA --
                INTERMEDIATE FACTOR (A)=  5.158
DESIGN PRESS.(P)= 877 PSI     SAFE PRESS.(P') = 690 PSI
REDUCE OPERATING PRESSURE SO IT WILL NOT EXCEED 690
PSI,          SO THAT PIPE WILL OPERATE LEGALLY AND SAFELY.
WITH CORR.LNGTH. 15 In., MAX.DEPTH IS 0.068 Inch.  A =   5.158
WITH CORR.DEPTH .08 In., MAX. LENGTH IS  11.634 In. A =   4.000

PRESS <1> FOR MORE CORROSION EVALUATIONS ON SAME PIPE,
   OR <2> FOR CORROSION EVALUATIONS ON DIFFERENT PIPE.?
```

```
EXAMPLE #6
MAXIMUM ALLOWABLE PRESSURE (MAOP) #/Sq.In.                  ? 1000
ENTER OUTSIDE DIAMETER OF PIPE (D) Inches                   ? 36
ENTER PIPE WALL THICKNESS (t) Inch(es)                      ? .5
ENTER STRENGTH OF STEEL (SMYS) Lbs/sq.in.                   ? 52000
ENTER DESIGN FACTOR (F) (.72,.60,.50,.40)                   ? .72
ENTER MAXIMUM CORROSION DEPTH (d)  Inch                     ? .41
MAX.LONGITDNAL.LGTH OF CORRODED AREA (L) Inches             ? 100

DEPTH OF CORROSION EXCEEDS 80% OF PIPEWALL. PIPE MUST BE REPLACED.
PRESS <ENTER> FOR FURTHER EVALUATION.?

                    -- INPUTTED DATA --
PIPE DIAMETER (D)= 36 In.     DESIGN FACTOR(F)= .72
WALL THICKNESS(t) = .5 In.    MAX.COR.DPTH(d) = .41 In.
SMYS     = 52000 PSI          MAX.COR.LGTH(L) = 100 In.
                    MAOP  = 1000 PSI
                    -- CALCULATED DATA --
                INTERMEDIATE FACTOR (A)= 21.048
DESIGN PRESS.(P)= 1040 PSI    SAFE PRESS.(P') = 206 PSI
REPAIR OR REPLACE PIPE BECAUSE CORROSION DEPTH EXCEEDS .8t.
REDUCE OPERATING PRESSURE SO IT WILL NOT EXCEED 206 PSI, SO THAT PIPE
WILL OPERATE LEGALLY AND SAFELY.
WITH CORR.LNGTH. 100 In., MAX.DEPTH IS 0.0630 Inch.  A =  21.048
WITH CORR.DEPTH .41 In., MAX. LENGTH IS   2.356 In. A =   0.538
!!! BUT .41 Inch EXCEEDS ALLOWABLE CORROSION DEPTH !!!

PRESS <1> FOR MORE CORROSION EVALUATIONS ON SAME PIPE,
   OR <2> FOR CORROSION EVALUATIONS ON DIFFERENT PIPE.?

EXAMPLE #7
MAXIMUM ALLOWABLE PRESSURE (MAOP) #/Sq.In.                  ? 877
ENTER OUTSIDE DIAMETER OF PIPE (D) Inches                   ? 12.625
ENTER PIPE WALL THICKNESS (t) Inch(es)                      ? .5
ENTER STRENGTH OF STEEL (SMYS) Lbs/sq.in.                   ? 35000
ENTER DESIGN FACTOR (F) (.72,.60,.50,.40)                   ? .4
ENTER MAXIMUM CORROSION DEPTH (d)  Inch                     ? .035
MAX.LONGITDNAL.LGTH OF CORRODED AREA (L) Inches             ? 3

CORROSION DEPTH IS LESS THAN 10% OF PIPE WALL. NO RESTRICTIONS ON OPERATION.
PRESS <ENTER> FOR FURTHER EVALUATION.?

                    -- INPUTTED DATA --
PIPE DIAMETER (D)= 12.625 In.DESIGN FACTOR(F)= .4
WALL THICKNESS(t) = .5 In.    MAX.COR.DPTH(d) = .035 In.
SMYS     = 35000 PSI          MAX.COR.LGTH(L) = 3 In.
                    MAOP  = 877 PSI
                    -- CALCULATED DATA --
                INTERMEDIATE FACTOR (A)=  1.066
DESIGN PRESS.(P)= 1109 PSI    SAFE PRESS.(P') = 1109 PSI
PIPE MAY BE OPERATED SAFELY AT MAOP, 877 PSI
WITH CORR.LNGTH. 3 In., MAX. DEPTH IS 0.4000 Inch.  A =  1.066
WITH CORR.DEPTH .035 In., MAX. LENGTH IS INFINITY.  A =  5.000

PRESS <1> FOR MORE CORROSION EVALUATIONS ON SAME PIPE,
   OR <2> FOR CORROSION EVALUATIONS ON DIFFERENT PIPE.?
```

```
EXAMPLE #8
                    -- INPUTTED DATA --
PIPE DIAMETER (D)= 24 In.     DESIGN FACTOR(F)= .5
WALL THICKNESS(t) = .5 In.    MAX.COR.DPTH(d) = .125 In.
SMYS     = 42000 PSI          MAX.COR.LGTH(L) = 12 In.
                    MAOP  = 790 PSI
                    -- CALCULATED DATA --
              INTERMEDIATE FACTOR (A)=  3.093
DESIGN PRESS.(P)= 875 PSI     SAFE PRESS.(P') = 845 PSI
PIPE MAY BE OPERATED SAFELY AT MAOP, 790 PSI
WITH CORR.LNGTH. 12 In., MAX. DEPTH IS 0.179 Inch.  A =  3.093
WITH CORR.DEPTH .125 In., MAX. LENGTH IS  15.519 In. A =   4.000

PRESS <1> FOR MORE CORROSION EVALUATIONS ON SAME PIPE,
   OR <2> FOR CORROSION EVALUATIONS ON DIFFERENT PIPE.?


THIS IS A TEST FOR THE ABOVE ALLOWABLE DEPTH AND LENGTH VALUES.
TEST #1. ENTER DEPTH OF .179 AND LENGTH OF 12.

                    -- INPUTTED DATA --
PIPE DIAMETER (D)= 24 In.     DESIGN FACTOR(F)= .5
WALL THICKNESS(t) = .5 In.    MAX.COR.DPTH(d) = .179 In.
SMYS     = 42000 PSI          MAX.COR.LGTH(L) = 12 In.
                    MAOP  = 790 PSI
                    -- CALCULATED DATA --
              INTERMEDIATE FACTOR (A)=  3.093
DESIGN PRESS.(P)= 875 PSI     SAFE PRESS.(P') = 791 PSI
PIPE MAY BE OPERATED SAFELY AT MAOP, 790 PSI
WITH CORR.LNGTH. 12 In., MAX. DEPTH IS 0.179 Inch.  A =  3.093
WITH CORR.DEPTH .179 In., MAX. LENGTH IS  12.182 In. A =   3.140

PRESS <1> FOR MORE CORROSION EVALUATIONS ON SAME PIPE,
   OR <2> FOR CORROSION EVALUATIONS ON DIFFERENT PIPE.?


TEST #1A.  ENTER DEPTH .179 AND LENGTH 12.182.

                    -- INPUTTED DATA --
PIPE DIAMETER (D)= 24 In.     DESIGN FACTOR(F)= .5
WALL THICKNESS(t) = .5 In.    MAX.COR.DPTH(d) = .179 In.
SMYS     = 42000 PSI          MAX.COR.LGTH(L) = 12.182 In.
                    MAOP  = 790 PSI
                    -- CALCULATED DATA --
              INTERMEDIATE FACTOR (A)=  3.140
DESIGN PRESS.(P)= 875 PSI     SAFE PRESS.(P') = 790 PSI
PIPE MAY BE OPERATED SAFELY AT MAOP, 790 PSI
WITH CORR.LNGTH. 12.182 In., MAX. DEPTH IS 0.178 Inch.  A =  3.140
WITH CORR.DEPTH .179 In., MAX. LENGTH IS  12.182 In. A =   3.140

PRESS <1> FOR MORE CORROSION EVALUATIONS ON SAME PIPE,
   OR <2> FOR CORROSION EVALUATIONS ON DIFFERENT PIPE.?
```

```
TEST #1B.  INCREASING DEPTH BY A THOUSANDTH SHOULD CAUSE UNSAFE OPERATION.
           ENTER DEPTH OF .180 AND LENGTH OF 12.182
                        — INPUTTED DATA —
PIPE DIAMETER (D)= 24 In.     DESIGN FACTOR(F)= .5
WALL THICKNESS(t) = .5 In.    MAX.COR.DPTH(d) = .18 In.
SMYS     = 42000 PSI          MAX.COR.LGTH(L) = 12.182 In.
                        MAOP  = 790 PSI
                        — CALCULATED DATA —
                  INTERMEDIATE FACTOR (A)=  3.140
DESIGN PRESS.(P)= 875 PSI     SAFE PRESS.(P') = 789 PSI
REDUCE OPERATING PRESSURE SO IT WILL NOT EXCEED 789
PSI,          SO THAT PIPE WILL OPERATE LEGALLY AND SAFELY.
WITH CORR.LNGTH. 12.182 In., MAX. DEPTH IS 0.178 Inch.  A =  3.140
WITH CORR.DEPTH .18 In., MAX. LENGTH IS  11.961 In. A =   3.083

PRESS <1> FOR MORE CORROSION EVALUATIONS ON SAME PIPE,
   OR <2> FOR CORROSION EVALUATIONS ON DIFFERENT PIPE.?

TEST #2.  INCREASING LENGTH BY A FEW HUNDREDTHS SHOULD CAUSE UNSAFE OPERATION.
          FROM THE SAFE CONDITION OF TEST #1A, INCREASE THE LENGTH FROM 12.182
          IN. TO 12.297 IN.

                        — INPUTTED DATA —
PIPE DIAMETER (D)= 24 In.     DESIGN FACTOR(F)= .5
WALL THICKNESS(t) = .5 In.    MAX.COR.DPTH(d) = .179 In.
SMYS     = 42000 PSI          MAX.COR.LGTH(L) = 12.297 In.
                        MAOP  = 790 PSI
                        — CALCULATED DATA —
                  INTERMEDIATE FACTOR (A)=  3.170
DESIGN PRESS.(P)= 875 PSI     SAFE PRESS.(P') = 789 PSI
REDUCE OPERATING PRESSURE SO IT WILL NOT EXCEED 789
PSI,          SO THAT PIPE WILL OPERATE LEGALLY AND SAFELY.
WITH CORR.LNGTH. 12.297 In., MAX. DEPTH IS 0.1780 Inch.  A =  3.170
WITH CORR.DEPTH .179 In., MAX. LENGTH IS  12.182 In. A =   3.140

PRESS <1> FOR MORE CORROSION EVALUATIONS ON SAME PIPE,
   OR <2> FOR CORROSION EVALUATIONS ON DIFFERENT PIPE.?

                    ***** END OF EXAMPLES *****
```

REFERENCES:

1. THE PROGRAMMABLE ELECTRONIC CALCULATOR IN UNDERGROUND CORROSION RELATED ACTIVITY. Part 2,"Determination of Safe Operating Pressure for a Corroded High Pressure Gas Pipeline" by R.L.Seifert. Materials Performance, Vol.19, No. 7, (1980) July.

2. Kiefner,J.F.,Duffy,A.R. Columbus Laboratories, Battelle Memorial Institute. SUMMARY OF RESEARCH TO DETERMINE THE STRENGTH OF CORRODED AREAS IN PIPE. (1971) 20 July

3. Marvin, C.W.,DETERMINING THE STRENGTH OF CORRODED PIPE. Materials Protection and Performance, Vol.11,No.11,p.34 (1972) November.

4. ASME GUIDE FOR GAS TRANSMISSION AND DISTRIBUTION PIPING SYSTEMS - 1976. Addendum No. 4, February, 1977 (Guide Material for Federal Standard 192.485), and Appendices G-6, G-7, and G-8.

=== END ===

APPENDIX B
BASIC Computer Program, CRLGTHU.BAS, Used in Generating Tables Like Those Which Are Printed in Part 3

Following is the BASIC computer program CRLGTHU.BAS, whose forerunner, CRLGTH.BAS, was used for generating some of the tables in Part 3 with the same computer equipment that is used in Appendix A. This upgraded version, CRLGTHU.BAS, does not require the BASIC program to be modified with each use as did the former version, CRLGTH.BAS, which was included in earlier printing(s) of this manual.

Enter the BASIC program which is listed on the following pages into the computer, and check its operation by running it and entering the following data as prompted: pipe diameter = 20; shallowest pit depth = .03; wall thicknesses as follows: .406, .438, .469, .5, .562, .625, .688, .750, .812, and .875. The printout should duplicate the example which is printed at the end of this Appendix. (Printer commands in the program are for the Epson FX series and compatible printers, and could result in strange formats on other printers.)

CRLGTHU.BAS

A computer program which provides the same type of information and printout as CRLGTH.BAS, except that the program does not need to be modified with each usage, and the user is asked for pipe diameter, the minimum pit depth to begin with, and up to 10 wall thicknesses. The program prompts the user for this information, in increasing order of thicknesses. (A thickness that is out of order will prompt a request to re-enter all of the thicknesses.)

```
10 'CRLGTHU.BAS
20 'THIS PROGRAM IS A UNIVERSAL PROGRAM, AND ALLOWS ENTRY OF ANY DIAMETER OF PIPE
 AND UP TO 10 WALL THICKNESSES TO EXAMINE FOR ALLOWABLE CORROSION LENGTHS.
30 CLS:'PROGRAM CRLGTHU.BAS BY R.L.SEIFERT TO LIST ALLOWED LENGTHS OF CORROSION
 FOR GIVEN DEPTHS OF CORROSION FOR SPECIFIED DIAMETER AND WALL THICKNESSES.FOR
 IBM-PC AND EPSON FX SERIES PRINTERS OR COMPATIBLE EQUIPMENT.
40 CLEAR 5000:DIM T(17):WIDTH "LPT1:",255
50 LPRINT CHR$(27);"@";:COLOR 7,1,0:CLS
60 PRINT TAB(30)"CRLGTHU.BAS"
70 PRINT TAB(26)"Revision of 2/17/89"
80 PRINT TAB(34)"by"
90 PRINT TAB(24)"Richard L. Seifert, P.E."
100 PRINT TAB(16)"Consultant for Pipeline Corrosion Control"
110 PRINT TAB(34)"and"
120 PRINT TAB(16)"Use and Application of Personal Computers"
130 PRINT TAB(25)"15602 Valley Bend Drive"
140 PRINT TAB(26)"Houston, Texas 77068"
150 PRINT
160 PRINT TAB(10)"This program prints a list of allowed lengths of corroded areas"
170 PRINT TAB(5)"on underground pressure piping for given pit depths. It is a
 general- "
180 PRINT TAB(5)"ized, conservative listing of allowed lengths, and if any
 corrodec area "
190 PRINT TAB(5)"is 'condemned' by this listing, the corroced area should be
 examined
200 PRINT TAB(5)"further using Seifert's program CRVL.BAS. CRVL.BAS will examine
 the"
210 PRINT TAB(5)"corroded pipe using precise input parameters, and may allow the
 use of"
220 PRINT TAB(5)"the pipe, when this program, CRLGTHU.BAS, condemns it."
```

```
230 PRINT:PRINT TAB(22);:INPUT"Press <Enter> to proceed. ";EN
240 LPRINT CHR$(27);"@";:CLS:PRINT:INPUT"ADJUST PRINTER PAPER TO TOP OF FORM,
 TURN PRINTER ON, THEN PRESS <ENTER>";EN
250 INPUT"ENTER O.D. OF PIPE TO BE EXAMINED (EXAMPLE: 20)";D
260 INPUT"SHALLOWEST CORROSION DEPTH IN RANGE OF DEPTHS (E.G. .010)";DE:DE1=DE
270 J=0
280 PRINT"BEGIN ENTERING PIPE WALL THICKNESSES IN ASCENDING ORDER, FOR
 CALCULATIONS AND FOR COLUMN HEADINGS. MAXIMUM NUMBER OF ENTRIES = 10."
290 IF J=10 THEN J1=10:INPUT"MAXIMUM NUMBER OF THICKNESSES HAVE BEEN
 ENTERED. PRESS <ENTER> TO PROCEED.";EN:GOTO 330
300 J=J+1:PRINT"COLUMN "J". LAST ENTRY WAS "T(J-1):INPUT"ENTER WALL THICKNESS
 FOR THIS COLUMN. (-1 TO END ENTRIES) ";T(J)
310 IF T(J)=-1 THEN J=J-1:J1=J:GOTO 330
320 GOTO 290
330 FOR J=1 TO J1
340 IF T(J)<T(J-1) THEN BEEP:CLS:FOR Q=1 TO J1-1:PRINT T(Q)"  ";:NEXT Q:PRINT
 T(J1):ELSE 360
350 PRINT:PRINT"Wall thicknesses are all not in ascending order. You must re-enter
 wall thicknesses. Press <Enter> for re-entry of wall
 thicknesses. ":INPUT;EN:CLS:GOTO 270
360 NEXT J
370 LPRINT CHR$(27)"O";:FOR N=1 TO 4:LPRINT:NEXT N:LPRINT CHR$(27)"U";CHR$(1);
380 LPRINT CHR$(27)"G";:LPRINT CHR$(18);TAB(17)"VALUES OF L FOR PIPE WITH
 O.D. OF"D"INCHES"
390 LPRINT STRING$(75,"*")
400 LPRINT CHR$(15);
410 LPRINT"Pit Depth";TAB(60)"Wall Thickness (t), Inches";TAB(128)"|"
420 J2=19:LPRINT"d(Inch) ";:LPRINT USING"##.###";T(1);:FOR J=2 TO J1:LPRINT
 TAB(J2) USING"##.###";T(J);:J2=J2+12:NEXT J:LPRINT TAB(128)"|"
430 LPRINT STRING$(127,"=");"|"
440 FOR N=1 TO 150
450 TAB=0:IF INT(N/5)=N/5 THEN TAB=1:TAB2=1:LPRINT
 CHR$(27)CHR$(45)CHR$(1);: 'START UNDERLINE
460 LPRINT USING"#.###";(INT((DE*1000)+.5))*.001;:LPRINT"|";:TAB=TAB+19:IF
 DE=DE1 AND DE/T(1)<.1 THEN TAB=TAB-1
470 FOR J=1 TO J1
480 T=T(J)
490 IF DE/T<.1 OR DE/T>.8 THEN L$=" ":GOTO 620
500 IF 100*(DE/T)=>10 AND 100*(DE/T)=<17.5 THEN B=4:GOTO 520
510 B=SQR((((DE/T)/((1.1*(DE/T))-.15))^2)-1)
520 L=1.12*B*SQR(D*T)
530 L2=L-INT(L):L3=INT((L2/.0625)+.5):L4$=STR$(L3)+"/16":L=INT(L)
540 IF L3=0 THEN 560
550 IF 16/L3=2 THEN L4$=" 1/2":GOTO 600
```

```
560 IF L3=0 THEN L4$=" ":GOTO 600
570 IF L3=16 THEN L=L+1:L4$=" ":GOTO 600
580 IF INT(L3/2)=L3/2 THEN L3=L3/2:L4$=STR$(L3)+"/8"
590 IF INT(L3/2)=L3/2 THEN L3=L3/2:L4$=STR$(L3)+"/4"
600 IF L=0 THEN L$="  "+L4$:ELSE L$=STR$(L)+L4$
610 IF LEN(STR$(L))=2 THEN LPRINT"  ";
620 GOTO 630
630 LPRINT L$;:IF DE=DE1 THEN 640: ELSE LPRINT TAB(TAB);:TAB=TAB+12:GOTO 650
640 LPRINT TAB(TAB-1);:TAB=TAB+12
650 NEXT J
660 IF DE=DE1 THEN LPRINT TAB(128)"":ELSE LPRINT TAB(128+TAB2)" "
670 LPRINT CHR$(27)CHR$(45)CHR$(0);:TAB2=0 'STOP UNDERLINE
680 IF DE>((T(J1)*.8)+.01) AND L$="  "THEN LPRINT:LPRINT:LPRINT:LPRINT
 CHR$(27)"2":LPRINT  CHR$(27)"U"CHR$(0);:LPRINT  CHR$(27)"H";:WIDTH
 "LPT1:",80:LPRINT CHR$(18);:GOTO 710
690 DE=DE+.01
700 NEXT N
710 FL=1:CLS:Y$="":PRINT:INPUT"Do you want to print another table of acceptable
 corrosion lengths (Y/N*)";Y$:IF Y$="n" OR Y$="N" OR Y$="" THEN END
720 CLEAR 5000:DIM T(17):WIDTH "LPT1:",255
730 LPRINT CHR$(27);"@";:COLOR 7,1,0:CLS:GOTO 240
```

VALUES OF L FOR PIPE WITH O.D. OF 20 INCHES

Pit Depth d(inch)	Wall Thickness (t), inches 0.406	0.438	0.469	0.500	0.562	0.625	0.688	0.750	0.812	0.875
0.030										
0.040										
0.050	12 3/4	13 1/4	13 3/4							
0.060	12 3/4	13 1/4	13 3/4	14 3/16	15					
0.070	12 3/4	13 1/4	13 3/4	14 3/16	15	15 13/16	16 5/8			
0.080	8 7/8	11 7/16	13 3/4	14 3/16	15	15 13/16	16 5/8	17 3/8		
0.090	6 13/16	8 5/16	10 3/16	12 13/16	15	15 13/16	16 5/8	17 3/8	18 1/16	18 3/4
0.100	5 11/16	6 11/16	7 15/16	9 1/2	14 1/8	15 13/16	16 5/8	17 3/8	18 1/16	18 3/4
0.110	4 7/8	5 11/16	6 5/8	7 11/16	10 5/8	15 1/2	16 5/8	17 3/8	18 1/16	18 3/4
0.120	4 5/16	5	5 3/4	6 9/16	8 11/16	11 3/4	16 5/8	17 3/8	18 1/16	18 3/4
0.130	3 15/16	4 1/2	5 1/16	5 3/4	7 7/16	9 11/16	12 15/16	17 3/8	18 1/16	18 3/4
0.140	3 9/16	4 1/16	4 5/8	5 3/16	6 9/16	8 5/16	10 11/16	14	18 1/16	18 3/4
0.150	3 5/16	3 3/4	4 3/16	4 3/4	5 7/8	7 5/16	9 3/16	11 5/8	15	18 3/4
0.160	3 1/16	3 1/2	3 7/8	4 3/8	5 3/8	6 5/8	8 1/8	10 1/16	12 9/16	16 1/16
0.170	2 7/8	3 1/4	3 5/8	4 1/16	4 15/16	6 1/16	7 5/16	8 7/8	10 7/8	13 1/2
0.180	2 11/16	3 1/16	3 7/16	3 13/16	4 5/8	5 9/16	6 11/16	8 1/16	9 11/16	11 3/4
0.190	2 9/16	2 7/8	3 3/16	3 9/16	4 5/16	5 3/16	6 3/16	7 3/8	8 3/4	10 7/16
0.200	2 7/16	2 3/4	3 1/16	3 3/8	4 1/16	4 7/8	5 3/4	6 13/16	8	9 7/16
0.210	2 5/16	2 5/8	2 7/8	3 3/16	3 7/8	4 9/16	5 7/16	6 3/8	7 7/16	8 11/16
0.220	2 3/16	2 1/2	2 3/4	3 1/16	3 5/8	4 5/16	5 1/8	5 15/16	6 15/16	8 1/6
0.230	2 1/8	2 3/8	2 5/8	2 7/8	3 1/2	4 1/8	4 13/16	5 5/8	6 1/2	7 1/2
0.240	2	2 1/4	2 1/2	2 3/4	3 5/16	3 15/16	4 5/8	5 5/16	6 1/8	7 1/16
0.250	1 15/16	2 3/16	2 7/16	2 11/16	3 3/16	3 3/4	4 3/8	5 1/16	5 13/16	6 11/16
0.260	1 7/8	2 1/16	2 5/16	2 9/16	3 1/16	3 5/8	4 3/16	4 13/16	5 9/16	6 5/16
0.270	1 3/4	2	2 1/4	2 7/16	2 15/16	3 7/16	4	4 5/8	5 5/16	6
0.280	1 11/16	1 15/16	2 1/8	2 3/8	2 13/16	3 5/16	3 7/8	4 7/16	5 1/16	5 3/4
0.290	1 5/8	1 7/8	2 1/16	2 1/4	2 3/4	3 3/16	3 3/4	4 1/4	4 7/8	5 1/2
0.300	1 9/16	1 3/4	2	2 3/16	2 5/8	3 1/8	3 5/8	4 1/8	4 11/16	5 5/16
0.310	1 1/2	1 11/16	1 15/16	2 1/8	2 9/16	3	3 1/2	4	4 1/2	5 1/8
0.320	1 7/16	1 5/8	1 7/8	2 1/16	2 7/16	2 7/8	3 3/8	3 7/8	4 3/8	4 15/16
0.330		1 5/8	1 13/16	2	2 3/8	2 13/16	3 1/4	3 3/4	4 3/16	4 3/4
0.340		1 9/16	1 3/4	1 15/16	2 5/16	2 3/4	3 1/8	3 5/8	4 1/16	4 5/8
0.350		1 1/2	1 11/16	1 7/8	2 1/4	2 5/8	3 1/16	3 1/2	3 15/16	4 7/16
0.360			1 5/8	1 13/16	2 3/16	2 9/16	3	3 3/8	3 13/16	4 5/16
0.370			1 9/16	1 3/4	2 1/8	2 1/2	2 7/8	3 5/16	3 3/4	4 3/16
0.380				1 11/16	2 1/16	2 7/16	2 13/16	3 3/16	3 5/8	4 1/16
0.390				1 5/8	2	2 3/8	2 3/4	3 1/8	3 1/2	3 15/16
0.400				1 9/16	1 15/16	2 5/16	2 11/16	3 1/16	3 7/16	3 7/8
0.410					1 7/8	2 1/4	2 9/16	2 15/16	3 3/8	3 3/4
0.420					1 13/16	2 3/16	2 1/2	2 7/8	3 1/4	3 11/16
0.430					1 3/4	2 1/8	2 7/16	2 13/16	3 3/16	3 9/16
0.440					1 3/4	2 1/16	2 3/8	2 3/4	3 1/8	3 1/2
0.450						2	2 3/8	2 11/16	3 1/16	3 7/16
0.460						1 15/16	2 5/16	2 5/8	3	3 5/16
0.470						1 15/16	2 1/4	2 9/16	2 7/8	3 1/4
0.480						1 7/8	2 3/16	2 1/2	2 13/16	3 3/16
0.490						1 13/16	2 1/8	2 7/16	2 3/4	3 1/8
0.500						1 3/4	2 1/16	2 3/8	2 3/4	3 1/16
0.510							2 1/16	2 3/8	2 11/16	3
0.520							2	2 5/16	2 5/8	2 15/16
0.530							1 15/16	2 1/4	2 9/16	2 7/8
0.540							1 15/16	2 3/16	2 1/2	2 13/16
0.550							1 7/8	2 3/16	2 7/16	2 3/4
0.560								2 1/8	2 3/8	2 11/16
0.570								2 1/16	2 3/8	2 11/16
0.580								2	2 5/16	2 5/8
0.590								2	2 1/4	2 9/16
0.600								1 15/16	2 1/4	2 1/2
0.610									2 3/16	2 7/16
0.620									2 1/8	2 7/16
0.630									2 1/8	2 3/8
0.640									2 1/16	2 5/16
0.650										2 5/16
0.660										2 1/4
0.670										2 3/16
0.680										2 3/16
0.690										2 1/8
0.700										2 1/8
0.710										
0.720										

ASME CODE FOR PRESSURE PIPING, B31

Power Piping B31.1-1989
Chemical Plant and Petroleum Refinery Piping B31.3-1990
Liquid Transportation Systems for Hydrocarbons,
Liquid Petroleum Gas, Anhydrous Ammonia,
and Alcohols B31.4-1989
Refrigeration Piping B31.5-1987
Gas Transmission and Distribution Piping Systems B31.8-1989
Building Services Piping B31.9-1988
Slurry Transportation Piping Systems B31.11-1989

Manual for Determining the Remaining Strength
of Corroded Pipelines: A Supplement
to ASME B31 Code for Pressure Piping B31G-1991

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THE CORROSION SOCIETY

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Standard
Recommended Practice

Control of External Corrosion on Underground or Submerged Metallic Piping Systems

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Foreword

This standard recommended practice presents procedures and practices for achieving effective control of external corrosion on buried or submerged metallic piping systems. These recommendations are also applicable to many other buried or submerged metallic structures. It is intended for use by corrosion control personnel concerned with the corrosion of buried or submerged piping systems, including oil, gas, water, and similar structures. This standard describes the use of electrically insulating coatings, electrical isolation, and cathodic protection as external corrosion control methods. It contains specific provisions for the application of cathodic protection to existing bare, existing coated, and new piping systems. Also included are procedures for control of interference currents on pipelines.

This standard should be used in conjunction with the practices described in the following NACE standards and publications when appropriate (use latest revisions):

RP0572[1]

RP0177[2]

RP0285[3]

RP0186[4]

RP0286[5]

RP0387[6]

RP0188[7]

TPC 11[8]

TM0497[9]

For accurate and correct application of this standard, the standard must be used in its entirety. Using or citing only specific paragraphs or sections can lead to misinterpretation and misapplication of the recommendations and practices contained in this standard.

This standard does not designate practices for every specific situation because of the complexity of conditions to which buried or submerged piping systems are exposed.

This standard was originally published in 1969, and was revised by NACE Task Group T-10-1 in 1972, 1976, 1983, and 1992. It was reaffirmed in 1996 by NACE Unit Committee T-10A on Cathodic Protection, and in 2002 by Specific Technology Group (STG) 35 on Pipelines, Tanks, and Well Casings. This standard is issued by NACE International under the auspices of STG 35, which is composed of corrosion control personnel from oil and gas transmission companies, gas distribution companies, power companies, corrosion consultants, and others concerned with external corrosion control of buried or submerged metallic piping systems.

In NACE standards, the terms *shall*, *must*, *should*, and *may* are used in accordance with the definitions of these terms in the *NACE Publications Style Manual*, 4th ed., Paragraph 7.4.1.9. *Shall* and *must* are used to state mandatory requirements. The term *should* is used to state something considered good and is recommended but is not mandatory. The term *may* is used to state something considered optional.

NACE International
Standard
Recommended Practice

Control of External Corrosion on Underground or Submerged Metallic Piping Systems

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Section 1: General

1.1 This standard presents acknowledged practices for the control of external corrosion on buried or submerged steel, cast iron, ductile iron, copper, and aluminum piping systems.

1.2 This standard is intended to serve as a guide for establishing minimum requirements for control of external corrosion on the following systems:

1.2.1 New piping systems: Corrosion control by a coating supplemented with cathodic protection, or by some other proven method, should be provided in the initial design and maintained during the service life of the piping system, unless investigations indicate that corrosion control is not required. Consideration should be given to the construction of pipelines in a manner that facilitates the use of in-line inspection tools.

1.2.2 Existing coated piping systems: Cathodic protection should be provided and maintained, unless investigations indicate that cathodic protection is not required.

1.2.3 Existing bare piping systems: Studies should be made to determine the extent and rate of corrosion on existing bare piping systems. When these studies indicate that corrosion will affect the safe or economic operation of the system, adequate corrosion control measures shall be taken.

1.3 The provisions of this standard should be applied under the direction of competent persons who, by reason of knowledge of the physical sciences and the principles of engineering and mathematics, acquired by education and related practical experience, are qualified to engage in the practice of corrosion control on buried or submerged metallic piping systems. Such persons may be registered professional engineers or persons recognized as corrosion specialists or cathodic protection specialists by NACE if their professional activities include suitable experience in external corrosion control of buried or submerged metallic piping systems.

1.4 Special conditions in which cathodic protection is ineffective or only partially effective sometimes exist. Such conditions may include elevated temperatures, disbonded coatings, thermal insulating coatings, shielding, bacterial attack, and unusual contaminants in the electrolyte. Deviation from this standard may be warranted in specific situations provided that corrosion control personnel in responsible charge are able to demonstrate that the objectives expressed in this standard have been achieved.

1.5 This standard does not include corrosion control methods based on chemical control of the environment, on the use of electrically conductive coatings, or on control of internal corrosion.

Section 2: Definitions[1]

Amphoteric Metal: A metal that is susceptible to corrosion in both acid and alkaline environments.

Anode: The electrode of an electrochemical cell at which oxidation occurs. Electrons flow away from the anode in the external circuit. Corrosion usually occurs and metal ions enter solution at the anode.

Anodic Polarization: The change of the electrode potential in the noble (positive) direction caused by current across the electrode/electrolyte interface.

Beta Curve: A plot of dynamic (fluctuating) interference current or related proportional voltage (ordinate) versus values of corresponding structure-to-soil potentials at a selected location on the affected structure (abscissa) (see Appendix A).

Cable: One conductor or multiple conductors insulated from one another.

Cathode: The electrode of an electrochemical cell at which reduction is the principal reaction. Electrons flow toward the cathode in the external circuit.

Cathodic Disbondment: The destruction of adhesion between a coating and the coated surface caused by products of a cathodic reaction.

Cathodic Polarization: The change of electrode potential in the active (negative) direction caused by current across the electrode/electrolyte interface.

[1] Definitions in this section reflect common usage among practicing corrosion control personnel and apply specifically to how the terms are used in this standard. In many cases, in the interests of brevity and practical usefulness, the scientific definitons are abbreviated or paraphrased.

Cathodic Protection: A technique to reduce the corrosion of a metal surface by making that surface the cathode of an electrochemical cell.

Coating: A liquid, liquefiable, or mastic composition that, after application to a surface, is converted into a solid protective, decorative, or functional adherent film.

Coating Disbondment: The loss of adhesion between a coating and the pipe surface.

Conductor: A material suitable for carrying an electric current. It may be bare or insulated.

Continuity Bond: A connection, usually metallic, that provides electrical continuity between structures that can conduct electricity.

Corrosion: The deterioration of a material, usually a metal, that results from a reaction with its environment.

Corrosion Potential (E_{corr}): The potential of a corroding surface in an electrolyte relative to a reference electrode under open-circuit conditions (also known as *rest potential*, *open-circuit potential*, or *freely corroding potential*).

Corrosion Rate: The rate at which corrosion proceeds.

Criterion: Standard for assessment of the effectiveness of a cathodic protection system.

Current Density: The current to or from a unit area of an electrode surface.

Diode: A bipolar semiconducting device having a low resistance in one direction and a high resistance in the other.

Distributed-Anode Impressed Current System: An impressed current anode configuration in which the anodes are "distributed" along the structure at relatively close intervals such that the structure is within each anode's voltage gradient. This anode configuration causes the electrolyte around the structure to become positive with respect to remte earth.

Electrical Isolation: The condition of being electrically separated from other metallic structures or the environment.

Electrical Survey: Any technique that involves coordinated electrical measurements taken to provide a basis for deduction concerning a particular electrochemical condition relating to corrosion or corrosion control.

Electrode: A conductor used to establish contact with an electrolyte and through which current is transferred to or from an electrolyte.

Electroosmotic Effect: Passage of a charged particle through a membrane under the influence of a voltage. Soil or coatings may act as the membrane.

Electrolyte: A chemical substance containing ions that migrate in an electric field. For the purpose of this standard, electrolyte refers to the soil or liquid adjacent to and in contact with a buried or submerged metallic piping system, including the moisture and other chemicals contained therein.

Foreign Structure: Any metallic structure that is not intended as a part of a system under cathodic protection.

Galvanic Anode: A metal that provides sacrificial protection to another metal that is more noble when electrically coupled in an electrolyte. This type of anode is the electron source in one type of cathodic protection.

Galvanic Series: A list of metals and alloys arranged according to their corrosion potentials in a given environment.

Holiday: A discontinuity in a protective coating that exposes unprotected surface to the environment.

Impressed Current: An electric current supplied by a device employing a power source that is external to the electrode system. (An example is direct current for cathodic protection.)

In-Line Inspection: The inspection of a steel pipeline using an electronic instrument or tool that travels along the interior of the pipeline.

Insulating Coating System: All components of the protective coating, the sum of which provides effective electrical isolation of the coated structure.

Interference: Any electrical disturbance on a metallic structure as a result of stray current.

Interference Bond: A metallic connection designed to control electrical current interchange between metallic systems.

IR Drop: The voltage across a resistance in accordance with Ohm's Law.

Isolation: See *Electrical Isolation*.

Line Current: The direct current flowing on a pipeline.

Long-Line Corrosion Activity: Current through the earth between an anodic and a cathodic area that returns along an underground metallic structure.

Mixed Potential: A potential resulting from two or more electrochemical reactions occurring simultaneously on one metal surface.

Pipe-to-Electrolyte Potential: The potential difference between the pipe metallic surface and electrolyte that is measured with reference to an electrode in contact with the electrolyte.

Polarization: The change from the open-circuit potential as a result of current across the electrode/electrolyte interface.

Polarized Potential: The potential across the structure/electrolyte interface that is the sum of the corrosion potential and the cathodic polarization.

Reference Electrode: An electrode whose open-circuit potential is constant under similar conditions of measurement, which is used for measuring the relative potentials of other electrodes.

Reverse-Current Switch: A device that prevents the reversal of direct current through a metallic conductor.

Shielding: Preventing or diverting the cathodic protection current from its intended path.

Shorted Pipeline Casing: A casing that is in direct metallic contact with the carrier pipe.

Sound Engineering Practices: Reasoning exhibited or based on thorough knowledge and experience, logically valid and having technically correct premises that demonstrate good judgment or sense in the application of science.

Stray Current: Current through paths other than the intended circuit.

Stray-Current Corrosion: Corrosion resulting from current through paths other than the intended circuit, e.g., by any extraneous current in the earth.

Telluric Current: Current in the earth as a result of geomagnetic fluctuations.

Voltage: An electromotive force or a difference in electrode potentials expressed in volts.

Wire: A slender rod or filament of drawn metal. In practice, the term is also used for smaller-gauge conductors (6 mm^2 [No. 10 AWG[2]] or smaller).

Section 3: Determination of Need for External Corrosion Control

3.1 Introduction

3.1.1 This section recommends practices for determining when an underground or submerged metallic piping system requires external corrosion control.

3.1.2 Metallic structures, buried or submerged, are subject to corrosion. Adequate corrosion control procedures should be adopted to ensure metal integrity for safe and economical operation.

3.2 The need for external corrosion control should be based on data obtained from one or more of the following: corrosion surveys, operating records, visual observations, test results from similar systems in similar environments, in-line inspections, engineering and design specifications, and operating, safety, and economic requirements. The absence of leaks alone is insufficient evidence that corrosion control is not required.

3.2.1 Environmental and physical factors include the following:

3.2.1.1 Corrosion rate of the particular metallic piping system in a specific environment (see Appendix B);

3.2.1.2 Nature of the product being transported, the working temperature, temperature differentials within the pipeline causing thermal expansion and contraction, tendency of backfill to produce soil stress, and working pressure of the piping system as related to design specification;

3.2.1.3 Location of the piping system as related to population density and frequency of visits by personnel;

3.2.1.4 Location of the piping system as related to other facilities; and

3.2.1.5 Stray current sources foreign to the system.

3.2.2 Economic factors include the following:

3.2.2.1 Costs of maintaining the piping system in service for its expected life (see Appendix B);

3.2.2.2 Contingent costs of corrosion (see Appendix C); and

3.2.2.3 Costs of corrosion control (see Appendix D).

[2] American Wire Gauge.

Section 4: Piping System Design

4.1 Introduction

4.1.1 This section provides accepted corrosion control practices in the design of an underground or submerged piping system. A person qualified to engage in the practice of corrosion control should be consulted during all phases of pipeline design and construction (see Paragraph 1.3). These recommendations should not be construed as taking precedence over recognized electrical safety practices.

4.2 External Corrosion Control

4.2.1 External corrosion control must be a primary consideration during the design of a piping system. Materials selection and coatings are the first line of defense against external corrosion. Because perfect coatings are not feasible, cathodic protection must be used in conjunction with coatings. For additional information, see Sections 5 and 6.

4.2.2 New piping systems should be externally coated unless thorough investigation indicates that coatings are not required (see Section 5).

4.2.3 Materials and construction practices that create electrical shielding should not be used on the pipeline. Pipelines should be installed at locations where proximity to other structures and subsurface formations do not cause shielding.

4.3 Electrical Isolation

4.3.1 Isolation devices such as flange assemblies, prefabricated joint unions, or couplings should be installed within piping systems where electrical isolation of portions of the system is required to facilitate the application of external corrosion control. These devices should be properly selected for temperature, pressure, chemical resistance, dielectric resistance, and mechanical strength. Installation of isolation devices should be avoided or safeguarded in areas in which combustible atmospheres are likely to be present. Locations at which electrical isolating devices should be considered include, but are not limited to, the following:

4.3.1.1 Points at which facilities change ownership, such as meter stations and well heads;

4.3.1.2 Connections to main-line piping systems, such as gathering or distribution system laterals;

4.3.1.3 Inlet and outlet piping of in-line measuring and/or pressure-regulating stations;

4.3.1.4 Compressor or pumping stations, either in the suction and discharge piping or in the main line immediately upstream and downstream from the station;

4.3.1.5 Stray current areas;

4.3.1.6 The junction of dissimilar metals;

4.3.1.7 The termination of service line connections and entrance piping;

4.3.1.8 The junction of a coated pipe and a bare pipe; and

4.3.1.9 Locations at which electrical grounding is used, such as motorized valves and instrumentation.

4.3.2 The need for lightning and fault current protection at isolating devices should be considered. Cable connections from isolating devices to arresters should be short, direct, and of a size suitable for short-term high-current loading.

4.3.3 When metallic casings are required as part of the underground piping system, the pipeline should be electrically isolated from such casings. Casing insulators must be properly sized and spaced and be tightened securely on the pipeline to withstand insertion stresses without sliding on the pipe. Inspection should be made to verify that the leading insulator has remained in position. Concrete coatings on the carrier pipe could preclude the use of casing insulators. Consideration should be given to the use of support under the pipeline at each end of the casing to minimize settlement. The type of support selected should not cause damage to the pipe coating or act as a shield to cathodic protection current.

4.3.4 Casing seals should be installed to resist the entry of foreign matter into the casing.

4.3.5 When electrical contact would adversely affect cathodic protection, piping systems should be electrically isolated from supporting pipe stanchions, bridge structures, tunnel enclosures, pilings, offshore structures, or reinforcing steel in concrete. However, piping can be attached directly to a bridge without isolation if isolating devices are installed in the pipe system on each side of the bridge to electrically isolate the bridge piping from adjacent underground piping.

4.3.6 When an isolating joint is required, a device manufactured to perform this function should be used, or, if permissible, a section of nonconductive pipe, such as plastic pipe, may be installed. In either case, these

should be properly rated and installed in accordance with the manufacturer's instructions.

4.3.7 River weights, pipeline anchors, and metallic reinforcement in weight coatings should be electrically isolated from the carrier pipe and designed and installed so that coating damage does not occur and the carrier pipe is not electrically shielded.

4.3.8 Metallic curb boxes and valve enclosures should be designed, fabricated, and installed in such a manner that electrical isolation from the piping system is maintained.

4.3.9 Insulating spacing materials should be used when it is intended to maintain electrical isolation between a metallic wall sleeve and the pipe.

4.3.10 Underground piping systems should be installed so that they are physically separated from all foreign underground metallic structures at crossings and parallel installations and in such a way that electrical isolation could be maintained if desired.

4.3.11 Based on voltage rating of alternating current (AC) transmission lines, adequate separation should be maintained between pipelines and electric transmission tower footings, ground cables, and counterpoise. Regardless of separation, consideration should always be given to lightning and fault current protection of pipeline(s) and personnel safety (see NACE Standard RP0177[2]).

4.4 Electrical Continuity

4.4.1 Nonwelded pipe joints may not be electrically continuous. Electrical continuity can be ensured by the use of fittings manufactured for this purpose or by bonding across and to the mechanical joints in an effective manner.

4.5 Corrosion Control Test Stations

4.5.1 Test stations for potential, current, or resistance measurements should be provided at sufficient locations to facilitate cathodic protection testing. Such locations may include, but not be limited to, the following:

4.5.1.1 Pipe casing installations,

4.5.1.2 Metallic structure crossings,

4.5.1.3 Isolating joints,

4.5.1.4 Waterway crossings,

4.5.1.5 Bridge crossings,

4.5.1.6 Valve stations,

4.5.1.7 Galvanic anode installations,

4.5.1.8 Road crossings,

4.5.1.9 Stray-current areas, and

4.5.1.10 Rectifier installations.

4.5.2 The span of pipe used for line current test stations should exclude:

4.5.2.1 Foreign metallic structure crossings;

4.5.2.2 Lateral connections;

4.5.2.3 Mechanical couplings or connections such as screwed joints, transition pieces, valves, flanges, anode or rectifier attachments, or metallic bonds; and

4.5.2.4 Changes in pipe wall thickness and diameter.

4.5.3 Attachment of Copper Test Lead Wires to Steel and Other Ferrous Pipes

4.5.3.1 Test lead wires may be used both for periodic testing and for current-carrying purposes. As such, the wire/pipe attachment should be mechanically strong and electrically conductive.

4.5.3.2 Methods of attaching wires to the pipe include (a) thermit welding process, (b) soldering, and (c) mechanical means.

4.5.3.3 Particular attention must be given to the attachment method to avoid (a) damaging or penetrating the pipe, (b) sensitizing or altering of pipe properties, (c) weakening the test lead wire, (d) damaging internal or external pipe coatings, and (e) creating hazardous conditions in explosive environments.

4.5.3.4 Attachment by mechanical means is the least desirable method. Such a connection may loosen, become highly resistant, or lose electrical continuity.

4.5.3.5 The connection should be tested for mechanical strength and electrical continuity. All exposed portions of the connection should be thoroughly cleaned of all welding slag, dirt, oils, etc.; primed, if needed; and coated with materials compatible with the cable insulation, pipe coating, and environment.

4.5.4 Attachment of Aluminum Test Lead Wire to Aluminum Pipes

4.5.4.1 Aluminum test lead wire, or aluminum tabs attached to aluminum wire, may be welded to aluminum pipe using the tungsten inert-gas shielded arc (TIG) or metal inert-gas shielded arc (MIG) process. Welded attachments should be

made to flanges or at butt weld joints. Attachment at other sites may adversely affect the mechanical properties of the pipe because of the heat of welding.

4.5.4.2 Test lead wire may be attached to aluminum pipe by soldering. If low-melting-point soft solders are used, a flux is required. Flux residues may cause corrosion unless removed.

NOTE: The use of copper test lead wire may cause preferential galvanic attack on the aluminum pipe. When copper wire or flux is used, care must be taken to seal the attachment areas against moisture. In the presence of moisture, the connection may disbond and be damaged by corrosion.

4.5.4.3 Aluminum tabs to which test lead wires have been TIG welded can be attached by an explosive bonding technique called high-energy joining.

4.5.4.4 Mechanical connections that remain secure and electrically conductive may be used.

4.5.5 Attachment of Copper Test Lead Wire to Copper Pipe

4.5.5.1 Copper test lead wire, or copper tabs attached to copper wire, may be attached to copper pipe by one of the following methods. The relative thickness of the wire and the pipe wall dictates, in part, which of the methods can be used.

4.5.5.1.1 Arc welding (TIG, MIG, or shielded metal);

4.5.5.1.2 Electrical resistance (spot) welding;

4.5.5.1.3 Brazing;

4.5.5.1.4 Soldering; or

4.5.5.1.5 Mechanical connection.

4.5.5.2 Attention should be given to proper joining procedures to avoid possible embrittlement or loss of mechanical properties of the metals from the heat of welding or brazing.

4.5.5.3 A flux may be required, or self-produced, when brazing with some filler metals or soldering with some low-melting-point soft solders. Because flux residues may cause corrosion, they should be removed.

Section 5: External Coatings

5.1 Introduction

5.1.1 This section recommends practices for selecting, testing and evaluating, handling, storing, inspecting, and installing external coating systems for external corrosion control on piping systems.

The function of external coatings is to control corrosion by isolating the external surface of the underground or submerged piping from the environment, to reduce cathodic protection current requirements, and to improve current distribution.

5.1.3 External coatings must be properly selected and applied and the coated piping carefully handled and installed to fulfill these functions. Various types of external coatings can accomplish the desired functions.

5.1.2.1 Desirable characteristics of external coatings include the following:

5.1.2.1.1 Effective electrical insulator;

5.1.2.1.2 Effective moisture barrier;

5.1.2.1.3 Application to pipe by a method that does not adversely affect the properties of the pipe;

5.1.2.1.4 Application to pipe with a minimum of defects;

5.1.2.1.5 Good adhesion to pipe surface;

5.1.2.1.6 Ability to resist development of holidays with time;

5.1.2.1.7 Ability to resist damage during handling, storage, and installation;

5.1.2.1.8 Ability to maintain substantially constant electrical resistivity with time;

5.1.2.1.9 Resistance to disbonding;

5.1.2.1.10 Resistance to chemical degradation;

5.1.2.1.11 Ease of repair;

5.1.2.1.12 Retention of physical characteristics;

5.1.2.1.13 Nontoxic to the environment; and

5.1.2.1.14 Resistance to changes and deterioration during aboveground storage and long-distance transportation.

5.1.2.2 Typical factors to consider when selecting an external pipe coating include:

5.1.2.2.1 Type of environment;

5.1.2.2.2 Accessibility of piping system;

5.1.2.2.3 Operating temperature of piping system;

5.1.2.2.4 Ambient temperatures during application, shipping, storage, construction, installation, and pressure testing;

5.1.2.2.5 Geographical and physical location;

5.1.2.2.6 Type of external coating on existing pipe in the system;

5.1.2.2.7 Handling and storage;

5.1.2.2.8 Pipeline installation methods;

5.1.2.2.9 Costs; and

5.1.2.2.10 Pipe surface preparation requirements.

5.1.2.3 Pipeline external coating systems shall be properly selected and applied to ensure that adequate bonding is obtained. Unbonded coatings can create electrical shielding of the pipeline that could jeopardize the effectiveness of the cathodic protection system.

5.1.3 Information in this section is primarily by reference to other documents. It is important that the latest revision of the pertinent reference be used.

5.1.3.1 Table 1 is a listing of types of external coating systems, showing the appropriate references for material specifications and recommended practices for application.

5.1.3.2 Table 2 is a grouping of references for general use during installation and inspection, regardless of coating type.

5.1.3.3 Table 3 is a list of external coating system characteristics related to environmental conditions containing suggested laboratory test references for various properties.

5.1.3.4 Table 4 is a list of external coating system characteristics related to design and construction, with recommended laboratory tests for evaluating these properties.

5.1.3.5 Table 5 lists the references that are useful in field evaluation of external coating systems after the pipeline has been installed.

5.2 Storage, Handling, Inspection, and Installation

5.2.1 Storage and Handling

5.2.1.1 Coated pipe to be stored should be protected internally and externally from atmospheric corrosion and coating deterioration.

5.2.1.2 Damage to coating can be minimized by careful handling and by using proper pads and slings.

TABLE 1
Generic External Coating Systems with Material Requirements and Recommended Practices for Application[A]

Generic External Coating System	Reference
Coal Tar	ANSI[B]/AWWA[C] C 203[10]
Wax	NACE Standard RP0375[11]
Prefabricated Films	NACE Standard MR0274[12] ANSI/AWWA C 214[13] ANSI/AWWA C 209[14]
Fusion-Bonded Epoxy Coatings	*Peabody's Control of Pipeline Corrosion*[15] ANSI/AWWA C 213[16] API[D] RP 5L7[17] CSA[E] Z245.20M[18] NACE Standard RP0190[19]
Polyolefin Coatings	NACE Standard RP0185[20] DIN[F] 30 670[21] ANSI/AWWA C215[22]

[A] NOTE: Many other references are available and this table is not comprehensive. Listing does not constitute endorsement of any external coating system in preference to another. Omission of a system may be due to unavailability of reference standards or lack of data.
[B] American National Standards Institute (ANSI), 1819 L Street, NW, Washington, DC 20036.
[C] American Water Works Association (AWWA), 6666 West Quincy Ave., Denver, CO 80235.
[D] American Petroleum Institute (API), 1220 L St. NW, Washington, DC 20005.
[E] CSA International, 178 Rexdale Blvd., Toronto, Ontario, Canada M9W 1R3.
[F] Deutsches Institut fur Normung (DIN), Burggrafenstrasse 6, D-10787 Berlin, Germany.

TABLE 2
References for General Use in the Installation and Inspection of External Coating Systems for Underground Piping

Subject	Reference
Application of Organic Pipeline Coatings	ANSI/AWWA C 203[10] NACE Standard RP0375[11] *Peabody's Control of Pipeline Corrosion*[15] ANSI/AWWA C 213[16] API RP 5L7[17] CSA Z245.20M[18] NACE Standard RP0190[19]
Film Thickness of Pipeline Coatings	ASTM[A] G 128[23]
Inspection of Pipeline Coatings	NACE Standard RP0274[24]

[A] ASTM, 100 Barr Harbor Drive, West Conshohocken, PA 19428-2959.

TABLE 3
External Coating System Characteristics Relative to Environmental Conditions[A]

Environmental Factor	Recommended Test Methods[B]
General underground exposure with or without cathodic protection	*Peabody's Control of Pipeline Corrosion*[15] ANSI/AWWA C 213[16] API RP 5L7[17] CSA Z245.20M[18] NACE Standard RP0190[19] ASTM G 8[25] ASTM G 19[26] ASTM G 42[27] ASTM G 95[28]
Resistance to water penetration and its effect on choice of coating thickness	ASTM G 9[29]
Resistance to penetration by stones in backfill	ASTM G 17[30] ASTM D 2240[31] ASTM G 13[32] ASTM G 14[33]
Soil stress	*Underground Corrosion*[34] ASTM D 427[35]
Resistance to specific liquid not normally encountered in virgin soil	ASTM D 543[36] Federal Test Standard[C] No. 406A, Method 7011[37] ASTM G 20[38]
Resistance to thermal effects	ASTM D 2304[39] ASTM D 2454[40] ASTM D 2485[41]
Suitability of supplementary materials for joint coating and field repairs	ASTM G 8[25] ASTM G 19[26] ASTM G 42[27] ASTM G 95[28] ASTM G 9[29] ASTM G 18[42] ASTM G 55[43]
Resistance to microorganisms	ASTM G 21[44] Federal Test Standard No. 406A, Method 6091[45]

[A] NOTE: Apply only those factors pertinent to the installation.
[B] No specific criteria are available. Comparative tests are recommended for use and evaluation as supplementary information only.
[C] Available from General Services Administration, Business Service Center, Washington, DC 20025.

TABLE 4
External Coating System Characteristics Related to Design and Construction

Design and Construction Factor	Recommended Test Methods[A]
Yard Storage, Weathering	ASTM G 11[46]
Yard Storage, Penetration Under Load	ASTM G 17[30] ASTM D 2240[31]
Handling Resistance, Abrasion	ASTM G 6[47]
Handling Resistance, Impact	ASTM G 13[32] ASTM G 14[33]
Field Bending Ability	ASTM G 10[48]
Driving Ability (Resistance to Sliding Abrasion)	ASTM G 6[47] ASTM D 2197[49]
Special Requirements for Mill-Applied Coating	ANSI/AWWA C 20[40] NACE Standard RP0375[11] NACE Standard MR0274[12] ANSI/AWWA C 214[13] ANSI/AWWA C 209[14] *Peabody's Control of Pipeline Corrosion*[15] ANSI/AWWA C 213[16] API RP 5L7[17] CSA Z245.20M[18] NACE Standard RP0190[19] NACE Standard RP0185[20] DIN 30 670[21] ANSI/AWWA C 215[22]
Special Requirements for Application of Coating Over the Ditch	ANSI/AWWA C 20[40] NACE Standard RP0375[11] NACE Standard MR0274[12] ANSI/AWWA C 214[13] ANSI/AWWA C 209[14] *Peabody's Control of Pipeline Corrosion*[15] ANSI/AWWA C 213[16] API RP 5L7[17] CSA Z245.20M[18] NACE Standard RP0190[19]
Backfill Resistance	ASTM G 13[32] ASTM G 14[33]
Resistance to Thermal Effects	ASTM G 8[25] ASTM G 19[26] ASTM G 42[27] ASTM G 95[28] ASTM D 2304[39] ASTM D 2454[40] ASTM D 2485[41]

Table 4 Continued

Design and Construction Factor	Recommended Test Methods[(A)]
Suitability of Joint Coatings and Field Repairs	*Peabody's Control of Pipeline Corrosion*[15] ANSI/AWWA C 213[16] API RP 5L7[17] CSA Z245.20M[18] NACE Standard RP0190[19] ASTM G 8[25] ASTM G 19[26] ASTM G 42[27] ASTM G 95[28] ASTM G 9[29] ASTM G 18[42] ASTM G 55[43]

[(A)] No specific criteria are available. Comparative tests are recommended for use and evaluation as supplementary information only.

TABLE 5
Methods for Evaluating In-Service Field Performance of External Coatings

Title or Subject of Method	Reference	Basis for Rating
(1) Rate of Change in Current Required for Cathodic Protection	*Underground Corrosion*[34]	Comparison of initial current requirement with subsequent periodic determination of current requirement
(2) Inspection of Pipeline Coating	NACE Standard RP0274[12]	(a) With cathodic protection: no active corrosion found (b) Without cathodic protection: no new holidays showing active corrosion
(3) Cathodic Disbondment	ASTM G 8[25] ASTM G 19[26] ASTM G 42[27] ASTM G 95[28]	Purpose is to obtain data relative to specific conditions for comparison with laboratory data

5.2.2 Inspection

5.2.2.1 Qualified personnel should keep every phase of the coating operation and piping installation under surveillance.

5.2.2.2 Surface preparation, primer application, coating thickness, temperature, bonding, and other specific requirements should be checked periodically, using suitable test procedures, for conformance to specifications.

5.2.2.3 The use of holiday detectors is recommended to detect coating flaws that would not be observed visually. The holiday detector should be operated in accordance with the manufacturer's instructions and at a voltage level appropriate to the electrical characteristics of the coating system.

5.2.3 Installation

5.2.3.1 Joints, fittings, and tie-ins must be coated with a material compatible with the existing coating.

5.2.3.2 Coating defects should be repaired.

5.2.3.3 Materials used to repair coatings must be compatible with the existing pipe coating.

5.2.3.4 The ditch bottom should be graded and free of rock or other foreign matter that could damage the external coating or cause electrical shielding. Under difficult conditions, consideration should be given to padding the pipe or the ditch bottom.

5.2.3.5 Pipe should be lowered carefully into the ditch to avoid external coating damage.

5.2.3.6 Care should be taken during backfilling so that rocks and debris do not strike and damage the pipe coating.

5.2.3.7 Care shall be exercised when using materials such as loose wrappers, nonconducting urethane foam, and rock shield around pipelines as protection against physical damage or for other purposes, because these materials may create an electrical shielding effect that would be detrimental to the effectiveness of cathodic protection.

5.2.3.8 When a pipeline comes above ground, it must be cleaned and externally coated, or jacketed with a suitable material, for the prevention of atmospheric corrosion.

5.3 Methods for Evaluating External Coating Systems

5.3.1 Established Systems Proven by Successful Use

5.3.1.1 Visual and electrical inspection of in-service pipeline coatings should be used to evaluate the performance of an external coating system. These inspections can be conducted wherever the pipeline is excavated or at bell holes made for inspection purposes.

5.3.2 Established or Modified Systems for New Environments

5.3.2.1 This method is intended for use when external coating systems will continue to be used and are qualified under Paragraph 5.3.1, but when application will be extended to new environments or when it is desired to revise a system to make use of new developments.

5.3.2.1.1 The use of applicable material requirements, material specifications, standards, and recommended practices for application, as given in Table 1, is recommended.

5.3.2.1.2 The use of applicable references in Table 2 is recommended unless previously covered in applicable references in Table 1.

5.3.3 New External Coating System Qualification

5.3.3.1 The purpose of this method is to qualify a new external coating material by subjecting it to laboratory tests appropriate for the intended service. After laboratory tests have been conducted and indicate that the external coating system appears to be suitable, application and installation are conducted in accordance with recommended practices. In-service field performance tests are made to confirm the success of the previous steps. The steps of the method are (1) laboratory tests, (2) application under recommended practices, (3) installation under recommended practices, and (4) in-service field performance tests. If good results are obtained after five years, only Steps 2 and 3 are required thereafter.

5.3.3.1.1 Applicable sections of Tables 3 and 4 are recommended for the initial laboratory test methods.

5.3.3.1.2 Applicable sections of Tables 1 and 2 are recommended for conditional use during Steps 2 and 3.

5.3.3.1.3 During a period of five years or more, the use of the evaluation methods given in Table 5, Item 1 or 2 are recommended. The test method in Item 3 may be used as a supplementary means for obtaining data for correlation with laboratory tests.

5.3.4 Method for Evaluating an External Coating System by In-Service Field Performance Only

5.3.4.1 The purpose of this method is to qualify an external coating system when none of the first three methods given in Paragraph 5.3 has been or will be used. It is intended that this method should be limited to minor pilot installations.

5.3.4.1.1 The use of at least one of the first two methods given in Table 5 is recommended on the basis of at least one investigation per year for five consecutive years.

Section 6: Criteria and Other Considerations for Cathodic Protection

6.1 Introduction

6.1.1 This section lists criteria and other considerations for cathodic protection that indicate, when used either separately or in combination, whether adequate cathodic protection of a metallic piping system has been achieved (see also Section 1, Paragraphs 1.2 and 1.4).

6.1.2 The effectiveness of cathodic protection or other external corrosion control measures can be confirmed by visual observation, by measurements of pipe wall thickness, or by use of internal inspection devices. Because such methods sometimes are not practical, meeting any criterion or combination of criteria in this section is evidence that adequate cathodic protection has been achieved. When excavations are made for

any purpose, the pipe should be inspected for evidence of corrosion and/or coating condition.

6.1.3 The criteria in this section have been developed through laboratory experiments and/or verified by evaluating data obtained from successfully operated cathodic protection systems. Situations in which a single criterion for evaluating the effectiveness of cathodic protection may not be satisfactory for all conditions may exist. Often a combination of criteria is needed for a single structure.

6.1.4 Sound engineering practices shall be used to determine the methods and frequency of testing required to satisfy these criteria.

6.1.5 Corrosion leak history is valuable in assessing the effectiveness of cathodic protection. Corrosion leak history by itself, however, shall not be used to determine whether adequate levels of cathodic protection have been achieved unless it is impractical to make electrical surveys.

6.2 Criteria

6.2.1 It is not intended that persons responsible for external corrosion control be limited to the criteria listed below. Criteria that have been successfully applied on existing piping systems can continue to be used on those piping systems. Any other criteria used must achieve corrosion control comparable to that attained with the criteria herein.

6.2.2 Steel and Cast Iron Piping

6.2.2.1 External corrosion control can be achieved at various levels of cathodic polarization depending on the environmental conditions. However, in the absence of specific data that demonstrate that adequate cathodic protection has been achieved, one or more of the following shall apply:

6.2.2.1.1 A negative (cathodic) potential of at least 850 mV with the cathodic protection applied. This potential is measured with respect to a saturated copper/copper sulfate reference electrode contacting the electrolyte. Voltage drops other than those across the structure-to-electrolyte boundary must be considered for valid interpretation of this voltage measurement.

NOTE: Consideration is understood to mean the application of sound engineering practice in determining the significance of voltage drops by methods such as:

6.2.2.1.1.1 Measuring or calculating the voltage drop(s);

6.2.2.1.1.2 Reviewing the historical performance of the cathodic protection system;

6.2.2.1.1.3 Evaluating the physical and electrical characteristics of the pipe and its environment; and

6.2.2.1.1.4 Determining whether or not there is physical evidence of corrosion.

6.2.2.1.2 A negative polarized potential (see definition in Section 2) of at least 850 mV relative to a saturated copper/copper sulfate reference electrode.

6.2.2.1.3 A minimum of 100 mV of cathodic polarization between the structure surface and a stable reference electrode contacting the electrolyte. The formation or decay of polarization can be measured to satisfy this criterion.

6.2.2.2 Special Conditions

6.2.2.2.1 On bare or ineffectively coated pipelines when long-line corrosion activity is of primary concern, the measurement of a net protective current at predetermined current discharge points from the electrolyte to the pipe surface, as measured by an earth current technique, may be sufficient.

6.2.2.2.2 In some situations, such as the presence of sulfides, bacteria, elevated temperatures, acid environments, and dissimilar metals, the criteria in Paragraph 6.2.2.1 may not be sufficient.

6.2.2.2.3 When a pipeline is encased in concrete or buried in dry or aerated high-resistivity soil, values less negative than the criteria listed in Paragraph 6.2.2.1 may be sufficient.

6.2.2.3 PRECAUTIONARY NOTES

6.2.2.3.1 The earth current technique is often meaningless in multiple pipe rights-of-way, in high-resistivity surface soil, for deeply buried pipe, in stray-current areas, or where local corrosion cell action predominates.

6.2.2.3.2 Caution is advised against using polarized potentials less negative than -850 mV for cathodic protection of pipelines when operating pressures and conditions are conducive to stress corrosion cracking (see references on stress corrosion cracking at the end of this section).

6.2.2.3.3 The use of excessive polarized potentials on externally coated pipelines should be avoided to minimize cathodic disbondment of the coating.

6.2.2.3.4 Polarized potentials that result in excessive generation of hydrogen should be avoided on all metals, particularly higher-strength steel, certain grades of stainless steel, titanium, aluminum alloys, and prestressed concrete pipe.

6.2.3 Aluminum Piping

6.2.3.1 The following criterion shall apply: a minimum of 100 mV of cathodic polarization between the structure surface and a stable reference electrode contacting the electrolyte. The formation or decay of this polarization can be used in this criterion.

6.2.3.2 PRECAUTIONARY NOTES

6.2.3.2.1 Excessive Voltages: Notwithstanding the minimum criterion in Paragraph 6.2.3.1, if aluminum is cathodically protected at voltages more negative than -1,200 mV measured between the pipe surface and a saturated copper/copper sulfate reference electrode contacting the electrolyte and compensation is made for the voltage drops other than those across the pipe-electrolyte boundary, it may suffer corrosion as the result of the buildup of alkali on the metal surface. A polarized potential more negative than -1,200 mV should not be used unless previous test results indicate that no appreciable corrosion will occur in the particular environment.

6.2.3.2.2 Alkaline Conditions: Aluminum may suffer from corrosion under high-pH conditions and application of cathodic protection tends to increase the pH at the metal surface. Therefore, careful investigation or testing should be done before applying cathodic protection to stop pitting attack on aluminum in environments with a natural pH in excess of 8.0.

6.2.4 Copper Piping

6.2.4.1 The following criterion shall apply: a minimum of 100 mV of cathodic polarization between the structure surface and a stable reference electrode contacting the electrolyte. The formation or decay of this polarization can be used in this criterion.

6.2.5 Dissimilar Metal Piping

6.2.5.1 A negative voltage between all pipe surfaces and a stable reference electrode contacting the electrolyte equal to that required for the protection of the most anodic metal should be maintained.

6.2.5.2 PRECAUTIONARY NOTE

6.2.5.2.1 Amphoteric materials that could be damaged by high alkalinity created by cathodic protection should be electrically isolated and separately protected.

6.3 Other Considerations

6.3.1 Methods for determining voltage drop(s) shall be selected and applied using sound engineering practices. Once determined, the voltage drop(s) may be used for correcting future measurements at the same location, providing conditions such as pipe and cathodic protection system operating conditions, soil characteristics, and external coating quality remain similar. (Note: Placing the reference electrode next to the pipe surface may not be at the pipe-electrolyte interface. A reference electrode placed at an externally coated pipe surface may not significantly reduce soil voltage drop in the measurement if the nearest coating holiday is remote from the reference electrode location.)

6.3.2 When it is impractical or considered unnecessary to disconnect all current sources to correct for voltage drop(s) in the structure-to-electrolyte potential measurements, sound engineering practices should be used to ensure that adequate cathodic protection has been achieved.

6.3.3 When feasible and practicable, in-line inspection of pipelines may be helpful in determining the presence or absence of pitting corrosion damage. Absence of external corrosion damage or the halting of its growth may indicate adequate external corrosion control. The in-line inspection technique, however, may not be capable of detecting all types of external corrosion damage, has limitations in its accuracy, and may report as anomalies items that are not external corrosion. For example, longitudinal seam corrosion and general corrosion may not be readily detected by in-line inspection. Also, possible thickness variations, dents, gouges, and external ferrous objects may be detected as corrosion. The appropriate use of in-line inspection must be carefully considered.

6.3.4 Situations involving stray currents and stray electrical gradients that require special analysis may exist. For additional information, see Section 9, "Control of Interference Currents."

6.4 Alternative Reference Electrodes

6.4.1 Other standard reference electrodes may be substituted for the saturated copper/copper sulfate

reference electrode. Two commonly used reference electrodes are listed below along with their voltage equivalent (at 25°C [77°F]) to -850 mV referred to a saturated copper/copper sulfate reference electrode:

6.4.1.1 Saturated KCl calomel reference electrode: -780 mV; and

6.4.1.2 Saturated silver/silver chloride reference electrode used in 25 ohm-cm seawater: -800 mV.

6.4.2 In addition to these standard reference electrodes, an alternative metallic material or structure may be used in place of the saturated copper/copper sulfate reference electrode if the stability of its electrode potential is ensured and if its voltage equivalent referred to a saturated copper/copper sulfate reference electrode is established.

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Section 7: Design of Cathodic Protection Systems

7.1 Introduction

7.1.1 This section recommends procedures for designing cathodic protection systems that will provide effective external corrosion control by satisfying one or more of the criteria listed in Section 6 and exhibiting maximum reliability over the intended operating life of the systems.

7.1.2 In the design of a cathodic protection system, the following should be considered:

7.1.2.1 Recognition of hazardous conditions prevailing at the proposed installation site(s) and the selection and specification of materials and installation practices that ensure safe installation and operation.

7.1.2.2 Specification of materials and installation practices to conform to the latest editions of applicable codes, National Electrical Manufacturers Association (NEMA)[7] standards, National

[7] National Electrical Manufacturers Association (NEMA), 2101 L St., NW, Washington, DC 20037.

Electrical Code (NEC),[8] appropriate international standards, and NACE standards.

7.1.2.3 Selection and specification of materials and installation practices that ensure dependable and economical operation throughout the intended operating life.

7.1.2.4 Selection of locations for proposed installations to minimize currents or earth potential gradients, which can cause detrimental effects on foreign buried or submerged metallic structures.

7.1.2.5 Cooperative investigations to determine mutually satisfactory solution(s) of interference problems (see Section 9).

7.1.2.6 Special consideration should be given to the presence of sulfides, bacteria, disbonded coatings, thermal insulating coatings, elevated temperatures, shielding, acid environments, and dissimilar metals.

7.1.2.7 Excessive levels of cathodic protection that can cause external coating disbondment and possible damage to high-strength steels as a result of hydrogen evolution should be avoided.

7.1.2.8 When amphoteric metals are involved, care should be taken so that high-pH conditions that could cause cathodic corrosion of the metal are not established.

7.2 Major objectives of cathodic protection system design include the following:

7.2.1 To provide sufficient current to the structure to be protected and distribute this current so that the selected criteria for cathodic protection are effectively attained;

7.2.2 To minimize the interference currents on neighboring underground structures (see Section 9);

7.2.3 To provide a design life of the anode system commensurate with the required life of the protected structure, or to provide for periodic rehabilitation of the anode system;

7.2.4 To provide adequate allowance for anticipated changes in current requirements with time;

7.2.5 To install anodes where the possibility of disturbance or damage is minimal; and

7.2.6 To provide adequate monitoring facilities to test and evaluate the system performance.

7.3 Information Useful for Design

7.3.1 Useful piping system specifications and information include the following:

7.3.1.1 Route maps and atlas sheets;

7.3.1.2 Construction dates;

7.3.1.3 Pipe, fittings, and other appurtenances;

7.3.1.4 External coatings;

7.3.1.5 Casings;

7.3.1.6 Corrosion control test stations;

7.3.1.7 Electrically isolating devices;

7.3.1.8 Electrical bonds; and

7.3.1.9 Aerial, bridge, and underwater crossings.

7.3.2 Useful information on piping system site conditions includes the following:

7.3.2.1 Existing and proposed cathodic protection systems;

7.3.2.2 Possible interference sources (see Section 9);

7.3.2.3 Special environmental conditions;

7.3.2.4 Neighboring buried metallic structures (including location, ownership, and corrosion control practices);

7.3.2.5 Structure accessibility;

7.3.2.6 Power availability; and

7.3.2.7 Feasibility of electrical isolation from foreign structures.

7.3.3 Useful information from field surveys, corrosion test data, and operating experience includes the following:

7.3.3.1 Protective current requirements to meet applicable criteria;

7.3.3.2 Electrical resistivity of the electrolyte;

7.3.3.3 Electrical continuity;

7.3.3.4 Electrical isolation;

7.3.3.5 External coating integrity;

7.3.3.6 Cumulative leak history;

[8] National Fire Protection Association, Batterymarch Park, Quincy, MA 02269.

7.3.3.7 Interference currents;

7.3.3.8 Deviation from construction specifications; and

7.3.3.9 Other maintenance and operating data.

7.3.4 Field survey work prior to actual application of cathodic protection is not always required if prior experience or test data are available to estimate current requirements, electrical resistivities of the electrolyte, and other design factors.

7.4 Types of Cathodic Protection Systems

7.4.1 Galvanic Anode Systems

7.4.1.1 Galvanic anodes can be made of materials such as alloys of magnesium, zinc, or aluminum. The anodes are connected to the pipe, either individually or in groups. Galvanic anodes are limited in current output by the anode-to-pipe driving voltage and the electrolyte resistivity.

7.4.2 Impressed Current Anode Systems

7.4.2.1 Impressed current anodes can be of materials such as graphite, high-silicon cast iron, lead-silver alloy, precious metals, or steel. They are connected with an insulated cable, either individually or in groups, to the positive terminal of a direct-current (DC) source, such as a rectifier or generator. The pipeline is connected to the negative terminal of the DC source.

7.5 Considerations influencing selection of the type of cathodic protection system include the following:

7.5.1 Magnitude of protective current required;

7.5.2 Stray currents causing significant potential fluctuations between the pipeline and earth that may preclude the use of galvanic anodes;

7.5.3 Effects of cathodic protection interference currents on adjacent structures that may limit the use of impressed current cathodic protection systems;

7.5.4 Availability of electrical power;

7.5.5 Physical space available, proximity of foreign structures, easement procurement, surface conditions, presence of streets and buildings, river crossings, and other construction and maintenance concerns.

7.5.6 Future development of the right-of-way area and future extensions to the pipeline system;

7.5.7 Costs of installation, operation, and maintenance; and

7.5.8 Electrical resistivity of the environment.

7.6 Factors Influencing Design of Cathodic Protection Systems

7.6.1 Various anode materials have different rates of deterioration when discharging a given current density from the anode surface in a specific environment. Therefore, for a given current output, the anode life depends on the environment and anode material, as well as the anode weight and the number of anodes in the cathodic protection system. Established anode performance data may be used to calculate the probable deterioration rate.

7.6.2 Data on the dimensions, depth, and configuration of the anodes and the electrolyte resistivity may be used to calculate the resultant resistance to electrolyte of the anode system. Formulas and graphs relating to these factors are available in the literature and from manufacturers.

7.6.3 Design of galvanic anode systems should consider anode-to-pipe potential, electrolyte resisivity, current output, and in special cases, anode lead-wire resistance. A separate design for each anode or anode system may not be necessary.

7.6.4 Galvanic anode performance in most soils can be improved by using special backfill material. Mixtures of gypsum, bentonite, and anhydrous sodium sulfate are most commonly used.

7.6.5 The number of impressed current anodes required can be reduced and their useful life lengthened by the use of special backfill around the anodes. The most common materials are coal coke, calcined petroleum coke, and natural or manufactured graphite.

7.6.6 In the design of an extensive distributed-anode impressed current system, the voltage and current attenuation along the anode-connecting (header) cable should be considered. In such cases, the design objective is to optimize anode system length, anode spacing and size, and cable size in order to achieve efficient external corrosion control at the extremities of the protected structure.

7.6.7 When it is anticipated that entrapment of gas generated by anodic reactions could impair the ability of the impressed current groundbed to deliver the required current, suitable provisions should be made for venting the anodes. For the same current output of the system, an increase in the surface area of the special backfill material or an increase in the number of anodes may reduce gas blockage.

7.6.8 When it is anticipated that electroosmotic effects could impair the ability of the impressed current groundbed to deliver the required current output, suitable provisions should be made to ensure adequate soil moisture around the anodes. Increasing the number of impressed current anodes or increasing the

surface area of the special backfill materials may further reduce the electroosmotic effect.

7.7 Design Drawings and Specifications

7.7.1 Suitable drawings should be prepared to designate the overall layout of the piping to be protected and the location of significant items of structure hardware, corrosion control test stations, electrical bonds, electrical isolation devices, and neighboring buried or submerged metallic structures.

7.7.2 Layout drawings should be prepared for each impressed current cathodic protection installation, showing the details and location of the components of the cathodic protection system with respect to the protected structure(s) and to major physical landmarks. These drawings should include right-of-way information.

7.7.3 The locations of galvanic anode installations should be recorded on drawings or in tabular form, with appropriate notes on anode type, weight, spacing, depth, and backfill.

7.7.4 Specifications should be prepared for all materials and installation practices that are to be incorporated in construction of the cathodic protection system.

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Section 8: Installation of Cathodic Protection Systems

8.1 Introduction

8.1.1 This section recommends procedures that will result in the installation of cathodic protection systems that achieve protection of the structure. The design considerations recommended in Sections 4 and 7 should be followed.

8.2 Construction Specifications

8.2.1 All construction work on cathodic protection systems should be performed in accordance with construction drawings and specifications. The construction specifications should be in accordance with recommended practices in Sections 4 and 7.

8.3 Construction Supervision

8.3.1 All construction work on cathodic protection systems should be performed under the surveillance of trained and qualified personnel to verify that the installation is in strict accordance with the drawings and specifications. Exceptions may be made only with the approval of qualified personnel responsible for external corrosion control.

8.3.2 All deviations from construction specifications should be noted on as-built drawings.

8.4 Galvanic Anodes

8.4.1 Inspection, Handling, and Storage

8.4.1.1 Packaged anodes should be inspected and steps taken to ensure that backfill material completely surrounds the anode. The individual container for the backfill material and anode should be intact. If individually packaged anodes are supplied in waterproof containers, the containers must be removed before installation. Packaged anodes should be kept dry during storage.

8.4.1.2 Lead wire must be securely connected to the anode. Lead wire should be inspected for assurance that it is not damaged.

8.4.1.3 Other galvanic anodes, such as the unpackaged "bracelet" or ribbon type, should be inspected to ensure that dimensions conform to design specifications and that any damage during handling does not affect application. If a coating is used on bands and the inner side of bracelet anode segments, it should be inspected and, if damaged, repaired before the anodes are installed.

8.4.2 Installing Anodes

8.4.2.1 Anodes should be installed according to construction specifications.

8.4.2.2 Packaged galvanic anodes should be backfilled with appropriately compacted material. When anodes and special chemical backfill are provided separately, anodes should be centered in special backfill, which should be compacted prior to backfilling. Care should be exercised during all operations so that lead wires and connections are not damaged. Sufficient slack should exist in lead wires to avoid strain.

8.4.2.3 When anodes in bracelet form are used, external pipe coating beneath the anode should be free of holidays. Care should be taken to prevent damage to the external coating when bracelet anodes are installed. After application of concrete (if used) to pipe, all coating and concrete should be removed from the anode surface. If reinforced concrete is used, there must be no metallic contact between the anode and the reinforcing mesh or between the reinforcing mesh and the pipe.

8.4.2.4 When a ribbon-type anode is used, it can be trenched or plowed in, with or without special chemical backfill as required, generally parallel to the section of pipeline to be protected.

8.5 Impressed Current Systems

8.5.1 Inspection and Handling

8.5.1.1 The rectifier or other power source should be inspected to ensure that internal connections are mechanically secure and that the unit is free of damage. Rating of the DC power source should comply with the construction specification. Care should be exercised in handling and installing the power source.

8.5.1.2 Impressed current anodes should be inspected for conformance to specifications concerning anode material, size, length of lead cable, anode lead connection, and integrity of seal. Care should be exercised to avoid cracking or damaging anodes during handling and installation.

8.5.1.3 All cables should be carefully inspected to detect defects in insulation. Care should be taken to avoid damage to cable insulation. Defects in the cable insulation must be repaired.

8.5.1.4 Anode backfill material should conform to specifications.

8.5.2 Installation Provisions

8.5.2.1 A rectifier or other power source should be installed so that the possibility of damage or vandalism is minimized.

8.5.2.2 Wiring to rectifiers shall comply with local and national electrical codes and requirements of the utility supplying power. An external disconnect switch should be provided in the AC circuit. A rectifier case shall be properly grounded.

8.5.2.3 On thermoelectric generators, a reverse-current device should be installed to prevent galvanic action between the anode bed and the pipe if the flame is extinguished.

8.5.2.4 Impressed current anodes can be buried vertically, horizontally, or in deep holes (see NACE Standard RP0572[1]) as indicated in construction specifications. Backfill material should be installed to ensure that there are no voids around anodes. Care should be exercised during backfilling to avoid damage to the anode and cable.

8.5.2.5 The cable from the rectifier negative terminal to the pipe should be connected to the pipe as described in Paragraph 8.6. Cable connections to the rectifier must be mechanically secure and electrically conductive. Before the power source is energized, it must be verified that the negative cable is connected to the structure to be protected and that the positive cable is connected to the anodes. After the DC power source has been energized, suitable measurements should be made to verify that these connections are correct.

8.5.2.6 Underground splices on the header (positive) cable to the groundbed should be kept to a minimum. Connections between the header and anode cables should be mechanically secure and electrically conductive. If buried or submerged, these connections must be sealed to prevent moisture penetration so that electrical isolation from the environment is ensured.

8.5.2.7 Care must be taken during installation of direct-burial cable to the anodes (positive cable) to avoid damage to insulation. Sufficient slack should be left to avoid strain on all cables. Backfill material around the cable should be free of rocks and foreign matter that might cause damage to the insulation when the cable is installed in a trench. Cable can be installed by plowing if proper precautions are taken.

8.5.2.8 If insulation integrity on the buried or submerged header cable, including splices, is not maintained, this cable may fail because of corrosion.

8.6 Corrosion Control Test Stations, Connections, and Bonds (see Paragraph 4.5)

8.6.1 Pipe and test lead wires should be clean, dry, and free of foreign materials at points of connection when the connections are made. Connections of test lead wires to the pipe must be installed so they will remain mechanically secure and electrically conductive.

8.6.2 All buried or submerged lead-wire attachments should be coated with an electrically insulating material, compatible with the external pipe coating and wire insulation.

8.6.3 Test lead wires should be color coded or otherwise permanently identified. Wires should be installed with slack. Damage to insulation should be avoided and repairs made if damage occurs. Test leads should not be exposed to excessive heat and sunlight. Aboveground test stations are preferred. If test stations are flush with the ground, adequate slack should be provided within the test station to facilitate test connections.

8.6.4 Cable connections at bonds to other structures or across isolating joints should be mechanically secure, electrically conductive, and suitably coated. Bond connections should be accessible for testing.

8.7 Electrical Isolation

8.7.1 Inspection and electrical measurements should ensure that electrical isolation is adequate (see NACE Standard RP0286[5]).

Section 9: Control of Interference Currents

9.1 Introduction

9.1.1 This section recommends practices for the detection and control of interference currents. The mechanism and its detrimental effects are described.

9.2 Mechanism of Interference-Current Corrosion (Stray-Current Corrosion)

9.2.1 Interference-current corrosion on buried or submerged metallic structures differs from other causes of corrosion damage in that the direct current,

which causes the corrosion, has a source foreign to the affected structure. Usually the interfering current is collected from the electrolyte by the affected structure from a DC source not metallically bonded to the affected structure.

9.2.1.1 Detrimental effects of interference currents usually occur at locations where the currents transfer between the affected structures and the electrolyte.

9.2.1.2 Structures made of amphoteric metals such as aluminum and lead may be subject to corrosion damage from a buildup of alkalinity at or near the metal surface collecting interference currents.

9.2.1.3 Coatings may become disbonded at areas where voltage gradients in the electrolyte force current onto the affected structure. However, as the external coating becomes disbonded, a larger area of metal may be exposed, which would increase the demand for a cathodic protection current. This disbondment may create shielding problems.

9.2.2 The severity of external corrosion resulting from interference currents depends on several factors:

9.2.2.1 Separation and routing of the interfering and affected structures and location of the interfering current source;

9.2.2.2 Magnitude and density of the current;

9.2.2.3 Quality of the external coating or absence of an external coating on the structures involved; and

9.2.2.4 Presence and location of mechanical joints having high electrical resistance.

9.2.3 Typical sources of interference currents include the following:

9.2.3.1 Direct current: cathodic protection rectifiers, thermoelectric generators, DC electrified railway and transit systems, coal mine haulage systems and pumps, welding machines, and other direct current power systems;

9.2.3.2 Alternating current: AC power systems and AC electrified railway systems; and

9.2.3.3 Telluric current.

9.3 Detection of Interference Currents

9.3.1 During external corrosion control surveys, personnel should be alert for electrical or physical observations that could indicate interference from a foreign source such as the following:

9.3.1.1 Pipe-electrolyte potential changes on the affected structure caused by the foreign DC source;

9.3.1.2 Changes in the line current magnitude or direction caused by the foreign DC source;

9.3.1.3 Localized pitting in areas near or immediately adjacent to a foreign structure; and

9.3.1.4 Damage to external coatings in a localized area near an anode bed or near any other source of stray direct current.

9.3.2 In areas in which interference currents are suspected, appropriate tests should be conducted. All affected parties shall be notified before tests are conducted. Notification should be channeled through corrosion control coordinating committees, when they exist (see NACE Publication TPC 11[8]). Any one or a combination of the following test methods can be used.

9.3.2.1 Measurement of structure-electrolyte potentials with recording or indicating instruments;

9.3.2.2 Measurement of current flowing on the structure with recording or indicating instruments;

9.3.2.3 Development of beta curves to locate the area of maximum current discharge from the affected structure (see Appendix A); and

9.3.2.4 Measurement of the variations in current output of the suspected source of interference current and correlations with measurements obtained in Paragraphs 9.3.2.1 and 9.3.2.2.

9.4 Methods for Mitigating Interference Corrosion Problems

9.4.1 Interference problems are individual in nature and the solution should be mutually satisfactory to the parties involved. These methods may be used individually or in combination.

9.4.2 Design and installation of electrical bonds of proper resistance between the affected structures is a technique for interference control. The bond electrically conducts interference current from an affected structure to the interfering structure and/or current source.

9.4.2.1 Unidirectional control devices, such as diodes or reverse-current switches, may be required in conjunction with electrical bonds if fluctuating currents are present. These devices prevent reversal of current flow.

9.4.2.2 A resistor may be necessary in the bond circuit to control the flow of electrical current from the affected structure to the interfering structure.

9.4.2.3 The attachment of electrical bonds can reduce the level of cathodic protection on the interfering structure. Supplementary cathodic protection may then be required on the interfering structure to compensate for this effect.

9.4.2.4 A bond may not effectively mitigate the interference problem in the case of a cathodically protected bare or poorly externally coated pipeline that is causing interference on an externally coated pipeline.

9.4.3 Cathodic protection current can be applied to the affected structure at those locations at which the interfering current is being discharged. The source of cathodic protection current may be galvanic or impressed current anodes.

9.4.4 Adjustment of the current output from interfering cathodic protection rectifiers may resolve interference problems.

9.4.5 Relocation of the groundbeds of cathodic protection rectifiers can reduce or eliminate the pickup of interference currents on nearby structures.

9.4.6 Rerouting of proposed pipelines may avoid sources of interference current.

9.4.7 Properly located isolating fittings in the affected structure may reduce or resolve interference problems.

9.4.8 Application of external coating to current pick-up area(s) may reduce or resolve interference problems.

9.5 Indications of Resolved Interference Problems

9.5.1 Restoration of the structure-electrolyte potentials on the affected structure to those values that existed prior to the interference.

9.5.2 Measured line currents on the affected structure that show that the interference current is not being discharged to the electrolyte.

9.5.3 Adjustment of the slope of the beta curve to show that current discharge has been eliminated at the location of maximum exposure (see Appendix A).

Section 10: Operation and Maintenance of Cathodic Protection Systems

10.1 Introduction

10.1.1 This section recommends procedures and practices for energizing and maintaining continuous, effective, and efficient operation of cathodic protection systems.

10.1.1.1 Electrical measurements and inspection are necessary to determine that protection has been established according to applicable criteria and that each part of the cathodic protection system is operating properly. Conditions that affect protection are subject to change. Correspondingly, changes may be required in the cathodic protection system to maintain protection. Periodic measurements and inspections are necessary to detect changes in the cathodic protection system. Conditions in which operating experience indicates that testing and inspections need to be made more frequently than recommended herein may exist.

10.1.1.2 Care should be exercised in selecting the location, number, and type of electrical measurements used to determine the adequacy of cathodic protection.

10.1.1.3 When practicable and determined necessary by sound engineering practice, a detailed (close-interval) potential survey should be conducted to (a) assess the effectiveness of the cathodic protection system; (b) provide base line operating data; (c) locate areas of inadequate protection levels; (d) identify locations likely to be adversely affected by construction, stray currents, or other unusual environmental conditions; or (e) select areas to be monitored periodically.

10.1.1.4 Adjustments to a cathodic protection system should be accompanied by sufficient testing to assure the criteria remain satisfied and to reassess interference to other structures or isolation points.

10.2 A survey should be conducted after each cathodic protection system is energized and/or adjusted to determine whether the applicable criterion or criteria from Section 6 have been satisfied.

10.3 The effectiveness of the cathodic protection system should be monitored annually. Longer or shorter intervals for monitoring may be appropriate, depending on the variability of cathodic protection factors, safety considerations, and economics of monitoring.

10.4 Inspection and tests of cathodic protection facilities should be made to ensure their proper operation and maintenance as follows:

10.4.1 All sources of impressed current should be checked at intervals of two months. Longer or shorter intervals for monitoring may be appropriate. Evidence

of proper functioning may be current output, normal power consumption, a signal indicating normal operation, or satisfactory cathodic protection levels on the pipe.

10.4.2 All impressed current protective facilities should be inspected annually as part of a preventive maintenance program to minimize in-service failure. Longer or shorter intervals for monitoring may be appropriate. Inspections may include a check for electrical malfunctions, safety ground connections, meter accuracy, efficiency, and circuit resistance.

10.4.3 Reverse-current switches, diodes, interference bonds, and other protective devices, whose failures would jeopardize structure protection, should be inspected for proper functioning at intervals of two months. Longer or shorter intervals for monitoring may be appropriate.

10.4.4 The effectiveness of isolating fittings, continuity bonds, and casing isolation should be evaluated during the periodic surveys. This may be accomplished by electrical measurements.

10.5 When pipe has been uncovered, it should be examined for evidence of external corrosion and, if externally coated, for condition of the external coating.

10.6 The test equipment used for obtaining each electrical value should be of an appropriate type. Instruments and related equipment should be maintained in good operating condition and checked for accuracy.

10.7 Remedial measures should be taken when periodic tests and inspections indicate that cathodic protection is no longer adequate. These measures may include the following:

10.7.1 Repair, replace, or adjust components of cathodic protection systems;

10.7.2 Provide supplementary facilities where additional cathodic protection is necessary;

10.7.3 Thoroughly clean and properly coat bare structures if required to attain cathodic protection;

10.7.4 Repair, replace, or adjust continuity and interference bonds;

10.7.5 Remove accidental metallic contacts; and

10.7.6 Repair defective isolating devices.

10.8 An electrical short circuit between a casing and carrier pipe can result in inadequate cathodic protection of the pipeline outside the casing due to reduction of protective current to the pipeline.

10.8.1 When a short results in inadequate cathodic protection of the pipeline outside the casing, steps must be taken to restore cathodic protection to a level required to meet the cathodic protection criterion. These steps may include eliminating the short between the casing and carrier pipe, supplementing cathodic protection, or improving the quality of the external coating on the pipeline outside the casing. None of these steps will ensure that external corrosion will not occur on the carrier pipe inside the casing; however, a shorted casing does not necessarily result in external corrosion of the carrier pipe inside the casing.

10.9 When the effects of electrical shielding of cathodic protection current are detected, the situation should be evaluated and appropriate action taken.

Section 11: External Corrosion Control Records

11.1 Introduction

11.1.1 This section describes external corrosion control records that will document in a clear, concise, workable manner, data that are pertinent to the design, installation, operation, maintenance, and effectiveness of external corrosion control measures.

11.2 Relative to the determination of the need for external corrosion control, the following should be recorded:

11.2.1 Corrosion leaks, breaks, and pipe replacements; and

11.2.2 Pipe and external coating condition observed when a buried structure is exposed.

11.3 Relative to structure design, the following should be recorded:

11.3.1 External coating material and application specifications; and

11.3.2 Design and location of isolating devices, test leads and other test facilities, and details of other special external corrosion control measures taken.

11.4 Relative to the design of external corrosion control facilities, the following should be recorded:

11.4.1 Results of current requirement tests;

11.4.2 Results of soil resistivity surveys;

11.4.3 Location of foreign structures; and

11.4.4 Interference tests and design of interference bonds and reverse-current switch installations.

11.4.4.1 Scheduling of interference tests, correspondence with corrosion control coordinating committees, and direct communication with the concerned companies.

11.4.4.2 Record of interference tests conducted, including location of tests, name of company involved, and results.

11.5 Relative to the installation of external corrosion control facilities, the following should be recorded:

11.5.1 Installation of cathodic protection facilities:

11.5.1.1 Impressed current systems:

11.5.1.1.1 Location and date placed in service;

11.5.1.1.2 Number, type, size, depth, backfill, and spacing of anodes;

11.5.1.1.3 Specifications of rectifier or other energy source; and

11.5.1.1.4 Cable size and type of insulation.

11.5.1.2 Galvanic anode systems:

11.5.1.2.1 Location and date placed in service;

11.5.1.2.2 Number, type, size, backfill, and spacing of anodes; and

11.5.1.2.3 Wire size and type of insulation.

11.5.2 Installation of interference mitigation facilities:

11.5.2.1 Details of interference bond installation:

11.5.2.1.1 Location and name of company involved;

11.5.2.1.2 Resistance value or other pertinent information; and

11.5.2.1.3 Magnitude and polarity of drainage current.

11.5.2.2 Details of reverse-current switch:

11.5.2.2.1 Location and name of companies;

11.5.2.2.2 Type of switch or equivalent device; and

11.5.2.2.3 Data showing effective operating adjustment.

11.5.2.3 Details of other remedial measures.

11.6 Records of surveys, inspections, and tests should be maintained to demonstrate that applicable criteria for interference control and cathodic protection have been satisfied.

11.7 Relative to the maintenance of external corrosion control facilities, the following information should be recorded:

11.7.1 Maintenance of cathodic protection facilities:

11.7.1.1 Repair of rectifiers and other DC power sources; and

11.7.1.2 Repair or replacement of anodes, connections, wires, and cables.

11.7.2 Maintenance of interference bonds and reverse current switches:

11.7.2.1 Repair of interference bonds; and

11.7.2.2 Repair of reverse-current switches or equivalent devices.

11.7.3 Maintenance, repair, and replacement of external coating, isolating devices, test leads, and other test facilities.

11.8 Records sufficient to demonstrate the evaluation of the need for and the effectiveness of external corrosion control measures should be maintained as long as the facility involved remains in service. Other related external corrosion control records should be retained for such a period that satisfies individual company needs.

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Appendix A—Interference Testing

A beta curve is a plot of dynamic (fluctuating) interference current or related proportional voltage (ordinate) versus values of corresponding structure-to-soil potentials at a selected location on the affected structure (abscissa). If the correlation is reasonably linear, the plot will indicate whether the affected structure is receiving or discharging current at the location where the structure-to-soil potential was measured. Dynamic interference investigation involves many beta curve plots to search for the point of maximum interference-current discharge. Interference is resolved when the correlation of maximum current discharge has been changed to a correlation that shows that current pickup is being achieved in the exposure area by the corrective measures taken. These corrective measures may be accomplished by metallic bonding or other interference control techniques.

Appendix B—Method for Determining Probable Corrosion Rate and Costs of Maintaining Service

Maintenance of a piping system may include repairing corrosion leaks and reconditioning or replacing all or portions of the system.

In order to make estimates of the costs involved, it is necessary to determine the probability of corrosion or the rate at which corrosion is proceeding. The usual methods of predicting the probability or rate of corrosion are as follows:

(a) Study of corrosion history on the piping system in question or on other systems of the same material in the same general area or in similar environments. Cumulative leak-frequency curves are valuable in this respect.

(b) Study of the environment surrounding a piping system: resistivity, pH, and composition. Redox potential tests may also be used to a limited extent. Once the nature of the environment has been determined, the probable corrosiveness is estimated by reference to actual corrosion experience on similar metallic structures where environmental conditions are similar. Consideration of possible environmental changes such as might result from irrigation, spillage of corrosive substances, pollution, and seasonal changes in soil moisture content should be included in such a study.

(c) Investigation for corrosion on a piping system by visual inspection of the pipe and/or by instruments that mechanically or electrically inspect the condition of the pipe. Condition of the piping system should be carefully determined and recorded each time a portion of the line is excavated for any reason.

(d) Maintenance records detailing leak locations, soil studies, structure-to-electrolyte potential surveys, surface potential surveys, line current studies, and wall thickness surveys used as a guide for locating areas of maximum corrosion.

(e) Statistical treatment of available data.

(f) Results of pressure testing. Under certain conditions, this may help to determine the existence of corrosion.

Appendix C—Contingent Costs of Corrosion

In addition to the direct costs that result from corrosion, contingent costs include:

(a) Public liability claims;

(b) Property damage claims;

(c) Damage to natural facilities, such as municipal or irrigation water supplies, forests, parks, and scenic areas;

(d) Cleanup of product lost to surroundings;

(e) Plant shutdown and startup costs;

(f) Cost of lost product;

(g) Loss of revenue through interruption of service;

(h) Loss of contract or goodwill through interruption of service; and

(i) Loss of reclaim or salvage value of piping system.

Appendix D—Costs of Corrosion Control

The usual costs for protecting buried or submerged metallic structures are for complete or partial cathodic protection or for external coatings supplemented with cathodic protection. Other corrosion control costs include:

(a) Relocation of piping to avoid known corrosive conditions (this may include installing lines above ground);

(b) Reconditioning and externally coating the piping system;

(c) Use of corrosion-resistant materials;

(d) Use of selected or inhibited backfill;

(e) Electrical isolation to limit possible galvanic action; and

(f) Correction of conditions in or on the pipe that might accelerate corrosion.

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