Battelle
Columbus Laboratories

Report

FINAL REPORT

on

GUIDELINES FOR LOWERING PIPELINES WHILE IN SERVICE

Sponsored by

American Society of Mechanical Engineers

and jointly funded by

UNITED STATES DEPARTMENT OF TRANSPORTATION
AMERICAN SOCIETY OF MECHANICAL ENGINEERS
AMERICAN PETROLEUM INSTITUTE

February 25, 1985

by

J. F. Kiefner, T. A. Wall, N. D. Ghadiali
K. Prabhat, and E. C. Rodabaugh

BATTELLE
Columbus Laboratories
505 King Avenue
Columbus, Ohio 43201-2693

Technical Report Documentation Page

1. Report No.	1. Government Accession No.	1. Recipient's Catalog No.
DOT-RSPA-DMT-30/84/8		

4. Title and Subtitle

GUIDELINES FOR LOWERING PIPELINES WHILE IN SERVICE

5. Report Date

FEBRUARY 35, 1985

6. Performing Organization Code

G8665-1

7. Author(s) Kiefner, J.F. , Wall, T.A. , Ghadiali, N.U. , Prabhat, K, and Rodabaugh, E.C.

8. Performing Organization Report No.

NA

9. Performing Organization Name and Address

Battelle Columbus Laboratories
505 King Avenue
Columbus, Ohio 43201-2693

10. Work Unit No. (TRAIS)

11. Contract or Grant No.

DTRS5683-C-00022

12. Sponsoring Agency Name and Address

U.S. Department of Transportation
Office of Pipeline Safety Regulation
400 Seventh Street, S.W.
Washington, D. C. 20590

13. Type of Report and Period Covered

FINAL REPORT
Sept 1983 - Aug 1984

14. Sponsoring Agency Code

15. Supplementary Notes

Technical Monitor: Douglas B. Chisholm

16. Abstract

A method was developed to calculate stresses induced into a pipeline as the result of lowering it. Simple computer programs were developed to calculate the following:

- Stress added as a result of lowering
- Initial axial stress existing prior to lowering (requires lifting the pipeline and making certain measurements)
- French profiles which limit the added stress to a desired value
- Temporary support spacing and allowable differences in support heights.

The safety issues associated with lowering a pipeline in service are discussed also. Recommended procedures for lowering are provided and the limitations on lowering are discussed.

17. Key Words

pipelines
road crossings

18. Distribution Statement

Available to the Public through the National Technical Information Service, Springfield, Virginia 22161.

19. Security Classif. (of this report)	20. Security Classif. (of this page)	21. No. of Pages	22. Price
Unclassified	Unclassified		

Form DOT F 1700.7 (8-72) Reproduction of completed page authorized

TABLE OF CONTENTS

Page

INTRODUCTION. 1

SUMMARY.. 3

Significant Findings 3

Stresses and Deflections. 3
Defect Criteria 5
Practical Procedures. 6
Limits on Lowering. 7

Conclusions. 7
Recommendations. 7

FACTORS INVOLVED IN LOWERING A PIPELINE IN SERVICE. 9

Deflection Requirement 9
The Pipe and the Pipeline. 11
Terrain. 12
Soil. 16
Safety 18
Stress 18

Existing Longitudinal Stress. 19
Lowering-Induced Stresses 22

ANALYTICAL ASSESSMENT OF STRESSES 23

Existing Stress Calculation. 25
General Buckling 34
Lowering Induced Stress. 34

Free Deflection Stresses. 34
Contoured Trench Solutions. 36
Examples of Free Deflection and Contoured Trench Solutions 37

Spacing of Supports or Side Boom Tractors to Limit Stresses to Desired Values. 42

POSSIBLE FAILURE MODES OF PIPELINES WHILE BEING LOWERED 47

Damage from Excavating Equipment 47
Circumferentially-Oriented Defects 47
Definition of Problem. 49
Technical Approach 51

TABLE OF CONTENTS
(Continued)

	Page
BCL Model	51
British Standard CTOD Approach	52
National Bureau of Standards-Critical COD Method	52
API Analysis	55
Other Approaches	57
Example Case	57
Local Buckling	58
PROCEDURES FOR LOWERING	61
Preliminary Lowering Profile	61
Profile of the Existing Pipeline	61
Preliminary Estimates of Span and Lowering Profile	62
Planning for Existing Elastic Curvature. Valves. Fittings. and Bends	63
Field Loweri'ng Procedures	66
Determining the Existing Axial Stress	69
Excavating the Trench for Lowering	71
Inspection	71
Lifting and Lowering	72
EXAMPLES	74
Example 1	74
Step 1. Determining Pipeline Parameters	74
Step 2. Determining Terrain and Soil Parameters	74
Step 3. Preliminary Calculations	78
Step 4. Decisions Based Upon Initial Review	81
Step 5. Initial Field Considerations	81
Step 6. Lifting to Determine Existing Stress	82
Step 7. Excavation. Inspection. Lowering	83
Example 2	85
Step 1. Determining Pipeline Parameters	85
Step 2. Determine Terrain and Soil Parameters	85
Step 3. Preliminary Calculations	86
Step 4. Decisions Based Upon Initial Review	88
Step 5. Initial Field Considerations	89

TABLE OF CONTENTS
(Continued)

		Page
	Step 6. Lifting to Determine Existing Stress.	89
	Step 7. Excavation, Inspection, Lowering.	91
REFERENCES.		92
APPENDIX A.	MINIMIZING THE CHANCES OF A LONGITUDINAL RUPTURE IN A PRESSURIZED PIPELINE.	A-1
APPENDIX B.	DEVELOPMENT OF EQUATIONS FOR DETERMINING EXISTING AXIAL STRESS AND LOWERING INDUCED STRESSES	B-1
APPENDIX C.	TABLES AND FIGURES FOR LOWERING PIPELINES OF VARIOUS SIZES..	C-1
APPENDIX D.	COMPUTER PROGRAMS FOR LOWERING CALCULATIONS.	D-1

LIST OF FIGURES

Figure 1.	Lowering an Existing Pipeline to Accommodate a New Crossing.	10
Figure 2.	Added Stress Imposed by Pipe Weight or Soil Instability in Hilly Terrain.	14
Figure 3.	Tendency of Pipeline to be Strained in Tension by Slope Instability	15
Figure 4.	Effect of Soil Type on Trenching Method	17
Figure 5.	Minimum Free Deflection Span as a Function of Deflection at Midspan and Initial Axial Stress	26
Figure 6.	Maximum Stress Due to Lowering as a Function of Deflection at Midspan and Initial Axial Stress.	27
Figure 7.	Initial Axial Stress as Determined From Lift Off Length and Lift Off Height.	29
Figure 8.	Lifting Force	30
Figure 9.	Maximum Stress as a Function of Initial Axial Stress and Lift Height	31

LIST OF FIGURES
(Continued)

		Page
Figure 10.	Elastic Buckling of a Pipeline Containing Compressive Axial Stress.	33
Figure 11.	Comparison of Contoured Trench Spans and Stresses With Free Deflection Spans and Stresses.	41
Figure 12.	Example of Stress Reduction Achieved by Lengthening the Span and Reducing the Curvature	43
Figure 13.	Relationship Between Surface Flaws and Equivalent Through-Wall Flaws for British Approach to COD Analysis	53
Figure 14.	Allowable Flaw Size From API 1104, Appendix A	54
Figure 15.	Bending Stress in Pipe Versus Flaw Size Curves Using BCL Criterion	56
Figure 16.	Comparison of Critical/Allowable Flaw Sizes From Various Criteria.	59
Figure 17.	Handling Actual Pipeline Profiles Where Elastic Curvature is Present.	64
Figure 18.	Handling Actual Pipeline Profiles Where Valves, Fittings, or Field Bends are Present.	65
Figure 19.	Measuring Existing Axial Stress by Lifting the Pipeline..	67
Figure 20.	Difference Between Amount Lowered and Calculated Deflection for an Offset Trench	70
Figure 21.	Pipeline Profiles for Example 1	79
Figure 22.	Pipeline Profiles for Example 2	87

LIST OF TABLES

Table 1.	Stresses and Span Length for Free Deflection of Pipe. . .	38
Table 2.	Stresses and Span Length for Minimum Length of Contoured Trench.	39

LIST OF TABLES
(Continued)

		Page
Table 3.	Maximum Distance in Feet Between Supports to Limit Total Stress to 28,100 psi.	45
Table 4.	Values for J_{Ic} Obtained from 2/3 Size CVN Energy. . . .	50
Table 5.	Results of Collapse Study	60
Table 6.	Steps in Lowering as Applied to Sample Problems	75

FINAL REPORT

on

GUIDELINES FOR LOWERING PIPELINES WHILE IN SERVICE

by

J. F. Kiefner, T. A. Wall, N. D. Ghadiali,
K. Prabhat and E. C. Rodabaugh

INTRODUCTION

When an existing pipeline is to be crossed by a new road or railroad that will expose the pipeline either to mechanical damage and/or excessive stresses from wheel loads, it is often necessary to take steps to protect the pipeline. It is highly desirable that the action taken avoid, if possible, removing the pipeline from service in order to prevent loss of service to customers and loss of revenue. One method which can be used to protect such a pipeline consists of lowering the pipeline into a deeper trench so that it will be positioned farther below the new road or railroad. The rationale for lowering is that in its new, deeper position the pipeline will experience stresses from wheel loads that are acceptably small and that the pipeline will be safe from mechanical damage during the grading and excavation associated with the new road or railroad.

Lowering of pipelines has been done over the years, apparently without incident in most cases. The lowering operation adds to the longitudinal stress in the pipe, but in most cases this added stress has caused no significant problems. In 1978, however, an 8-inch propane pipeline failed at Donnellson, Iowa* after having been lowered. There was much controversy over whether or not this failure was related to the lowering-induced stresses since the failure occurred after the lowering as the result of a mechanical damage

* National Transportation Safety Board--Pipeline Accident Report "Mid-America Pipeline System Liquified Petroleum Gas Pipeline Rupture and Fire, Donnellson, Iowa, August 4, 1978", Report No. NTSB-PAR-79-1.

defect. Because this defect was oriented approximately 20 degrees from the direction of the pipe axis, it should not have been greatly affected by the added longitudinal stress. Nevertheless, the incident exposed the fact that no uniform guidelines existed to insure that lowering a pipeline in service could be done with reasonable safety. As a result the American Society of Mechanical Engineers, the American Petroleum Institute and the Office of Pipeline Safety Regulation of the U.S. Department of Transportation decided to undertake jointly the study described herein to establish guidelines for safely lowering pipelines without taking them out of service.

The objectives of the study described herein were to develop detailed guidelines for conducting a pipeline lowering operation without taking the pipeline out of service, to develop equations for predicting the lowering induced stresses, and to establish reasonable limits on the lowering-induced stresses so that the pipeline will not be damaged or ruptured due to lowering operations. It is noted that this study is not intended to be an endorsement of lowering as a method of addressing the safety of an existing pipeline at a new road crossing. It is merely intended to provide guidance to pipeline operators or contractors who choose lowering as their preferred alternative.

The objectives were accomplished by means of an analytical research project in which elastic beam-column theory was used to determine stresses induced by lowering and to calculate deflected profiles which result in acceptable values of added stresses.

SUMMARY

This research project has produced the elements of guidelines for safely lowering a pipeline without removing it from service. During the course of the project the research team made detailed assessments of the major pipeline lowering issues which are:

- Factors which affect lowering--the pipe, the pipeline and its condition, terrain, soil, and stress
- Safety--pressure reduction, excavation safety, response to emergencies, protection of personnel and the public
- Stresses--existing stress in the pipeline, lowering induced stresses, measuring and calculating stresses, support spacing, safe limits on stresses
- Failure modes--ruptures, leaks, or buckles from improper lowering operations
- Procedures--Initial review, trench types and profiles, lowering alternatives, measuring stresses, minimizing temporary stresses, inspection.

As a result of this project a rational procedure has been developed for lowering a pipeline in-service without causing excessively high stresses.

Significant Findings

Stresses and Deflections

The analysis presented herein allows one to calculate stresses and deflections for a wide variety of pipeline lowering situations. The minimum possible span length which may be used to achieve a given maximum deflection at midspan is the free deflection profile. The free deflection profile is that which is achieved by letting the pipeline sag under its own unsupported weight until the desired midspan deflection is achieved. The stresses in the free deflection profile are poorly distributed, however, and become unacceptably high near the ends of the span. Longer spans result in lower stresses, and one case which stands out as being a reasonable compromise between the length of the trench and the added stress is the contoured trench profile. The contoured trench profile is based upon the equalization of curvature throughout as nearly as possible (except near the inflection points). Although minimum contoured spans are up to 60 percent longer than free deflection spans, the maximum stresses are 33 to 67 percent lower. As a result it should be possible to lower most pipelines in service without exceeding the stress limits of applicable design codes.

It was found that stresses and span lengths for the contoured profiles are not strongly dependent upon pipe geometry. Therefore, it is possible to create guidelines with charts and tables of lowering parameters for only a few pipe sizes. For example, all sizes larger than 30-inch diameter could be covered by one set of parameters for 48-inch pipe, all sizes between 16-inch diameter and 30-inch diameter could be covered by one set of parameters for 30-inch pipe, and so on, In contrast to the effect of pipe geometry, however, the stresses and span lengths for lowering were found to be highly dependent on the amount of axial stress already present in the pipeline, making it necessary to determine the existing stress or at least conservatively estimate it. As one might expect, span length and stress increase with increasing required deflection.

It is hypothesized with sound reasoning that the existing axial stress in a pipeline except in certain circumstances will lie in the range of -10,000 to +20,000 psi. The exceptions where the existing axial stress might be less than -10,000 psi or more than +20,000 psi are cases where the slopes are unstable and the soil movement deflects the pipeline, where frost heave or soil liquifaction cause movement of the pipeline or where the pipeline was installed in cold weather or is well above ambient ground temperature because of being near a compressor station or because it transmits a heated product. These initial stresses arise either from the biaxial effect of pressure and the temperature differential between construction and operation where soil restraint is present or from pressure acting on closed ends or bends in the absence of soil restraint. Calculations of lowering-induced stresses by means of these guidelines can be made for any initial value of axial stress within this range of -10,000 to +20,000 psi. In view of the fact that in most cases (except for slack lines as noted below) the operator will not know the amount of the axial stress, a conservative procedure is suggested as follows for calculating the lowering-induced stresses. By assuming a maximum value of +20,000 psi for most pipe grades, one can calculate the stresses for lowering and expect that the resulting values will not be exceeded if the existing stress lies anywhere in the range of -10,000 to +20,000 psi.

It is generally safe to apply these guidelines to cases in which the axial stress might be less than zero or have less than -10,000 psi as long as an assumed axial stress level not less than zero is used in the calculations. An assumed axial stress level of zero may be used in the case of a "slack" line where the line has intentionally been allowed to curve from side-to-side in the ditch to minimize residual stress in the pipe. It is recommended that these guidelines not be used in cases where the existing axial stress is suspected or known to be in excess of +20,000 psi.

A method for measuring the existing axial stress by lifting a portion of the line and making certain measurements is described herein, but its practicality remains to be demonstrated. The analysis technique presented herein is also used to predict support spacing or lift points for the pipeline to avoid excessive stresses. Finally, if the contoured profile technique and the correct support spacing are used, there is no danger of local buckling occurring during the lowering operation.

Defect Criteria

The greatest danger to the pipeline from longitudinal stresses induced during a lowering operation was reasoned to be the presence of circumferential defects. Since these are most likely to occur at girth welds and since girth welds also constitute regions of high residual stress and variable material properties, it was further reasoned that the failure resistance of the girth welds would be the limiting factor. Various fracture mechanics approaches were reviewed in an attempt to obtain a satisfactory defect size versus failure stress level criterion. There was considerable disagreement between the various criteria with regard to allowable/critical flaw sizes. Since limited experimental data were available, selecting one criterion as being the most appropriate or accurate could not be done. This finding, coupled with the inability of a pipeline operator to adequately inspect the girth welds in a live pipeline and the probable lack of information on the fracture toughness of the welds, led us to abandon for the time being the attempt to set up a defect criterion for use as a part of any guidelines for lowering. Instead, it is suggested that a conservative limit be placed upon the maximum stress to be allowed during lowering. It is shown herein that most lowering situations can be handled without the stresses exceeding 54 percent of the specified minimum yield strength (**SMYS**) of the pipe, the maximum longitudinal stress allowed by the applicable design codes.* This limit is particularly appropriate, having been established lower than the allowable hoop stress to allow for the fact that girth welds are regions of high residual stress and variable material properties.

Practical Procedures

A number of practical issues were reviewed during the study as a means of enhancing the effectiveness of any resulting guidelines and the safety and effectiveness of any lowering operations. To minimize the risk of a leak or rupture from defects that might be created by the excavating equipment, an equation is presented for an upper limit on the operating pressure during a lowering operation. In addition, suggestions are made to reduce other risks associated with lowering. These include stationing personnel at valves, evacuating nearby residents, creating berms to contain spills, and examining soil characteristics and considering an appropriate trench design to avoid cave-ins.

Trench types, support systems, and lowering methods are examined from the standpoint of practicality. Inspection procedures and limitations are discussed. Methods are suggested for handling field bends, valves or fittings, and examples are presented which show how to apply the analysis methods and how to handle existing elastic curvature of the pipeline.

---

* The applicable codes are the ANSI/ASME 831.4 Code for Liquid Petroleum Transportation Piping Systems and 831.8 Code for Gas Transmission and Distribution Piping Systems.

Limits on Lowering

It was found that under certain situations of terrain, soil, slope stability, pipeline joint type, and weather the analysis methods and the guidelines based on them would not be valid. Situations in which lowering in service by use of these guidelines is not recommended are:

- o Where slopes are steep or unstable
- o Where the soil is subject to frost heave or liquifaction
- o Where the pipeline is joined by acetylene welds, mechanical joints, or girth welds of known poor quality (unless welds are reinforced by full encirclement sleeves or other acceptable means)
- o When excessive cooling upon exposure of the pipeline might cause the initial axial stress level to exceed +20,000 psi.

Conclusions

It is concluded that lowering a pipeline in service usually can be done safely and effectively and that the methods and suggestions contained herein provide a useful guide for lowering. However, it is also concluded that more study is needed to completely resolve some of the issues.

Recommendations

From the standpoint of use of the methods presented herein, it is recommended that guidelines for lowering, for the present, be based upon the contoured trench profile concept described herein, and that the maximum stresses arising from supporting the pipeline and lowering it not be allowed to exceed 54 percent of SMYS.* It is also recommended that lowering be limited to situations of moderate terrain and stable soils where the axial

* The limit on longitudinal stress from pressure and external loads in a restrained pipeline according to the ANSI/ASME B31.4 and B31.8 design codes. In a gas pipeline the limit of 54 percent of SMYS applies to Class 1 locations only. The limit is 75 percent of the design stress level for other class locations.

stress is likely to be in the range of -10,000 to +20,000 psi. It is recognized that technological developments may occur which will allow more flexibility in any guidelines for lowering. Improvements in nondestructive testing methods and the interpretation of the data they generate could permit defects to be characterized much better than is currently possible. Also, a satisfactory criterion relating circumferential defect size to failure stress is likely to be developed in the near future. When these improvements are realized, it may be possible to increase the allowable stress during lowering. In particular, if an operator can show by adequate inspection and by the use of an accepted "fitness for purpose" criterion that the pipeline is capable of withstanding a higher stress level, then such a higher stress level should be permitted.

A list of technological developments and research which would enhance the art and science of pipeline lowering includes, but is not necessarily limited to:

- Monitoring a lowering operation by measuring appropriate strains to check the analysis methods
- Attempting a lift-off operation to see if the measurement of axial stress is feasible
- Trying various trenching and lowering methods suggested herein to measure their effectiveness
- Developing better inspection techniques
- Validating a defect size criteria by means of full-scale tests.

FACTORS INVOLVED IN LOWERING A PIPELINE IN SERVICE

When a lowering situation is contemplated, the various known factors must be reviewed. Most likely, the pipeline operator will be faced with a new road or railroad being built over an existing pipeline. For any rational decision to be made, a final cross section of the road or railroad right-of-way must be available showing the horizontal and vertical dimensions of pavements, roadbeds, subbases and drainage ditches. From these the pipeline operator must decide how to protect his pipeline. If lowering in-service is an option to be considered, the guidelines given herein should facilitate the decision as to whether or not it can be done safely, and is so, provide guidance for accomplishing satisfactory safe lowering.

In the lowering of a pipeline in service, the following factors must be considered.

Required Deflection. Depends on the type and nature of crossing.

The Pipe. Diameter, wall thickness, grade.

The Pipeline. Product, pressure, type of girth welds, test and operating history, presence of defects, existing curvature, bends, valves and fittings.

Terrain. Hilly, sloping, flat, etc.

Soil. Sand, silt, clay, rock, water table level, slope stability.

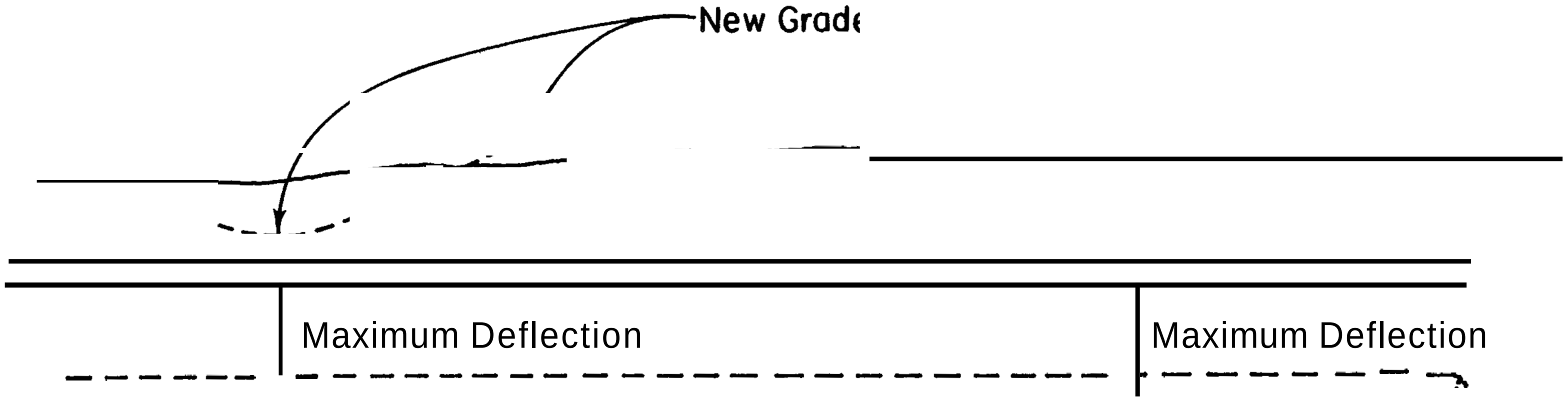
Safety. Minimizing the risk.

Stress. Lowering will increase the tensile stress. How much is present initially? How much can be safely added?

These factors are discussed below in detail pursuant to establishing guidelines for lowering.

Deflection Requirement

Given an imposed crossing situation with final roadway dimensions and elevations as shown in Figure 1, the pipeline operator must decide how much to lower the pipeline to protect it from excavation or maintenance


New Grade
Maximum Deflection
Maximum Deflection

associated with the roadway and from extra stresses imposed by static and dynamic loads on the roadway. Once established, this amount of lowering or "maximum deflection'' must be obtained in a safe and effective manner.

The Pipe and The Pipeline

The pipeline operator should review the pipe and the pipeline involved in the potential lowering situation. The diameter, wall thickness, and grade of the pipe must be known in order to calculate lowering induced stresses and deflections and to decide if the resulting stresses are acceptable. The type of product should be assessed from the following points of view.

- Weight of the product. This enters into certain calculations as will be shown
- Vapor pressure. This affects safety precautions. Gases have the potential for causing extensive fracture propagation in the event of an accident. High vapor pressure liquids may produce extensive amounts of flammable or toxic vapors in the event of a leak or rupture. Low vapor pressure liquids create environmental hazards in the event of a leak or rupture.

Pressure at the lowering site or, more specifically, hoop stress, affects the potential consequences of any accident such as digging equipment striking the pipe during excavation for lowering. The operator should consider lowering the pressure from two points of view. First, an unknown defect may be present at the excavation site. Lowering the pressure to 80 percent of the normal level at the excavation site provides substantial assurance that any unknown axial defect will not fail during the lowering operation. While pressure reduction should be considered from the standpoint of axially-oriented defects that might be present, pressure also has a lesser but still significant effect on circumferential defects. The latter are of concern in a lowering situation because of the added longitudinal stress. The added lowering stress would be expected to have little, if any, influence on axial defects.

Secondly, excavation around a live pipeline is hazardous in itself. The risk of rupture from excavating equipment hitting the pipe can be reduced significantly if the pressure, P, at the site is reduced to

$$P \leq 0.66\ Yt/D \tag{1}$$

where:

P is the pressure at the site, psig

t is the nominal wall thickness, inches

D is the diameter of the pipe, inches

Y is the specified minimum yield strength of the pipe.

The explanation of this limit is presented in Appendix A.

The history and condition of the pipeline should be considered in the initial review. For example:

- o Has the pipeline been hydrostatically tested to a minimum of 1.25 times the maximum allowable operating pressure? If not the operator should very definitely consider lowering the pressure before excavation begins in order to enhance the safety of the operation.

- o Has the pipeline been operated relatively trouble-free or has there been a history of leaks or failures? A pipeline with a history of leak problems should rate greater attention from the standpoint of safety, and the type of leaks may even dictate whether or not lowering while in service should even be attempted. A pipeline with a known history of girth weld problems might represent a high risk in a lowering situation. A pipeline with known problems from seam weld defects would certainly be a candidate for substantially reduced pressure during lowering.

Unique features such as existing elastic curvature of the pipe, field bends, elbows, valves, or other fittings that are within 1000 feet on either side of the proposed maximum deflection point should be flagged on alignment sheets so that they will be properly accounted for as the lowering plan proceeds.

Terrain

Terrain can have a significant effect on the existing axial stress in the pipe and must, therefore, be considered in the initial review. In absolutely flat terrain a pipeline is usually laid initially free of axial tensile or flexural stress. It is, in fact, difficult to put axial stress into a pipeline of any significant size because the pipe handling equipment simply cannot exert enough axial force. For example, one would have to pull on a 30-inch OD by 0.375-inch wall pipeline with a force of 350,000 lb. to put 10,000 psi tensile stress in the pipe. On the other hand, a pipeline in flat terrain does not stay stress-free in service. As will be shown below, such a pipeline is very likely to contain significant stress (-10,000 to +20,000 psi).

The existing stress situation is further complicated if the terrain is not flat. In gently rolling terrain the pipeline is likely to be laid by allowing it to elastically conform to the terrain. The elastic curvature induces flexural stress. In hilly or mountainous terrain, permanent overbends and sag bends will be made for sharp changes in terrain, but elastic curvature is also likely to be present. Also, where frequent bends exist, the pipeline may not be restrained by the soil but instead may be subjected to longitudinal stress from pressure acting on the bends.

Slope instability in hilly or mountainous terrain tends to produce tensile stress situations on hilltops and compressive stress situations in valleys when the pipeline lies in line with the slope (Figure 2). In situations where the pipeline is carried sideways by slope instability as shown in Figure 3, the entire affected area may sustain additional tensile and flexural strain.

Finally, adverse terrain will make any lowering operation more difficult and perhaps more dangerous. While the pipeline operator may have no choice as to where the crossing will be located with respect to terrain, he will certainly want to consider the implications of the terrain in any lowering operation. In fact, the terrain may govern whether or not lowering in-service is the most appropriate response to a proposed new crossing. At the very least, if the terrain is not relatively flat, the operator will need to study contour maps and profiles of the pipeline to locate areas of potentially high existing stresses. He will also need to review his own experience and pertinent geotechnical data regarding the stability of slopes in the area.

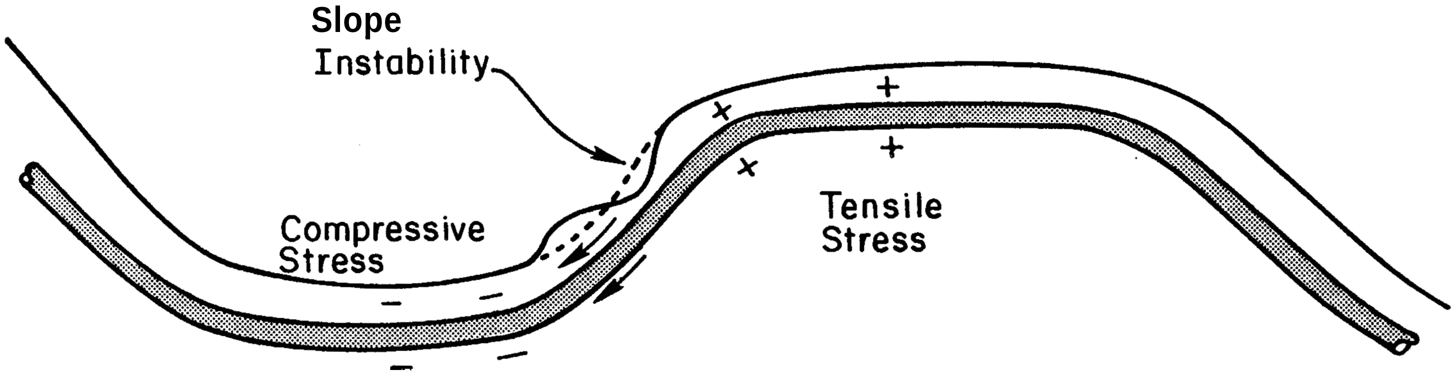


FIGURE 2. ADDED STRESS IMPOSED BY PIPE WEIGHT OR SOIL INSTABILITY IN HILLY TERRAIN

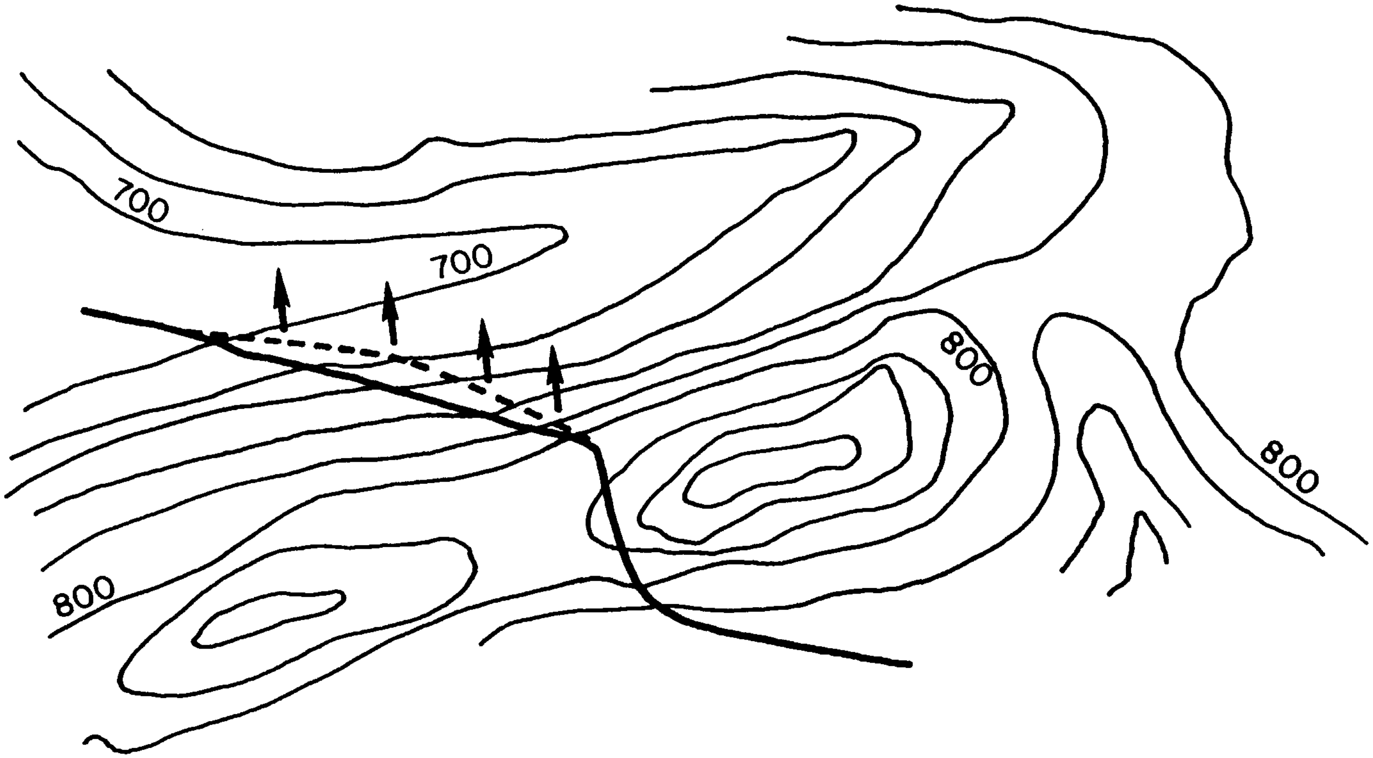


FIGURE 3. TENDENCY OF PIPELINE TO BE STRAINED IN TENSION BY SLOPE INSTABILITY

Soil

Soil type greatly affects the mode of excavation and lowering. As shown in Figure 4a, a vertical-sided excavation is possible with cohesive soil or rock. A parallel, deeper ditch may be excavated and the pipeline may be lifted by means of a side boom tractor, moved laterally, and lowered into it. Alternatively, as shown, the beam and winch method may be used. As shown in Figure 4b, in noncohesive soils the beam and winch method may be used, or it may be desirable to excavate bell holes around the pipe at intervals and to build a crib of wooden ties to support the pipe. Then, after the rest of the soil is removed, the pipeline can be lifted to permit removal of the cribs, and lowered into the new trench.* Shoring up the sides of the ditch is possible of course, but very expensive and time consuming for a lowering operation.

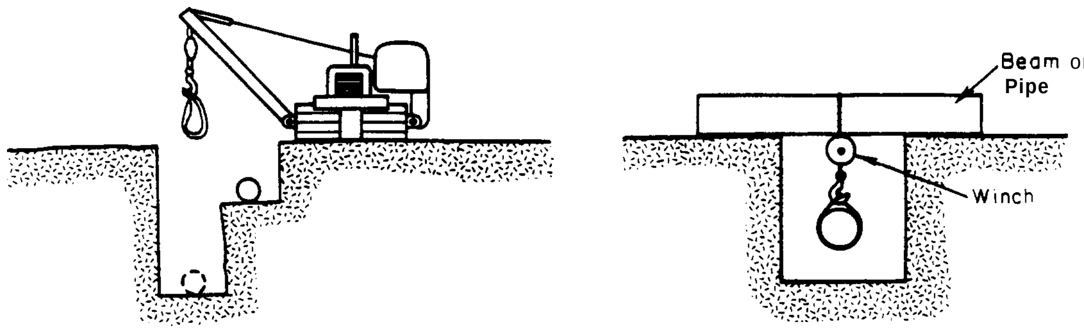
The pipeline operator should consider taking soil borings at appropriate intervals along the site of the lowering to establish the soil types at various depths and locations and the depth of the water table. These data are needed to deal with the following:

- Type of Trench. The operator must decide ahead of time whether to dig a vertical sided trench or a sloping sided trench or to take some other action such as constructing shoring.
- Safe Distance from Trench for Heavy Equipment. The properties of soil should be considered from the standpoint of its ability to support heavy equipment near the edge of the ditch.
- Blasting. If rock is to be removed by blasting, the operator will need to consider the proximity of the blasting to the live pipeline.
- Water Table. If the pipeline is to be lowered to a depth below the existing water table, the operator will have to consider providing weight for negative bouyancy.

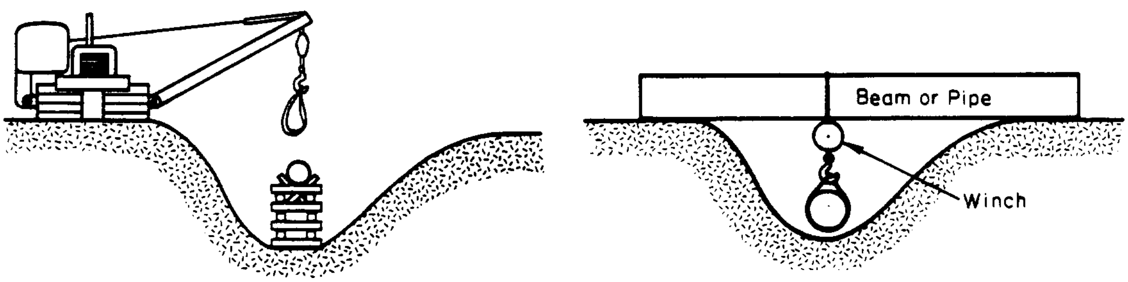
Also, special conditions such as frost heave or loss of shear strength with water intrusion (liquifaction) may affect the stress level in the pipeline. Any such conditions should be noted.

---

* Alternatively, soil pillars can be left at intervals to be removed in stages during the lowering operation.



(a) Cohesive Soil or Rock



(b) Noncohesive Soil

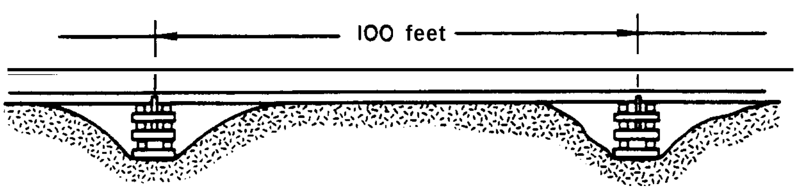


FIGURE 4. EFFECT OF SOIL TYPE ON TRENCHING METHOD

Safety

From the standpoint of safety, besides the normal safety practices required for pipeline construction, the operator must consider that lowering an in-service pipeline entails some special risks. One of these, the potential for rupture due to excavating equipment striking the pipeline, has been addressed previously. Another risk, that of a rupture or leak from improper lowering or an unanticipated event, may be dealt with at the outset of any lowering operation by developing emergency procedures. This can be done by:

- Minimizing personnel in the vicinity of the excavation.
- Keeping an observer posted a safe distance from the excavation with radio access to the pipeline dispatcher and other personnel in the vicinity to inform the dispatcher and others of any emergency situation and to render help if needed.
- Providing for immediate closure of upstream and downstream values in the event of an emergency.
- Evacuating any nearby residents who might be endangered by a rupture, a fire, or a dispersing cloud of flammable or toxic vapor.
- Creating temporary berms to contain spilled liquids

Stress

Stress is an extremely significant factor in lowering a pipeline in service. The question of hoop stress is best dealt with as described previously by lowering the operating pressure throughout the entire lowering operation. From the standpoint of longitudinal stress, the situation is as follows. Lowering the pipeline will permanently change the longitudinal stress because the pipeline must deflect to a new position. During lowering the pipeline may be subjected temporarily to increased stresses, but even without considering lowering induced stresses, it is highly probable that a buried pipeline is already under longitudinal stress. Longitudinal stress in the pipeline may or may not cause problems. In the most extreme case increased tensile or flexural stress might, in the presence of a circumferentially-oriented defect cause a failure or a leak. Compressive stress or severe flexural stress might cause general or local buckling. Neither a failure nor buckling can be tolerated, and hence, the stress, whether existing or lowering induced or a combination thereof, must be limited to levels which fall safely short of those which would produce such results. The essence of this study is the development of safe limits on lowering practices to avoid excessive longitudinal stress.

Existing Longitudinal Stress

The existing longitudinal stress in a buried pipeline arises from multiple sources. First, there is pressure-induced longitudinal stress. When fully restrained by the soil so it cannot move longitudinally an initially stress free pipeline picks up tensile stress in proportion to internal pressure because it cannot freely contract longitudinally as it expands circumferentially. This axial tensile stress is:

$$\sigma_{LP} = \nu PD/2t = .15\ PD/t \tag{2}$$

where:

- σ_{LP} is the longitudinal stress due to pressure, psi
- P is the pressure, psig
- D is the pipe diameter, inches
- t is the pipe wall thickness, inches
- ν is Poisson's ratio (0.3 for steel)

For a 30-inch OD by 0.375-inch wall X52 pipeline operating at 936 psig the longitudinal tensile stress is 11,232 psi. Even when the pressure is lowered to 429 psig as suggested by Equation (1) for safe lowering, the longitudinal stress would still be 5148 psi.

Another stress-inducing factor is the differential between the temperature at which the pipeline was laid and that at which it operates at the location of interest. Most pipelines are laid in warm weather. After being backfilled, the temperature of the pipeline approaches that of the ground, except near the discharge side of a compressor station of a gas pipeline or at all points in a heated oil pipeline. If the pipeline is fully restrained, this change in temperature produces a stress due to the fact that thermal expansion or contraction is prevented. As an example, from the standpoint of tensile stress, one might assume that the pipeline cools from 100 F to 60 F. The resulting tensile stress is:

$$\sigma_{LT} = \alpha(\Delta T)E = 6.5 \times 10^{-6} \times 40 \times 30 \times 10^{6} = 7800 \text{ psi} \qquad (3)^{*}$$

where

σ_{LT} is the longitudinal stress due to temperature change, psi
a is the coefficient of thermal expansion, in./in./F
AT is the temperature change, F
E is the elastic modulus, psi.

Compressive stress may arise if a pipeline is laid when the temperature is 60 F, for example, and later operates at a temperature of 140 F due to being near a compressor station or to carrying heated oil. By means of Equation 3 one finds that such a pipeline contains a compressive stress of

$$\sigma_{LT} = 6.5 \times 10^{-6} \times 80 \times 30 \times 10^{6} = 15{,}600 \text{ psi}$$

A brief review of the literature revealed only one published document[1]** containing actual measurements of existing stresses in a

---

* If a pipeline is not restrained by the soil such as may occur in areas of frequent bends, axial tensile stress arises from pressure acting on an effective area equal to the cross-sectional area of the pipe ($\pi D^2/4$). The longitudinal stress then becomes 0.25 PD/t, 67 percent higher than that of Equation 2. However, when the restraint does not exist, then neither does the stress given by Equation 3. Hence, either way the total axial stress is about the same.

** Numbers in parentheses refer to references in the list of "References" on page 92.

pipeline. This document revealed longitudinal stress in a 20-inch pipeline at zero internal pressure ranging from -14,500 psi to +18,900 psi. The authors state that they had insufficient instrumentation to separate axial from flexural stresses. These values, nevertheless, provided a crude confirmation of the range of existing stresses in a pipeline that one might expect on the basis of Equations 2 and 3. Therefore, it would seem that if one were to combine the stresses represented by Equations 2 and 3, it is reasonable to assume that the existing axial stress in a pipeline (not including any flexural stress) will lie in the range of -10,000 to +20,000 psi. In fact, many older pipelines and most small diameter lines are laid by intentionally curving them from side-to-side in the trench to induce slack. Such pipelines may be expected to have little or no axial stress in areas where they are uncovered for lowering.

If the pipeline has been laid to conform elastically to a given trench profile (i.e., it changes vertical direction without the benefit of a permanent bend or fitting), it will contain induced flexural stress in amounts proportional to the curvature. In extremely hilly terrain, where slopes are unstable or where soils are subject to frost heave or liquifaction, the pipeline is likely to be in an unpredictable state of stress ranging from near-yield strength levels in tension to near buckling compressive or flexural stress. The problem for the pipeline operator is that the existing stress, whatever it is, must be taken into account in a lowering situation. Fortunately, in flat to relatively gently rolling terrain, where soils are not subjected to frost heave or liquifaction one can expect that the pipeline will be subject only to tensile stress from pressure and the temperature differential as noted above and to flexural stress to the degree that it is elastically curved. The axial stress is important and can either be measured or conservatively estimated. The flexural stress from existing curvature is not particularly important, as will be shown.

Lowerins-Induced Stresses

Lowering-induced stresses are of two types, one is temporary, the other is permanent. Stresses induced by lifting the pipeline prior to and during lowering and stresses induced by temperature differentials of the exposed pipe are temporary. These temporary stresses must be accounted for and minimized to the degree possible, but they will disappear when the pipeline is in its new position and backfilled. The permanent stress induced by lowering is that associated with the curvature and elongation required for the pipeline to fit the new trench profile.

The effect of thermally induced stress once the pipeline is exposed can be minimized by conducting lowering operations in warm weather periods. Since most pipelines are normally in a state of tensile longitudinal stress as described previously, and since they are generally at ground temperature, the exposure to warm air would be expected to cause a net reduction in stress. Unless the direct sun shining on the top of the pipe causes excessive flexural stress, the thermally induced stress (i.e., stress reduction) is not harmful. Furthermore, the fluid flowing in the pipeline tends to keep the pipeline nearer to its normal operating temperature than would be the case for an empty pipeline. Therefore, by conducting lowering operations in moderately warm weather and by maintaining product flow, the operator can safely ignore the effects of temporary thermal stress during lowering.

The stresses that arise in the pipe from being suspended between supports and/or side boom tractor slings as it is lifted and lowered into place can be calculated and must be limited to acceptable values as will be shown.

The final change in stress resulting from the new trench profile can also be calculated. The trench length and contour can be chosen to minimize the added stress and to keep it within acceptable bounds.

The amount of temporary or permanent added stress due to a lowering operating that can be tolerated depends on the ability of the operator to assure that the pipeline is capable of handling the added stress. In most situations, as will be shown, the limit on added stress will necessarily be that specified in the applicable pipeline code.*

ANALYTICAL ASSESSMENT OF STRESSES

The likely existence of an initial axial stress in a pipeline has already been discussed. Not only is it important because it must be added to any lowering induced stress to assess whether or not the total stress is acceptable, it also significantly influences the structural behavior of the pipe span. As any structural engineer knows, in a simple beam carrying lateral loads, the moments and deflections are expressible in algebraic polynomial functions of span length. When axial load is applied to a beam, however, the situation becomes more complex. The deflections and moments for a given lateral load are not the same as when no axial load exists. This is because the axial load, through the deflected shape, contributes to deflections and moments. Moreover, the axial compressive loads cause radically different behavior from axial tensile loads. The deflections under axial compressive loads become larger for a given lateral load than would be the case for no axial load, whereas they become smaller under axial tensile loads. The deflections under axial compressive loads are expressed in terms of trigonometric functions (sines and cosines) where singularities or infinite values denote buckled conditions. In contrast, the deflections under axial tensile loads are expressed in terms of hyperbolic sines and cosines (i.e., catenary curves). In general, pipelines, which almost invariably have existing axial loads, are not treatable as simple beams. Instead they must be treated as "elastic beam-columns" for purposes of analysis.

---

* Typical applicable codes are ANSI/ASME B31.4 Code for Liquid Petroleum Transportation Piping Systems and B31.8 Code for Gas Transmission and Distribution Piping Systems. Both of these codes limit longitudinal stress to 75 percent of the allowable hoop stress or 54 percent of SMYS in most cases. In the case of gas pipelines where class locations are a factor, the limit is 54 percent of SMYS for Class 1 locations, 45 percent of SMYS for Class 2 locations, 37.5 percent of SMYS for Class 3 locations, and 30 percent of SMYS for Class 4 locations.

Even if the axial stress were to remain unchanged during lowering, the problem would be substantially more difficult to solve than the case of a simple beam. The fact that it increases significantly during lowering makes the analytical problem impractical to solve over the total range of the lowering operation. Instead we have chosen to solve by trial and error for the stresses in the final lowered configuration. We approach the problem by assuming a value of added axial stress due to lowering. We then calculate the final length to see whether or not assumed added axial stress was correct. When the difference between our assumed value and the value resulting from the calculation becomes insignificant, the resulting stresses and deflections are assumed to be the correct solution.

The analytical technique for calculating the final longitudinal stress in the pipeline in lowering situations treats the pipeline as an elastic beam-column and is explained in detail in Appendix B. The end conditions where the pipeline enters the undisturbed backfill are treated as a continuation of the open trench span in terms of a beam on an elastic foundation for the purpose of calculating flexural stress. A representative soil stiffness of K = 2000 psi is shown to be adequate for most practical cases. It is assumed, however, that no elongation is possible beyond the points where the pipe enters the soil. The amount of axial elongation required to lower the pipe from its initial position into the new position is calculated by subtracting the initial length from the final length of the pipeline between the points where it enters the soil. As stated before a value of added axial stress level is assumed in order to make the calculations. One iterates until a final lowered profile is obtained in which the assumed added axial stress level is consistent with the calculated change in axial stress due to lowering. For the purpose of this discussion it is noted that the analytical technique is based upon the assumption that the pipeline is initially straight, level, and uniform in geometry along its length. As will be shown, however, the technique can be adapted to an initially nonstraight, nonlevel, nonuniform pipeline.

The technique permits calculation of the following:

(1) Existing stress in a pipeline provided certain measurements can be made

(2) Tendency of the pipeline to undergo general elastic buckling due to compressive axial load

(3) The length and contour of trench required for "free deflection" of the pipeline and the maximum stress

(4) The unique length and contour which gives the shortest possible excavation for a reasonably efficient stress distribution

(5) The ability to lower the stress to any reasonable desired value by lengthening the excavation and reducing the curvature

(6) The spacing of support points and/or sideboom tractor lift locations to avoid exceeding a critical value of stress.

These calculations and their utility in a pipeline lowering situation are described below.

Existing Stress Calculation

The existing axial stress in an initially straight pipeline has been discussed previously. The importance of this stress to a lowering operation is illustrated in Figures 5 and 6. Figure 5 represents the minimum free deflection span length required to achieve a given amount of deflection (i.e., lowering) at mid-span as a function of initial axial stress. Free deflection is defined as that deflection which would occur if the empty pipeline span between the ends fixed in the undisturbed soil were allowed to freely deflect under the influence of its own weight. Note the influence of the initial axial stress. For a mid-span deflection of 10 feet, the span length required ranges from 550 feet for a negative (compressive axial stress) of 10,000 psi to 950 feet for a positive (tensile) axial stress of 30,000 psi. This is the nature of an elastic beam-column; the axial stress greatly influences the stiffness. Therefore, it is essential to have some idea of the initial axial stress in the pipeline prior to conducting a lowering operation.

The maximum stresses accompanying the deflections of Figure 5 are illustrated in Figure 6. The maximum stresses become quite high for large deflections. Note that for an initial axial compressive stress of -10,000 psi, the stress versus deflection relationship crosses over the zero initial stress case at lower deflections. This is because we have plotted the absolute value of the maximum stress and in the case of the -10,000 psi

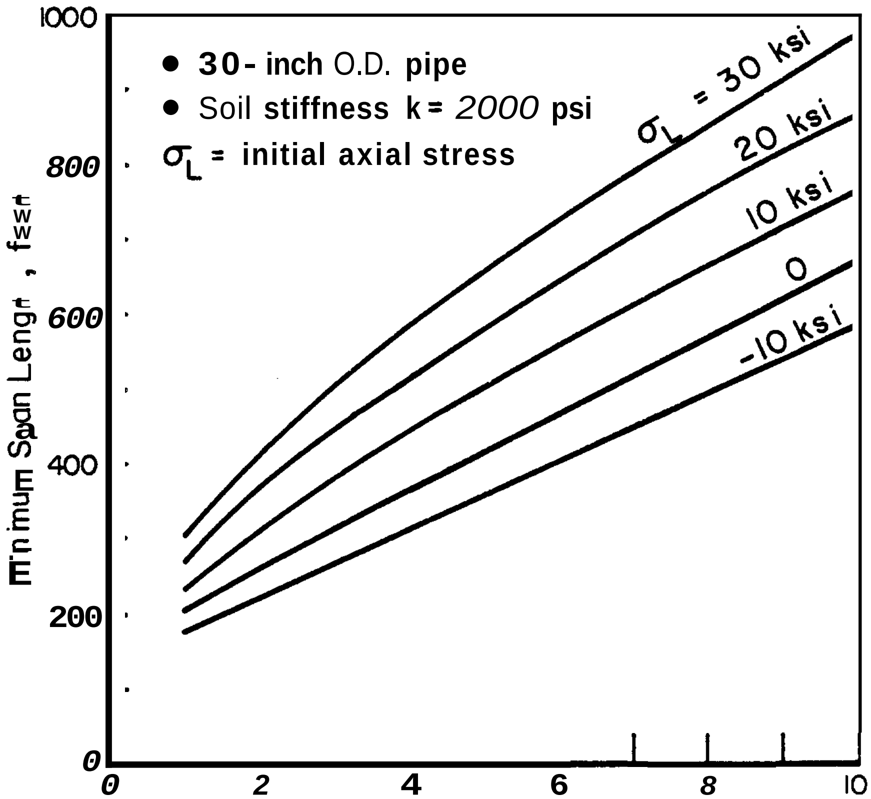


FIGURE 5. MINIMUM FREE DEFLECTION SPAN AS A FUNCTION OF DEFLECTION AT MIDSPAN AND INITIAL AXIAL STRESS

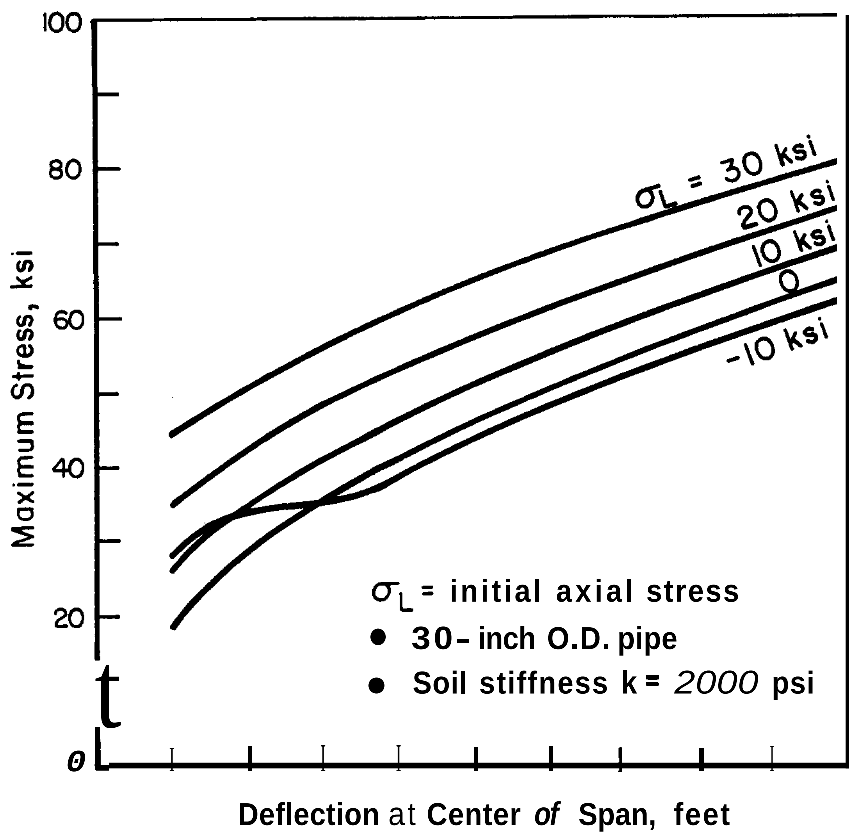


FIGURE 6. MAXIMUM STRESS DUE TO LOWERING AS A FUNCTION OF DEFLECTION AT MIDSPAN AND INITIAL AXIAL STRESS

initial stress, the maximum value remains compressive until the deflection exceeds 4 feet. Then the positive stress becomes the maximum stress. Note also that while Figure 6 is said to be for 30-inch OD by 0.375-inch wall pipe, it can be shown that these stresses are virtually independent of pipe geometry for the free deflection case.

The existing axial stress in a pipe can be calculated from measurements or it can be estimated for a wide variety of lowering situations. The calculation based on measurements evolves from the relationship between deflection and axial stress. If an exposed pipeline subjected to axial stress is deflected a given amount, (e.g., pick up a fixed distance at a point by means of a side-boom tractor), both the amount of pipe that leaves the ground and the load required to pick the pipeline up are uniquely related to the stress.

The relationship of the lift-off length to initial axial stress for 30-inch OD pipe is shown in Figure 7 and the relationship for lift-off force is shown in Figure 8. The lift-off force is much more sensitive to the deflection than is the lift-off length. The limiting factor in using the lift-off span or the lift-off force is the accompanying high stress as illustrated in Figure 9. For lifts of more than one foot the stresses become unacceptably high. With a lift of only one foot, however, the lift-off span is not very sensitive to axial stress as shown in Figure 7, and the use of this technique may be impractical in the field. The lift-off load shown in Figure 8 is much more sensitive to the axial stress, but load measurement requires specialized equipment. The use of axial stress measuring techniques is discussed later in this report under the procedures section.

The estimation of a reasonable upper bound for the existing axial stress in a pipeline is possible for pipelines which are initially straight, reasonably level, fully restrained from longitudinal movement, and not located in unstable or frost heave susceptible soils. As was noted previously, such a pipeline is likely to contain only the axial stress resulting from internal pressure and the thermal differential due to its being constructed at a temperature different from that of its operation. As was indicated by Equations 2 and 3, the existing axial stress due to those sources is likely

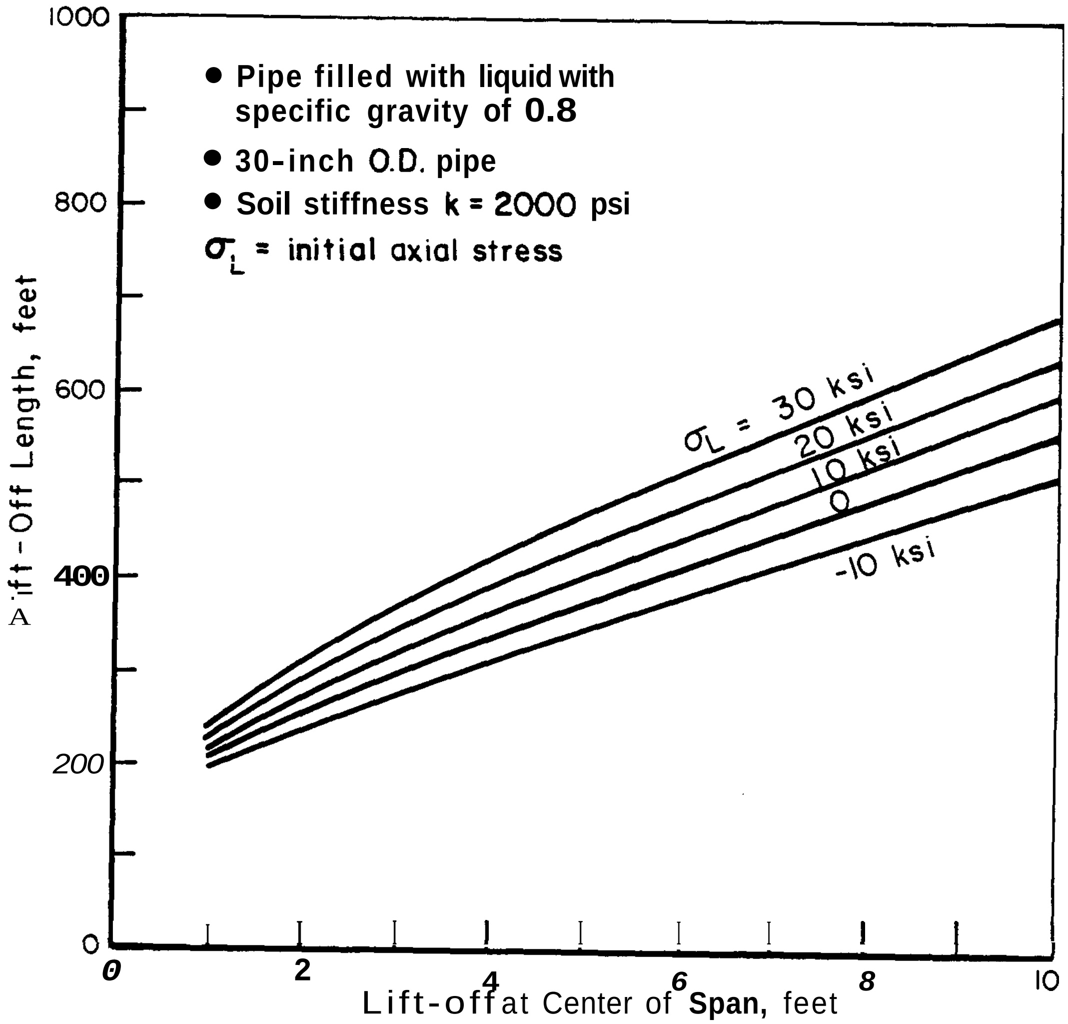


FIGURE 7. INITIAL AXIAL STRESS AS DETERMINED FROM LIFT OFF LENGTH AND LIFT OFF HEIGHT

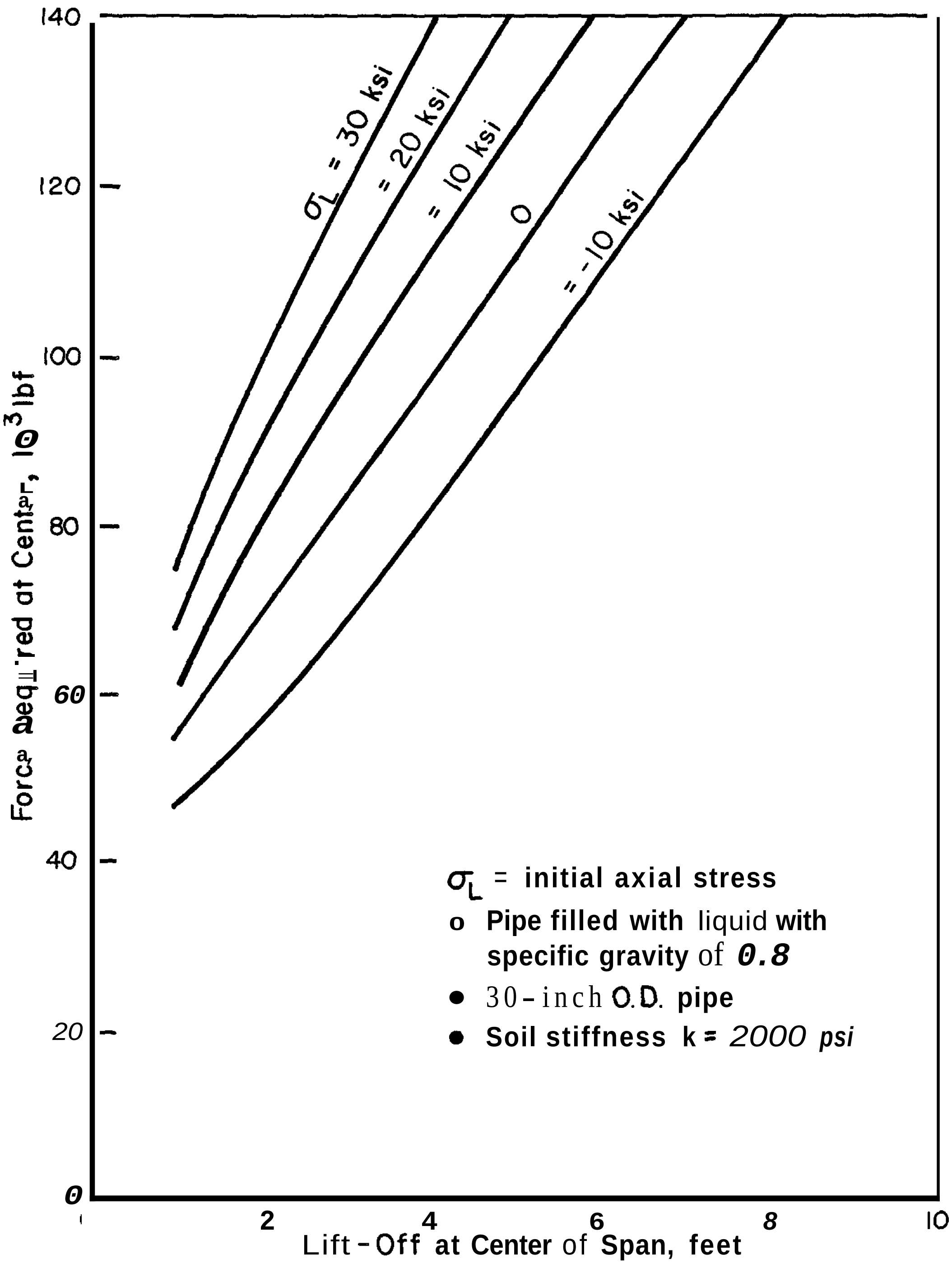


FIGURE 8. LIFTING FORCE

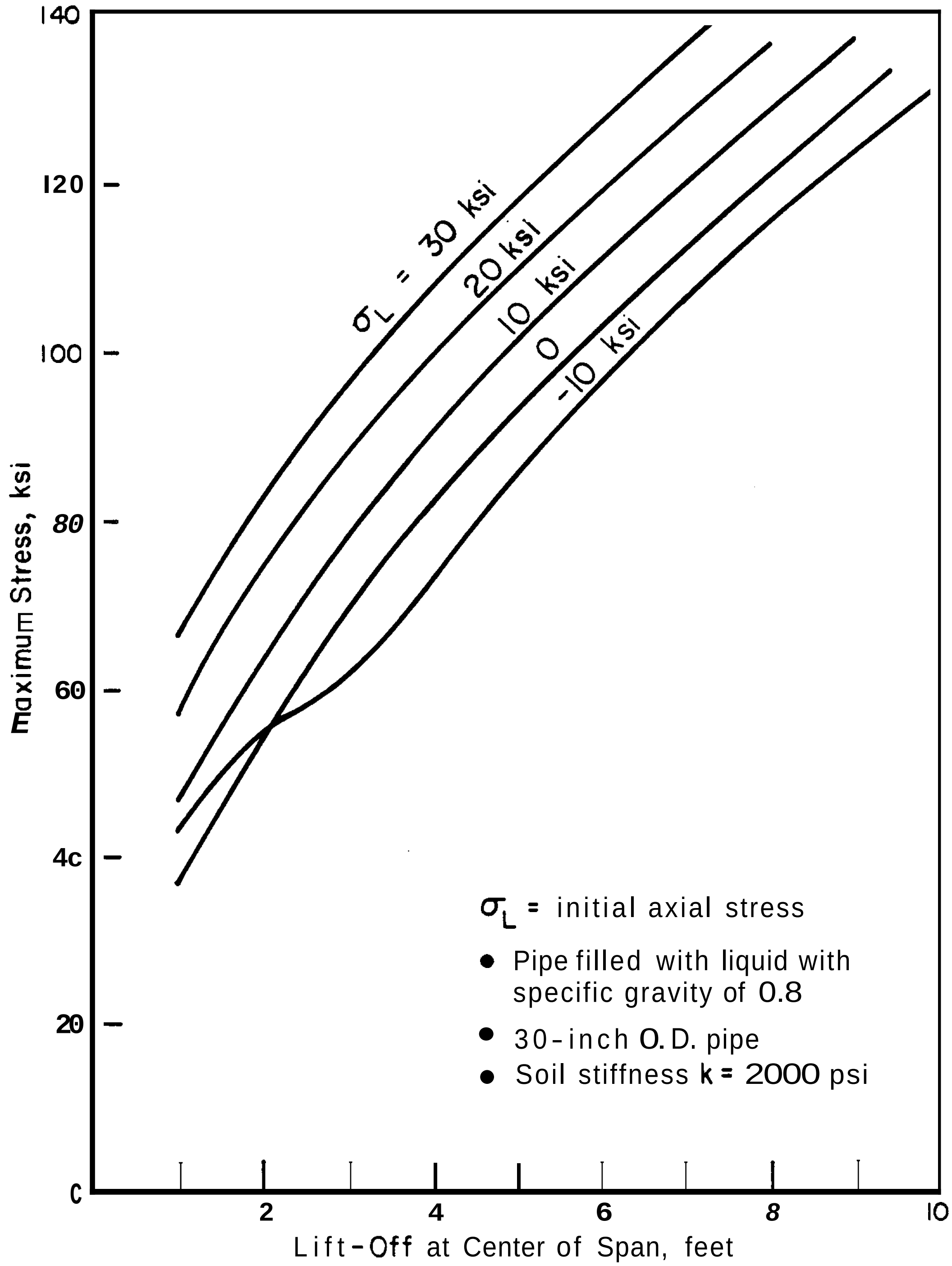


FIGURE 9. MAXIMUM STRESS AS A FUNCTION OF INITIAL AXIAL STRESS AND LIFT HEIGHT

not to exceed 20,000 psi.* Therefore, 20,000 psi can be taken as a reasonable upper bound for the axial stress in a restrained pipeline unless there are unusual terrain or soil conditions which could make the situation appreciably different. If the pipeline is not restrained it will have 67 percent higher stress due to pressure than predicted by Equation 2, but it will have no stress due to the temperature differential (Equation 3). Therefore, 20,000 psi is also a reasonable upper bound for the axial stress in an unrestrained pipeline.

Even though intentional changes in direction and slope of a pipeline are normally accommodated by permanently curved (field bent) pipe, slight variations in the original trench profile are accommodated by elastic flexural deformation. As a result most pipelines will not be free of bending stress. It will be shown however, that these elastic bending stresses are not important. During lowering these existing bending strains can actually be reduced or at least held constant.

General Buckling

A pipeline containing axial compressive stress, as it is exposed, becomes a long slender column which can buckle elastically. The analysis method employed in these guidelines predicts when such lateral bowing will occur. The relationship for 30-inch OD X 0.375-inch wall pipe is shown in Figure 10. When 300 feet of such a pipeline containing 10,000 psi compressive stress have been uncovered, lateral bowing is likely to initiate. Unless the surrounding slopes are unstable and continue to move, however, the pipeline will not undergo gross deformation. The pipeline might deflect sideways somewhat, especially if more backfill is removed. As long as the pipeline operator is prepared for possible movement of the pipeline as it is uncovered, existing axial compressive stress does not present any particular problems.

---

* The value of 20,000 psi turns out to a reasonable approximation of the upper bound for Grades X52 through X65. (Actual values are 19,032, 20,760, and 21,840 psi, respectively, for Grades X52, X60, and X65). Similarly, 15,000 psi is a good approximation of the upper bound for Grade B and X42 pipe.

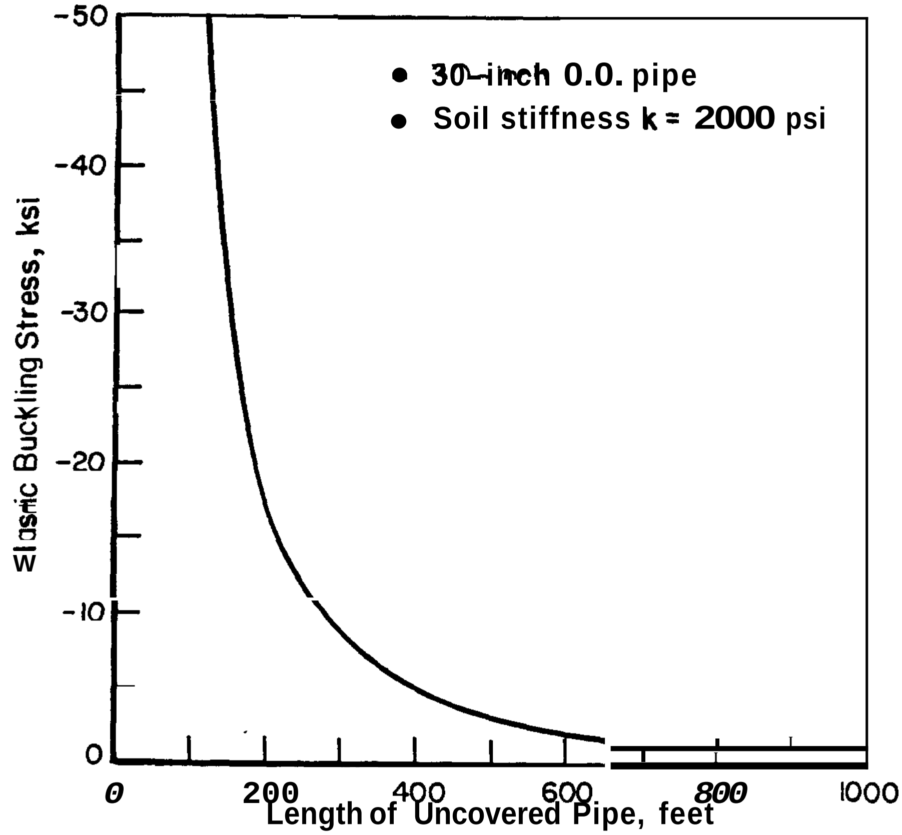


FIGURE 10. ELASTIC BUCKLING OF A PIPELINE CONTAINING COMPRESSIVE AXIAL STRESS

Lowering Induced Stress

Free Deflection Stresses

The free deflection solution to lowering a pipeline consists of defining the deflected shape that the pipeline would assume if a given span length were permitted to deflect due to its weight. For reasons which will become apparent, the weight of the pipe only and not that of its contents is considered in calculating the final stress and profile.*

To illustrate the important variables that determine the lowering induced stresses, the following equation for a simple uniformly loaded beam with end supports but no end moments is examined. The beam is also assumed to be free to move axially unlike an actual buried pipeline so that an increase in axial stress is precluded in this simple example. For such a beam any elementary structures text book reveals that the maximum deflection is

$$\Delta = \frac{5wL^4}{384EI} \qquad (4)$$

where:

- W is the weight per unit length, lb/in.
- L is the span length, inches
- E is the elastic modulus, psi
- I is the moment of inertia, in^4

For pipe, I is approximately $\pi r^3 t$ (r being the radius and t being the wall thickness of the pipe), and W is approximately $2\pi r t \gamma$, where γ is the unit weight of steel. Substituting these approximations into Equation (4) and assuming for the sake of illustration that the pipeline is empty, one obtains

$$\Delta = \frac{5(2)\pi r t \gamma\, L^4}{384\, E\pi r^3 t} = 2.45 \times 10^{-10}\, \frac{L^4}{r^2} \qquad (5)$$

---

* The weight of the contents is important in considering how many temporary support points or lift points are needed.

In other words the span length, L required to produce a given deflection A at mid-span is

$$L = 253\ (\Delta)^{\frac{1}{4}}\ (r)^{\frac{1}{2}} \tag{6}$$

Note that the span length is not dependent on t.

Such a simply supported beam solution is not adequate for predicting the span lengths required for road crossing lowering where the pipe contains axial load and the ends are not simply supported. Equation (6) does illustrate a principle which holds generally true even in the elastic beam column analysis, namely that the solution is independent of pipe wall thickness.

Another important aspect of the lowering induced stresses is illustrated by the following. If one attempts to calculate the maximum stress for the simply supported beam one finds that

$$\begin{aligned} \sigma &= \frac{Mc}{I} = \frac{\left(\frac{WL^2}{8}\right) r}{\pi r^3 t} \\ &= \frac{2\pi r^2 t \gamma\ L^2}{8 \pi r^3 t} = \frac{L^2 \gamma}{4r} \end{aligned} \tag{7}$$

But from Equation (6) one can substitute for L and obtain:

$$\sigma = \frac{18077 (A)^{1/2} r}{4r} = 4519\ A^{1/2} \tag{8}$$

Equation 8 illustrates that the maximum stress in the deflected pipe is independent of r or t and dependent only upon deflection. This situation is approximately true for the elastic beam column solution as well.

The kinds of solutions that are generated by the elastic beam-column analysis explained in Appendix B are shown in Figures 5 and 6, which were discussed previously. As indicated in Figure 6, the maximum stresses become quite high for realistic values of deflection. A study of the stress distribution throughout the span reveals that the areas of high stress are concentrated near the ends of the span, and that elsewhere the stresses are not nearly as high, The free deflection solutions of Figure 6 represent the shortest possible spans in which a given maximum deflection can be achieved. Yet, they are inefficient because they cause local areas of high stress. Therefore, a solution is needed which might result in a longer span being required for a given deflection but which would result in a much more efficient distribution of the stress and a lower maximum stress. Many such solutions are available as illustrated below.

Contoured Trench Solutions

Other than the free deflection span which is the minimum possible span for a given deflection, axial load, and pipe geometry there are an infinite number of longer spans, many of which will result in less induced stress, The key to choosing an appropriate solution is to examine solutions which distribute the stresses efficiently.

Contoured trench solutions are derived herein in which the stresses are efficiently distributed.* The first step is achieved by allowing the pipeline to deflect under the influence of less than its own weight. This results in a larger span being required for the pipeline to reach a given deflection than would be the case if its full weight were acting on it. In its final position the pipeline will be supported by the soil under it, and it will not in fact, be supporting its own weight. Furthermore, during the actual lowering operation, the pipeline is suspended at a number of points by side boom tractors resulting in spans much shorter than the actual lowered region. Therefore, the utilization of less than the full weight of the pipeline to calculate an overall lowering profile represents an artificial

* These solutions are derived for existing axial tensile stress and zero axial stress only. It is not necessary to consider existing axial compressive stress because the solutions for zero or tensile stress give conservative trench dimensions for the case of compressive stress. It is, of course, perfectly feasible to lower a pipeline which contains compressive axial stress as long as the operator or contractor is prepared in case the line moves laterally upon being exposed. The initial compressive value will become less compressive or may change to tensile as the lowering proceeds.

condition for the purposes of calculations. The longer span (or more accurately the longer trench) results in a lower maximum stress in the pipe than would be the case with the free deflection span.

Pursuing this approach, one finds that lighter and lighter pipes lead to longer and longer spans with increasingly lower maximum stresses. The only problem is that the inefficiency of concentrated stress near the ends still exists. As a result extremely long spans are required to achieve low maximum stress values. For example, in 30-inch pipeline with a 15,000 psi axial stress, the span required to get a free deflection of 5 feet is 543 feet and the maximum stress is 54 ksi. In order to lower the maximum stress to 30 ksi, by the reduced weight concept, a span length of 1175 feet is required. To achieve a maximum stress of 20 ksi, a span length of 3173 feet is required. Thus, using a reduced weight span lowers the stress but greatly lengthens the span. Another step is required to optimize both span lengths and stress reduction.

One solution is to utilize the curvature nearest the center of the reduced weight span for the ends of the span as well as the center. This is done by joining the two curves at an inflection point as shown in detail in Appendix B. This type of solution produces a "minimum" span length when the weight of the pipeline utilized in the calculation is about 94* percent of the actual weight. This is not a true minimum span since other solutions between it and the free deflection span exist. However, these usually produce less efficient stress distributions and higher maximum stresses. Spans longer than the minimum which result in lower stresses can also be achieved and these may be necessary if a high value of initial axial stress is assumed. As will be shown, the minimum contoured trench span often produces acceptable levels of added stress.

Examples of Free Deflection and Contoured Trench Solutions

The maximum stresses and span lengths as computed for both the free deflection and minimum contoured trench cases are presented in Tables 1 and 2

---

* The weight fraction was chosen on the basis of trial and error solutions which showed that the value of .935 gives the minimum contoured trench solution.

TABLE 1. STRESSES AND SPAN LENGTH FOR FREE DEFLECTION OF PIPE

Required Deflection, feet	Initial Axial Stress (psi): 0 — Span Length, feet	0 — Maximum Stress psi	10,000 — Span Length, feet	10,000 — Maximum Stress psi	15,000 — Span Length, feet	15,000 — Maximum Stress psi	20,000 — Span Length, feet	20,000 — Maximum Stress psi
30-inch pipe								
3	319	35,823	383	41,300	415	44,780	448	48,556
5	423	50,908	503	51,366	543	54,493	584	57,919
10	672	65,398	768	69,741	818	72,394	868	75,301
16-inch pipe								
3	285	36,728	357	42,011	393	45,356	428	48,995
5	402	47,301	484	52,087	526	55,059	567	58,325
10	662	66,065	757	70,196	807	72,704	857	75,466
8-5/8-inch pipe								
3	273	37,129	346	41,985	383	45,144	419	48,758
5	395	47,441	476	51,755	518	54,648	560	57,907
10	659	65,406	753	69,395	802	71,921	852	74,713

TABLE 2. STRESSES AND SPAN LENGTH FOR MINIMUM LENGTH OF CONTOURED TRENCH

	Initial Axial Stress (psi)							
	0		10,000		15,000		20,000	
Required Deflection, feet	Span Length, feet	Maximum Stress psi	Span Length, feet	Maximum Stress psi	Span Length, feet	Maximum Stress psi	Span Length, feet	Maximum Stress psi
				30 X 0.375-inch pipe				
3	388	18,547	491	21,384	545	24,145	598	27,508
5	509	20,717	640	22,871	709	25,392	800*	28,100*
10	805	22,197	971	25,126	1,059	27,699	1,324*	28,100*
				16 X 0.250-inch pipe				
3	341	15,414	460	18,252	522	21,371	580	25,121
5	480	16,125	621	19,502	694	22,588	765	26,230
10	794	17,824	963	22,153	1,051	25,201	1,179*	28,100*
				8.625 X 0.156-inch pipe				
3	325	11,961	452	16,149	515	19,722	575	23,704
5	473	12,880	616	17,587	690	21,052	762	24,959
10	793	15,486	960	20,562	1,049	~ 24,000**	1,137	~ 27,500**

* Stress-level controlled, span length greater than minium contoured value.
** Accurate values not possible due to machine limits.

for three sizes of pipe and four different axial stress levels. The materials are assumed to be X52; hence, the maximum allowable stress is 28.1 ksi (54 percent of **SMYS**). The results of both types of calculations for 30-inch O.D. by 0.375-inch wall pipe are also plotted in Figure 11. Several important trends are evident from these calculations.

- o Span length and maximum stress increase with increasing maximum deflection. These trends are as one would expect and, in fact, were previously illustrated in Figures 5 and 6. However, it is noted that the increase in stress with increasing deflection for the contoured trench cases is very slight.
- o The minimum contoured trench solution does not always produce an acceptable stress level. However, if the initial axial stress is less than the allowable stress level, a trench length exists which will give a final stress at or below the allowable.
- o Span lengths are 20 to 60 percent longer for the contoured trench cases than for the free deflection cases.
- o Maximum stresses are 33 to 67 percent lower for the contoured trench case than for the free deflection case.

Overall comparisons of span lengths and stresses for 30-inch pipe are shown in Figure 11. Similar trends are exhibited for other pipe sizes.

Note that for cases of high axial stress, 20 ksi for example, where large deflections (4 to 10 feet) are involved, the total stress associated with the minimum contoured trench exceeds the chosen allowable stress level. Therefore, it is not advisable to use the minimum contoured trench solution for such cases. Instead, it is necessary to select a longer contoured trench span by setting a limit on stress (the chosen allowable) and calculating the resulting curve. Such a limit is built into the computer programs of Appendix D which can be used to calculate lowering profiles.

As an example, if one selects 54 percent of SMYS for the allowable stress, then for Grade X52 pipe the limiting value of stress is 28.1 ksi. With this limit on stress, the length of the contoured trenches for 20 ksi axial stress, for a 10-foot deflection, and for various pipe sizes calculated **by** means of Program TRENCH in Appendix D.

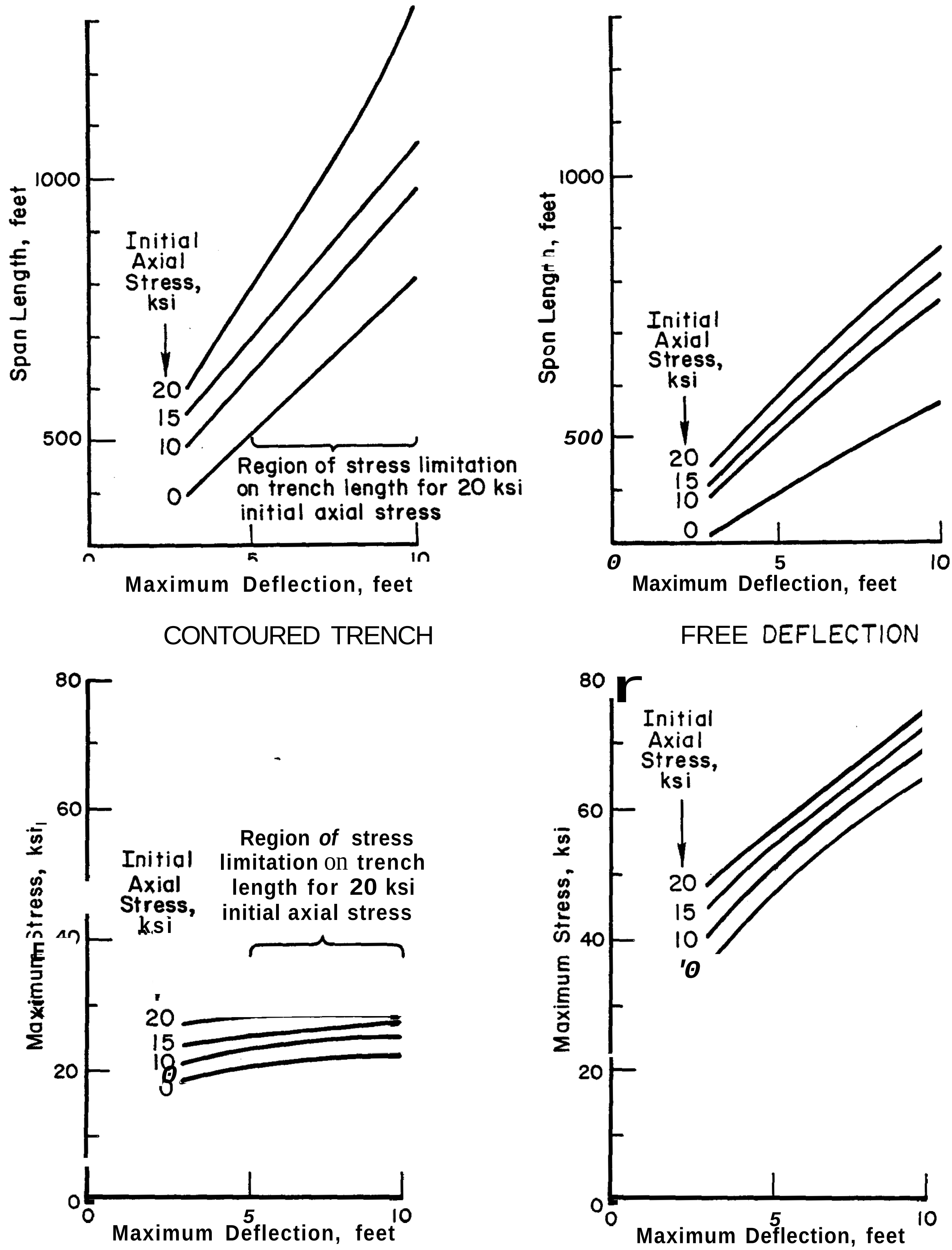


FIGURE 11. COMPARISON OF CONTOURED TRENCH SPANS AND STRESSES WITH FREE DEFLECTION SPANS AND STRESSES FOR 30-INCH O.D. BY 0.375-INCH WALL X52 PIPE

	30-inch pipe	16-inch pipe	8-5/8-inch pipe
Length (feet)	1,324	1,179	1,137
Stress (psi)	28,100	28,100	27,500

For comparison, the minimum contoured trench solutions give:

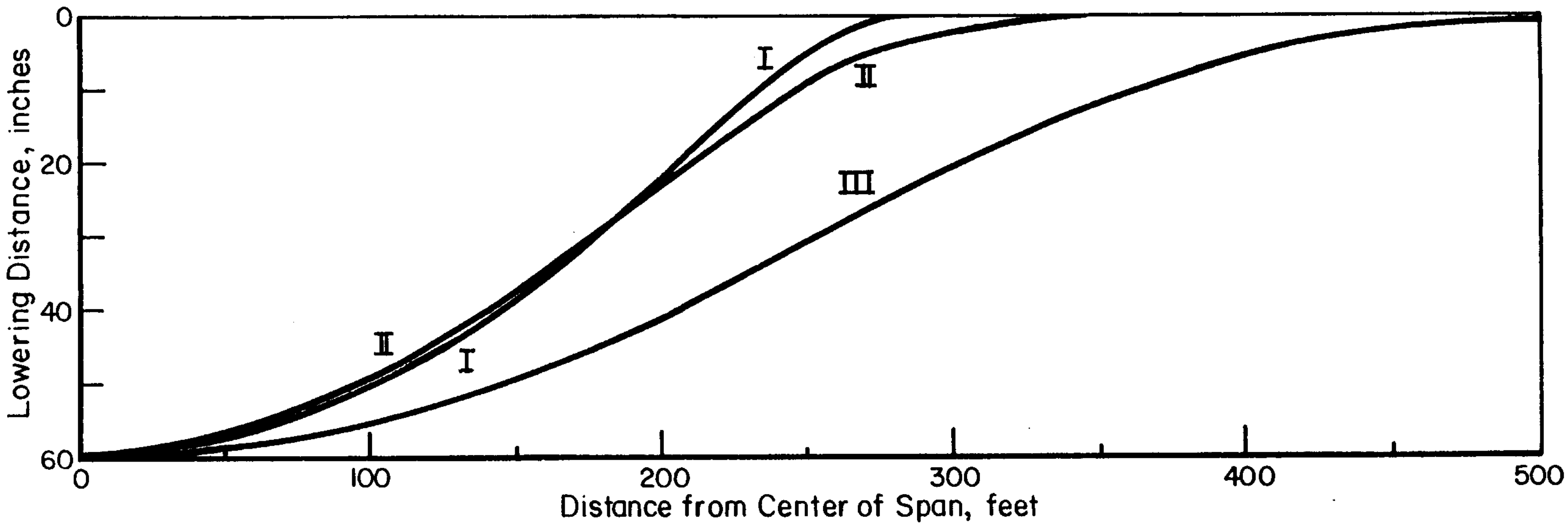
	30-inch pipe	16-inch pipe	8-5/8-inch pipe
Length (feet)	1,145	1,139	1,137
Stress (psi)	30,827	28,690	27,500

Obviously it is advantageous to chose the slightly longer trench and the lower stress.

A comparison of the trench profiles for free deflection and two contoured trench cases is shown in Figure 12. Note that Curve I is the free deflection case (L = 543 feet, σ_{max} = 54.5 ksi), that curve II is the minimum contoured trench span (L = 709 feet, σ_{max} = 25.4 ksi) and that Curve III is a longer contoured trench (L = 1,017 feet, σ_{max} = 20 ksi). This case, which can be calculated as shown in Appendix D, is one of any number that can be calculated for longer spans than that of Curve II all of which will give lower stresses than Curve 11.

Spacing of Supports or Side Boom Tractors to Limit Stresses to Desired Values

The methods of Appendix B can be used to predict support and/or lift points of a pipeline span to avoid exceeding a desired stress limit. Note that the span length can be expected to vary with specific gravity of the contents because unlike the case of final lowering induced stresses where the pipeline is supported by the final profile, the stress in a pipeline on discrete supports is a function of the total weight per foot. Note also that the support spacing or span length can be expected to vary according to the schedule of lowering. It is unlikely that the lowering can be done simultaneously at all support points with such precision that the relative deflection between support points will always be less than the relative deflection



30-inch pipe, 3/8-inch wall

15 ksi axial tension (before lowering)

I. Minimum span length

L = 543 feet

σ_{max} = 54.5 ksi

II. Contoured trench

L = 709 feet

σ_{max} = 25.4 ksi

III. Contoured trench

L = 1,017 feet

σ_{max} = 20 ksi

FIGURE 12. EXAMPLE OF STRESS REDUCTION ACHIEVED BY LENGTHENING THE SPAN AND REDUCING THE CURVATURE

between those same points in the final lowered profile. Therefore, calculations for support point locations must take into account the probable differentials in deflections between adjacent support points. For example, in a case where a pipeline is supported on wooden ties or soil pillars, it is reasonable to expect that the increment of change in deflection at each support point as the pipeline is lowered will be 6 to 12 inches. Since this change is likely to occur progressively from support to support rather than simultaneously at all supports, the variation in relative deflection between any two adjacent supports may be as great as 6 to 12 inches.

Examples of allowable span lengths are presented in Table 3 for three pipe sizes, three support height differentials, three specific gravities, five initial axial stress levels, and a limiting stress level of 28,100 psi (54 percent of SMYS for Grade X52). Note that for a pipeline with existing elastic curvature, the differential support height is defined as the relative change when an increment of lowering is induced and not as the absolute difference in support heights. This is justifiable as will be shown in a subsequent section of the report because the aim of any lowering schedule will be to reduce or maintain any existing elastic curvature and not to increase it (except to extent temporarily necessitated by differential support heights). Note in Table 3 that a specific gravity of 0 represents an empty line. The weight of the pipe is already accounted for in the calculation. Specific gravities of 0.1 and 0.8 represent a gas filled line and liquid filled line, respectively. Specific gravities of 1.2 and 1.9 (not included in Table 3) represent weight coated 30-inch gas and oil pipelines where a 3-inch thick concrete weight coating is added to provide negative bouyancy since the pipe will be below the water table. Obviously one must adjust the specific gravity as required to suit a particular case, especially in the case of weight coating since the term specific gravity as used here refers only to added weight. The actual negative bouyancy depends on the total weight of the pipe the contents, and the weight coating. Therefore, the specific gravity term when intended to represent added concrete weight coating for negative bouyancy must be

$$\text{sp. gr.} = \frac{\text{Weight of Concrete/ft.} + \text{Weight of Pipeline Product/ft}}{\text{Density of Water} \times \text{Volume of Pipeline/ft.}} \qquad (11)$$

TABLE 3. MAXIMUM DISTANCE IN FEET BETWEEN SUPPORTS TO LIMIT TOTAL STRESS TO 28,100 PSI (54 PERCENT OF SMYS FOR AN X52 MATERIAL)*

Initial Axial Stress, L, ksi	Empty Pipeline Sp. gr. = 0 Differential Support Height, inches 0	3	6	Gas Pipeline Sp. gr. = 0.1 Differential Support Height, inches 0	3	6	Liquid Pipeline Sp. gr. = 0.8 Differential Support Height, inches 0	3	6
8-5/8-inch diameter pipe									
0	155	148	142	138	132	125	88	82	75
5	161	153	143	143	135	125	88	79	60 (28.8)
10	156	143	125	138	125	105	83	66	64 (33.6)
15	136	113	91 (30.3)	120	95	85 (31.6)	72	53 (31.2)	68 (38.5)
20	101	74 (30.6)	98 (35.2)	90	70 (31.5)	93 (36.5)	55	55 (36.2)	72 (43.3)
16-inch diameter pipe									
0	186	181	175	167	162	156	111	105	96
5	189	181	172	168	160	151	106	97	75 (29.2)
10	180	167	150	159	146	126	98	79	78 (34.1)
15	156	133	108 (30.1)	138	112	102 (31.5)	84	67 (31.8)	81 (39.1)
20	118	89 (30.5)	113 (35.1)	105	84 (31.5)	107 (36.4)	65	67 (36.7)	83 (44.0)
30-inch diameter pipe									
0	244	239	233	217	212	206	141	132	119
5	238	230	221	210	202	191	131	118	97 (30.5)
10	221	208	191	194	180	157	119	89	99 (35.5)
15	191	166	136 (29.9)	167	138	128 (31.6)	102	83 (32.8)	101 (40.5)
20	147	113 (30.4)	142 (34.9)	129	107 (31.6)	132 (36.6)	79	84 (37.8)	102 (45.5)

* Underlined values represent conditions for which no span length exists which will give a stress level at the supports within the acceptable range. Values in parentheses are the stresses at the supports accompanying the corresponding span length and are the minimum possible values.

Table 3 presents adjacent support height differentials of 0, 3, and 6 inches. (These are arbitrary choices; one could calculate values for any reasonable differential 1, 2, 4, 5, etc.) Note that the initial removal of a 3-inch support layer at every other support point (points 1, 3, 5, etc.) can be followed by the removal of a 6-inch support layer at points 2, 4, 6, etc. without causing more than a 3-inch differential between adjacent supports. Similarly, the initial removal of a 6-inch support layer at points 1, 3, 5, etc. can be followed by removal of a 12-inch support layer at points 2, 4, 6, etc. without causing more than a 6-inch differential between adjacent supports. Thus, support height differentials of no greater than six inches need be considered as long as the lowering sequence involves incremental change at every other support.

It is noted in Table 3 that an acceptable span length does not always exist for differential support heights. The underlined span lengths in Table 3 each followed by a number in parentheses represent cases in which no span length exists which will produce a stress level at or below 28.1 ksi. This phenomenon results from the fact that as support spacing decreases in cases of differential support height, the elastic stiffness of the pipeline prevents efficient utilization of all supports. It is easy to visualize that at very close spacings, the pipeline would touch only a few of the supports.

In each differential support height case where the limiting stress of 28.1 ksi is exceeded, the span length given is that which results in the lowest stress, and the number in parentheses is that stress level (ksi). These cases are included even though the maximum stress level is not less than 28.1 ksi because lowering under the resulting conditions is not necessarily unsafe. As will be discussed in the next section of this report, the main concern in limiting the stress level is to avoid failure of potentially present concealed defects in girth welds. Since the maximum stress occurs at the support points, one can avoid exposing girth welds to the maximum stress level by assuring that the supports are located away from the girth welds.

POSSIBLE FAILURE MODES OF PIPELINES WHILE BEING LOWERED

Three possible types of failure are hypothesized in connection with an improper lowering operation. First, the pipeline may leak or rupture if the excavating equipment gouges or punctures it. Second, the pipeline may develop a leak or become completely severed as the result of a circumferentially-oriented defect. Third, the pipeline may buckle locally if subjected to excessive bending moment. Outlined below are the procedures for avoiding these types of failures during a lowering operation.

Damage from Excavating Equipment

Since mechanical damage defects tend to be most severe when oriented in the axial or near-axial direction, the chances of a leak or rupture from mechanical damage during the excavation for the lowering of a pipeline can be minimized by lowering the operating pressure according to Equation (1) presented previously. Besides lowering the pressure, the pipeline operator should take reasonable care to see that mechanical damage is not inflicted on the pipe in the first place. Any such damage, regardless of how it is oriented, should be repaired before the pipeline is lowered.

Circumferentially-Oriented Defects

The pipeline operator should visually inspect the pipeline to detect the presence of any defects regardless of how they are oriented, but he should pay special attention to girth welds where circumferentially-oriented defects are most likely to exist. Depending upon the procedure chosen to lower the line, it may be necessary to carry out a more intense inspection of the girth welds such as by means of ultrasonic inspection or radiography. The following discussion gives a brief introduction to fracture mechanics after which the various design/failure criteria used to evaluate circumferentially-oriented defects will be described. An example case is then considered to compare the various criteria.

An elementary principle of fracture mechanics holds that the larger a defect is, the lower will be the stress level required to cause the defect to grow to failure. For certain materials and defect geometries there are unique relationships between failure stress levels and defect sizes. These relationships are generally of the form:

$$K = \sigma\sqrt{\pi a}\ f(a/t,\ a/c,\ c/W)\ g\ (\sigma/\bar{\sigma}) \tag{12}$$

K is a material parameter representing the maximum fracture toughness of the material, ksi $\sqrt{in.}$

σ is the applied stress level at failure, ksi

a is a characteristic of the defect size, either a characteristic length in the case of a through-wall defect or depth in the case of a surface defect, inches

t is the thickness of the material, inch

W is the width of the material, inch

c is a surface dimension of a surface crack, inch

f is a function which depends upon the geometry of the structure

$\bar{\sigma}$ is the flow stress of the material, ksi

g is a function which accounts for the effect of plastic strain and is required to correct for real materials what is basically a linear elastic theory of failure.

Not all fracture mechanics relationships are of this form, but this form is useful in illustrating the significance of defects to the limitations of a pipeline lowering operation. The fracture mechanics relationships used to evaluate circumferential defects are based on the elastic plastic toughness on the crack opening displacement (COD) or J, rather than a linear elastic fracture toughness, K.

Since K or J or COD is a fixed material property which presumably can be determined for any material, one can readily see from Equation 12 that as applied stress is increased, the "critical" defect size which will cause failure decreases. In a pipeline lowering situation where the longitudinal stress is highly likely to be increased, it is essential that one of two limits are observed.

Either:

(1) The lowering-induced stress when added to any existing stress in the pipeline must be limited in such a way that the defect required to cause failure is so large that it will be readily detectable without sophisticated equipment or extensive examination, and that the toughness of the material will not have to be known with great accuracy.

or

(2) If the total stress is to be allowed to reach levels where small defects may fail, then the pipeline operator must be prepared to apply sophisticated nondestructive testing techniques to assure that no critical size defects are present, he must have a very accurate measure of the total stress present, and he will find it advantageous to have a fairly accurate measure of the toughness of the material.

With this brief introduction to fracture mechanics, the problem of modeling finite length circumferential surface cracks will now be defined and various approaches to arrive at fracture/design curves discussed.

Definition of Problem

The problem involves determining an appropriate failure criterion that models a finite length circumferential surface crack in girth welds under combined axial and bending loads. The criterion could then be used to calculate allowable defect sizes for known applied stresses during lowering. Or, conversely, it can be used to determine the permissible bending and axial stress (or trench depth and length) for known defect sizes. In order to do this, however, a lower bound on the toughness (J_{Ic}, K_{Ic} or COD) of the pipeline has to be assumed since this is not known in most cases. Toughness values can be based on correlation from a minimum Charpy impact energy from a 2/3 size specimen as shown in Table 4 (References 2, 3, and 4). Choosing a failure criterion, however, is inherently complex for three reasons.

(i) The problem is elastic-plastic in nature and in order for the model to be accurate, strain hardening, flaw geometry and pipe geometry effects need to be considered

(ii) The magnitude of residual stresses in the pipe is not known and needs to be incorporated in the chosen model, and

(iii) Very limited experimental data are available for circumferential surface flaws in pipes subjected to bending and tension and verifying a given model is therefore difficult.

TABLE 4. VALUES FOR J_{Ic} OBTAINED FROU 2/3 SIZE CVN ENERGY

Empirical Correlation[a]	Reference	2/3 CVN E rgy Energy ft lbs	K_{Ic} ksi in	J_{Ic}[c] in lb/in^2
(i) $K_{Ic} = \left(4\ \sigma_y^{2}\left(\frac{CVN}{\sigma_y} - 0.1\right)\right)^{1/2}$	2	10	45.1	61.8
		20	71.8	156.5
		30	91.0	251.1
(ii) $K_{Ic} = 9.35\ (CVN)^{0.63}$	2	10	51.5	80.4
		20	79.7	192.6
		30	102.9	321.1
(iii) $K_{Ic} = (2E\ CVN^{3/2})^{1/2}/1000$	3	10	59.0	105.7
		20	99.3	299.1
		30	134.6	549.4
(iv) $K_{Ic} = 15.5\ (CVN)^{1/2}$	4	10	60.0	109.3
		20	84.9	218.6
		30	104.0	327.9

(a) Units for K_{Ic}, σ_y, CVN, and E are ksi in$^{1/2}$, ksi, ft lb and psi, respectively.

(b) 2/3 CVN to be multipled by 1.5 to obtain CVN for correlations.

(c) $J_{Ic} = K_{Ic}^{2}\ (1 - \nu^{2})/E = 0.89\ (\bar{\sigma})\ (COD)$

Technical Approach

Various existing criteria that can be used to model the problem will now be discussed along with their limitations. A typical example case will then be described to compare the various criteria.

BCL Model

The BCL criterion [Reference 5] is based on the Dugdale model with corrections for pipe ovalization, elastic bending and a geometric function to limit the plastic zone size ahead of the crack tip. The failure criterion, Equation (13), applies for pipes with circumferential surface flaws in pure bending. Combined bending and axial loads are therefore treated as a single bending stress in this model.

$$\frac{\xi J \pi E}{8c\,\bar{\sigma}^2} = \ln \sec \left[\frac{\pi \Psi}{2} \left\{\frac{1 - (\bar{\sigma}/\sigma)\,(1-a/t)}{(a/t)}\right\}\right] \qquad (13)$$

where

J = pipe toughness

E = modulus of elasticity

$\bar{\sigma}$ = flow stress = $\frac{1.15}{2}$(yield strength + ultimate strength)

$2c$ = crack length

ϕ = total circumferential crack angle in radians

ξ = elastic bending correction factor

= $J\,(.4286 - .4574\emptyset + .17324\emptyset^2 - .00514\emptyset^3)$

Y = geometric plastic zone limiting function

= $\left[\frac{2}{\pi}\,(2\cos(\frac{\phi}{4} - \sin(\phi/2))\,V(\phi)\right]^{-1}$

$V(\emptyset)$ = pipe ovalization correction factor

= $\frac{\pi}{4}\,\{1 + .067\phi + .00038\phi^2 + .00876\phi^3\}$

σ = nominal bending stress in pipe

a = crack depth

t = wall thickness.

Typical bending stress versus crack length relationships are shown in Figure 13.

Two major limitations of this criterion are (i) residual stresses are not incorporated in this model and (ii) the criterion does not predict failure stresses accurately for very long circumferential flaws or for very low toughness pipes.

British Standard CTOD Approach

This approach [Reference 6] is used as a design standard rather than a failure criterion for pipes with circumferential surface flaws. It is based on allowable COD' concept and permissible stresses are governed by Equation (14)

$$\delta_c = \frac{2\pi \bar{a}\, \sigma_y}{E}\left(\frac{\sigma+\sigma_r}{\sigma_y} - 0.25\right) \tag{14}$$

where

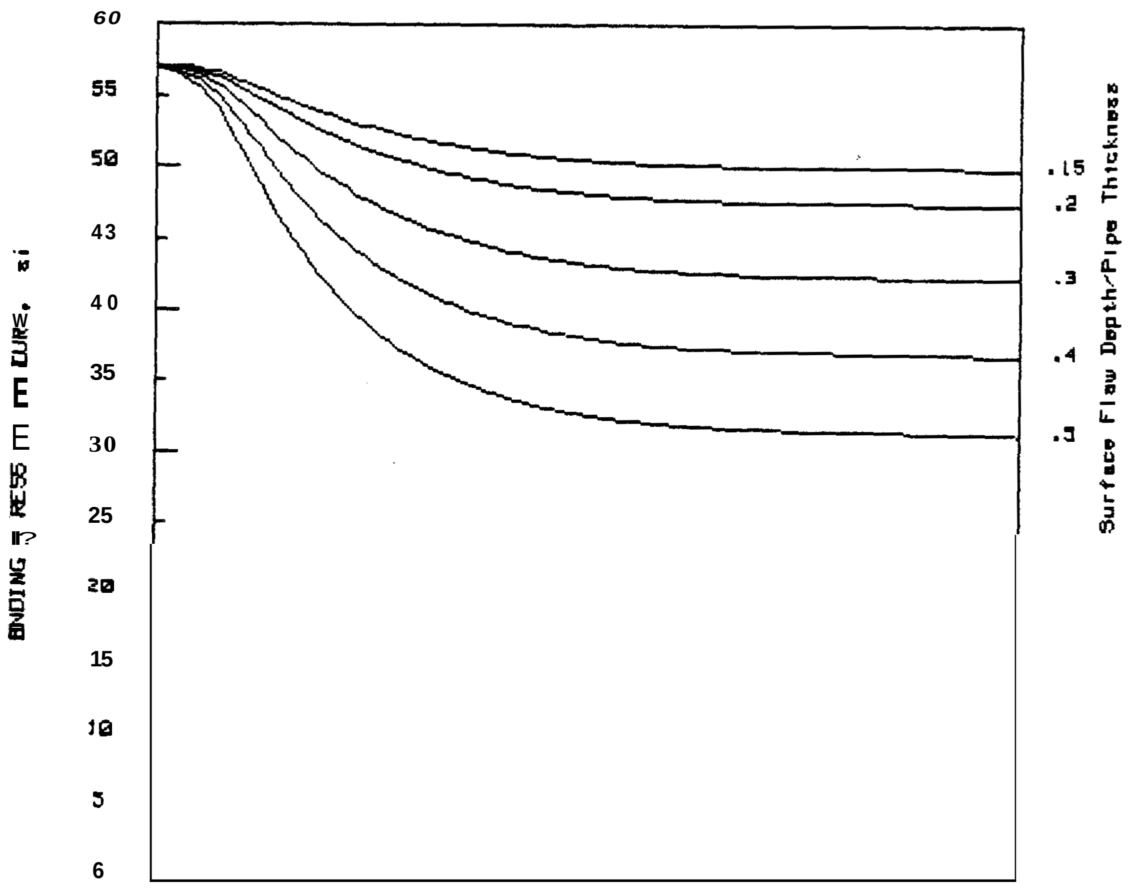
δ_c = critical crack opening displacement
σ_y = yield stress
σ_r = residual stress in pipe ($\backsim$ yield stress)
$\bar{a}$ = allowable flaw size parameter, determined from Figure 14.
σ = nominal stress in pipe.

A safety factor of $\backsim$ 2.5 on flaw size is already incorporated in arriving at this design criterion.

National Bureau of Standards-Critical COD Method

This approach [Reference 7) was developed by Begley, McHenry and Reed and is also based on a critical crack opening displacement. However, residual stresses are incorporated in the model by subtracting .001 from δ_c as shown in Equation (15)

DIAMETER = 38 in.
FLOW STRESS = 57.2 ksi
TOUGHNESS J = 61.8 in-lb/in-sq



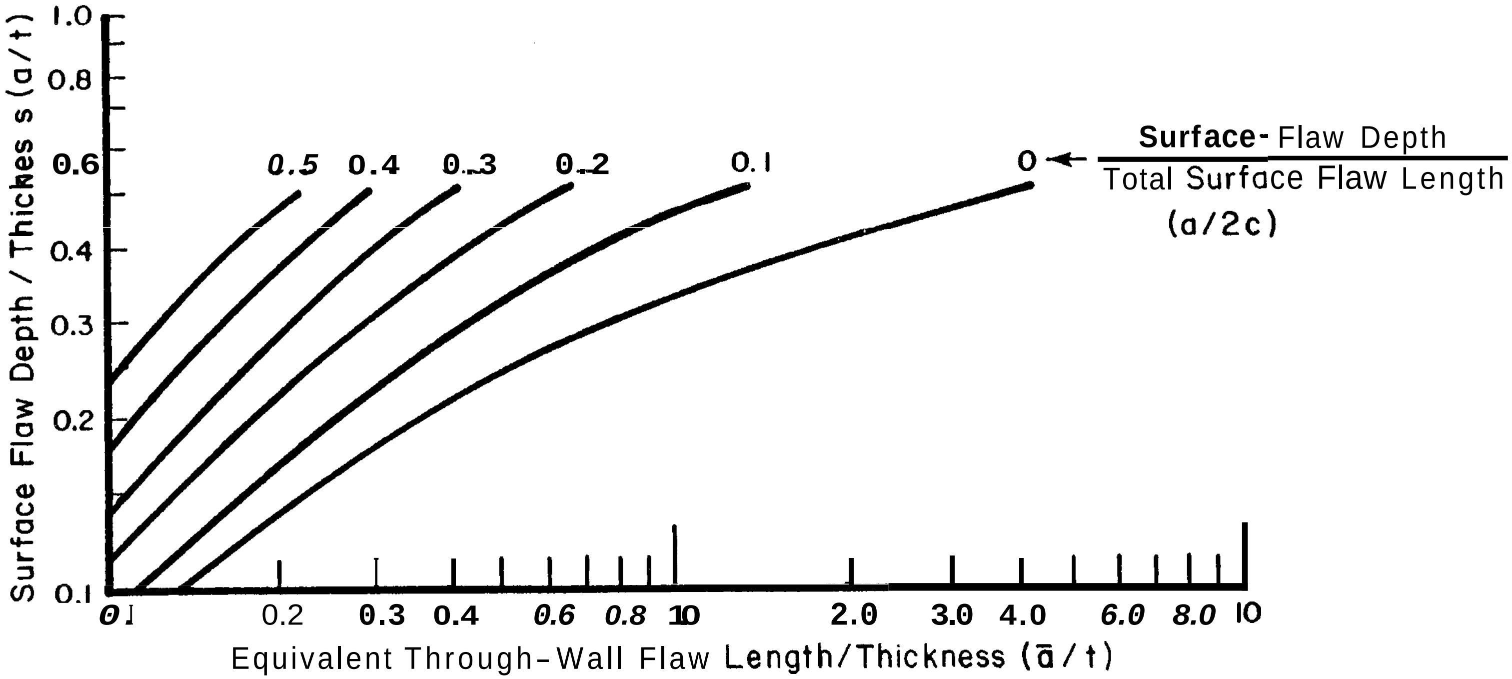


FIGURE 14. RELATIONSHIP BETWEEN SURFACE FLAWS AND EQUIVALENT THROUGH-WALL FLAWS FOR BRITISH APPROACH TO COD ANALYSIS

$$\delta_c - .001 = \frac{2c}{E}[\sigma - (1 - a/t)\bar{\sigma}] \tag{15}$$

where

δ_c = critical COD
$2c$ = surface crack length
σ = nominal stress
$\bar{\sigma}$ = flow stress = $\frac{1}{2}$ (yield + ultimate strength)
a = flaw depth
t = wall thickness

Recently, NBS has developed a more detailed analysis [Reference 8] for determining failure stress levels and allowable flaw size in pipeline girth weld. This approach is also based on a critical COD (δ_c) concept, the failure criterion being

$$\delta_c = \delta_{el} + \delta_{\ell y} + \delta_r \tag{16}$$

where

$\delta_{e\ell}$ = elastic component of COD
$\delta_{\ell y}$ = crack opening displacement due to ligament yielding
and δ_r = crack opening displacement due to residual stress.

Expressions for $\delta_{e\ell}$, $\delta_{\ell y}$ and δ_r are given in Reference 8 and determining critical flaw sizes involves an iterative solution to Equation (16).

<u>API Analysis</u>

The API 1104 [Reference 9, 10] analysis is also based on critical COD. However, only two levels of toughness δ_c = .005 inch and δ_c = 0.01 inch are considered in developing design guidelines. Allowable flaw depth is determined from the longitudinal strain in the pipe for the two levels of toughness, as shown in Figure 15. Maximum allowable flaw length is also governed by critical COD and pipe wall thickness.

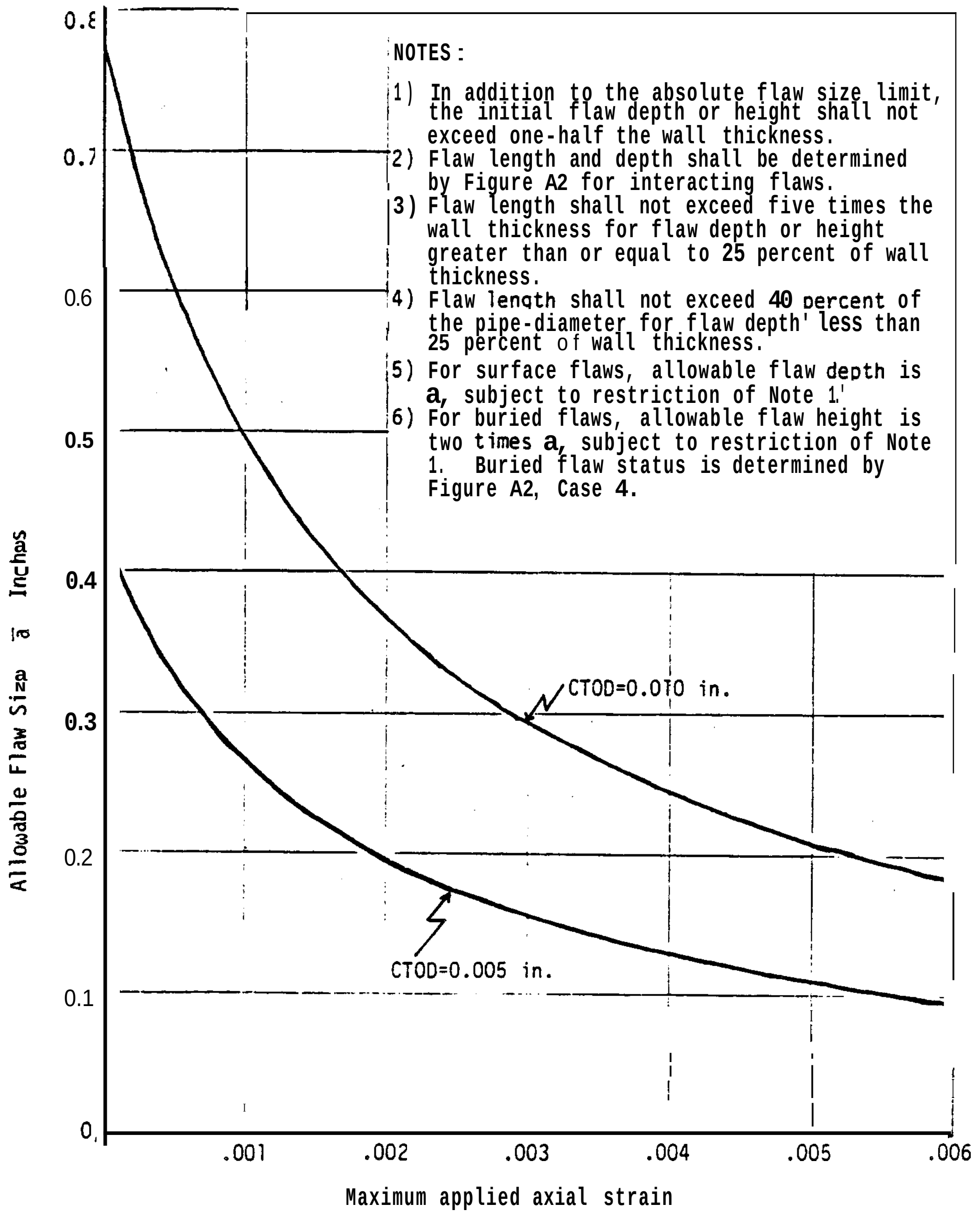


FIGURE 15. ALLOWABLE FLAW SIZE FROM API 1104, APPENDIX A

Other Approaches

Among other analyses available for determining allowable circumferential flaws in pipeline, is the one developed by the Welding Institute in Canada [Reference 11] and is similar to the British Standard. The only modifications being those for very long shallow flaws with aspect ratios of $\sim$ .01.

The elastic plastic fracture handbook developed by General Electric Company [Reference 12] deals only with 3600 circumferential surface flaws in pipes. This analysis therefore is inappropriate for finite length surface flaws.

Example Case

The following case will be analyzed with regard to allowable/critical flaw sizes using the various criteria described above.

Diameter, D = 30 inch
Wall thickness, t = 0.375 pipe
Grade, API 5LX-52
Yield stress, σ_y = 52 ksi
Toughness (corresponding to 10 ft/lb of 2/3 size CVN energy)
J_c = 61.8 in lb/in^2 from Table 4
or COD, δ_c = 0.0012 inch
Flow stress, $\bar{\sigma}$ = (1.1)(52) = 57.2 ksi.

Lowering depth, H = 3 feet
Soil stiffness, K = 2000 psi
Axial stress, σ_L = 15 ksi.

For the above case, from Figure 6, the maximum longitudinal stress (bending + tension) = 47 ksi. The flaw sizes can now be determined from Equations (13), (14), and (15) for the Battelle (BCL), British Standard (BS) and National Bureau of Standards (NBS) approach respectively.

The **API** 1104 Appendix **A** criterion however, is applicable for toughness levels of δ_c = .005 inch and .01 inch only. Hence allowable flaw depth and corresponding lengths are calculated from an extrapolation of data in Figure 14 which is developed from Equation (17) [Reference 10]

$$\bar{a} = \left[\left\{ \frac{\delta}{2\pi \left(\varepsilon_{a} + .0015 \right)} \right\}^{-\frac{1}{2}} + .1667 \right]^{-2} \tag{17}$$

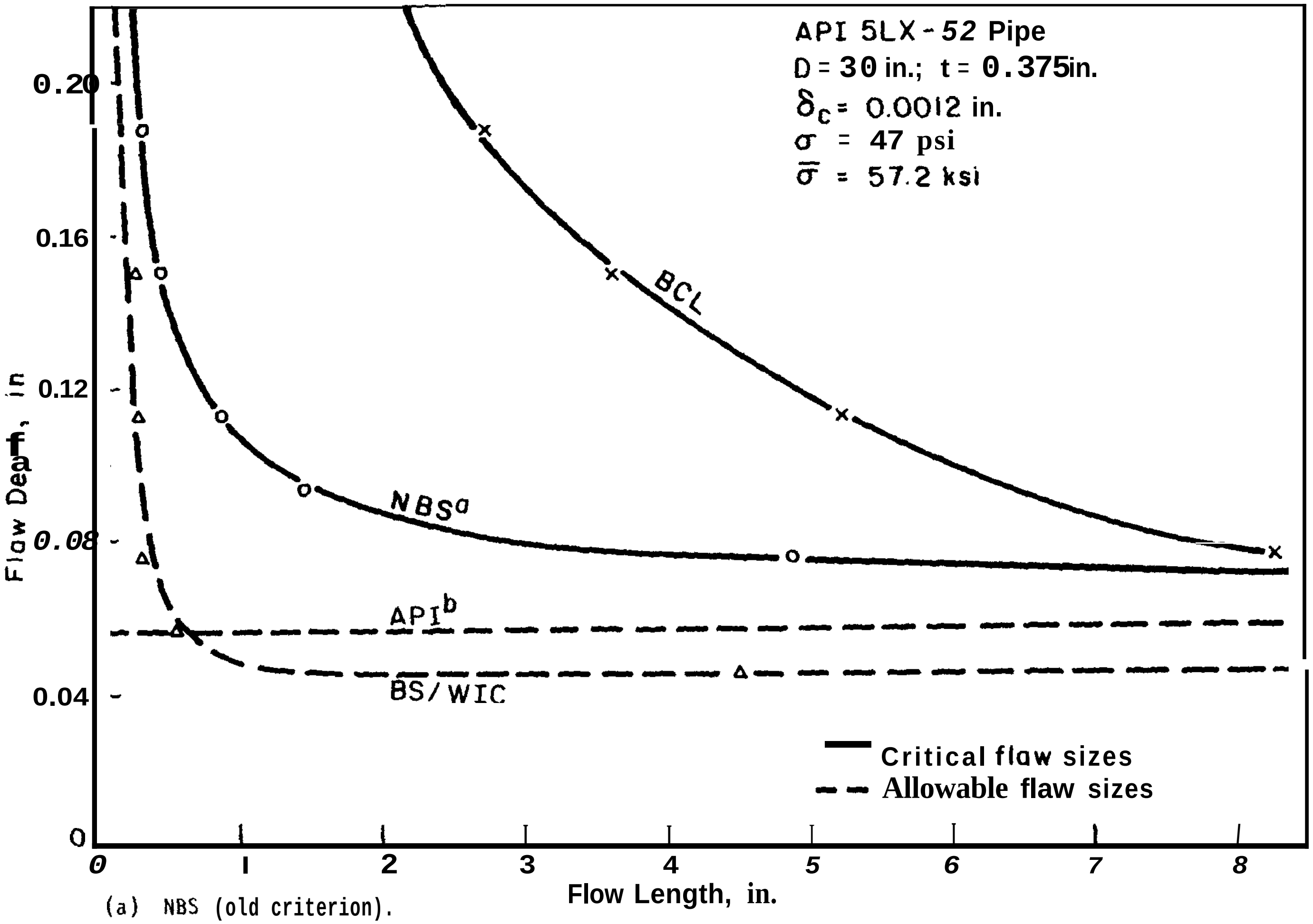
where $\varepsilon_a = \sigma/E$.

The flaw sizes calculated from the four approaches are shown in Figure 16. It must be noted that the BS and **API** models are design criteria, where the flaw sizes calculated are the maximum allowable, including a factor of safety, whereas the BCL and **NBS** approaches provide the critical flaw sizes at failure. The recent approach of NBS [Reference 8] was not yet available for comparison.

As seen in Figure 16 critical and allowable flaw depths and lengths vary considerably depending on the approach, the BS and **API** models being the most conservative since they are design criteria. Existing experimental data are extremely limited to verify the analyses and recommend any one single approach at this point.

Local Buckling

The failure of the pipeline by localized buckling (ovalization or wrinkling) may occur if the curvature exceeds a certain critical value depending on the geometry of the pipe and the strain hardening characteristics of the material. Collapse or buckling moments were calculated for a variety of pipe geometries with assumed material properties (i.e., stress vs. strain relationships) by means of a proprietary computer program. These limit moments are compared to the maximum moments for ten feet of lowering for the minimum contoured spans for the least wall thickness listed in the **API** 5L and 5LX specifications for 30, 16, and 8-5/8 inch pipe in Table **5**. **As** seen therein the maximum moments for all cases are well below the two limit moments



(a) NBS (old criterion).

(b) Without inspection error allowance.

FIGURE 16. COMPARISON OF CRITICAL/ALLOWABLE FLAW SIZES FROM VARIOUS CRITERIA

TABLE 5. RESULTS OF COLLAPSE STUDY
(Minimum API Wall Thicknesses)

Pipe Size	Initial Axial Stress, psi	Calculated Collapse Parameters: Ovalization MO in-kips	Calculated Collapse Parameters: Wrinkling MC in-kips	Maximum Moment Due to Lowering: Ms[a] in-kips
30-inch O.D.	0	13,902	11,905	1,776
by	10,000	13,600	11,978	1,179
0.250-inch	15,000	13,248	11,859	981
wall	20,000	12,755	12,146	831
16-inch O.D.	0	3,158	2,672	196
by	10,000	3,103	2,659	132
0.188-inch	15,000	3,022	2,619	110
wall	20,000	2,915	2,756	93
8-inch O.D.	0	545	453	16
by	10,000	535	446	(b)
0.125-inch	15,000	520	455	(b)
wall	20,000	499	466	(b)

(a) Based upon minimum contoured trench profile and 10 feet of deflection at mid span.

(b) Beyond the limits of accuracy of the calculations.

(one is for ovalizations, one for wrinkling or bifurcation). These examples do not of course, cover all pipe geometries. Additional data can be generated, if necessary, which permit one to check any reasonable pipe geometry for buckling. These cases strongly suggest that if the pipeline operator elects to use the contoured trench option the maximum moments will be much lower than the collapse moments. Hence, buckling the pipe with the contoured trench option is believed highly unlikely.

PROCEDURES FOR LOWERING

In order to properly conduct a pipeline lowering operation the pipeline operator must review and evaluate the factors listed and discussed at the beginning of this report, namely,

- Required Deflection
- The pipe
- The pipeline
- Terrain
- Soil
- Safety
- Stress

On the assumption that the operator will have or be able to obtain sufficient information concerning these factors and that they are favorably disposed toward lowering in service, we will now consider how one might go about carrying out a lowering operation.

Preliminary Lowering Profile

Profile of the Existing Pipeline

At the outset, the pipeline operator should develop a vertical profile drawing of the pipeline in the vicinity of the proposed lowering location. It is essential that the profile be that of the pipeline and not the existing land surface grade. If this is not known from the construction of the pipeline, it will have to be determined. It can be determined by surveying the existing surface grade and physically probing by bore holes to locate the pipeline. The pipeline should be accurately located in any case prior to excavation to minimize the risk of inflicting damage on it. Boring to locate the pipe can be done in conjunction with any soil sampling that is considered necessary for characterizing excavating conditions and soil cohesiveness or determining the depth of the water table.

Preliminary Estimates of Span and Lowering Profile

Once the accurate elevation of the pipeline is known at distances to 750 feet on either side of the proposed center of lowering, the proposed road crossing section can be plotted as was illustrated in Figure 1, and the maximum lowering distance, H, can be determined. The required H may be fixed by state highway department regulations or, in the absence of such regulations, by engineering judgement of the operator,

Having fixed H and determined the pipeline profile in the area, the operator may make preliminary estimates of the trench contour and plan field operations as follows. As has been discussed, one can make a conservative estimate of the existing axial stress in the pipeline by assuming that it is 20,000 psi. Such an assumption is not necessary in the case of slack lines or lines with known compressive stresses. For these cases one can safely assume the presence of zero axial stress and make calculations accordingly. It is highly unlikely except in landslide areas as discussed previously that the stress will be more than 20,000 psi*.

* If the stress level is more than 20,000 psi and a value of 20,000 psi is assumed, the resulting lowering induced stresses and temporary stresses are likely to exceed the limit of 54 percent of SMYS suggested herein. The analytical methods described in Appendix B can be used for cases in which the axial stress exceeds 20,000 psi but such a condition must be recognized prior to the start of lowering operations. If such a condition is anticipated, the stress should be determined or else lowering should not be attempted.

One can then determine the preliminary minimum span length, L, and maximum stress for the minimum contoured trench case in Tables C-1 and C-2 provided in Appendix C. In addition, the final mimimum contoured trench shape based on an initially flat, straight pipeline can be obtained from Table C-4 of Appendix C.

Planning for Existing Elastic Curvature, Valves, Fittings, and Bends

The preliminary lowering profile can be superimposed on existing profiles as shown in Figures 17 and 18 for the purpose of planning field lowering operations. Figure 17 provides suggestions for dealing with pipelines which have initial elastic curvature, and Figure 18 provides suggestions for dealing with valves, fittings, and permanent field bends. Note in Figure 17, that the initial elastic curvature need not be determined because the final curvature after lowering is all that matters. All that is necessary is for the curvature of the final profile to be less than or equal to the maximum curvature specified in Table C-4. The final lowered profile shape is fixed at the center where the maximum deflection H is desired. Elsewhere the trench profile is specified in Table C-4 until a "transition" zone is reached. In the transition zone the curvature is modified to provide a smooth transition to the existing profile. This may be done graphically as explained in Example 1 which follows to insure that the maximum curvature of Table C-4 is not exceeded. The use of transition zones may actually shorten the excavation over that required for a flat, straight pipeline as shown in Case I and the right half of Case II in Figure 17, or it may lengthen the excavation as shown in Case III and the left half of Case II.

For valves and fittings Case IV of Figure 18 provides a suggested solution. As long as a contoured trench profile is used, no special trench profile needs to be considered. This is justifiable on the basis that the added stress associated with the low curvature is not particularly high (less than 10,000 psi in most cases) and because the small adjustments that would be necessary to keep curvature unchanged over the short space of a valve or a fitting would be difficult to achieve with excavating equipment. In the

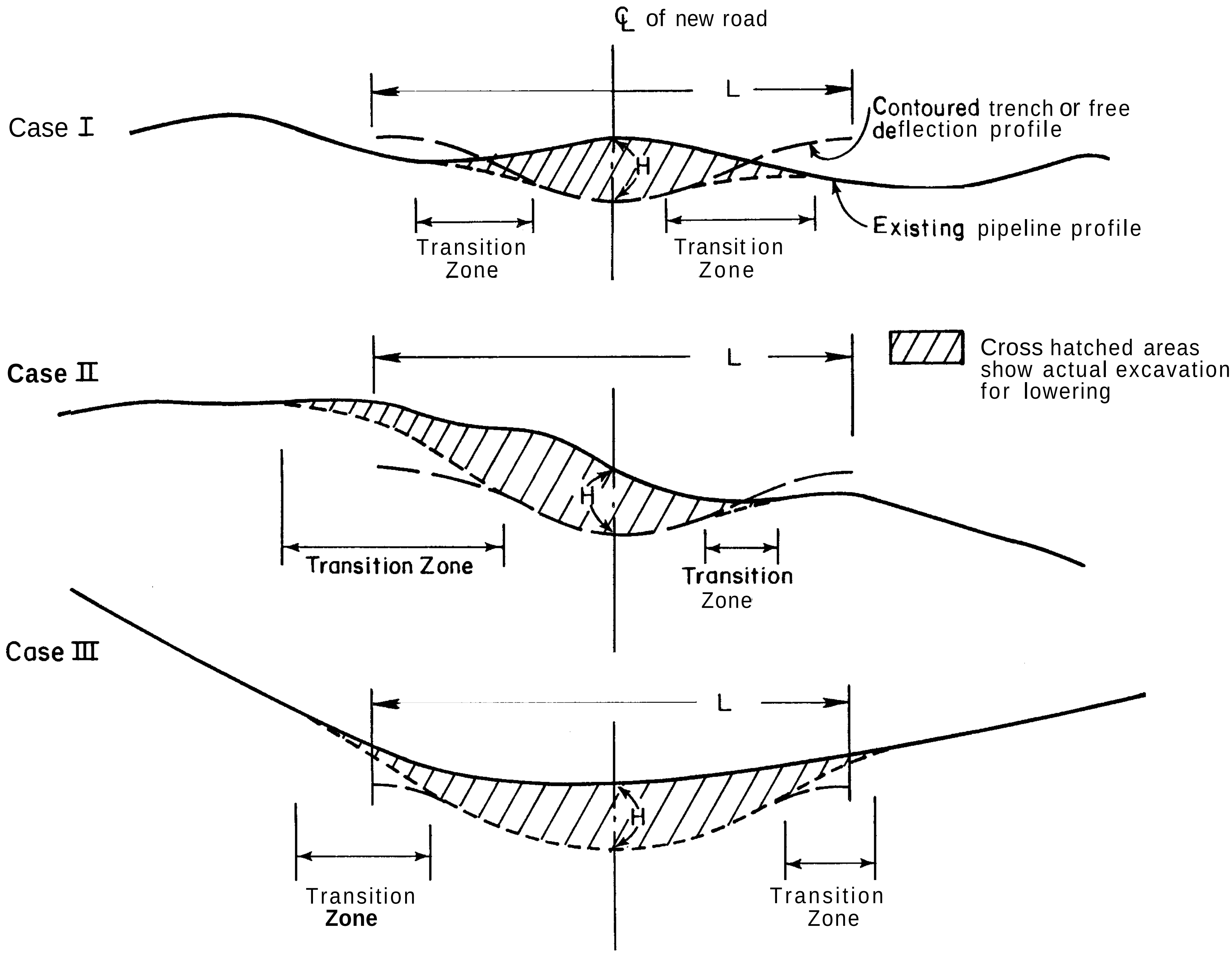


FIGURE 17. HANDLING ACTUAL PIPELINE PROFILES WHERE ELASTIC CURVATURE IS PRESENT

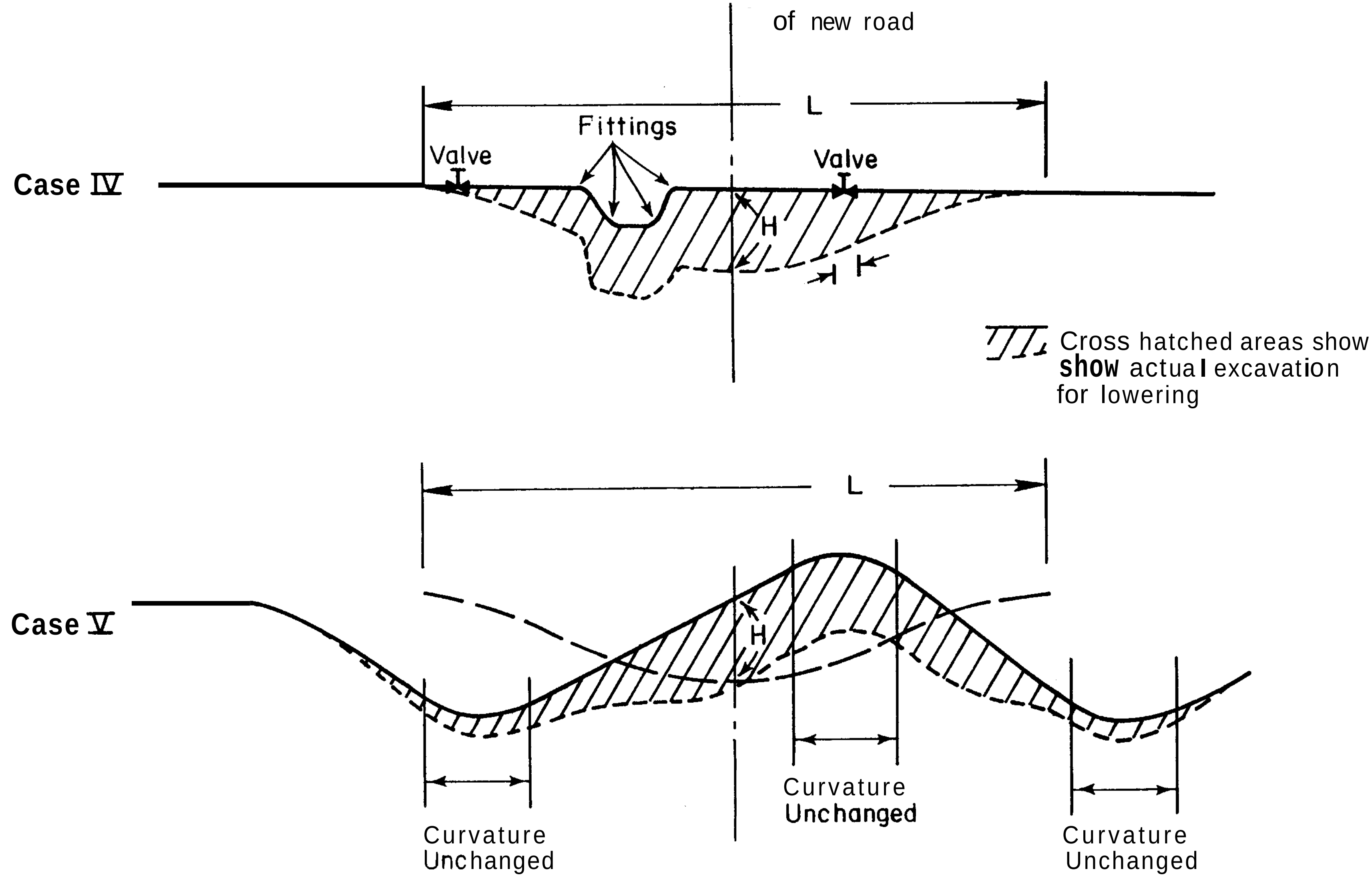


FIGURE 18. HANDLING ACTUAL PIPELINE PROFILES WHERE VALVES, FITTINGS, OR FIELD BENDS ARE PRESENT

actual lowering operation, lift locations should be planned such that valves are located neither at a sideboom tractor or support nor in the middle of a long span of pipe. Supports should be located such that valves are in the middle of a short span or at the inflection point of a long span.

Unlike valves and fittings which are short, it is probably desirable to lower a pipeline having permanent bends without changing the curvature in the bend area. Field bends are usually made of the same materials as the straight pipe by cold bending. Such bends are usually ovalized to greater extent than straight pipe, and hence, are more prone to buckling. As shown in Case V of Figure 18, the trench can be shaped so that field bends do not change curvature.

Field Lowering Procedures

At the outset of operations in the field, prior to the beginning of any excavation, the pipeline operator should consider lowering the pressure to the level given by Equation (1).

Determining the Existing Axial Stress

If the pipeline operator decides that he must determine the existing axial stress in the pipeline rather than assuming a value, he must locate and excavate a relatively straight, relatively flat 300-foot segment of the pipe within the area to be lowered and prepare to lift it at the mid point. Prior to lifting he should carefully measure the elevations of the top of the pipe as shown in Figure 19 at 5-foot intervals starting 50 feet from the mid point on both sides and going out to 150 feet. Also, prior to lifting the entire exposed segment should be examined visually for gross defects, and the top quadrant of all girth welds within 50 feet on either side of the mid point should be inspected by means of radiography or ultrasonics (the problems and limitations associated with these techniques will be discussed later). If no defects are found, the operator should select an appropriate value of

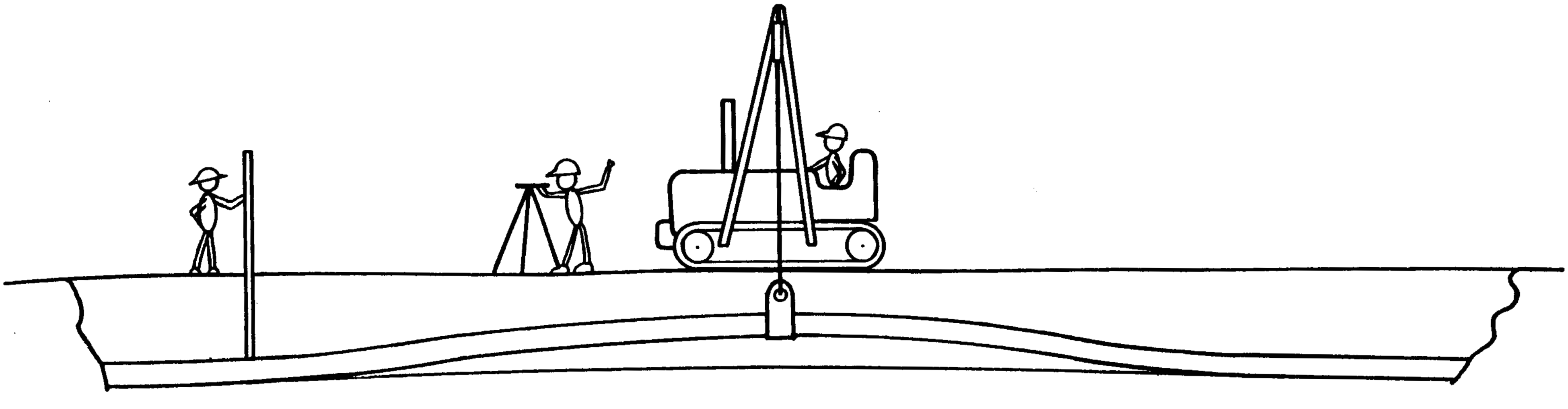


FIGURE 19. MEASURING EXISTING AXIAL STRESS BY LIFTING THE PIPELINE

allowable lifting stress.* Using this limit on stress and an assumed value of initial axial stress he then selects an allowable lift height from the appropriate section of Table C-5 of Appendix C.

After the pipeline is lifted to the allowable lift height, the survey of elevations at 5-foot intervals is repeated as shown in Figure 19 until the point of lift-off is determined at each end. These measurements must be accurate to 0.1-inch elevation to be able to locate the lift-off length to the nearest 10 feet. Using the appropriate portion of Table C-5 in Appendix C, the operator can then determine from the lifted length, the existing axial stress. Alternatively, if a load cell is available to insert in series with the lifting cable, the lifting load can be measured at the allowable lift height and translated into axial stress via the appropriate portion of Table C-5 of Appendix C.

Once the exiting axial stress is determined, the operator should remember that it is the stress at the current reduced pressure. To get the existing stress as it would be at the maximum pressure one must add that portion due to the difference between the reduced and the maximum pressure. The added amount is

$$\sigma_{added} = (MOP - P)\,\frac{D}{2t}\nu \tag{18}$$

where

MOP is the maximum operating pressure at the site, psig

P is the reduced pressure determined by Equation (1), psig

D is the diameter of the pipe, inches

t is the wall thickness, inch

ν is Poisson's ratio (0.3) for steel.

Since the pressure will be restored to MOP, it is important to add this stress to the value determined from the lifting operation.

If the pipeline operator decides he does not need to measure the exiting stress but can reasonably assume a maximum value, he may skip the above steps and go directly to the following (after making sure that the operating pressure does not exceed the value expressed in Equation 1).

---

* As will be shown in Example 2 which follows, a precedent exists for using 85 percent of SMYS for this value.

Excavating the Trench for Lowering

The operator must decide from his soil data whether to lower the pipeline into a parallel, offset trench as shown in Figure 4a or to lower the pipeline directly in its present vertical plane as shown in Figure 4b. If a parallel, offset trench is selected, it must be remembered that stresses and spans are based upon calculated deflection and not necessarily upon the actual amount of lowering achieved. The difference between the two for an offset trench is illustrated in Figure 20. For a 10-foot lowering, if the pipe is moved 3 feet laterally, the total deflection is actually 10.44 feet. This is almost a negligible difference, but is gets worse for a smaller amount of lowering. For a 3-foot lowering, if the pipe is moved 3 feet laterally, the total deflection is 4.24 feet. The resulting spans and stresses should be based upon the 4.24 foot value in such a case. In reality the parallel, offset trench must converge with the exiting trench near the ends of the excavation. Otherwise, it will not be physically possible to lower the pipeline.

Knowing the desired H, or maximum lowering amount, and the existing axial stress, one can calculate the span length, L, the maximum stress, σ, and the final profile as discussed previously. These parameters can be read directly from Tables C-1 and C-2 of Appendix C for the minimum contoured trench case. For any other cases such as the free deflection case or longer contoured trench spans, one must resort to using the calculations described in Appendix B. Whatever the procedure used, the outcome is a profile to be excavated. The procedure one chooses to use is governed by the allowable added stress. For cases in which values for existing stresses are measured, and in which the operator is willing to use sophisticated inspection techniques, the allowable stress, the minimum span length and the final profile can be optimized. For cases in which the stresses are not measured directly, and in which sophisticated inspection techniques will not be used, the contoured trench profile which gives a maximum stress no greater than 54 percent of SMYS should be used.

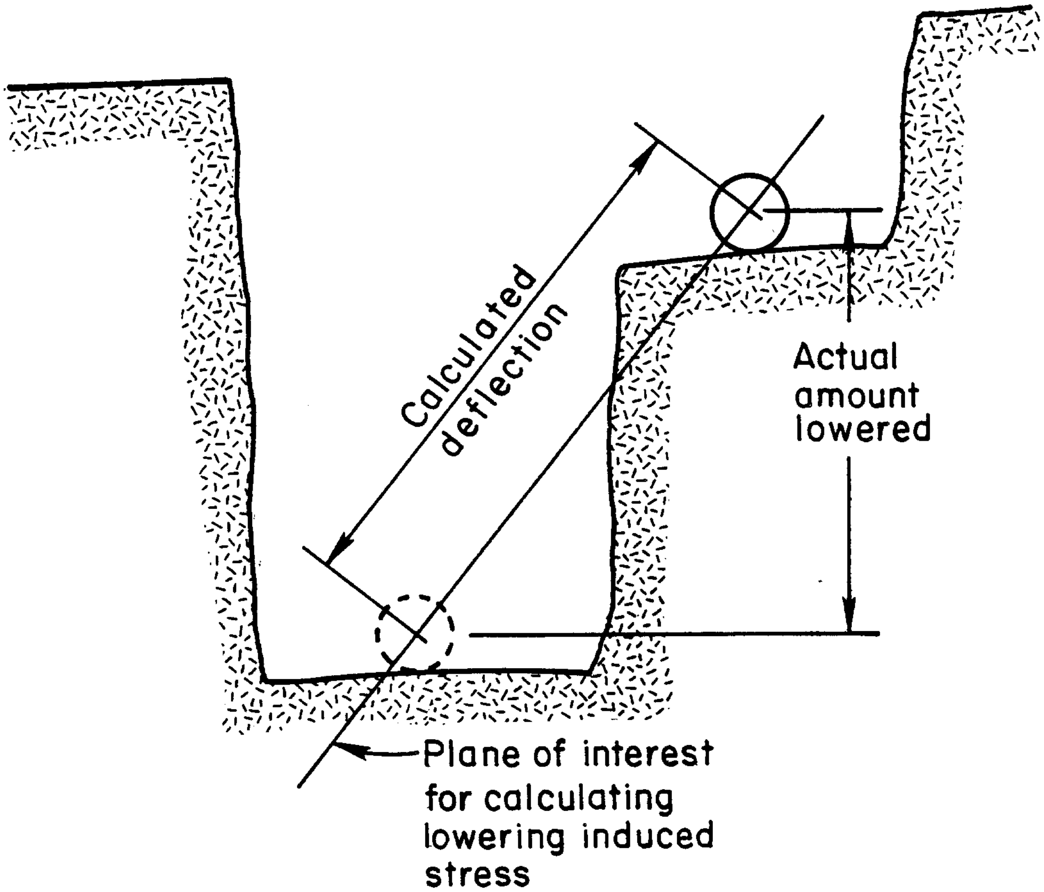


FIGURE 20. DIFFERENCE BETWEEN AMOUNT LOWERED AND CALCULATED DEFLECTION FOR AN OFFSET TRENCH

Inspection

Regardless of the method chosen for establishing a trench profile, the exposed portion of the pipeline should be given a thorough overall visual inspection Coating need not be removed because the main objective of the inspection is to find corrosion or mechanical damage that has occurred since the initia hydrostatic test. In such areas the coating itself will be damaged or missing. Gouge and dent defects require repair, as does corrosion which does not meet the criterion in the **ASME** Guide for Gas Transmission and Distribution Piping, the 831.8 Code or the B31.4 Code. Superficial scratches can either be smoothed by grinding or left alone.

Girth welds should receive special attention if the lowering operation will result in the total longitudinal stress exceeding 54 percent **SMYS.*** Girth welds can be inspected visually, by radiography or by ultrasonics. Visual inspection and ultrasonics require removal of the coating. Visual inspection by itself is not particularly useful as many types of weld defects are not surface connected. Radiography is difficult and, in some cases, impossible to perform successfully on a pipeline in service. The source must be capable of penetrating clear through the pipeline and the product inside. **As** a result in the case of liquid pipelines, the use of radiography in service is limited to sizes 8-5/8-inches and smaller. Such radiography is more time consuming and less reliable than radiography of new construction welds. Radiographs of welds in an in-service pipeline are not of sufficient quality to permit interpretation to the API 1104 standard. And, as is well known, radiography is not particularly good at finding cracks and not capable of characterizing the depths of flaws except in special cases. Ultrasonic shear-wave equipment can be useful in finding most types of defects including cracks, and it can be used to characterize the sizes of defects. It is very inaccurate with respect to sizing defects. However, one advantage of ultrasonics is that it works as well on an in-service line (if the coating is removed) as on a new pipeline. The bottom line on inspection is that if the

---

* In a pipeline in which 90% or more of the welds were initially shown to meet the API Standard 1104, subsequent inspection is less important.

operator plans to use sizes of defects via one of the criteria described previously herein to limit the total stress due to lowering, he needs to have a high degree of confidence in his ability to characterize the defects. If that confidence is lacking, he is better off repairing any defects he finds prior to lowering or reducing the maximum stress to a level of 54 percent **SMYS** or less.

One further note on inspection, is that it is necessary to inspect only the quadrant (25 percent) of the weld that will be subjected to the maximum tensile stress, and only those few welds that exist in highly stressed regions along the profile need to be carefully inspected.

Lifting and Lowering

The most critical part of the operation is the actual lifting and lowering of the pipeline. Lift or support points must be located according to Table **C-3** of Appendix **C** in order that the acceptable maximum stress not be exceeded. Sufficient side boom tractors or winches must be present to carry out the lift and lowering of the entire segment in unison or in a carefully controlled sequence.* Since the relative elevation of the pipeline at adjacent pick-up or support points is critical to the stress, the variation in movement between adjacent tractors or supports must not exceed the support height differential in Table **C-3** on which the support spacing is based. It is especially critical that the tractors nearest the ends of the span not lift the pipeline more than it will be lowered at that point.

A lowering operation using sideboom tractors and a parallel, offset trench is the most difficult to coordinate. The tractors must lift the pipeline slightly, move it laterally, and then lower it all without having any differential movement of more than that of Table **C-3** on which the support spacing is based. The center tractor must effect the greatest amount of movement, the end tractors, the least. While it is theoretically possible that these movements could be carried out in unison, it is probably easier to

---

* The supporting cribs or beams and lifting or lowering gear must be capable of supporting the suspended weight of the unsupported span of the pipeline.

maintain effective control by having one movement made at a time. By limiting the extent of the movements and by properly sequencing the movements the line can be moved with a minimum of added stress and little or no impact loading.

A lowering operation involving supporting the pipeline from beams or setting the pipeline on temporary supports and then removing the intervening soil to permit a vertical drop is perhaps the easiest to effect and control. Fewer sideboom tractors (perhaps only one or two) would be needed. When the trench is ready, the tractor lifts the segment of the pipe at one support just enough (never more than the amount on which the support spacing is based) to allow one layer of supporting ties to be removed. Then, letting the pipe down on this support, the tractor operator proceeds to the next appropriate support (every other support in most cases as discussed elsewhere) and the process is repeated layer by layer, support by support until the pipeline is lying in the trench.

Special attention must be given to heavy components such as valves as mentioned previously. Such components should have nearby support points. It is not necessarily a good idea to support the valve directly, as this puts it at a high stress point. Similarly, supports should not be located such that a valve is near midspan.

Once the pipeline is on the trench bottom, the backfilling can begin, the operation can be completed, and the operating pressure level can be restored to normal.