BASIC DESIGN CALCULATIONS OF GAS PIPELINE

Under The Guidance of:

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Submitted by

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UNIVERSITY OF PETROLEUM & ENERGY STUDIES
(ISO 9001:2000 Certified& NAAC Accredited)

CERTIFICATE

This is to certify that the project work on "BASIC DESIGN CALCULATIONS OF GAS PIPELINE" submitted to the University of Petroleum and Energy Studies, Dehradun, by CHINMOY BHATTACHARYA (R040307010), SHAKTI AGARWAL (R040307052), NITESH NEGI (R040307036), and NISHANT JOSHI (R040307035) in partial fulfilment of the requirement for the award of degree of B.Tech in Applied Petroleum Engg. (2007-2011) is a bonafide work carried out by them under my supervision and guidance.

Place: DEHRADUN

Date: 05-05-11

Signature of Mentor

(Mr.A.KUMAR)

DECLARATION

We declare that **technical paper entitled "BASIC DESIGN CALCULATIONS OF GAS PIPELINE"** has been prepared by us during the academic year 2010-11 under the Guidance of Mr. A.Kumar (Senior faculty, COLLEGE OF ENGINEERING) to fulfil the research paper.

We also declare that this project is a result of our own effort and that it has not been submitted to any other University or published any time before.

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Abstract

Keeping in mind, for fulfilling the demand of petroleum product from one place to other pipeline played a major role in transporting of crude oil from one destination to other .This facility comes out to be more environment friendly, economical and safest mode of transportation. Pipeline affects daily life in most part of the world. Modern people's lives are based on the environment in which energy plays a predominant role. Oil and gas are the major supply of the energy and pipelines are the means of transporting the energy .These pipelines are mostly buried and operate without disturbing the normal pursuit .They carry large volume of natural gas,crude oil and other products in continuous stream.

The objective of this project is to design a basic calculation on gas pipeline which starts from source A to destination B in order to meet the present demand. The total throughput required is 175MMSCMD. Hence designing is done by taking the two pipes of different diameter. Thereby making proper analysis of the result, on the basis of economic feasibility the best suited diameter is selected.

The designing for this project is been done on the basis of standards approved by the petroleum industry in order to attain the satisfactory design. The standards followed are ASME B 31.8,API 5L, pipeline rule of thumb, gas pipeline hydraulics and construction along with relevant data picked through websites.

The conclusion of this thesis is been drawn by analyzing all the facts come across by designing and later on while performing economic calculation.

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Introduction:

In this project the preliminary stages of a new pipeline design in which steady state flow analysis is done has been covered. In this project we have covered various cases of pressure loss situations like on a flat terrain, elevated terrain, series piping, parallel piping etc. Then the concept of the number of compressor stations required to send the gas through a pipeline at required pressure to the receiving section at the specified pressure has also been discussed. Finally in this project economic evaluation has also been done to select the best possible diameter from a choice of 2 or 3 types of diameter of the pipeline.

At the end of the project we have selected a case study where all the aspects for designing a new pipeline and its cost estimation have been considered.

The only limitation of this project is that these calculations cannot be used for the final laying of the pipe as this project is only based on steady state calculations (which are based on steady state and isothermal simple assumptions) which is only valid to understand the basic modeling of the pipeline. These calculations must be supplemented with transient state flow analysis to get the final design of the pipeline. These calculations are generally based on computer simulated models.

Chapter 1

1.1) Steel Piping Systems Design Requirements

Steel Pipe Design Formula

(a) The design pressure for steel gas piping system or the nominal wall thickness for a given design pressure must be determined by the following formula

$$\boxed{P = 2StFET/D}$$

Eq...........1.1

Where,

D = nominal outside diameter of pipe, in.

E = longitudinal joint factor obtained

F =design factor obtained

P =design pressure, psig

S =specified minimum yield strength, psi

T =temperature de-rating factor

t = nominal wall thickness, in.

(b) The design factor for pipelines in Location Class 1, Division 1 is based on gas pipeline operational experience at operation levels better than of those previously recommended by this Code.

(c) ***Fracture Control and Arrest.*** A fracture toughness criterion must be specified to control fracture propagation when a pipeline is designed to operate either at a hoop stress over 40% through 80% of SMYS in sizes NPS 16 or larger, or at a hoop stress over 72% through 80% of SMYS in sizes smaller than NPS 16.

(1) ***Brittle Fracture Control.*** To ensure that the pipe has adequate ductility, fracture toughness testing must be performed according to the testing procedures of supplementary requirements SR5 or SR6 of API 5L, or other equivalent alternatives. .

(2) ***Ductile Fracture Arrest.*** To ensure that the pipeline has adequate toughness to arrest a ductile fracture. the pipe must be tested according to the procedures of supplementary

requirements SR5 of API 5L.

*(3) **Mechanical Crack Arrestors**.* Mechanical crack arrestors consisting of sleeves, wire-rope wrap, heavy-wall pipe, or other suitable types are present to provide reliable methods of arresting ductile fracture. The mechanical crack arrestors must be placed at intervals along the pipeline.

Limitations on Design Pressure *P*

The design pressure obtained by the formula must give the following results:

(a) P for furnace butt welded pipe must not exceed the restrictions of 60% of mill test pressure.

(b) P must not exceed 85% of the mill test pressure for all other pipes provided; however, that pipe, mill tested to a pressure less than 85% of the pressure required to produce a hoop stress equal to the specified minimum yield, might be retested with a mill type hydrostatic test or tested in place after installation

Limitations on Specified Minimum Yield Strength *S*

(a) If the pipe under consideration is not a new pipe purchased under specification approved and listed in this Code, the value of *S* may be determined in accordance with one of the following:

Basic Design Factor, *F*

Location Class	Design Factor, *F*
Location Class 1, Division 1	0.80
Location Class 1, Division 2	0.72
Location Class 2	0.60
Location Class 3	0.50
Location Class 4	0.40

Table 1.1

(b) When pipe that has been cold worked for meeting the specified criteria of minimum yield strength is subsequently heated to a temperature higher than 900°F for any period of time or over 600°F for more than 1 hr, the maximum allowable pressure at which it can be used must not exceed 75% of the value obtained by use of the steel pipe design formula.

(c) In no case the higher actual value of a property the Code refers to the specified minimum value of a mechanical property must be substituted in the steel pipe design formula regarding the reuse of steel pipe.

Additional Requirements for Nominal Wall Thickness *t* in.:

(a) The minimum wall thickness *t* required for pressure containment might not be adequate for other forces to which the pipeline may be subjected.

(b) Transportation, installation, or repair of pipe must not reduce the wall thickness at any point to a thickness less than 90% of the nominal wall thickness as determined for the design pressure to which the pipe is to be subjected.

Design Factor '*F*' and Location Classes: These design factors must be used for the designated Location Class.

Design Factors for Steel Pipe Construction

	Location Class				
	1				
Facility	Div. 1	Div. 2	2	3	4
Pipelines, mains, and service lines	0.80	0.72	0.60	0.50	0.40
Crossings of roads, railroads without casing:					
(a) Private roads	0.80	0.72	0.60	0.50	0.40
(b) Unimproved public roads	0.60	0.60	0.60	0.50	0.40
(c) Roads, highways, or public streets, with hard surface and railroads	0.60	0.60	0.50	0.50	0.40
Crossings of roads, railroads with casing:					
(a) Private roads	0.80	0.72	0.60	0.50	0.40
(b) Unimproved public roads	0.72	0.72	0.60	0.50	0.40
(c) Roads, highways, or public streets, with hard surface and railroads	0.72	0.72	0.60	0.50	0.40
Parallel encroachment of pipelines and mains on roads and railroads:					
(a) Private roads	0.80	0.72	0.60	0.50	0.40
(b) Unimproved public roads	0.80	0.72	0.60	0.50	0.40
(c) Roads, highways, or public streets, with hard surface and railroads	0.60	0.60	0.60	0.50	0.40
Fabricated assemblies	0.60	0.60	0.60	0.50	0.40
Pipelines on bridges	0.60	0.60	0.60	0.50	0.40
Pressure/Flow Control and Metering Facilities	0.60	0.60	0.60	0.50	0.40
Compressor station piping	0.50	0.50	0.50	0.50	0.40
Near concentration of people in Location Classes 1 and 2	0.50	0.50	0.50	0.50	0.40

Table1.2

(1.2) Additional Design Information or Instructions:

Fabricated Assemblies: When fabricated assemblies, such as connections for separators, main line valve assemblies, cross connections, river crossing headers, etc., are to be installed in areas defined in Location Class 1, a design factor of 0.6 is required throughout the assembly and for a distance lesser than 5 diameters or 10 ft in each direction beyond the last fitting

Pipelines or Mains on Bridges: The design factor for pipelines or mains supported by railroad, vehicles, pedestrian, or pipeline bridges must be determined in accordance with the Location Class prescribed for the area in which the bridge is located. In Location Class 1, however, a design factor of 0.6 must be used.

Design of Metering and Pressure/Flow Control:

(a) All piping and piping components, up to and including the outlet stop valve(s) of individual meter and pressure/flow control runs, must meet or exceed the maximum design

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pressure of the inlet piping system. Threaded reducing bushings should not be used in pressure flow control facilities where they are subject to high frequency piping vibrations.

(b) All piping must be tested in accordance with and the class location requirements of Instrumentation devices such as transmitters, recorders, controllers, etc., excluding testing instrumentation, should be isolated from the piping during the test. Test fluids must be removed from piping and piping components and the piping purged with natural gas before placing the facilities in service.

(c) The corrosion control measures as appropriate must be applied to meter and pressure flow control piping.

Metering Facilities: Particular consideration and attention must be given to sizing meter run blow downs and flow restricting plates for turbine and positive displacement meters. Rapid depressurization of meter runs can damage or destroy meters due to meter over spin and high differentials and can endanger personnel.

Longitudinal Joint Factor, *E*

Spec. No.	Pipe Class	*E* Factor
ASTM A 53	Seamless	1.00
	Electric Resistance Welded	1.00
	Furnace Butt Welded: Continuous Weld	0.60
ASTM A 106	Seamless	1.00
ASTM A 134	Electric Fusion Arc Welded	0.80
ASTM A 135	Electric Resistance Welded	1.00
ASTM A 139	Electric Fusion Welded	0.80
ASTM A 211	Spiral Welded Steel Pipe	0.80
ASTM A 333	Seamless	1.00
	Electric Resistance Welded	1.00
ASTM A 381	Double Submerged-Arc-Welded	1.00
ASTM A 671	Electric Fusion Welded	
	Classes 13, 23, 33, 43, 53	0.80
	Classes 12, 22, 32, 42, 52	1.00
ASTM A 672	Electric Fusion Welded	
	Classes 13, 23, 33, 43, 53	0.80
	Classes 12, 22, 32, 42, 52	1.00
API 5L	Seamless	1.00
	Electric Resistance Welded	1.00
	Electric Flash Welded	1.00
	Submerged Arc Welded	1.00
	Furnace Butt Welded	0.60

Table 1.3

Temperature Derating Factor, *T*, for Steel Pipe

Temperature, °F	Temperature Derating Factor, *T*
250 or less	1.000
300	0.967
350	0.933
400	0.900
450	0.867

GENERAL NOTE: For intermediate temperatures, interpolate for derating factor.

Table 1.4

Other (Non-mandatory) Considerations for

Metering Facilities:

(a) Meter proving reduces measurement uncertainty. Where meter design, size, and flow rate allows, consider installing meter proving taps.

(b) Upstream dry gas filter(s) should be considered when installing rotary or turbine meters.

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(1.3) Pressure/Flow Control Facilities:

(a) Overpressure protection must be provided by the use of:

(1) A monitor regulator in series with a controlling regulator (each regulator run)

(2) Adequately sized relief valve(s) downstream of the controlling regulator(s).

(3) Overpressure shut-off valve(s) *upstream* or downstream of the controlling regulator(s). Installation of alarm devices which indicate primary (controlling) regulator failure are useful and should be considered for monitor regulator systems.

(b) Each regulator supply, control, and sensing line must have a separate isolation valve for isolation purposes during regulator set-up and maintenance and to prevent a safety device (i.e., monitor, regulator) from becoming unintentionally inoperable due to plugging or freezing of instrument lines.

(c) Steps must be taken to prevent the freezing-up (internal and external) of regulators, control valves, instrumentation, pilot controls, and valve actuation equipment caused by moisture saturated instrument air or gas, pipeline gas, or external ambient conditions.

(d) Sound pressure levels of 110 db and greater must be avoided to prevent damage to control equipment and piping.

(e) Gas velocities in piping should not exceed 100 ft/ sec at peak conditions. Lower velocities are recommended. High gas velocities in piping increase turbulence and pressure drop and contribute to excessive sound pressure levels (aerodynamic noise) and can cause internal piping erosion.

Other (Non-mandatory) Considerations for Pressure/Flow Control Facilities:

(a) Filtration of gas, particularly for instrumentation, instrument regulators, etc., must be

considered where particulate contaminants are a present or potential problem.

(b) Installation of conical reducers immediately downstream of a regulator or control valve will allow a more gradual expansion of gas to larger piping and thus reduce turbulence and pressure drop during gas expansion.

(1.4) Electrical Facilities and Electronic Equipment for Pressure/Flow Control and Metering Facilities:

(a) All electrical equipment and wiring installed in pressure/flow control facilities and metering facilities must comply to the requirements of ANSI/NFPA 70 and other applicable electrical codes.

(b) Electronic control, monitoring, and gas measurement equipment must be properly grounded and isolated from piping to help prevent overpressure or accidental shutoff situations caused by equipment failure due to lightning strikes and electrical transients and to prevent safety hazards caused by fault currents.

(c) Uninterruptible power sources or redundant backup systems should be considered to help prevent overpressure or unintentional shutoff situations caused by power outages.

1.5) Protection of Pipelines and Mains from Hazards:

(a) When pipelines and mains are installed where they are subject to natural hazards, such as washouts, floods, unstable soil, landslides, earthquake related events (such as surface faulting, soil liquefaction, and soil and slope instability characteristics), or other conditions that may cause serious movement of, or abnormal loads on, the pipeline, reasonable precautions must be taken to protect the pipeline, such as increasing the wall thickness, constructing revetments, preventing erosion, and installing anchors.

(b) Where pipelines and mains cross areas that are normally under water or subject to flooding (i.e., lakes, bays, or swamps), sufficient weight or anchorage must be applied to the line to prevent flotation.

(c) Because submarine crossings may be subject to washouts due to the natural hazards of changes in the waterway bed, water velocities, deepening of the channel, or changing of the channel location in the waterway, design consideration must be given to protect the pipeline or main at such crossings. The crossing must be located in the more stable bank and bed locations.

The depth of the line, location of the bends installed in the banks, wall thickness of the pipe, and weighting of the line must be selected based on the characteristics of the waterway.

(d) Where pipelines and mains are exposed, such as at spans, trestles, and bridge crossings, the pipelines and mains must be reasonably protected by distance or barricades from accidental damage by vehicular traffic or other causes.

Cover, Clearance, and Casing Requirements for Buried Steel Pipelines and Mains Cover Requirements for Mains:

Buried mains must be installed with a cover not less than 24 in. Where this cover provision cannot be met, or where external loads may be excessive, the main must be encased, bridged, or designed to withstand any such anticipated external loads. Where farming or other operations might result in deep ploughing, in areas subject to erosion, or in locations where future grading is likely, such as road, highway, railroad, and ditch crossings, additional protection must be provided. Where these cover provisions cannot be met or where external loads may be excessive, the pipeline must be encased, bridged, or designed to withstand any such anticipated external loads.

Cover Requirements for Pipelines. Except for offshore pipelines, buried pipelines must be installed with a cover not less than that shown in the following table:

	Design Factors, *F*	
Holder Size Class Location	For Minimum Clearance Between Containers and Fenced Boundaries of Site of 25 ft to 100 ft	For Minimum Clear-ance Between Containers and Fenced Boundaries of Site of 100 ft and Over
1	0.72	0.72
2	0.60	0.72
3	0.60	0.60
4	0.40	0.40

Table1.5

Where these cover provisions cannot be met or where external loads are excessive, the pipeline must be encased, bridged, or designed to withstand any such anticipated external loads. In areas where farming or other operations might result in deep ploughing, in areas subject to erosion, or in locations where future grading is likely, such as at roads, highways, railroad crossings, and ditch crossings, additional protection must be provided.

Clearance between Pipelines or Mains and Other Underground Structures:

(a) There must be at least 6 in. of clearance wherever possible between any buried pipeline and any other underground structure not used in conjunction with the pipeline. When such clearance cannot be attained, precautions to protect the pipe must be taken, such as the installation of casing, bridging, or insulating material.

(b) There must be at least 2 in. of clearance wherever possible between any buried gas main and any other underground structure not used in conjunction with the main. When such clearance cannot be attained, precautions to protect the main must be taken, such as the installation of insulating material or casing.

Casing Requirements under Railroads, Highways, Roads, or Streets:

Casings must be designed to withstand the superimposed loads. Where there is a possibility of water entering the casing, the ends of the casing must be sealed. If the end sealing is of a type that will retain the maximum allowable operating pressure of the carrier pipe, the casing must be designed for this pressure and at least to the design factor of 0.72 to prevent water from entering the casing.

Additional Underground Pipe Protection:

The pipe design factor, *F* must be in accordance with for the crossing of roads and railroads. The guidance provided by API RP 1102, Steel Pipelines Crossing Railroads and Highways; or GRI Report No. 91/0284, Guidelines for Pipelines Crossing Highways; or Gas Piping Technology Committee's Guide Material Appendix G-15, Design of Uncased Pipelines Crossing of Highways and Railroads, may be considered for design and installation of pipeline crossing. The pipeline must evaluate the need for extending additional pipe protection over the pipeline when the road or railroad right-of-way width is undefined based on anticipated loading from traffic or heavy equipment performing maintenance activities adjacent to the road or railroad. Varying degrees of additional protection from third party damage to a buried main or pipeline crossing within (or parallel to) the right-of-way of road or railroad may be achieved using the following techniques, or variants thereof, singly or in combination.

(a) A physical barrier or marker may be installed above or around the pipe. If a physical barrier is used, the potential conflict with the right-of way maintenance activities should be recognized. Physical barrier or marker methods include:

(1) A concrete or steel barrier placed above the pipe.

(2) A concrete slab placed vertically adjacent to the pipe on each side and extended above the top of pipe elevation.

(3) Damage-resistant coating material, such as concrete.

(4) Extra depth of cover additional to that required.

(5) Buried high-visibility warning tape placed parallel to and above the pipe.

(6) Pipe casing.

(b) A heavier wall thickness than is required by the pipe design factor, *F*.

(c) Pipeline alignment should be as straight and perpendicular to the road or railroad alignment as possible to promote reliable marking of the pipe location through the right-of-way and at the right-of-way limits.

(1.6) Installation of Steel Pipelines and Mains:

Construction Specifications: All construction work performed on piping systems in accordance with the requirements of this Code must be done under construction specifications. The construction specifications must cover all phases of the work and must be in sufficient detail to cover the requirements of this Code.

Inspection Provisions:

The operating company must provide suitable inspection. Inspectors must be qualified either by experience or training. The inspector must have the authority to order the repair or removal and replacement of any component found that fails to meet the standards of this Code. The installation inspection provisions for pipelines and other facilities to operate at hoop stresses of 20% or more of the specified minimum yield strength must be adequate to make possible at least the following inspections at sufficiently frequent intervals to ensure good quality of workmanship.

(a) Inspect the surface of the pipe for serious surface defects just prior to the coating operation.

(b) Inspect the surface of the pipe coating as it is lowered into the ditch to find coating lacerations that indicate the pipe might have been damaged after being coated.

(c) Inspect the fit up of the joints before the weld is made.

(d) Visually inspect the stringer beads before subsequent beads are applied.

(e) Inspect the completed welds before they are covered with coating.

(f) Inspect the condition of the ditch bottom just before the pipe is lowered in, except for offshore pipelines.

(g) Inspect the fit of the pipe to the ditch before backfilling, except for offshore pipelines.

(h) Inspect all repairs, replacements, or changes ordered before they are covered.

(i) Perform such special tests and inspections as are required by the specifications, such as non destructive testing of welds and electrical testing of the protective coating.

(j) Inspect backfill material prior to use and observe backfill procedure to ensure no damage occurs to the coating in the process of backfilling.

Bends, Elbows, and Mitres in Steel Pipelines and Mains:

Changes in direction may be made by the use of bends, elbows, or mitres under the limitations noted below.

(a) A bend must be free from buckling, cracks, or other evidence of mechanical damage.

(b) The maximum degree of bending on a field cold bend may be determined by either method in the table below. The first column expresses the maximum deflection in an arc length equal to the nominal outside diameter, and the second column expresses the minimum radius as a function of the nominal outside diameter.

Nominal Pipe Size	Deflection of Longitudinal Axis, deg	Minimum Radius of Bend in Pipe Diameters [see 841.231(c)]
Smaller than 12	841.231(d)	18*D*
12	3.2	18*D*
14	2.7	21*D*
16	2.4	24*D*
18	2.1	27*D*
20 and larger	1.9	30*D*

Table 1.6

(c) A field cold bend may be made to a shorter minimum radius than permitted in (b) above, provided the completed bend meets all other requirements of this section, and the wall thickness after bending is not less than the minimum permitted by. This may be demonstrated through appropriate testing.

(d) For pipe smaller than NPS 12, the requirements of (a) above must be met, and the wall thickness after bending must not be less than the minimum permitted by. This may be demonstrated through appropriate testing.

(e) Except for offshore pipelines, when a circumferential weld occurs in a bend section, it must be subjected to radiography examination after bending.

(f) Hot bends made on cold worked or heat treated pipe must be designed for lower stress levels

(g) Wrinkle bends must be permitted only on systems operating at hoop stress levels of less than 30% of the specified minimum yield strength. When wrinkle bends are made in welded pipe. the longitudinal weld must be located on or near to the neutral axis of the bend. Wrinkle bends with sharp kinks must not be permitted. Spacing of wrinkles must be measured along the crotch of the pipe bend, and the peak to peak distance between the wrinkles must exceed the diameter of the pipe. On pipe NPS 16 and larger, the wrinkle must not produce an angle of more than 1 1/2 deg per wrinkle. Mitred bends are permitted provided the following limitations are met:

(a) In systems intended to operate at hoop stress levels of 40% or more of the specified minimum yield strength, mitred bends are not permitted. Deflections caused by misalignment up to 3 deg are not considered as mitres.

(b) In systems intended to operate at hoop stress levels of 10% or more but less than hoop stress levels of 40% of the specified minimum yield strength, the total deflection angle at each mitre must not exceed 12 1/2 °.

(c) In systems intended to operate at hoop stress levels of less than 10% of the specified minimum yield strength, the total deflection angle at each mitre must not exceed 90°.

(d) In systems intended to operate at hoop stress levels of 10% or more of the specified minimum yield strength, the minimum distance between mitres measured at the crotch must not be less than one pipe diameter.

(e) Care must be taken in making mitred joints to provide proper spacing and alignment and full penetration. Factory-made, wrought-steel welding elbows or transverse segments cut there from may be used for changes in direction, provided that the arc length measured along the crotch is at least 1 in. on pipe sizes NPS 2 and larger.

(1.7) Pipe Surface Requirements Applicable to Pipelines and Mains to Operate at a Hoop Stress of 20% or More of the Specified Minimum Yield Strength:

Gouges, grooves, and notches have been found to be an important cause of pipeline failures, and all harmful defects of this nature must be prevented, eliminated, or repaired. Precautions must be taken during manufacture, hauling, and installation to prevent the gouging or grooving of pipe.

Detection of Gouges and Grooves

(a) The field inspection provided on each job must be suitable to reduce to an acceptable minimum the chances that gouged or grooved pipe will get into the finished pipeline or main. Inspection for this purpose just ahead of the coating operation and during the lowering-in and backfill operation is required.

(b) When pipe is coated, inspection must be made to determine that the coating machine does not cause harmful gouges or grooves.

(c) Lacerations of the protective coating must be carefully examined prior to the repair of the coating to determine if the pipe surface has been damaged.

Field Repair of Gouges and Grooves:

(a) Injurious gouges or grooves must be removed.

(b) Gouges or grooves may be removed by grinding to a smooth contour.

Dents:

(a) A dent may be defined as a depression that produces a gross disturbance in the curvature of the pipe wall (as opposed to a scratch or gouge, which reduces the pipe wall thickness). The depth of a dent must be measured as the gap between the lowest point of the dent and a prolongation of the original contour of the pipe in any direction.

(b) All dents that affect the curvature of the pipe at the longitudinal weld or any circumferential weld must be removed. All dents that exceed a maximum depth of 1⁄4 in. in pipe NPS 12 and smaller or 2% of the nominal pipe diameter in all pipe greater than NPS 12 must not be permitted in pipelines or mains intended to operate at hoop stress levels of 40% or more of the specified minimum yield strength.

Notches:

(a) Notches on the pipe surface can be caused by mechanical damage in manufacture, transportation, handling, or installation, and when determined to be mechanically caused,

(b) Stress concentrations that may or may not involve a geometrical notch may also be created by a process involving thermal energy in which the pipe surface is heated sufficiently to change its mechanical or metallurgical properties. These imperfections are termed "metallurgical notches." Examples include an arc burn produced by accidental contact with a welding electrode or a grinding burn produced by excessive force on a grinding wheel.

Elimination of Arc Burns:

The metallurgical notch caused by arc burns must be removed by grinding, provided the grinding does not reduce the remaining wall thickness to less than the minimum prescribed by this Code for the conditions of use.1 In all other cases, repair is prohibited, and the portion of pipe containing the arc burn must be cut out as a cylinder and replaced with a good piece. Insert patching is prohibited.

Backfilling

(a) Backfilling must be performed in a manner to provide firm support under the pipe.

(b) If there are large rocks in the material to be used for backfill, care must be used to prevent damage to the coating by such means as the use of rock shield material, or by making the initial fill with rock-free material sufficient to prevent damage.

(c) Where the trench is flooded to consolidate the backfill, care must be exercised to see that the pipe is not floated from its firm bearing on the trench bottom.

Purging of Pipelines and Mains

(a) When a pipeline or main is to be placed in service, the air in it must be displaced. The following are some acceptable methods:

(1) Introduce a moderately rapid and continuous flow of gas into one end of the line and vent the air out the other end. The gas flow must be continued without interruption until the vented gas is free of air.

(2) If the vent is in a location where the release of gas into the atmosphere may cause a hazardous condition, then a slug of inert gas must be introduced between the gas and air. The gas flow must then be continued without interruption until all of the air and inert gas have been removed from the facility.

(b) In cases where gas in a pipeline or main is to be displaced with air and the rate at which air can be supplied to the line is too small to make a procedure similar to but the reverse of that described in (a) above feasible, a slug of inert gas should be introduced to prevent the formation of an explosive mixture at the interface between gas and air.

(c) If a pipeline or main containing gas is to be removed, the operation may be carried out, or the line may be first disconnected from all sources of gas and then thoroughly purged with air, water, or inert gas before any further cutting or welding is done.

(d) If a gas pipeline main, or auxiliary equipment is to be filled with air after having been in service and there is a reasonable possibility that the inside surfaces of the facility are wetted with volatile inflammable liquid, or if such liquids might have accumulated in low places,

purging procedures designed to meet this situation must be used. Steaming of the facility until all combustible liquids have been evaporated and swept out is recommended. Filling of the facility with an inert gas and keeping it full of such gas during the progress of any work that might ignite an explosive mixture in the facility is an alternative recommendation.

Testing after Construction:

General Provisions:

All piping systems must be tested after construction to the requirements as discussed except for pretested fabricated assemblies, pretested tie-in sections, and tie-in connections. Non-welded tie-in connections not pressure tested after construction must be leak tested at not less than the pressure available when the tie-in is placed into service.

(1.8)Test Required to prove Strength of Pipelines and Mains to Operate at Hoop Stresses of 30% or More than Specified Minimum Yield Strength of the Pipe:

All pipelines and mains to be operated at a hoop stress of 30% or more of the specified minimum yield strength of the pipe must be given a test for at least 2 hr to prove strength after construction and before being placed in operation.

Location Classes 1–4:

(a) Pipelines located in Location Class 1, Division 1 must be tested hydrostatically to 1.25 times design pressure if the maximum operating pressure produces a hoop stress level greater than 72% SMYS.

b) Pipelines located in Location Class 1, Division 2 must be tested either with air or gas to 1.1 times the maximum operating pressure or hydrostatically to at least 1.1 times the maximum operating pressure if the maximum operating pressure produces a hoop stress level of 72% SMYS or less.

(c) Pipelines and mains in Location Class 2 must be tested either with air to 1.25 times the maximum operating pressure or hydrostatically to at least 1.25 times the maximum operating pressure.

(d) Pipelines and mains in Location Classes 3 and 4 must be tested hydrostatically to a pressure not less than 1.4 times the maximum operating pressure. This requirement does not apply if at the time the pipeline or main is first ready for test, one or both of the following conditions exist:

(1) The ground temperature at pipe depth is 32°F or less, or might fall to that temperature before the hydrostatic test could be completed, or

(2) Water of satisfactory quality is not available in sufficient quantity. Notwithstanding the limitations on air testing imposed on air testing may be used in Location Classes 3 and 4, provided that all of the following conditions apply:

(a) The maximum hoop stress during the test is less than 50% of the specified minimum yield strength in Location Class 3, and less than 40% of the specified minimum yield strength in Location Class 4.

(b) The maximum pressure at which the pipeline or main is to be operated does not exceed 80% of the maximum field test pressure used.

(c) The pipe involved is new pipe having a longitudinal joint factor, *E.*

Records: The operating company must maintain in its file for the useful life of each pipeline and main, records showing the procedures used and the data developed in establishing its maximum allowable operating pressure.

(1.9)Tests Required to Prove Strength for Pipelines and Mains to Operate at Hoop Stress Levels of Less Than 30% of the Specified Minimum Yield Strength of the Pipe, but in Excess of 100 psi:

Steel piping that is to operate at hoop stress levels of less than 30% of the specified minimum yield strength in Class 1 Locations must at least be tested in accordance with.

Leak Tests for Pipelines or Mains to Operate at 100 psi or More

Each pipeline and main must be tested after construction and before being placed in operation to demonstrate that it does not leak. If the test indicates that a leak exists, leak or leaks must be located and eliminated, unless it can be determined that no undue hazard to public safety exists. The test procedure used must be capable of disclosing all leaks in the section being tested and must be selected after giving due consideration to the volumetric content of the section and to its location. This requires the exercise of responsible and experienced judgement, rather than numerical precision.

Leak Tests for Pipelines and Mains to Operate at Less Than 100 psi

Each pipeline, main, and related equipment that will operate at less than 100 psi must be tested after construction and before being placed in operation to demonstrate that it does not leak. Gas may be used as the test medium at the maximum pressure available in the distribution.

Table 841.322(f) Test Requirements for Pipelines and Mains to Operate at Hoop Stresses of 30% or More of the Specified Minimum Yield Strength of the Pipe (03)

1	2	3	4	5
Location Class	Permissible Test Fluid	Pressure Test Prescribed		Maximum Allowable Operating Pressure, the Lesser of
		Minimum	Maximum	
1 Division 1	Water	1.25 × m.o.p.	None	t.p. ÷ 1.25 or d.p.
1 Division 2	Water Air Gas	1.1 × m.o.p. 1.1 × m.o.p. 1.1 × m.o.p.	None 1.1 × d.p. 1.1 × d.p.	t.p. ÷ 1.1 or d.p.
2	Water Air	1.25 × m.o.p. 1.25 × m.o.p.	None 1.25 × d.p.	t.p. ÷ 1.25 or d.p.
3 and 4 [Note (1)]	Water	1.40 × m.o.p.	None	t.p. ÷ 1.40 or d.p.

d.p. = design pressure
m.o.p. = maximum operating pressure (not necessarily the maximum allowable operating pressure)
t.p. = test pressure

Table 1.7

(1.10) Commissioning of Facilities:

General:

Written procedures must be established for commissioning. Procedures must consider the characteristics of the gas to be transported, the need to isolate the pipeline from other connected facilities, and the transfer of the constructed pipeline to those responsible for its operation. Commissioning procedures, devices, and fluids must be selected to ensure that nothing is introduced into the pipeline system that will be incompatible with the gas to be transported, or with the materials in the pipeline components.

Cleaning and Drying Procedures: Consideration must be given to the need for cleaning and drying the pipe and its components beyond that required for removal of the test medium.

Functional Testing of Equipment and Systems: As a part of commissioning, all pipeline and compressor station monitor and control equipment and systems must be fully function-tested, especially including safety systems such as pig trap interlocks, pressure and flow monitoring systems, and emergency pipeline shut-down systems. Consideration should also be given to performing a final test of pipeline valves before the gas is introduced to ensure that each valve is operating correctly.

Chapter 2

Pressure drop calculation:

In this chapter we will discuss the various methods of calculating the pressure drop due to friction in a gas pipeline. The pipeline throughput (flow rate) will depend upon the gas properties, pipe diameter and length, initial gas pressure and temperature, and the pressure drop due to friction. Commonly used formulas will be reviewed and illustrated using examples. The impact of internal conditions of the pipe on the pipe capacity will also be explored.

(2.1) FLOW EQUATIONS:

Several equations are available that relate the gas flow rate with gas properties, pipe diameter and length, and upstream and downstream pressures. These equations are listed as follows:

1. General Flow equation
2. Colebrook-White equation
3. Modified Colebrook-White equation
4. Weymouth equation
5. Panhandle A equation
6. Panhandle B equation

(2.11) GENERAL FLOW EQUATION

The General Flow equation, also called the Fundamental Flow equation, for the steady-state isothermal flow in a gas pipeline is the basic equation for relating the pressure drop with flow rate. The most common form of this equation in the U.S. Customary System (USCS) of units is given in terms of the pipe diameter, gas properties, pressures, temperatures, and flow rate as follow.

$$\boxed{Q = 77.54\left(\frac{T_b}{P_b}\right)\left(\frac{P_1^2 - P_2^2}{GT_f LZf}\right)^{0.5} D^{\cdot}}$$

eq..................2.1

Where.

Q=gas flow rate, measured at standard conditions, ft^3/day (SCFD)

f=friction factor, dimensionless

P_b=base pressure. psia

T_b=base temperature,°R(460+°F)

P_1=upstream pressure, psia

P_2=downstream pressure, psia

G=gas gravity (air=1.00)

T_f=average gas flowing temperature,°R (460+°F)

L=pipe segment length, mi

Z=gas compressibility factor at the flowing temperature, dimensionless

D=pipe inside diameter, in.

EFFECT OF PIPE ELEVATIONS

When elevation difference between the ends of a pipe segment is included, the General Flow equation is modified as follows:

$$Q = 38.77F\left(\frac{T_b}{P_b}\right)\left(\frac{P_1^2 - e^s P_2^2}{GT_f L_e Z}\right)^{0.5} D^{2.5}$$

eq.................2.2

Where,

$$\mathbf{Le} = \frac{\mathbf{L\ (e^s\text{-}1)}}{\mathbf{s}}$$

eq.................2.3

The equivalent length, L_e, and the term e^stake into account the elevation difference between the upstream and downstream ends of the pipe segment. The parameter s depends upon the gas gravity, gas compressibility factor, the flowing temperature, and the elevation difference. It is defined as follows in USCS units:

$$s = 0.0375G\left(\frac{H_2 - H_1}{T_f Z}\right)$$

eq.................2.4

Where,

$H1$ = upstream elevation, m

$H2$ = downstream elevation, m

If the pipe segment of length L has a series of slopes, then we introduce a parameter j as follows for each individual pipe subsegment that constitutes the pipe length from point 1 to point 2.

$$\boxed{j = \frac{e^{S} - 1}{S}}$$

eq.................2.5

The parameter j is calculated for each slope of each pipe subsegment of length $L1$, $L2$, etc. that make up the total length L. The equivalent length term Le in Equation 2.7 and Equation 2.8 is calculated by summing the individual slopes as defined below

$$\boxed{L_e = j_1 L_1 + j_2 L_2 e^{s1} + j_3 L_3 e^{s2} + \cdots}$$

eq.................2.6

The terms $j1, j2$, etc. for each rise or fall in the elevations of individual pipe sub-segments are calculated for the parameters $s1$, $s2$, etc. for each segment in accordance with Equation 2.12, from the pipeline inlet to the end of each segment.

(2.22) WEYMOUTH EQUATION

The Weymouth equation is used for high pressure, high flow rate, and large diameter gas gathering systems. This formula directly calculates the flow rate through a pipeline for given values of gas gravity, compressibility, inlet and outlet pressures, pipe diameter, and length. In USCS units, the Weymouth equation is stated as follows:

$$Q = 433.5E\left(\frac{T_b}{P_b}\right)\left(\frac{P_1^2 - e^s P_2^2}{GT_f L_e Z}\right)^{0.5} D^{2.667}$$

eq.................2.7

(2.23) COLEBROOK-WHITE EQUATION

The Colebrook-White equation, sometimes referred to simply as the Colebrook equation, is a relationship between the friction factor and the Reynolds number, pipe roughness, and inside diameter of pipe. The following form of the Colebrook equation is used to calculate the frict--ion factor in gas pipelines in turbulent flow:

$$\frac{1}{\sqrt{f}} = -2\,\mathrm{Log}_{10}\left(\frac{e}{3.7D} + \frac{2.51}{Re\sqrt{f}}\right) \quad \text{for } Re > 4000$$

eq.................2.8

Where,

f = friction factor, dimensionless

D = pipe inside diameter, in.

e = absolute pipe roughness, in.

Re = Reynolds number of flow, dimensionless

It can be seen from the Colebrook Equation 2.39, for turbulent flow in smooth pipes, the first term within the square brackets is negligible compared to the second term, since pipe roughn--ess e is very small.

Therefore, for smooth pipe flow, the friction factor equation reduces to

$$\frac{1}{\sqrt{f}} = -2\,\mathrm{Log}_{10}\left(\frac{2.51}{Re\sqrt{f}}\right)$$

eq.................2.9

Similarly, for turbulent flow in fully rough pipes, with *Re* being a large number, f depends mostly on the roughness e and, therefore, the friction factor equation reduces to

$$\boxed{\frac{1}{\sqrt{f}} = -2\,\mathrm{Log}_{10}\left(\frac{e}{3.7D}\right)}$$

eq.................2.10

(2.24) MODIFIED COLEBROOK-WHITE EQUATION

The Colebrook-White equation discussed in the preceding section has been in use for many years in both liquid flow and gas flow. The U.S. Bureau of Mines, in 1956, published a report that introduced a modified form of the Colebrook-White equation. The modification results in a higher friction factor and, hence, a smaller value of the transmission factor. Because of this, a conservative value of flow rate is obtained due to the higher friction and pressure drop. The modified version of the Colebrook- White equation for turbulent flow is as follows:

$$\boxed{\frac{1}{\sqrt{f}} = -2\,\mathrm{Log}_{10}\left(\frac{e}{3.7D} + \frac{2.825}{Re\sqrt{f}}\right)}$$

eq.................2.11

(2.25) PANHANDLE-A EQUATION

The Panhandle-A Equation was developed for use in natural gas pipelines, incorporating an efficiency factor for Reynolds numbers in the range of 5 to 11 million. In this equation, the pipe roughness is not used. The general form of the Panhandle A equation is expressed in USCS units as follows:

$$\boxed{Q = 435.87E\left(\frac{T_b}{P_b}\right)^{1.0788}\left(\frac{P_1^2 - e^s P_2^2}{G^{0.8539} T_f L_e Z}\right)^{0.5394} D^{2.6182}}$$

eq.................2.12

(2.26) PANHANDLE B EQUATION

The Panhandle B equation. also known as the revised Panhandle equation, is used in large diameter, high pressure transmission lines. In fully turbulent flow, it is found to be accurate for values of Reynolds number in the range of 4 to 40 million. This equation in USCS units is as follows:

$$Q = 737E\left(\frac{T_b}{P_b}\right)^{1.02}\left(\frac{P_1^2 - e^s P_2^2}{G^{0.961}T_f L_e Z}\right)^{0.51} D^{2.53}$$

eq..................2.13

Thickness Calculations :

The design pressure for steel gas piping systems or the nominal wall thickness for a given piping system or the nominal wall thickness for a given design pressure is determined by the formula

$$t = \frac{PD}{2SFET} + \text{Corrosion allowance}$$

eq.................2.14

Where,

- P = design pressure in psi
- S = specified minimum yield strength in psi
- t = nominal wall thickness, in mm
- D = pipe outside diameter, in mm
- F = design factor
- E = Longitudinal joint factor
- T = temperature derating factor.

Design pressure (P)

It is the maximum pressure permitted by this code, as determined by the design procedures applicable to the materials and locations involved.

Nominal wall thickness (t)

It is the wall thickness computed by or used in the design equation. Under this code, pipe may be ordered to this computed wall thickness without adding allowance to compensate for the under thickness tolerance permitted in approved specification.

Specified minimum yield strength (S)

It is expressed in pound per square inch, is the minimum yield strength prescribed by the specification under which pipe is purchased from the manufacturer.

Diameter or Nominal outside diameter (D)

It is the as produced or as-specified outside diameter of the pipe, not to be confused with dimensionless NPS. For example,

NPS 12 pipe has a specified outside diameter of 12.750 in.

NPS 8 pipe has a specified outside diameter of 8.625 in.

NPS 24 pipe has a specified outside diameter of 24.000in.

Longitudinal Joint Factor (E)

If the type of longitudinal joint can be determined with certainty, the corresponding longitudinal joint factor, E may be used. Otherwise, E is taken as .60 for NPS4 and smaller, or .80 for pipe larger than NPS4.

Importance of the Equations:

The following guide lines are recommended in the use of gas flow equations:

1. The general gas flow equation is recommended for most general usage. If it is not known whether the Weymouth or the Panhandle equations are applicable, compute the results using both Weymouth and Panhandle equations and use the higher calculated pressure drop.

2. Use the Weymouth equation only for small-diameter, short-run pipe within the production facility where the Reynolds number is expected to be high.

3. Use the Panhandle equations only for large-diameter, long-run pipelines where the Reynolds number is expected to be moderate.

4. Use the Spitzglass equation for low pressure vent lines less than 12-inches in diameter.

5. When using gas flow equations for old pipe, attempt to derive the proper efficiency factor through field tests. Buildup of scale, corrosion, liquids, paraffin, etc. can have a large effect on gas flow efficiency.

Example:

A 150 mi long natural gas pipeline consists of several injections and deliveries as shown in figure. The pipeline is NPS 20, has 0.500 in. wall thickness, and has an inlet volume of 250 MMSCFD. At points B (milepost 20) and C (milepost 80), 50 MMSCFD and 70 MMSCFD, respectively, are delivered. At D (milepost 100), gas enters the pipeline at 60 MMSCFD. All streams of gas may be assumed to have a specific gravity of 0.65. Assume a constant gas flow temperature of 86°F and base pressure and base temperature of 14.7 psia and 60°F, respectively. Use a constant compressibility factor of 0.85 throughout. Neglect elevation differences along the pipeline. Find out the inlet pressure required from above data.

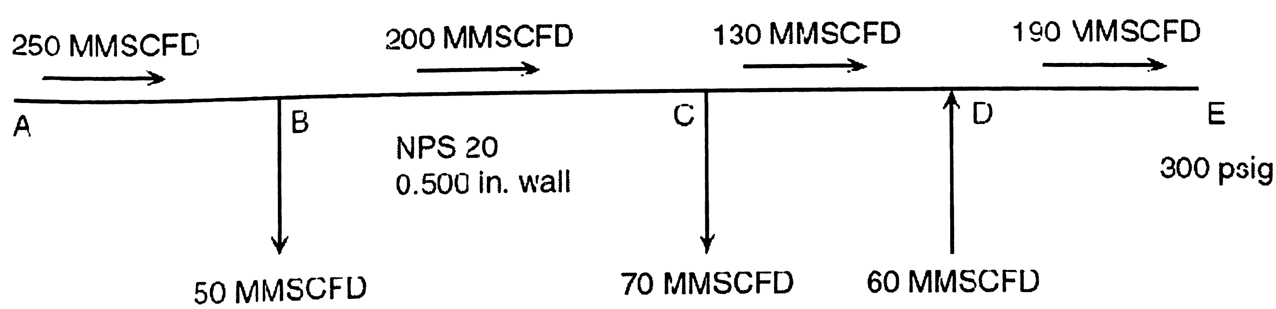


Figure 2.1: Pipeline with several injections and deliveries.

Solution:

Pipe inside diameter $D = 20 - 2 \times 0.500 = 19.00$ in.

Using Weymouth equation, for the last pipe segment from milepost 100 to milepost 150, we get

$$190*10^6 = 433.5*0.95 \quad (520/14.7) \left(\frac{P_D^2 - (314.7)^2}{0.65*544*50*0.85} \right)^{0.5} \quad (19)^{2.667}$$

$$190*10^6 = 305762.3281 \, [P_D^2 - (314.7)^2]^{0.5}$$

$P_D = 696.54$ psia

Next we will use this pressure P_D to calculate the pressure P_C for the 20 mi section of pipe segment BC flowing 130 MMSCFD.

Using Weymouth equation,

$$130*10^6 = 433.5*0.95 \quad (520/14.7) \left(\frac{P_C^2 - (696.54)^2}{} \right)^{0.5} \quad (19)^{2.667}$$

$$0.65*544*20*0.85$$

$$130*10^6 = 483452.6898\,[P_C^2 - (696.54)^2]^{0.5}$$

$P_C = 746.64$ psia

Next we will use this pressure P_C to calculate the pressure P_B for the 60 mi section of pipe segment BC flowing 200 MMSCFD.

Using Weymouth equation,

$$200*10^6 = 433.5*0.95 \quad (520/14.7) \left(\frac{P_B^2 - (746.64)^2}{0.65*544*60*0.85}\right)^{0.5} \quad (19)^{2.667}$$

$$200*10^6 = 837364.6218\,[P_B^2 - (746.64)^2]^{0.5}$$

$P_B = 1034.83$ psia

Finally, we calculate the pressure P_1 by considering the 20 mi pipe segment from A to point B that flows 250 MMSCFD.

Using Weymouth equation,

$$200*10^6 = 433.5*0.95 \quad (520/14.7) \left(\frac{P_1^2 - (1034.83)^2}{0.65*544*20*0.85}\right)^{0.5} \quad (19)^{2.667}$$

$$200*10^6 = 483452.6898\,[P_1^2 - (1034.83)^2]^{0.5}$$

$P_1 = 1156.84$ psia

(2.2) Series Piping:

There are situations where a gas pipeline can consist of different pipe diameters connected together in a series. This is especially true when the different pipe segments are required to transport different volumes of gas. In below diagram section AB with a diameter of 16 in. is used to transport a volume of 100 MMSCFD, and after making a delivery of 20 MMSCFD at B, the remainder of 80 MMSCFD flows through the 14 in. diameter pipe BC. At C, a delivery of 30 MMSCFD is made, and the balance volume of 50 MMSCFD is delivered to the terminus D through a 12 in. pipeline CD. It is clear that the pipe section AB flow the largest volume (100 MMSCFD), whereas the pipe segment CD transports the least volume (50 MMSCFD). Therefore, segments AB and CD, for reasons of economy, should be of different pipe diameters, as indicated in diagram. If we maintained the same pipe diameter of 16 in. from A to D, it would be a waste of pipe material and, therefore, cost. Constant diameter is used only when the same flow that enters the pipeline is also delivered at the end of the pipeline, with no intermediate injections or deliveries .However, in reality, there is no way of determining ahead what the future delivery volumes will be along the pipeline. Hence, it is difficult to determine initially the different pipe sizes for each segment. Therefore, in many cases you will find that the same-diameter pipe is used throughout the entire length of the pipeline even though there are intermediate deliveries. Even with the same nominal pipe diameter, different pipe sections can have different wall thicknesses. Therefore, we have different pipe inside diameters for each pipe segment. Such wall thickness changes are made to compensate for varying pressures along the pipeline. The pressure required to transport gas in a series pipeline from point A to point D in diagram is calculated by considering each pipe segment such as AB and BC and applying the appropriate flow equation, such as the General Flow equation, for each segment.

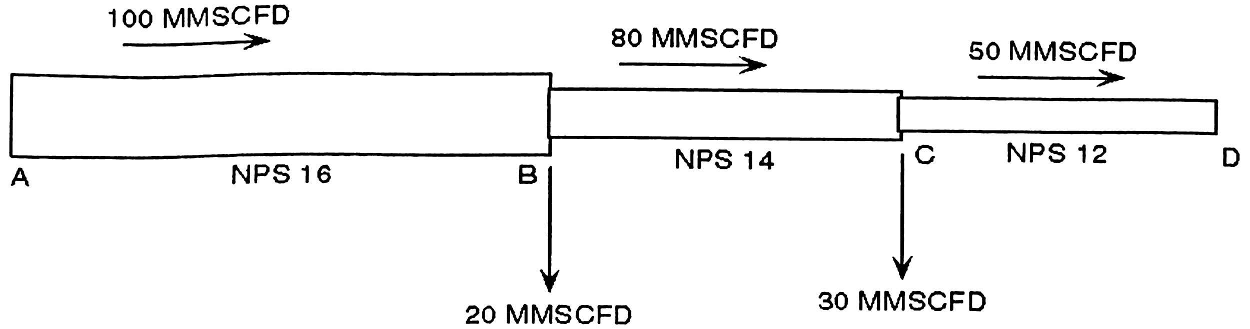


Figure 2.2: Pipeline consisting of different pipe diameters connected together in series.

Another approach to calculating the pressures in series piping systems is to use the equivalent length concept. This method can be applied when the same uniform flow exists throughout the pipeline, with no intermediate deliveries or injections. We will explain this method of calculation for a series piping system with the same flow rate Q through all pipe segments. Suppose the first pipe segment has an inside diameter D_1 and length L_1, followed by the second segment of inside diameter D_2 and length L_2 and so on. We calculate the equivalent length of the second pipe segment based on the diameter D_1 such that the pressure drop in the equivalent length matches that in the original pipe segment of diameter D_2. The pressure drop in diameter D_2 and length L_2 equals the pressure drop in diameter D_1 and equivalent length L_{e2}. Thus, the second segment can be replaced with a piece of pipe of length L_{e2} and diameter D_1. Similarly, the third pipe segment with diameter D_3 and length L_3 will be replaced with a piece of pipe of L_{e3} and diameter D_1. Thus, we have converted the three segments of pipe in terms of diameter D_1 as follows:

Segment 1 — diameter D_1 and length L_1

Segment 2 — diameter D_1 and length L_{e2}

Segment 3 — diameter D_1 and length L_{e3}

For convenience, we picked the diameter D_1 of segment 1 as the base diameter to use, to convert from the other pipe sizes. We now have the series piping system reduced to one constant-diameter (D_1) pipe of total equivalent length given by

$L_e = L_1 + L_{e2} + L_{e3}$ (3.1)

The pressure required at the inlet of this series piping system can then be calculated based on diameter D_1 and length L_e. We will now explain how the equivalent length is calculated. Upon examining General Flow Equation, we see that for the same flow rate and gas properties, neglecting elevation effects, the pressure difference ($P_1^2 - P_2^2$) is inversely proportional to the fifth power of the pipe diameter and directly proportional to the pipe length. Therefore, we can state that, approximately

$$\Delta P_{sq} = CL/D^5$$

Where,

ΔP_{sq}=difference in the square of pressures ($P_1^2 - P_2^2$) for the pipe segment

C=a constant

L=pipe length

D=pipe inside diameter

Actually, C depends on the flow rate, gas properties, gas temperature, base pressure, and base temperature. Therefore, C will be the same for all pipe segments in a series pipeline with constant flow rate. Hence, we regard C as a constant for all pipe segments. From above equation we conclude that the equivalent length for the same pressure drop is proportional to the fifth power of the diameter. Therefore, in the series piping discussed in the foregoing, the equivalent length of the second pipe segment of diameter D_2 and length L_2 is

$$CL_2/ D_2^5 = CL_{e2}/D_1^5$$

Or

$$L_{e2}= L_2 (D_1/D_2)^5$$

Similarly, for the third pipe segment of diameter D_3 and length L_3, the equivalent length is

$$L_{e3}= L_3 (D_1/D_3)^5$$

Therefore, the total equivalent length Le for all three pipe segments in terms of diameter $D1$ is

$$Le= L_1+ L_2 (D_1/D_2)^5+L_3(D_1/D_3)^5$$

It can be seen from above equation that if $D_1 =D_2 =D_3$, the total equivalent length reduces to $(L_1 +L_2 +L_3)$, as expected. We can now calculate the pressure drop for the series piping system, considering a single pipe of length L_e and uniform diameter D_1 flowing a constant volume Q.

An example will illustrate the use of the equivalent length method.

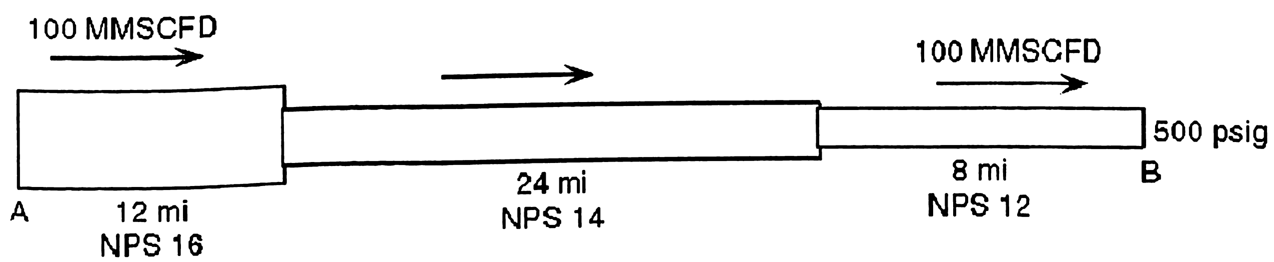


Figure 2.3 :Using equivalent method.

A series piping system, shown in above Figure , consists of 12 mi of NPS 16, 0.375 in. Wall thickness connected to 24 mi of NPS 14, 0.250 in. Wall thickness and 8 miles of NPS 12, 0.250 in. Wall thickness pipes. Calculate the inlet pressure required at the origin A of this pipeline system for a gas flow rate of 100 MMSCFD. Gas is delivered to the terminus B at a delivery pressure of 500 psig. The gas gravity and viscosity are 0.6 and 0.000008 lb/ft-s, respectively. The gas temperature is assumed constant at 60°F. Use a compressibility factor of 0.90 and the General Flow equation with Darcy friction factor=0.02. The base temperature and base pressure are 60°F and 14.7 psia, respectively.

Compare results using the equivalent length method and with the more detailed method of calculating pressure for each pipe segment separately.

Solution

Inside diameter of first pipe segment=16 – 2 *0.375=15.25 in.

Inside diameter of second pipe segment=14 – 2 *0.250=13.50 in.

Inside diameter of third pipe segment=12.75 – 2 *0.250=12.25 in.

Using Equation for Le, we calculate the equivalent length of the pipeline, considering NPS 16 as the base diameter:

$$L_e=12 + 24 *(15.25/13.5)^5 +8*(15.25/12.25)^5$$

Or L_e = 12+44.5+23.92= 80.07 mi

Therefore, we will calculate the inlet pressure $P1$ considering a single pipe from A to B having a length of 80.07 mi and inside diameter of 15.25 in.

Outlet pressure=500 +14.7=514.7 psia

Using General Flow Equation, neglecting elevation effects and substituting given values, we get:

$$100* 10^6 =77.54(1/\sqrt{0.02}) (520/14.7)[(P_1^2 -514.7^2) /(0.6*520*80.07*0.9]^{0.5}\ 15.25^{2.5}$$

Or

Solving for the inlet pressure $P1$, we get

$P1$=994.77 psia=980.07 psig

Next, we will compare the preceding result, using the equivalent length method, with the more detailed calculation of treating each pipe segment separately and adding the pressure drops. Consider the 8 mi pipe segment 3 first, since we know the outlet pressure at B is 500 psig. Therefore, we can calculate the pressure at the beginning of segment 3 using General Flow Equation, as follows:

$$100* 10^6 =77.54(1/\sqrt{0.02}) (520/14.7)[(P_1^2 -514.7^2) /(0.6*520*8*0.9]^{0.5}\ 12.25^{2.5}$$

Solving for the pressure $P1$, we get

$P1$=693.83 psia=679.13 psig

This is the pressure at the beginning of the pipe segment 3, which is also the end of pipe segment 2.

Next, consider pipe segment 2 (24 mi of NPS 14 pipe) and calculate the upstream pressure $P1$ required for a downstream pressure of 679.13 psig, calculated in the preceding section. Using General Flow Equation for pipe segment 2, we get

$$100*10^6=77.54(1/\sqrt{0.02})(520/14.7)[(P_1^2-693.83^2)/(0.6*520*24*0.9]^{0.5}\,13.5^{2.5}$$

Solving for the pressure $P1$, we get

$P1$=938.58 psia=923.88 psig

This is the pressure at the beginning of pipe segment 2, which is also the end of pipe segment 1. Next, we calculate the inlet pressure $P1$ of pipe segment 1 (12 mi of NPS 16 pipe) for an outlet pressure of 923.88 psig, just calculated. Using the General Flow equation for pipe segment 1, we get

$$100*10^6=77.54(1/\sqrt{0.02})(520/14.7)[(P_1^2-938.58^2)/(0.6*520*12*0.9]^{0.5}\,15.25^2$$

Solving for pressure $P1$, we get

$P1$=994.75 psia=980.05 psig

This compares well with the pressure of 980.07 psig we calculated earlier using the equivalent length method.

(2.3) Parallel Piping:

Sometimes two or more pipes are connected such that the gas flow splits among the branch pipes and eventually combines downstream into a single pipe, as illustrated in diagram below. Such a piping system is referred to as *parallel pipes*. It is also called a looped piping system, where each parallel pipe is known as a loop. The reason for installing parallel pipes or loops is to reduce pressure drop in a certain section of the pipeline due to pipe pressure limitation or for increasing the flow rate in a bottleneck section. By installing a pipe loop from B to E, in Figure below we are effectively reducing the overall pressure drop in the pipeline from A to F, since between B and E the flow is split through two pipes. In Figure below we will assume that the entire pipeline system is in the horizontal plane with no changes in pipe elevations. Gas enters the pipeline at A and flows through the pipe segment AB at a flow rate of Q. At the junction B, the gas flow splits into the two parallel pipe branches BCE and BDE at the flow rates of $Q1$ and $Q2$, respectively. At E, the gas flows recombine to equal the initial flow rate Q and continue flowing through the single pipe EF. In order to calculate the pressure drop due to friction in the parallel piping system, we follow two main principles of parallel pipes. The first principle is that of conservation of flow at any junction point. The second principle is that there is a common pressure across each parallel pipe.

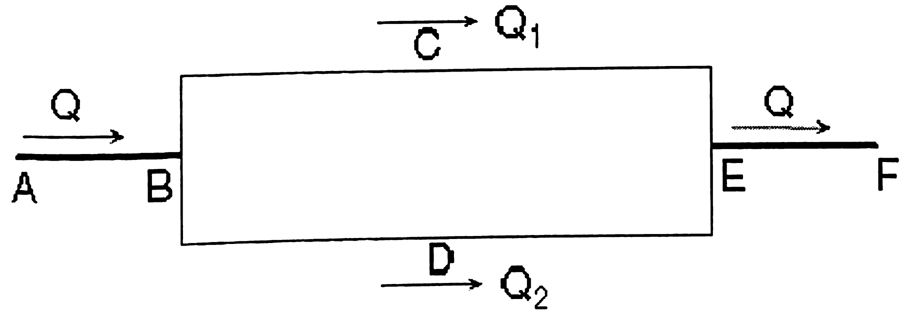


Figure 2.4: Parallel piping or loop piping.

Applying the principle of flow conservation, at junction B, the incoming flow into B must exactly equal the total outflow at B through the parallel pipes.

Therefore, at junction B,

$Q = Q1 + Q2$

Where.

Q=inlet flow at A

$Q1$=flow through pipe branch BCE

$Q2$=flow through pipe branch BDE

According to the second principle of parallel pipes, the pressure drop in pipe branch BCE must equal the pressure drop in pipe branch BDE. This is due to the fact that both pipe branches have a common starting point (B) and common ending point (E). Therefore, the pressure drop in the branch pipe BCE and branch pipe BDE are each equal to ($PB - PE$), where PB and PE are the pressures at junctions B and E, respectively. Therefore, we can write

$\Delta PBCE = \Delta PBDE = PB - PE$

P represents pressure drop. and $\Delta PBCE$ is a function of the diameter and length of branch BCE and the flow rate $Q1$. Similarly, $\Delta PBDE$ is a function of the diameter and length of branch BDE and the flow rate $Q2$. In order to calculate the pressure drop in parallel pipes, we must first determine the flow split at junction B. From Equation 3.7, we know that the sum of the two flow rates $Q1$ and $Q2$ must equal the given inlet flow rate Q. If both pipe loops BCE and BDE are equal in length and pipe inside diameter, we can infer that the flow rate will be split equally between the two branches.

Thus, for identical pipe loops.

$Q1=Q2=Q/2$

rate of Q/2 flowing through one of the pipe loops.

To illustrate this further, suppose we are interested in determining the pressure at A for the given flow rate Q and a specified delivery pressure (PF) at the pipe terminus F. We start with the last pipe segment EF and calculate the pressure required at E for a flow rate of Q in order to deliver gas at F at a pressure PF. We could use the General Flow equation for this and substitute PE for upstream pressure, $P1$, and PF for downstream pressure $P2$. Having calculated PE, we can now consider one of the pipe loops, such as BCE, and calculate the upstream pressure PB required for a flow rate of Q/2 through BCE for a downstream pressure of PE. In the General Flow equation, the upstream pressure $P1=PB$ and the downstream pressure $P2=PE$. It must be noted that this is correct only for identical pipe loops. Otherwise, the flow rate $Q1$ and $Q2$ through the pipe branches BCE and BDE will be unequal. From the calculated value of PB, we can now determine the pressure required at A by applying the General Flow equation to pipe segment AB that has a gas flow rate of Q. The upstream pressure $P1$ will be calculated for a downstream pressure $P2=PB$. Consider now a situation in which the pipe loops are not identical. This means that the pipe branches BCE and BDE can have different lengths and different diameters. In this case, we must determine the flow split between these two branches by equating the pressure drops through each of the branches in accordance with Equation above. Since $Q1$ and $Q2$ are two unknowns, we will use the flow conservation principle and the common pressure drop principle to determine the values of $Q1$ and $Q2$. From the General Flow equation we can state the following:

The pressure drop due to friction in branch BCE can be calculated from

$$P_B^2 - P_E^2 = K_1 L_1 Q_1^2 / D_1^5$$

where

$K1$=a parameter that depends on gas properties, gas temperature, etc.

$L1$=length of pipe branch BCE

$D1$=inside diameter of pipe branch BCE

$Q1$=flow rate through pipe branch BCE

Other symbols are as defined earlier.

$K1$ is a parameter that depends on the gas properties, gas temperature, base pressure, and base temperature that will be the same for both pipe branches BCE and BDE in a parallel pipeline system. Hence, we regard this as a constant from branch to branch. Similarly, the pressure drop due to friction in branch BDE is calculated from

$$P_B^2 - P_E^2 = K_2 L_2 Q_2^2 / D_2^5$$

Where.

$K2$=a constant like $K1$

$L2$=length of pipe branch BDE

$D2$=inside diameter of pipe branch BDE

$Q2$=flow rate through pipe branch BDE

Other symbols are as defined earlier.

In above Equations, the constants $K1$ and $K2$ are equal, since they do not depend on the diameter or length of the branch pipes BCE and BDE. Combining both equations, we can state the following for common pressure drop through each branch:

$$L_1 Q_1^2 / D_1^5 = L_2 Q_2^2 / D_2^5$$

Simplifying further. we get the following relationship between the two flow rates $Q1$ and $Q2$

$$Q1 / Q2 = (L_2 / L_1)^{.5} (D_1 / D_2)^{.5}$$

Combining above equation with $Q1$=$Q2$=Q/2, we can solve for the flow rates $Q1$ and $Q2$. To illustrate this, consider the inlet flow Q=100 MMSCFD and the pipe branches as follows:

L_1=10 mi D_1=15.5 in. for branch BCE

L_2=15 mi D_2=13.5 in. for branch BDE

$Q_1 + Q_2 = 100$

$Q_1 / Q_2 = (15/10)^{0.5}(15.5/13.5)^{2.5} = 1.73$

Solving these two equations in Q_1 and Q_2, we get

$Q_1 = 63.37$ MMSCFD

$Q_2 = 36.63$ MMSCFD

Once we know the values of $Q1$ and $Q2$, we can easily calculate the common pressure drop in the branch pipes BCE and BDE. Another method of calculating pressure drops in parallel pipes is using the equivalent diameter. In this method, we replace the pipe loops BCE and BDE with a certain length of an equivalent diameter pipe that has the same pressure drop as one of the branch pipes. The equivalent diameter pipe can be calculated using the General Flow equation. The equivalent pipe with the same ΔP that will replace both branches will have a diameter De and a length equal to one of the branch pipes, say $L1$. Since the pressure drop in the equivalent diameter pipe, which flows the full volume Q, is the same as that in any of the branch pipes, from Equation 3.10, we can state the following

$(P_B^2 - P_E^2) = K_e L_e Q_e^2 / D_e^5$

where $Q = Q1 + Q2$ and Ke represents the constant for the equivalent diameter pipe of length Le flowing the full volume Q Equating the value of $(P_B^2 - P_E^2)$ to the corresponding values, considering each branch separately, we get

$K_1 L_1 Q_1^2 / D_1^5 = K_2 L_2 Q_2^2 / D_2^5 = K_e L_e Q_e^2 / D_e^5$

Also, setting $K1 = K2 = Ke$ and $Le = L1$

$L_1 Q_1^2 / D_1^5 = L_2 Q_2^2 / D_2^5 = L_e Q_e^2 / D_e^5$

we solve for the equivalent diameter De as

$D_e = D_1 [(1 + \text{const } 1 / \text{const } 1)^2]^{1/5}$ where

$\text{Const} = \sqrt{(D_1 / D_2)^5 (L_2 / L_1)}$

and the individual flow rates $Q1$ and $Q2$ are calculated from

$Q_1 = Q \text{ const } 1/(1+ \text{const}1)$

And

$Q_2 = Q/(1+ \text{const}1)$

To illustrate the equivalent diameter method, consider the inlet flow Q=100 MMSCFD and the pipe branches as follows:

$L1$=10 mi $D1$=15.5 in. for branch BCE

$L2$=15 mi $D2$=13.5 in. for branch BDE

Const 1 $=\sqrt{(15.5/13.5)^2(15/10)} = 1.73$

the equivalent diameter is

$D_e = 15.5\ [(1+1.73/1.73)^2]^{1/5} = 18.6$ in.

Thus, the NPS 16 and NPS 14 pipes in parallel can be replaced with an equivalent pipe having an inside diameter of 18.6 in we get the flow rates in the two branch pipes as follows:

$Q_1 = 100*1.73/1+1.73 = 63.37$ MMSCFD and $Q_2 = 36.63$ MMSCFD

Having calculated an equivalent diameter De, we can now calculate the common pressure drop in the parallel branches by considering the entire flow Q flowing through the equivalent diameter pipe.

Example:

A gas pipeline consists of two parallel pipes, as shown in diagram. It is designed to operate at a flow rate of 100 MMSCFD. The first pipe segment AB is 12 miles long and consists of NPS 16, 0.250 in. wall thickness pipe. The loop BCE is 24 mi long and consists of NPS 14, 0.250 in. wall thickness pipe. The loop BDE is 16 miles long and consists of NPS 12, 0.250 in. wall thickness pipe. The last segment EF is 20 miles long and consists of NPS 16, 0.250

in. wall thickness pipe. Assuming a gas gravity of 0.6, calculate the outlet pressure at F and the pressures at the beginning and the end of the pipe loops and the flow rates through them. The inlet pressure at A=1200 psig. The gas flowing temperature=80°F, base temperature=60°F, and base pressure = 14.73 psia. The compressibility factor Z=0.92. Use the General Flow equation with Colebrook friction factor f=0.015.

Solution

From Equation, the ratio of the flow rates through the two pipe loops is given by

$Q_1/ Q_2 = (16/ 24)^{0.5} (14- 2* .25/12.75 -2*.25)^{2.5} = 1.041$

And $Q1 + Q2 = 100$

Solving for $Q1$ and $Q2$, we get

$Q1$=51.0 MMSCFD and $Q2$=49.0 MMSCFD

Next, considering the first pipe segment AB, we will calculate the pressure at B based upon the inlet pressure of 1200 psig at A, using General Flow Equation , as follows

$100* 10^6 =77.54(1/\sqrt{0.015}) (520/14.7)[(1214.73^2-P_2^2) /(0.6*540*12*0.92]^{0.5} 15.25^2$

Solving for the pressure at B, we get

$P2$=1181.33 psia=1166.6 psig

This is the pressure at the beginning of the looped section at B. Next we calculate the outlet pressure at E of pipe branch BCE, considering a flow rate of 51 MMSCFD through the NPS 14 pipe, starting at a pressure of 1181.33 psia at B. Using the General Flow equation, we get

$51* 10^6 =77.54(1/\sqrt{0.015}) (520/14.7)[(1181.33^2-P_2^2) /(0.6*540*24*0.92]^{0.5} 13.5^2$

Solving for the pressure at E, we get

$P2$=1145.63 psia=1130.9 psig

Next, we use this pressure as the inlet pressure for the last pipe segment EF and calculate the outlet pressure at F using the General Flow equation, as follows:

$$100^* 10^6 = 77.54(1/\sqrt{0.015})(520/14.7)[(1145.63^2 - P_2^2)/(0.6^*540^*20^*0.92]^{0.5}\ 15.5^{2.5}$$

Solving for the outlet pressure at F, we get

$P2$=1085.85 psia=1071.12 psig

In summary, the calculated results are as follows:

Pressure at the beginning of pipe loops=1166.6 psig

Pressure at the end of pipe loops=1130.9 psig

Outlet pressure at the end of pipeline=1071.12 psig

Flow rate in NPS 14 loop=51 MMSCFD

Flow rate in NPS 12 loop=49 MMSCFD

We will now calculate the pressures using the equivalent diameter method

$$\text{Const } 1 = \sqrt{(13.5/12.25)^2(16/24)} = 1.041$$

the equivalent diameter is

$$D_e = 13.5\ [(1+1.041/1.041)^2]^{1/5} = 17.76 \text{ in}$$

Thus, we can replace the two branch pipes between B and E with a single piece of pipe 24 mi long. having an inside diameter of 17.67 in., flowing 100 MMSCFD. The pressure at B was calculated earlier as

PB=1181.33 psia

Using this pressure, we can calculate the downstream pressure at E for the equivalent pipe diameter as follows:

$100 * 10^6 = 77.54(1/\surd 0.015)\ (520/14.7)[(\ 1181.33.^2 - P_2^2)\ /(0.6*540*24*0.92]^{0.5}\ 17.67^{2.5}$

Solving for the outlet pressure at E, we get *P*2=1145.60 psia, which is almost the same as what we calculated before. The pressure at F will therefore be the same as what we calculated before Therefore, using the equivalent diameter method, the parallel pipes BCE and BDE can be replaced with a single pipe 24 mi long, having an inside diameter of 17.67 in.

Chapter 3

Compressor Station

(3.1) Horsepower Required:

The amount of energy input to the gas by the compressors is dependent upon the pressure of the gas and flow rate. The horsepower (*HP*), which represents the energy per unit time, also depends upon the gas pressure and the flow rate. As the flow rate increases, the pressure also increases and, hence, the horsepower needed will also increase. Since energy is defined as work done by a force, we can state the power required in terms of the gas flow rate and the discharge pressure of the compressor station. The *head* developed by the compressor is defined as the amount of energy supplied to the gas per unit mass of gas. Therefore, by multiplying the mass flow rate of gas by the compressor head, we can calculate the total energy supplied to the gas. Dividing this by compressor efficiency, we will get the horsepower required to compress the gas. The equation for horsepower can be expressed as follows:

$$\boxed{HP = \frac{M \times \Delta H}{\eta}}$$

eq..................3.1

Where,

HP = compressor horsepower

M = mass flow rate of gas, lb/min

ΔH = compressor head, ft-lb/lb

h = compressor efficiency, decimal value

Another more commonly used formula for compressor horsepower that takes into account the compressibility of gas is as follows:

$$\boxed{HP = 0.0857\left(\frac{\gamma}{\gamma-1}\right)QT_1\left(\frac{Z_1+Z_2}{2}\right)\left(\frac{1}{\eta_a}\right)\left[\left(\frac{P_2}{P_1}\right)^{\frac{\gamma-1}{\gamma}}-1\right]}$$

eq..................3.2

Where,

HP = compressor horsepower

g = ratio of specific heats of gas, dimensionless

Q = gas flow rate, MMSCFD

*T*1 = suction temperature of gas, °R

*P*1 = suction pressure of gas, psia

*P*2 = discharge pressure of gas, psia

*Z*1 = compressibility of gas at suction conditions, dimensionless

*Z*2 = compressibility of gas at discharge conditions, dimensionless

ha = compressor adiabatic (isentropic) efficiency, decimal value

Example

A gas transmission pipeline is 240 mi long, NPS 30, 0.500 in. wall thickness, with an origin compressor station at "A "and two intermediate compressor stations tentatively located at "B" (milepost 80) and C (milepost 160), as shown in Figure 4.7. There are no intermediate flow deliveries or injections, and the inlet flow rate of 900 MMSCFD at "A" equals the delivery flow rate at Douglas. The delivery pressure required at "D" is 600 psig and the MOP of the pipeline is 1400 psig throughout. Neglect the effects of elevation and assume constant gas flow temperature of 80°F and constant values of transmission factor F = 20 and compressibility factor Z = 0.85 throughout the pipeline. The gas gravity = 0.6, base pressure =14.7 psia, and base temperature = 60°F. Use a polytropic compression coefficient of 1.38 and a compression efficiency of 0.9.

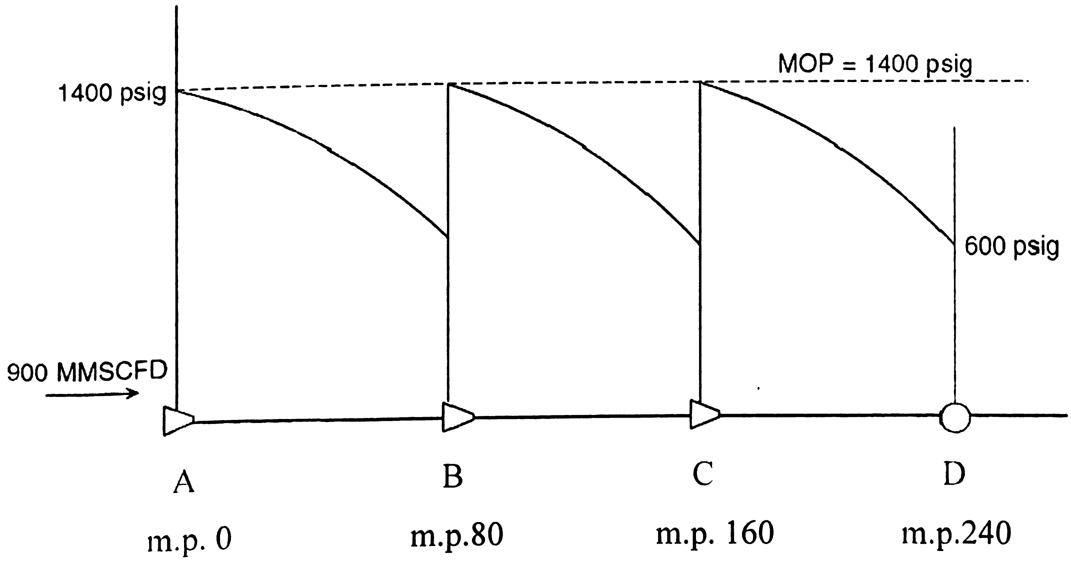


Figure 3.1: Gas pipeline with three compressor stations

Solution:

First. we will perform the backward calculations for segment 3, starting with an downstream pressure of 600 psig at "D" and an upstream pressure of 1400 psig at "C". With these constraints, we will calculate the pipe length, L, miles between "C" and "D".

Using General Flow Equation , neglecting elevations,

$$Q = 38.77F\left(\frac{T_b}{P_b}\right)\left(\frac{P_1^2 - P_2^2}{GT_f LZ}\right)^{0.5} D^{2.5}$$

$$900*10^6 = 38.77*20 \left(\frac{520}{14.7}\right) \left(\frac{1414.7^2 - 614.7^2}{0.6 * 540 * L * 0.85}\right)^{0.5} (29)^{2.5}$$

Solving for pipe length, we get

$$L = 112.31 \text{ mi}$$

Therefore, in order to discharge at 1400 psig at 'C" and deliver gas at 600 psig at "D", the "C" compressor station will be located at a distance of 112.31 mi upstream of "D"—or at milepost (240 – 112.31) = 127.69 measured from "A".

Next, keeping the location of the "B" compressor at milepost 80, we will calculate the downstream pressure at "C" for pipe segment 2 starting at 1400 psig at Williams. This calculated pressure will be the suction pressure of the "C" compressor station.

Using General Flow Equation , neglecting elevations,

$$900*10^6 = 38.77*20 \left(\frac{520}{14.7}\right) \left(\frac{1414.7^2 - P_2^2}{0.6 * 540 * 47.69 * 0.85}\right)^{0.5} (29)^{2.5}$$

where the pipeline segment length between "B" and "C" was calculated as

$$127.69 - 80 = 47.69 \text{ mi}$$

Solving for suction pressure at "C", we get

$$P_2 = 1145.42 \text{ psia} = 1130.72 \text{ psig}$$

Therefore, the compression ratio at "C" is $\dfrac{1414.7}{1145.42} = 1.24$

Next, for pipe segment 1 between "A" and "B", we will calculate the downstream pressure at "B", starting at 1400 psig at "A". This calculated pressure will be the suction pressure of the "B" compressor station.

Using General Flow Equation , neglecting elevations,

$$900*10^6 = 38.77*20 \left(\frac{520}{4.7}\right) \left(\frac{1414.7^2 - P_2^2}{0.6 * 540 * 80 * 0.85}\right)^{0.5} (29)^{2.5}$$

Solving for suction pressure at "B", we get

$$P2 = 919.20 \text{ psia} = 904.5 \text{ psig}$$

Therefore, the compression ratio at "B" = $\dfrac{1414.7}{919.20} = 1.54$

Therefore, from the foregoing calculations, the compressor station at "B" requires a compression ratio r = 1.54, whereas the compressor station at "C" requires a compression ratio r = 1.24. Obviously, this is not a hydraulically balanced compressor station system. One way would be to obtain the same compression ratios for all three compressor stations by simply relocating the "C" compressor station toward "D" such that its suction pressure will drop from 1131 psig to 905 psig while keeping the discharge at "C" at 1400 psig. This will then ensure that all three compressor stations will be operating at the following suction and discharge pressures and compression ratios:

Suction pressure Ps = 904.5 psig

Discharge pressure Pd = 1400 psig

Compression ratio $r = \dfrac{1400+14.7}{904.5+14.7} = 1.54$

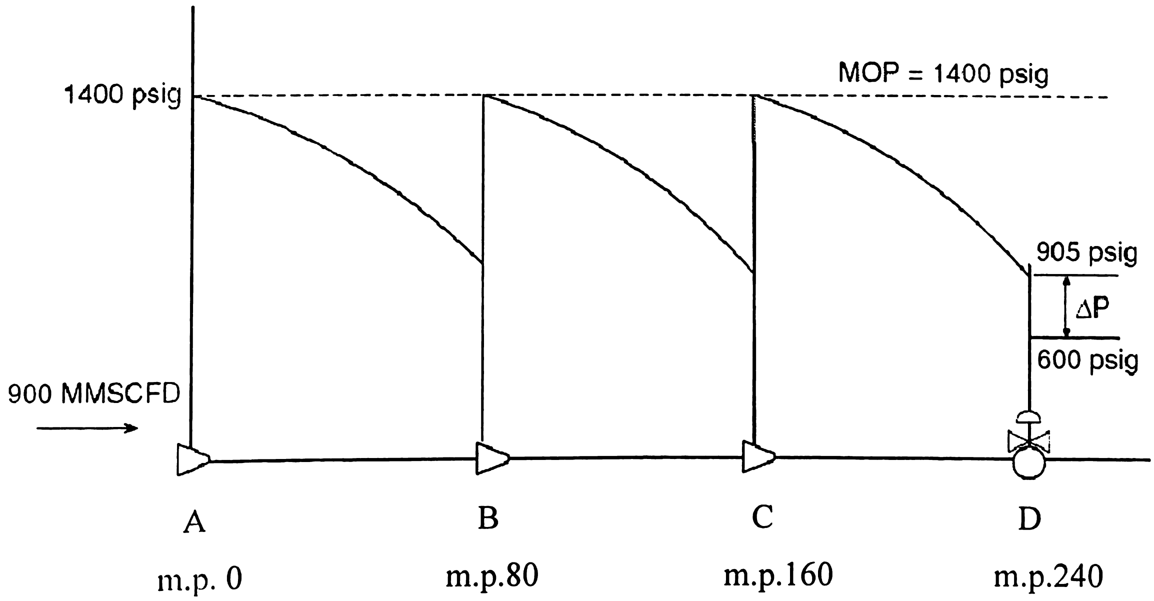


Figure 3.2: Pressure regulation at "D"

To illustrate this pressure regulation scenario, we will now determine the revised locatifon of the "C" compressor station for hydraulic balance. We will calculate the length of pipe segment 2 by assuming 1400 psig discharge pressure at "B" and a suction pressure of 904.5 psig at "C".

Using General Flow Equation , neglecting elevations,

$$900*10^6 = 38.77*20 \left(\frac{520}{14.7}\right) \left(\frac{1414.7^2 - 919.2^2}{0.6 * 540 * L * 0.85}\right)^{0.5} (29)^{2.5}$$

Solving for pipe length for segment 2, we get,

$L = 80$ mi

Therefore, the "C" compressor station should be located at a distance of 80 mi from "B" or at milepost 160. With the "C" compressor station located at milepost 160. and we conclude that the delivery pressure at "D" will also be 904.5 psig, since all three pipe segments are hydraulically the same. We see that the delivery pressure at "D" is approximately 305 psig more than the desired pressure.

By applying approximate cost per installed horsepower, we can compare these two cases. First. using Equation of horsepower, calculate the horsepower required at each compressor station. assuming polytropic compression and a compression ratio of 1.54 for a balanced compressor station:

Using eq. 3.2:

$$HP = 0.0857\left(\frac{\gamma}{\gamma-1}\right)QT_1\left(\frac{Z_1+Z_2}{2}\right)\left(\frac{1}{\eta_a}\right)\left[\left(\frac{P_2}{P_1}\right)^{\frac{\gamma-1}{\gamma}}-1\right]$$

$$HP = 0.0857 * 900*\left(\frac{1.38}{1.38-1}\right)* (80+460) * \left(\frac{1+0.85}{2}\right) * \left(\frac{1}{0.9}\right) * \left((1.54)^{0.38/1.38} -1\right)$$

HP = 19627

Therefore, the total horsepower required in the hydraulically balanced case is

Total $HP = 3 \times 19{,}627 = 58.881$

At a cost of $2000 per installed *HP*,

Total *HP* cost = $2000 × 58,881 = $117.76 million

In the hydraulically unbalanced case, the "A" and "B" compressor stations will operate at a compression ratio of 1.54 each, whereas the "C" compressor station will require a compression ratio of 1.24.

Using Equation of horsepower, the horsepower required at the "C" compressor station is:

$$HP = 0.0857 * 900*\left(\frac{1.38}{1.38-1}\right)* (80+460) * \left(\frac{1+0.85}{2}\right) * \left(\frac{1}{0.9}\right) * \left((1.24)^{0.38/1.38} -1\right)$$

HP = 9487

Therefore, the total horsepower required in the hydraulically unbalanced case is

Total $HP = (2 \times 19.627) + 9487 = 48{,}741$

At a cost of $2000 per installed *HP*,

Total *HP* cost = $2000 × 48,741 = $97.48 million

The hydraulically balanced case requires (58,881 − 48,741) *HP* more = 10140 HP and cost approximately ($117.76 − $97.48) million more = $20.28

Chapter 4

Pipeline Cost Estimation:

In a gas pipeline system the major components that contribute to the initial capital cost are the pipeline, compressor stations, mainline valve stations and metering facilities. Other costs include engineering and construction management, legal and regulatory costs, contingency, and allowance for funds used during construction (AFUDC).

The recurring annual costs will include operating and maintenance (O&M) costs, fuel, energy and utility costs, rental, permitting, and annual right of way costs. The O&M costs will include payroll and general and administrative (G&A) costs. In any pipeline system constructed to provide transportation of gas, there will be capital costs and annual operating costs. If we decide on a useful life of the pipeline (say, 30 or 40 years) we can annualize all costs and also determine the revenue stream necessary to amortize the total investment in the pipeline project. The revenue earned after expenses and taxes plus a percentage for profit divided by the volume transported will give the transportation tariff necessary. The calculation of capital cost, operating cost, and transportation tariff will be illustrated using an example. The equation relating the present value of a series of annual payments over a number of years at a specified interest rate is as follows:

$$\boxed{PV = \frac{R}{i}\left(1 - \frac{1}{(1+i)^n}\right)}$$

Where,

PV=present value, $

R=series of cash flows, $

i=interest rate, decimal value

n=number of periods, years

(4.1) Pipeline material cost:

The pipeline cost consists of those costs associated with the pipe material, coating, pipe fittings, and the actual installation or labor cost. Given the cost per ton of pipe material, the total pipe material cost can be calculated knowing the construction cost per unit length of pipe. we can also calculate the labor cost for installing the pipeline. The sum of these two costs is the pipeline capital cost. Using following equation the cost of pipe required for a given pipeline length is found from

$$PMC = \frac{10.68(D-T)TLC \times 5280}{2000}$$

Where,

PMC = pipe material cost, $

L = length of pipe, mi

D = pipe outside diameter, in.

T=pipe wall thickness, in.

C=pipe material cost, $/ton

Pipe Diameter, in.	Average Cost, S/in.-dia/mi
8	18,000
10	20,000
12	22,000
16	14,900
20	20,100
24	33,950
30	34,600
36	40,750

Typical pipeline installation cost

Table4.1

Description			Million $
1	Pipeline		160.00
2	Compressor stations		20.00
3	Mainline valve stations		1.20
4	Meter stations		1.20
5	Pressure regulator stations		0.10
6	SCADA and telecommunications	2 to 5%	5.48
7	Environmental and permitting	10 to 15%	21.90
8	Right of way acquisiton	6 to 10%	14.60
9	Engineering and construction management	15 to 20%	36.50
10	Contingency	10%	26.10
	Sub-Total		287.08
11	Working capita		5.00
12	AFUDC	5%	14.35
	Total		306.43

Cost Breakdown for a Typical Natural Gas Pipeline Project

Table 4.2

Example:

A gas pipeline is to be constructed to transport 150 MMSCFD of natural gas from Dixie to Florence, 120 mi away. Consider three pipe sizes—NPS 14, NPS 16, and NPS 18—all having 0.250 in. wall thickness. Determine the most economical pipe diameter, taking into account the pipe material cost, cost of compressor stations, and fuel costs. The selection of pipe size may be based on a 20-year project life and a present value (*PV*) of discounted cash flow at 8% per year. Use $800 per ton for pipe material and $2000 per installed HP for compressor station cost. Fuel gas can be estimated at $3 per MCF.

The following information from hydraulic analysis is available:

NPS 14 pipeline: Two compressor stations, 8196 HP total. Fuel consumption is 1.64 MMSCFD. NPS 16 pipeline: One compressor station, 3875 HP. Fuel consumption is 0.78 MMSCFD.

NPS 18 pipeline: One compressor station, 2060 HP. Fuel consumption is 0.41 MMSCFD.

Solution

First, calculate the capital cost of 120 mi of pipe for each case.

Using equation,

$$\boxed{PMC = \frac{10.68(D-T)TLC \times 5280}{2000}}$$

From Equation, the cost of NPS 14 pipe is

$$PMC' = \frac{10.68 \times (14 - 0\ 250) \times 0\ 250 \times 120 \times 800 \times 5280}{2000} = \$9.3 \text{ million}$$

Similarly, the cost of NPS 16 pipe is

$$PMC' = \frac{10.68 \times (16 - 0\ 250) \times 0\ 250 \times 120 \times 800 \times 5280}{2000} = \$10.66 \text{ million}$$

and the cost of NPS 18 pipe is

$$PMC' = \frac{10.68\times(18 - 0\ 250)\times 0\ 250\times120 \times 800 \times 5280}{2000} = \$12.01 \text{ million}$$

Next, calculate the installed cost of compressor stations for each pipe size.

For NPS 14 pipe, the compressor station cost is

$$8196 \times 2000 = \$16.39 \text{ million}$$

For NPS 16 pipe, the compressor station cost is

$$3875 \times 2000 = \$7.75 \text{ million}$$

For NPS 18 pipe, the compressor station cost is

$$2060 \times 2000 = \$4.12 \text{ million}$$

The operating fuel cost for each case will be calculated next, considering fuel gas at \$3 per MCF and 24-hour-a-day operation for 350 days a year. A shutdown for 15 days per year is allowed for maintenance and any operational upset conditions.

For NPS 14 pipe, the fuel cost is

$1.64 \times 10^3 \times 350 \times 3 = \$1.72$ million per year

For NPS 16 pipe, the fuel cost is

$0.78 \times 10^3 \times 350 \times 3 = \$0.82$ million per year

For NPS 18 pipe, the fuel cost is

$0.41\times 10^3 \times 350 \times 3 = \$0.43$million per year

The actual operating cost includes many other items besides the fuel cost. For simplicity, in this example we will only consider the fuel cost. The annual fuel cost for the project life of 20 years will be discounted at 8% in each case. This will thenm be added to the sum of the pipeline and compressor station capital cost to arrive at a present value (*PV*). The present value of a series of cash flows, each equal to *R* for a period of *n* years at an interest rate of *i*%, is given by Equation

$$\boxed{PV = \frac{R}{i}\left(1 - \frac{1}{(1+i)^n}\right)}$$

The PV of NPS 14 fuel cost is, from Equation ,

$$PV = \frac{1.72}{0\ 08}\left(1 - \frac{1}{(1+0.08)^{20}}\right) = 1.\ 72 \times 9.\ 8181 = \$16.89 \text{ million}$$

The PV of NPS 16 fuel cost is

$$PV = 0.82 \times 9.8181 = \$8.05 \text{ million}$$

The PV of NPS 18 fuel cost is

$$PV = 0.43 \times 9.8181 = \$4.22 \text{ million}$$

Therefore, adding up all costs, the PV for NPS 14 is

$$PV14 = 9.3 + 16.39 + 16.89 = \$42.58 \text{ million}$$

Adding up all costs, the PV for NPS 16 is

$$PV16 = 10.66 + 7.75 + 8.05 = \$26.46 \text{ million}$$

and adding up all costs, the PV for NPS 18 is

$$PV18 = 12.01 + 4.12 + 4.22 = \$20.35 \text{ million}$$

Therefore, we see that the lowest cost option is NPS 18 pipeline with a PV of \$20.35 million.

Chapter5

Case Study

A gas pipeline from Dover to Leeds, NPS 16 with 0.250 in. wall thickness, 140 miles long, transports natural gas (specific gravity=0.6) at a flow rate of 175 MMSCFD at an inlet temperature of 80°F. Assuming isothermal flow, calculate the inlet pressure required if the required delivery pressure at the pipeline terminus is 800 psig. The base pressure and base temperature are 14.7 psig and 60°F, respectively. absolute roughness of pipe is .0007

Use a polytropic compression coefficient of 1.38 and a compression efficiency of 0.9

Solution:

Inside diameter of pipe D= 16 – 2×0.250=15.5 in.

We will use Z=0.85 throughout,

Using Equation 2.10, the elevation adjustment factor is first calculated for each of the two segments.

$$\boxed{s = 0.0375G\left(\frac{H_2 - H_1}{T_f Z}\right)}$$

where

s=elevation adjustment parameter, dimensionless

H_1=upstream elevation, ft

H_2=downstream elevation, ft

e=base of natural logarithms (e=2.718...)

For the first segment, from milepost 0.0 to milepost 70.0, we get

$$\mathbf{S=0.0375*0.6\left[\frac{250-100}{544*0.86}\right] = 0.0075}$$

Similarly, for the second segment, from milepost 70.0 to milepost 140.0, we get

$$S=0.0375*0.6\left[\frac{450-250}{544*0.86}\right] = 0.0099$$

Therefore, the adjustment for elevation is, using Equation:

$$\boxed{j=\frac{e^{s}-1}{s}}$$

$$J = \frac{e^{0.0075}-1}{0.0075} = 1.0038$$

And,

$$J = \frac{e^{0.0099}-1}{0.0099} = 1.0045$$

For the entire length,

$$S=0.0375*0.6\left[\frac{450-100}{544*0.86}\right] = 0.0175$$

The equivalent length from Equation is then

$$\boxed{L_e = j_1L_1 + j_2L_2e^{s_1} + j_3L_3e^{s_2} + \cdots}$$

$L_e = 1.0038 \times 70 + 1.0045 \times 70 \times e^{0.0075} = 141.1103$mi.

Using General Flow equation with Colebrook friction factor:

$$\boxed{Q = 38.77F\left(\frac{T_b}{P_b}\right)\left(\frac{P_1^2 - e^{s}P_2^2}{GT_fL_eZ}\right)^{0.5} D^{2.5}}$$

$$Re = 0.0004778\left(\frac{P_b}{T_b}\right)\left(\frac{GQ}{\mu D}\right)$$

$$Re = \frac{0\ 0004778 * 175 * 10^6 \ *0.6* 14\ 7}{15.5* 8 * 10^{-6} * 520}$$

=11,437,412

$$\frac{1}{\sqrt{f}} = -2\ \mathrm{Log}_{10}\left(\frac{e}{3.7D} + \frac{2.51}{Re\sqrt{f}}\right) \quad \text{for } Re > 4000$$

f=0.0107

$$F = \frac{2}{\sqrt{f}}$$

F =19.342

P_1 = 1594 psia = 1579.3 psig

Using General Flow equation with Darcy friction factor:

$$Q = 38.77F\left(\frac{T_b}{P_b}\right)\left(\frac{P_1^2 - e^s P_2^2}{GT_f L_e Z}\right)^{0.5} D^{2.5}$$

Absolute roughness=0.0007 in

Relative roughness= absolute roughness/diameter

= .0007/15.5

= 4.516 * 10^-5

From the moody chart

We get f= 0.0105

P_1 = 1594 psia = 1579.3 psig

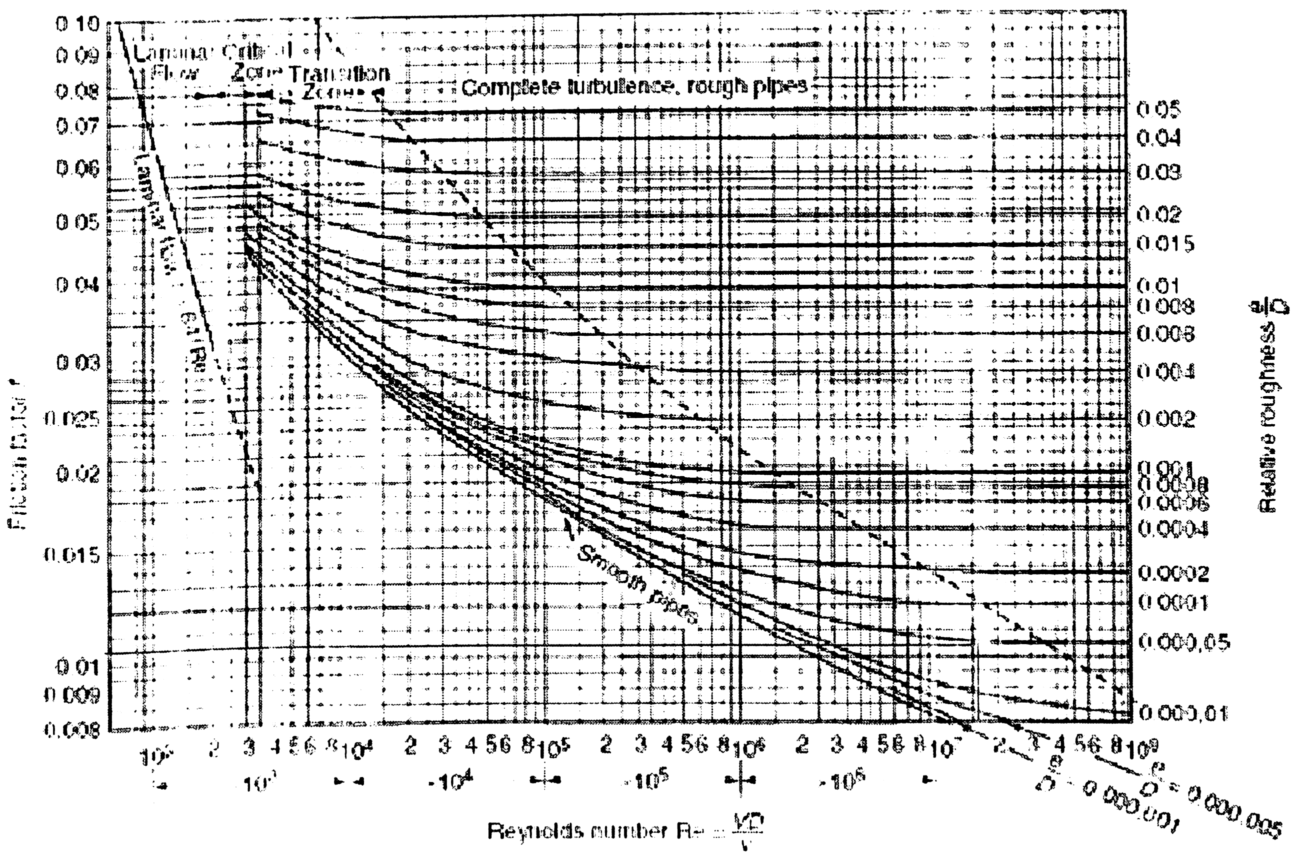


Figure 5.1

Using Weymouth equation

$$Q = 433.5E\left(\frac{T_b}{P_b}\right)\left(\frac{P_1^2 - e^s P_2^2}{GT_f L_e Z}\right)^{0.5} D^{2.667}$$

$$175*10^6 = 433.5*0.95\left[\frac{520}{14.7}\right]\left(\frac{P_1^2 - e^{0.0175}* 814.7^2}{0.6*540*141.11*0.85}\right)^{0.5}(15.5)^{2.667}$$

P_1 = 1784.61 psia = 1769.91 psig

Using Panhandle A equation:

$$Q = 435.87E\left(\frac{T_b}{P_b}\right)^{1.0788}\left(\frac{P_1^2 - e^s P_2^2}{G^{0.8539} T_f L_e Z}\right)^{0.5394} D^{2.6182}$$

And substituting the values

We have P_1=1475.803psia=1490.50 psig

Using Panhandle B equation:

$$Q = 737E\left(\frac{T_b}{P_b}\right)^{1.02}\left(\frac{P_1^2 - e^s P_2^2}{G^{0.961} T_f L_e Z}\right)^{0.51} D^{2.53}$$

And substituting the values

We have P1=1479.340psig=1494.040psia

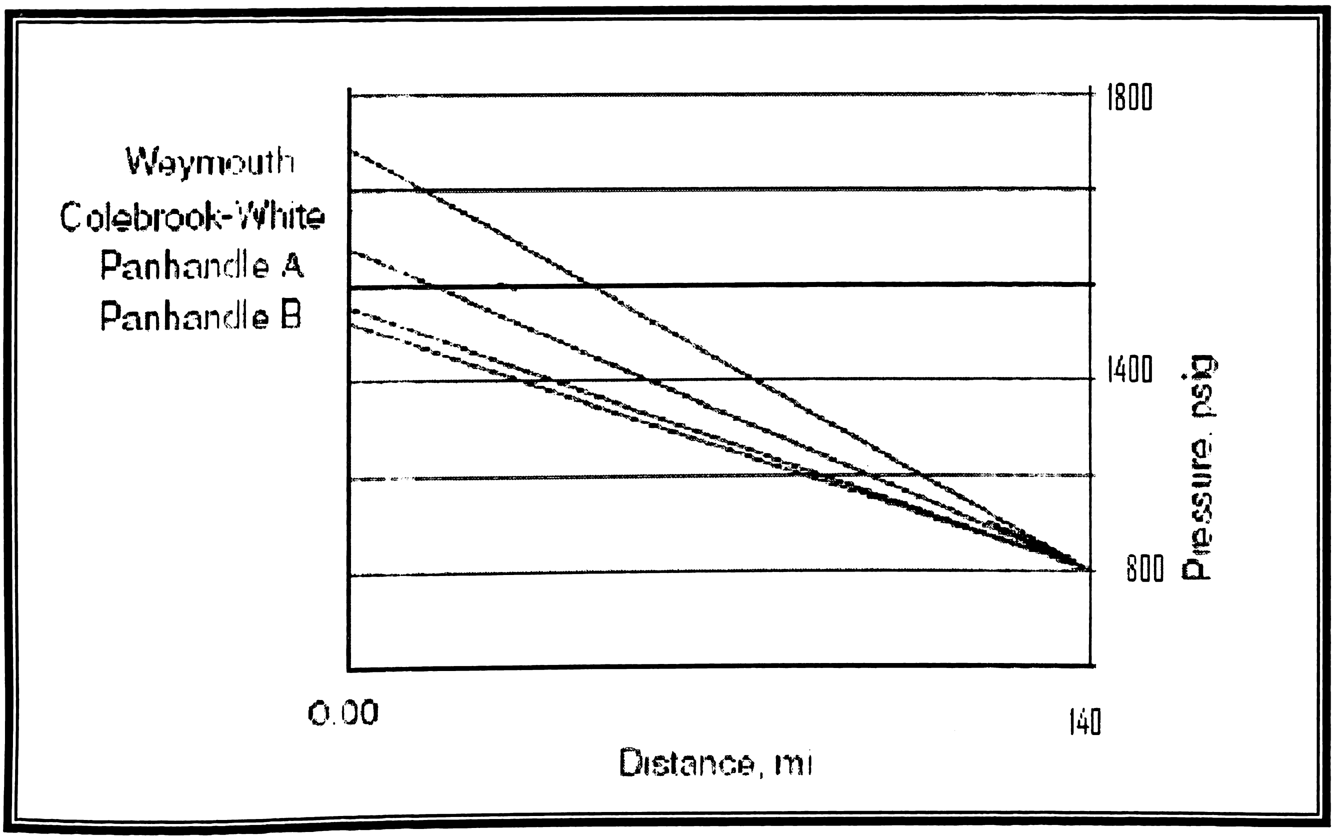


Figure 5.2

Since the pipe diameter is not very large the results given by Colebrook equation and General equation can be taken into consideration for the calculation of problem

MAOP Calculation

For X 52 grade pipe

MAOP=2st/d

= (2*52000*0.25)/15.5

= 1207.741 psi

Taking MAOP as 1200 psi to be conservative

Number of compressor station to be installed are n = (1579.3-800)/(1200-800)

= 1.94825

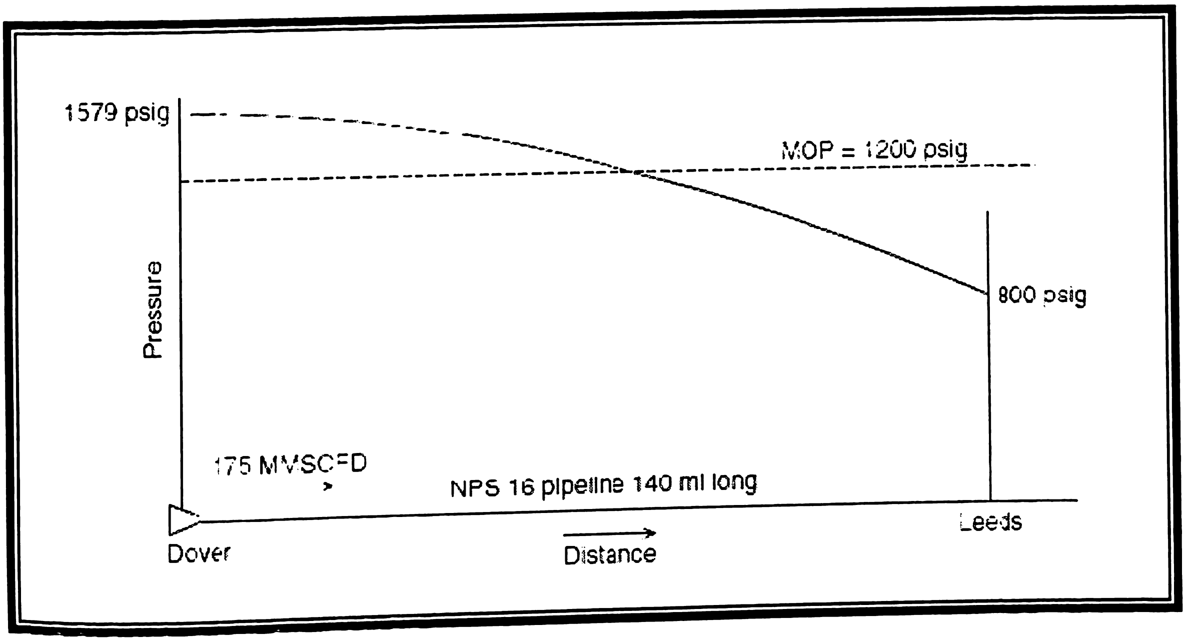
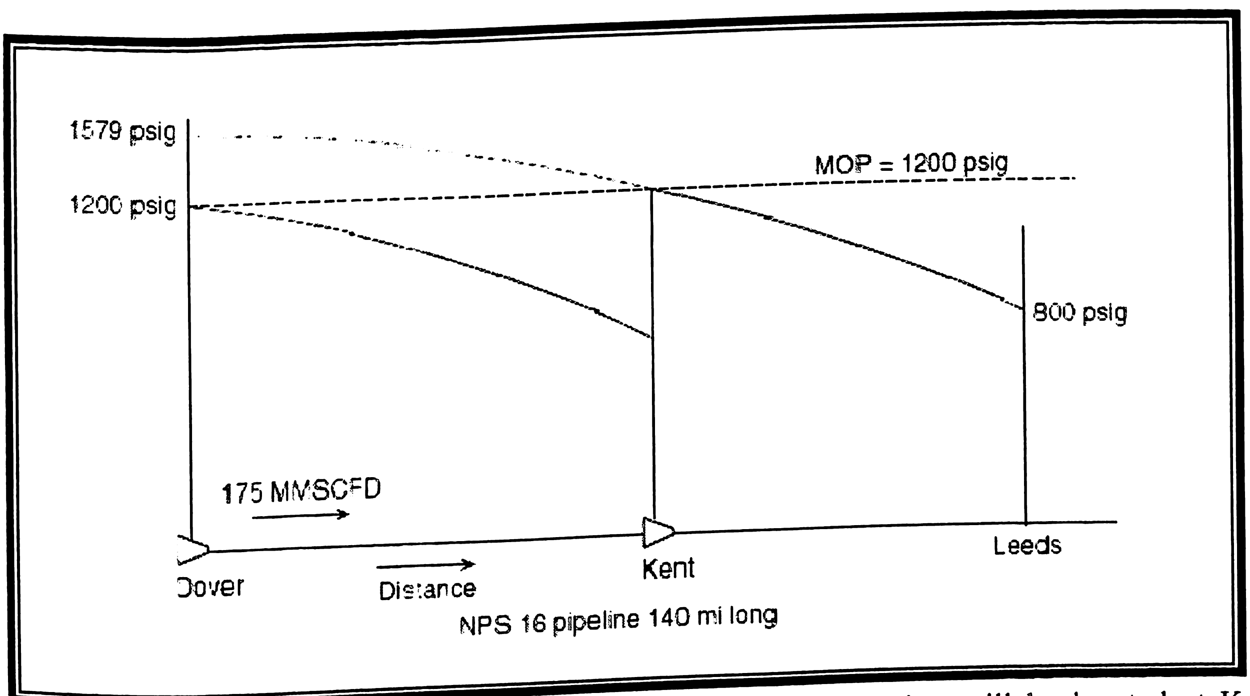


Figure 5.3

This indicates that along with a main compressor station an intermediate compressor station is also required.

We will need to reduce the discharge pressure at Dover to 1200 psig and install an additional compressor station at some point between Dover and Leeds



We will initially assume that the intermediate compressor station will be located at Kent, halfway between Dover and Leeds. For the pipe segment from Dover to Kent, we will calculate the suction pressure at the Kent compressor station as follows.

Using General Flow Equation

$$175*10^6 = 77.54*\left(\frac{520}{14.7}\right) \frac{(1214.7^2 - e^{0.0175}* P_2^2)^{0.5}}{(0.0107*0.6*540*70*0.85)^{0.5}} (15.5)^{2.5}$$

Solving for the pressure at Kent (suction pressure), P_2=733 psia=718 psig

At Kent, if we boost the gas pressure from 718 psig to 1200 psig (MOP), the compression ratio at Kent is 1.66

This is a reasonable compression ratio for a centrifugal compressor. Next, we will see if the 1200 psig pressure at Kent will give the desired 800 psig delivery pressure at Leeds.

Considering the 70 mi segment from Kent to Leeds, using the General Flow equation we get

$$175*10^6 = 77.54*\left(\frac{520}{14.7}\right) \frac{(1214.7^2 - e^{0.0175}* P_2^2)^{0.5}}{(0.0107*0.6*540*70*0.85)^{0.5}} (15.5)^{2.5}$$

resulting in a pressure at Leeds of $P2$=733 psia=718 psig

This is less than the 800 psig desired. Hence, we must move the location of the Kent compressor station slightly toward Leeds so that the 800 psig delivery pressure can be achieved. We will calculate the distance L required between Kent and Leeds. To achieve this, using General Flow Equation

$$175*10^6 = 77.54*\left(\frac{520}{14.7}\right) \frac{(1214.7^2 - e^{0.0175}* 814.7^2)^{0.5}}{(0.0107*0.6*540*L*0.85)^{0.5}} (15.5)^{2.5}$$

Solving for length L, we get

L=60.57 miles

Therefore, Kent must be located approximately 61 miles from Leeds. We must now recalculate the suction pressure at the Kent compressor station based on the pipe length of

79.43 140−60.57) miles between Dover and Kent. From this suction pressure, we must also check the compression ratio.

Using General Flow Equation 2.2 for the pipe segment between Dover and Kent, we get

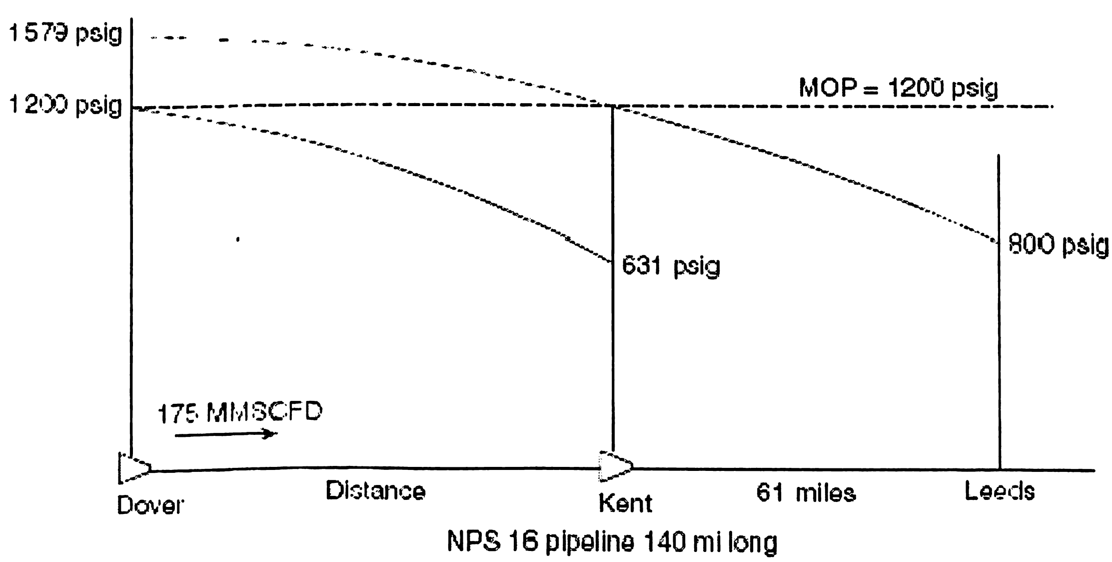
$$175*10^6 = 77.54*\left(\frac{520}{14.7}\right) \frac{(1214.7^2 - e^{0.0175} * P_2^2)^{0.5}}{(0.0107*0.6*540*79.43*0.85)^{0.5}} (15.5)^{2.5}$$

Solving for P_2, we get

P_2=645.49 psia=630.79 psig

Therefore, the suction pressure at Kent =630.79 psig. The compression ratio at Kent=1.88.

The compression ratio is slightly more than the 1.5 we would like to see. However, for now, we will go ahead with this compression ratio. Figure shows the revised configuration with the new location of the Kent compressor station.



Horse power calculations

$$\boxed{HP = 0.0857\left(\frac{\gamma}{\gamma-1}\right)QT_1\left(\frac{Z_1+Z_2}{2}\right)\left(\frac{1}{\eta_a}\right)\left[\left(\frac{P_2}{P_1}\right)^{\frac{\gamma-1}{\gamma}}-1\right]}$$

where

HP = compressor horsepower

g = ratio of specific heats of gas, dimensionless

Q = gas flow rate, MMSCFD

$T1$ = suction temperature of gas, °R

$P1$ = suction pressure of gas, psia

$P2$ = discharge pressure of gas, psia

$Z1$ = compressibility of gas at suction conditions, dimensionless

$Z2$ = compressibility of gas at discharge conditions, dimensionless

ha = compressor adiabatic (isentropic) efficiency, decimal value

$$HP = 0.0857 * 175*\left(\frac{1.38}{1.38-1}\right)* (80+460) * \left(\frac{1+0.85}{2}\right) * \left(\frac{1}{0.9}\right) * \left((1.88)^{0.38/1.38} -1\right)$$

$= 5738.80$

Therefore total horsepower HP=5738.80

At a cost of $2000 per installed *HP*,

Total *HP* cost = $2000 × 5739 = $ 11.47 million

DISCHARGE TEMPERATURE OF COMPRESSED GAS

$$\boxed{\left(\frac{T_2}{T_1}\right)=\left(\frac{Z_1}{Z_2}\right)\left(\frac{P_2}{P_1}\right)^{\frac{\gamma-1}{\gamma}}}$$

Where

T1=80F

Z1=1.00

Z2=0.85

P2/P1=1.88

Y=1.38

Calculating

T2=183F

Economic evaluation for selection of pipe from NPS 14, NPS 16, and NPS 18

Objective

To determine the most economical pipe diameter, taking into account the pipe material cost, cost of compressor stations, and fuel costs. The selection of pipe size may be based on a 20-year project life and a present value (*PV*) of discounted cash flow at 8% per year. Use $800 per ton for pipe material and $2000 per installed HP for compressor station cost. Fuel gas can be estimated at $3 per MCF.

The following information from is also available:

NPS 14 pipeline: Fuel consumption is 1.64MMSCFD.

NPS 16 pipeline: Fuel consumption is 0.78MMSCFD.

NPS 18 pipeline: Fuel consumption is 0.41MMSCFD.

For NPS 14

Internal diameter of pipe = 13.5

$$Re = \frac{0\ 0004778 * 175 * 10^{6} * 0.6 * 14\ 7}{13.5 * 8 * 10^{-6} * 520}$$

= 1313184341

Absolute roughness = 0.0007/13.5

$=5.185185*10^{-5}$

$$\boxed{\frac{1}{\sqrt{f}} = -2\,\mathrm{Log}_{10}\left(\frac{e}{3.7D} + \frac{2.51}{Re\sqrt{f}}\right) \quad \text{for } Re > 4000}$$

Using f = .010 and by trial and error

f= 0.01086

$$Q = 38.77F\left(\frac{T_b}{P_b}\right)\left(\frac{P_1^2 - e^s P_2^2}{GT_f L_e Z}\right)^{0.5} D^{2.5}$$

Substituting values we get

P_1=2118.77psia

=2104.07psig

For this inlet pressure and delivery pressure of 800psig

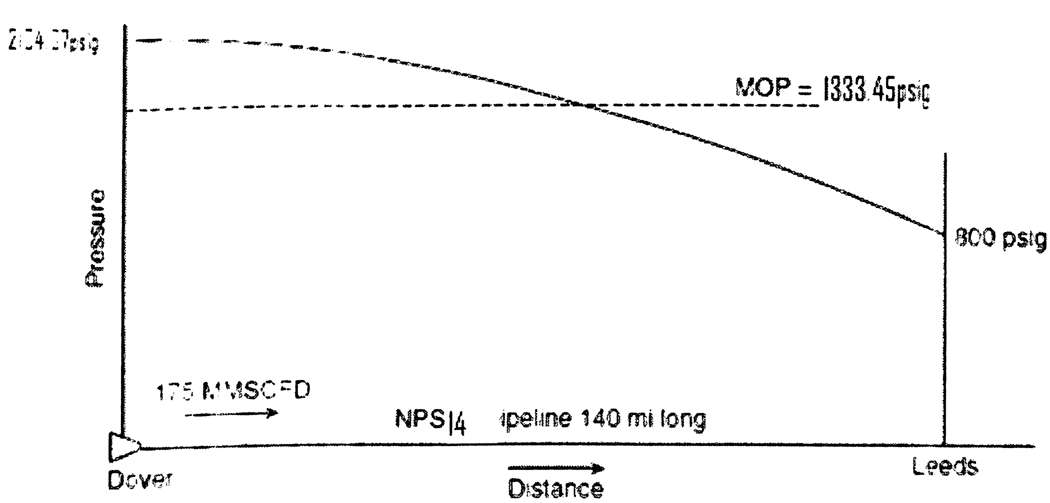
MAOP Calculation

For X 52 grade pipe

MAOP=2st/d

= 0.72*(2*52000*0.25)/13.5

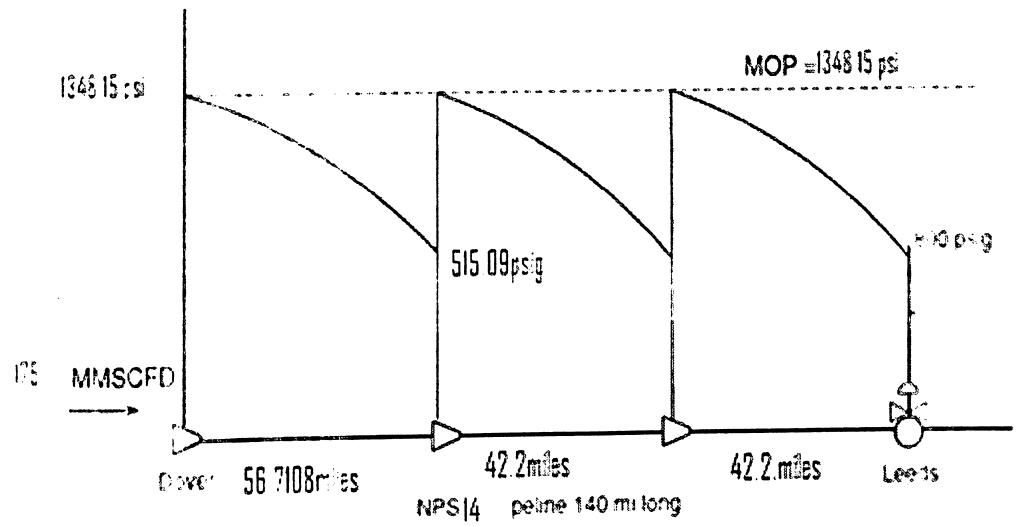
= 1348.15 psi



Number of compressor stations = (2104.07-800)/(1333.45-800)

= 2.44

This means that along with a main station compressor 2 intermediate compressors are required at a distance calculated from general equation as 42.24



$$HP = 0.0857\left(\frac{\gamma}{\gamma-1}\right)QT_1\left(\frac{Z_1+Z_2}{2}\right)\left(\frac{1}{\eta_a}\right)\left[\left(\frac{P_2}{P_1}\right)^{\frac{\gamma-1}{\gamma}}-1\right]$$

$$HP_1 = 0.0857 * 175 * \left(\frac{1.38}{1.38-1}\right) * (80+460) * \left(\frac{1+0.85}{2}\right) * \left(\frac{1}{0.9}\right) * \left[(2.54)^{0.38/1.38} - 1\right]$$

$=7172.21$

$$HP_2 = 0.0857 * 175 * \left(\frac{1.38}{1.38-1}\right) * (80+460) * \left(\frac{1+0.85}{2}\right) * \left(\frac{1}{0.9}\right) * \left[(1.65)^{0.38/1.38} - 1\right]$$

$=3645.33$

Total HP = $HP_1 + HP_2$

$=7172.21 + 3645.33$

$= 10817$

For NPS 18

Internal diameter of pipe = 17.5

$$Re = \frac{0\ 0004778 * 175 * 10^6 * 0.6 * 14\ 7}{17.5 * 8 * 10^{-6} * 520}$$

= 10130279.2

Absolute roughness = 0.0007/17.5

=4*10^{-5}

$$\frac{1}{\sqrt{f}} = -2\ \mathrm{Log}_{10}\left(\frac{e}{3.7D} + \frac{2.51}{Re\sqrt{f}}\right) \quad \text{for } Re > 4000$$

Using f = .010 and by trial and error

f= 0.0105

$$Q = 38.77F\left(\frac{T_b}{P_b}\right)\left(\frac{P_1^2 - e^s P_2^2}{GT_f L_e Z}\right)^{0.5} D^{2.5}$$

We get P1=1310.690psia

=1295.99psig

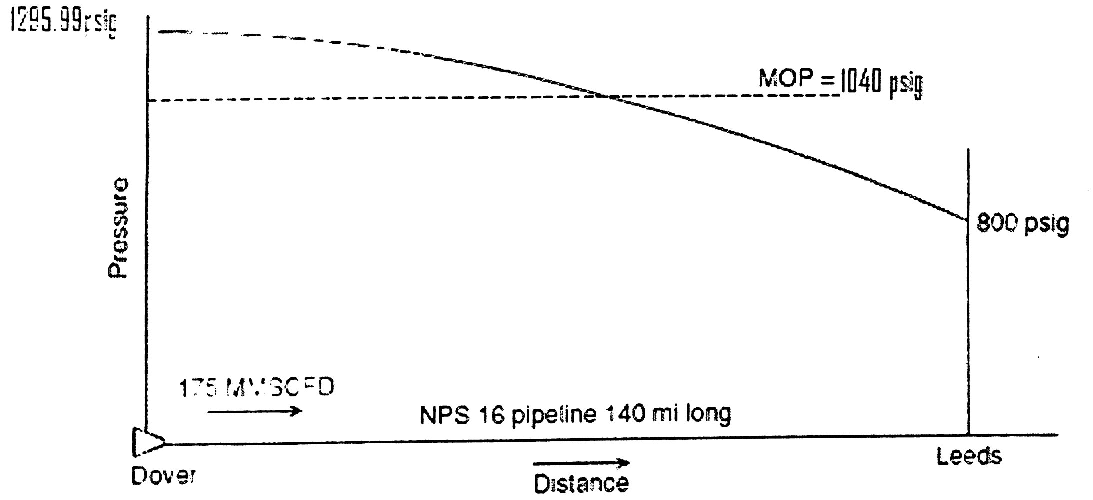
MAOP Calculation

For X 52 grade pipe

MAOP=0.72*2st/d

= 0.72*(2*52000*0.25)/17.5

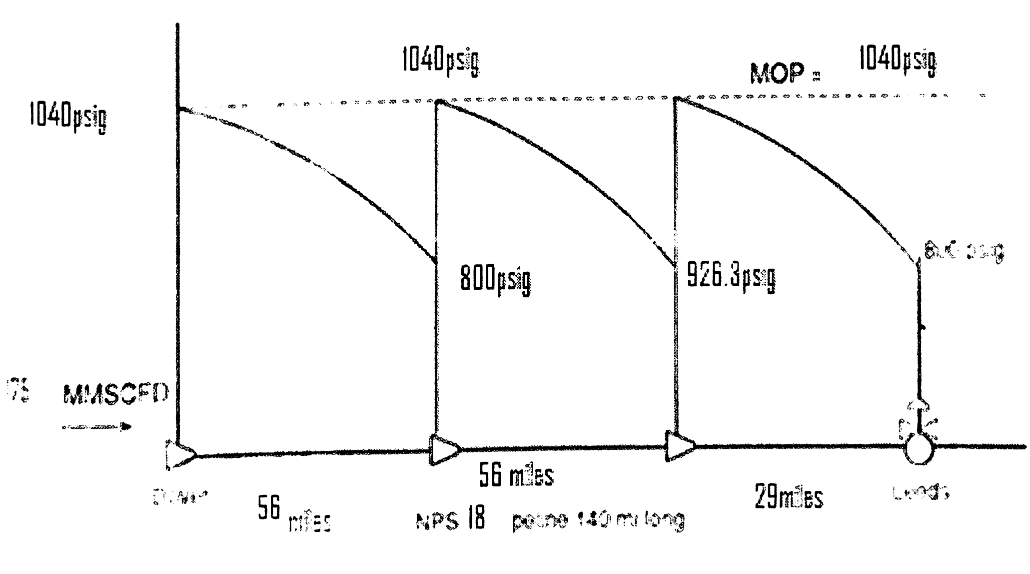
= 1040 psi



Number of compressor station = (1295.99-800)/(1027.5-800)

=2.2

Therefore only two intermediate compressor is required



$$HP = 0.0857\left(\frac{\gamma}{\gamma-1}\right)QT_1\left(\frac{Z_1+Z_2}{2}\right)\left(\frac{1}{\eta_a}\right)\left[\left(\frac{P_2}{P_1}\right)^{\frac{\gamma-1}{\gamma}}-1\right]$$

Compression ratio for first intermediate compressor= 1040/814.7 = 1.28

Compression ratio for second intermediate compressor= 1040/941 = 1.15

$$HP_1 = 0.0857 * 175 * \left(\frac{1.38}{1.38-1}\right) * (80+460) * \left(\frac{1+0.85}{2}\right) * \left(\frac{1}{0.9}\right) * \left[(1.28)^{0.38/1.38} - 1\right]$$

=2102

$$HP_2 = 0.0857 * 175 * \left(\frac{1.38}{1.38-1}\right) * (80+460) * \left(\frac{1+0.85}{2}\right) * \left(\frac{1}{0.9}\right) * \left[(1.15)^{0.38/1.38} - 1\right]$$

=1261

Total HP = $HP_1 + HP_2$

=2102 + 1261

= 3363

First, calculate the capital cost of 140 mi of pipe for each case. Using equation,

$$\boxed{PMC = \frac{10.68(D-T)TLC \times 5280}{2000}}$$

From Equation, the cost of NPS 14 pipe is

$$PMC = \frac{10.68 \times (14 - 0\ 250) \times 0\ 250 \times 141.1103 \times 800 \times 5280}{2000} = \$10.94 \text{ million}$$

Similarly, the cost of NPS 16 pipe is

$$PMC = \frac{10.68 \times (16 - 0\ 250) \times 0\ 250 \times 141.1103 \times 800 \times 5280}{2000} = \$12.53 \text{ million}$$

and the cost of NPS 18 pipe is

$$PMC = \frac{10.68\times(18-0\ 250)\times 0\ 250\times 141.1103\times 800\times 5280}{2000} = \$14.12 \text{ million}$$

Next, calculate the installed cost of compressor stations for each pipe size.

For NPS 14 pipe, the compressor station cost is

$$10817\times 2000 = \$21.63 \text{ million}$$

For NPS 16 pipe, the compressor station cost is

$$5738.80\times 2000 = \$12.7 \text{ million}$$

For NPS 18 pipe, the compressor station cost is

$$3363\times 2000 = \$6.726 \text{ million}$$

The operating fuel cost for each case will be calculated next, considering fuel gas at \$3 per MCF and 24-hour-a-day operation for 350 days a year. A shutdown for 15 days per year is allowed for maintenance and any operational upset conditions.

For NPS 14 pipe, the fuel cost is

$1.64\times 10^3\times 350\times 3 = \$1.72$ million per year

For NPS 16 pipe, the fuel cost is

$0.78\times 10^3\times 350\times 3 = \$0.82$ million per year

For NPS 18 pipe, the fuel cost is

$0.41\times 10^3\times 350\times 3 = \$0.43$million per year

The actual operating cost includes many other items besides the fuel cost. For simplicity, in this example we will only consider the fuel cost. The annual fuel cost for the project life of 20 years will be discounted at 8% in each case. This will them be added to the sum of the pipeline and compressor station capital cost to arrive at a present value (*PV*). The present value of a series of cash flows, each equal to *R* for a period of *n* years at an interest rate of *i*%, is given by Equation

$$\boxed{PV = \frac{R}{i}\left(1-\frac{1}{(1+i)^n}\right)}$$

i=interest rate, decimal value

n=number of periods, years

The PV of NPS 14 fuel cost is, from Equation ,

$$PV= \frac{1.72}{0\ 08}\left(1-\frac{1}{(1+0.08)^{20}}\right) = 1.\ 72 \times 9.\ 8181 = \$16.89 \text{ million}$$

The PV of NPS 16 fuel cost is

$$PV = 0.82 \times 9.8181 = \$8.05 \text{ million}$$

The PV of NPS 18 fuel cost is

$$PV = 0.43 \times 9.8181 = \$4.22 \text{ million}$$

Therefore, adding up all costs, the PV for NPS 14 is

$$PV14 = 10.94 + 21.63 + 16.89 = \$49.46 \text{ million}$$

Adding up all costs, the PV for NPS 16 is

$$PV16 = 12.53 + 12.7 + 8.05 = \$33.28 \text{ million}$$

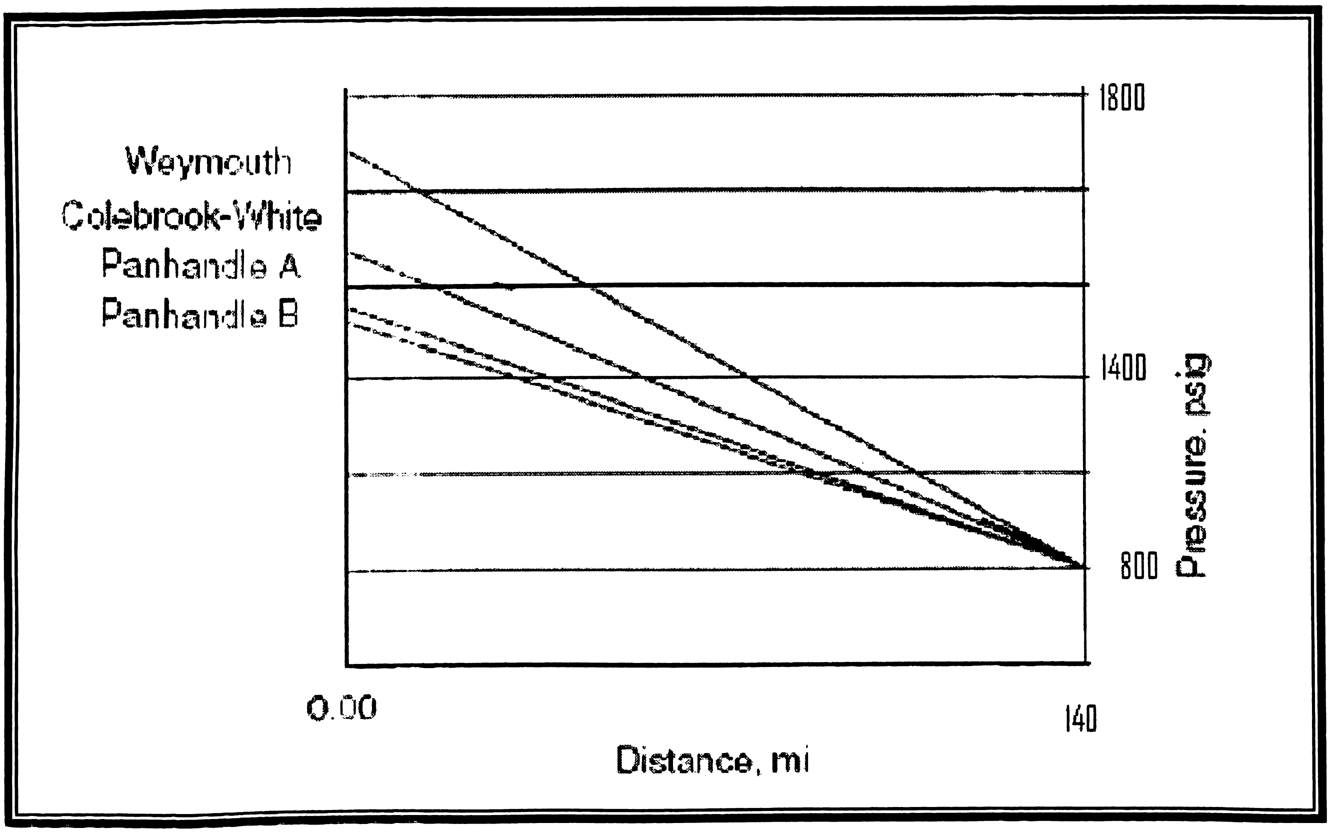
and adding up all costs, the PV for NPS 18 is

$$PV18 = 14.12 + 6.726 + 4.22 = \$25.066 \text{ million}$$

Therefore, we see that the lowest cost option is NPS 18 pipeline with a PV of \$25.066 million.

Results and Discussion

1). The first result that we conclude from the project is that the most conservative equation is the Weymoth equation as we can see from the graph below:



2). The second result that we conclude is that the 18 in. pipeline is better than the 16in. pipeline for the given condition on the basis of the economic evaluation.

Conclusion

In this project the steady state flow analysis has been successfully explained giving the desired results. In the case study almost all the aspects that are needed to do this kind of flow analysis have been considered and also the procedure for the selection of the best pipeline on the basis of the cost estimation has been done.

Thus at the end of the project we now understand that which is the most conservative pressure equation and which is the least one, we know to calculate the pressure drops for various scenarios. we know how to calculate the number of compressor stations and where to place them and in the end the most important thing that is the economic evaluation of the gas pipeline.

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